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September 3, 2014

Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Attention: Mr. Bruce McLennan, Chair

Re: Yukon Energy Corporation Application to Revise the Diesel Contingency Fund and Related Amendments to the Energy Reconciliation Adjustment - UCG Evidence

Dear Mr. McLennan:

As a registered intervenor in this proceeding, the Utilities Consumers' Group (UCG) hereby submits evidence related to rate stabilization mechanisms approved in other jurisdictions which UCG feels should be used to broaden the review of how a mechanism like the proposed Diesel Contingency Fund should be established and used in the Yukon.

In response to information request YUB-YEC-1-1(f) in this proceeding, Yukon Energy Corporation (YEC) states that experiences in other jurisdictions indicate that it would be appropriate for the Yukon ratepayers to be paying for their own contingencies related to low water conditions. However, YEC did not provide any detail on the experiences from other jurisdictions.

In response to information request YUB-YECL-5(d) in this proceeding, ATCO Electric Yukon / YECL state that the DCF used in the Yukon should be based in part on the method approved by the Northwest Territories Public Utilities Board for Northland Utilities. However, AEY / YECL did not provide details of the mechanism approved for Northland Utilities nor its evolution.

UCG submits the following summaries and attachments as evidence of how other jurisdictions have addressed rate stabilization mechanisms similar to the DCF.

Northwest Territories

A temporary rate rider is required by the Northwest Territories Power Corporation (NTPC) to collect increased costs due to two factors: 1) the price of fuel has increased in relation to the price used to determine electrical rates; and 2) the volume of hydro production has decreased in relation to the level used to determine electrical rates which results in increased diesel generation costs.

The additional cost due to these factors has been recorded in a fund called the "stabilization fund". The stabilization fund allows changes in the price diesel price and hydro volume to be managed without having to change customer's rates on a daily, weekly, or monthly basis. When the balance in the stabilization fund, either positive or negative, reaches a pre-determined "trigger point", a rate rider is applied for to the NWT Public Utilities Board. This rider recovers these additional costs or refunds any savings.

The rate stabilization funds used by the NTPC were originally established by the NWT Public Utilities Board in fiscal 1998 through Decision 1-97 (see attachment 1) and updated through subsequent decisions.

In its Decision 1-97 dated January 14, 1997, the NWT Public Utilities Board approved the establishment of water and fuel stabilization funds as detailed in a Settlement Agreement submitted by the NTPC.

In its original General Rates Application for the test period consisting of the fiscal years ending March 31, 1996 and March 31, 1997, NTPC proposed the implementation of Rate Stabilization Funds to mitigate the adverse impact on rates of unanticipated changes in fuel prices and deviations of hydro conditions from normal.

The proposal called for the creation of four funds - one for each of NTPC's hydro zones which would cover variations in both fuel price and water levels for each zone, one large fund to cover fuel price fluctuations for all the diesel communities, and a fourth fund for the Town of Norman Wells to cover primarily fluctuations in the cost of purchased power. In all of the zones, except the Taltson, a surcharge would be implemented to build up a cash balance in the fund. There would also be a "trigger" mechanism whereby NTPC would be at risk, or receive the benefit, for the first \$450,000 deviation from forecast conditions.

As part of the Settlement Agreement, the parties agreed to the establishment of stabilization funds but with different parameters for their operation. The significant parameters are as follows:

- a) there is no "trigger" mechanism;
- b) there would be no surcharge implemented to build up the funds;
- c) as the balance in each fund moved within its range there would be an imputed return to the customer if the fund were in a positive position or an imputed cost to the customer if the fund should be in a negative position;
- d) a separate water fund and a separate fuel fund would be set up in each of the hydro zones;
- e) the range for the Snare Yellowknife zone water fund would be plus or minus \$3 million and \$0 for Taltson with NTPC being able to implement a rider once the range was exceeded. However, while the fund would have a \$0 target balance based on long term average water levels, the rider would only remain in effect until the fund balance was brought back to its upper or lower range limit, not to a zero balance; and
- f) the fuel fund ranges would be \$1 million for the Snare Yellowknife zone, \$2 million for the diesel communities (as with the original proposal there would be only one fund for all diesel communities), \$100,000 for Norman Wells, and \$0 for Taltson. NTPC would be able to implement a rider once the fund's upper or lower range limit was reached but, unlike the water funds, a fuel rider would remain in effect until the zonal fund balance had returned to \$0.

As part of its General Rates Application for the test period consisting of the fiscal years ending March 31, 2007 and March 31, 2008, NTPC requested approval to file applications by February 15 and August 15 for "automatic" stabilization rider adjustments to be effective annually on April 1 and October 1. NTPC stated the following:

"In the Corporation's view, this will benefit customers by providing more regular and predictable price changes. It will also ensure fairness to future customers by improving the timing between when fuel cost increases are incurred and when those costs are collected from customers. Further, the proposed timing of the rider changes avoid the summer and winter holiday periods. Finally, in the Corporation's view this is consistent with the intent of the 1995/98 Phase I negotiated settlement that the rider adjustments be automatic, with Board review of the calculation of proposed riders as necessary." (GRA, p. C-8, l. 1-7)

In its Decision 26-2008 (see attachment 2) dated October 27, 2008, the NWT Public Utilities Board approved the NTPC's request to file applications by February 15 and August 15 of each year for stabilization rider adjustments to be effective April 1 and October 1 of each year.

In its Decision 11-2009 (see attachment 3) dated April 17, 2009, the NWT Public Utilities Board expressed its concern that increasing fuel prices can have on the potential need for significant "keep up" collections on top of the "catch up" components of the fund riders.

In its Decision 16-2010 (see attachment 4), the NWT Public Utilities Board directed NTPC to consolidate the Diesel, Inuvik, Norman Wells, Taltson, Snare-Yellowknife fuel and Snare-Yellowknife water funds into one NTPC Territory-wide Consolidated Fuel and Water Rate Stabilization Fund ("RSF"). The purpose of the RSF is to flow through to NTPC's customers, subject to a \$2.5 million threshold, variances in fuel prices and purchased power prices relative to the GRA forecast, and to flow through fuel mix variances in dual fuel communities.

In its Decision 1-2013 (see attachment 5) dated January 21, 2013, the NWT Public Utilities Board addressed issues related to NTPC's General Rates Application for the test period consisting of the fiscal years ending March 31, 2013 and March 31, 2014. In this Decision, the Board approved changes to the operational mechanics of the RSF:

Thermal and Norman Wells Zones:

- The actual cost of diesel (and where relevant purchase power cost per kWh) is compared to the forecast cost of fuel reflected in the base rate (i.e., the fuel cost as approved by the Board for the latest GRA test year).
- The difference is multiplied by the number of litres required to meet the load at the GRA approved efficiency factor (based on actual generation).
- The total fuel cost variance will be charged / credited to the RSF.
- For dual fuel communities, namely, Norman Wells, which uses purchased power and diesel generation and Inuvik, which uses diesel and gas generation, the cost impacts of changes in the mix of supply from the GRA forecast are flowed through to the RSF.

Snare Zone

- the fuel costs for diesel generation built into base rates (1.2 GWh/year) will not be charged via the fund, but fuel costs for diesel generation which are greater or less than this level are charged or credited to the fund.
- to maximize the use of the hydro resource, the RSF will address the recovery of both volume and price variances relative to the diesel cost forecast.

Taltson Zone

- the Board denies the inclusion of the fuel cost variances relative to the Taltson Zone in the RSF until there is agreement between NTPC and Northland to operate the RSF on a combined utility basis. This means, if the RSF is triggered at any time prior to implementation of the RSF on a combined utility basis, the recoveries and/or refunds of the balance in the RSF would not apply to the Taltson Zone customers.

The NWT Public Utilities Board noted in its Decision 1-2013 that it remained concerned by an RSF mechanism which allows pass through of all diesel costs as this may not provide the appropriate incentive for NTPC to maximize use of the hydro resource. The Board directed NTPC to address the feasibility of NTPC assuming forecast risk on diesel volume variances for the Snare Zone at the time of the next GRA.

According to its 2013 annual report, the funds in NTPC's RSF:

"...mitigate the impact on utility rates from changes in diesel and natural gas fuel prices as well as fluctuations in hydro generation caused by water levels. The impact of any increases or decreases in fuel prices or hydro generation over the PUB-approved amounts is deferred. The deferred amounts are accumulated until the consolidated balance in the funds reaches +/- \$2,500 and management's judgement deems the recovery (refund) appropriate, at which time rate-riders are applied, with PUB approval, to recover or refund the amounts necessary to bring the funds back to a balance of \$0. The remaining recovery period is indeterminate as the amounts deferred in the account depend on the market price of fuel and water levels on the Snare and Yellowknife river systems. Traditionally, once the PUB-specified trigger limits are reached, the recovery period of the balance of the rate stabilization fund receivable (payable) has been approximately 12 to 24 months." (page 49)

"In fiscal 2012 the GNWT made specified contributions of \$8,957 to pay down the balance of the stabilization funds instead of NTPC applying a rate rider to recover the outstanding balance in the funds directly from customers. At the end of fiscal 2012, \$3,856 of this balance was recorded in accounts receivable. In addition to offsetting the balances accumulated in the stabilization funds, these contributions were reported as rider revenue with an offsetting and equal charge to fuel expense in fiscal 2012. There were no similar contributions from the GNWT in fiscal 2013." (page 50)

"In fiscal 2013, NTPC signed a contribution agreement with the GNWT to provide a direct operating subsidy (cash contribution) to retire the balance in NTPC's Consolidated Fuel Stabilization Fund at March 31, 2012 to mitigate the impact of the revenue requirement changes on customers and to ensure a transition from current rates to final approved rates, over a 3 year period from fiscal 2013 to fiscal 2015. Under the agreement the GNWT provided \$15,600 to NTPC in fiscal 2013. \$4,000 paid down the receivable set up by NTPC as at March 31, 2012 to retire the Consolidated Fuel Stabilization Fund. The remaining \$11,600 was recorded as revenues. All of the funding for fiscal 2013 was received in fiscal 2013." (page 60)

Manitoba

The review of Manitoba Hydro's 2008/2009 General Rate Application resulted in a couple of Orders by the Manitoba Public Utilities Board (MPUB) related to rate stabilization. As noted by the MPUB in Order 116/08 (see attachment 6), in regards to proposals including those of the Manitoba Industrial Power Users Group (MIPUG) regarding alternative forms of reserves (Rate Stabilization Reserve or "RSR") for Manitoba Hydro:

"However, if the Board were to adopt such an approach, a process would need to be developed to determine an appropriate level of the RSR. What would represent an adequate RSR? Previously, the Board has requested that MH file a quantified analysis of its major risks and analysis that would put numbers to the major risks that have been identified. Not only would the risks associated with a five-year drought be quantified (MH has suggested that such a drought could result in losses of over \$3 billion), but also the risks associated with the failure of major infrastructure, interest rate increases, further currency changes and, for any reason, the loss, even if temporary and for whatever reason, of the export market. In the absence of much more rigorous analysis, the Board is uncertain whether such an analysis would arrive at a RSR lower or higher than the current level of retained earnings required under a 75: 25 debt to equity target. The Board is concerned that there may be a case for establishing a higher reserve requirement, one that would further push rates. On balance, the Board is of the view that a regulated RSR, i.e. the adoption of MIPUG's specific reserve proposal, is currently premature, at least ahead of MH identifying and properly quantifying its risks, as has been requested in past orders. Such quantification is vitally important given the increased risks that will accompany a debt level that may reach \$20 billion by 2022." (Page 131)

MPUB Order 7/03 (see attachment 7) indicates on page 89:

"The Board believes that Hydro should develop a policy to identify a reserve provision amount and, in particular, to set the circumstances under which it can be drawn down or increased, keeping in mind the statutory limitations in the Manitoba Hydro Act."

Manitoba Hydro's response to this directive was filed in its 2004 General Rates Application in the form of a general Corporate Risk Management plan, with no discussion about reserve provisions, or circumstances for increasing or drawing down such a provision. On page 34 of its Order 101/04 (see attachment 8), the MPUB directed Manitoba Hydro to conduct a "study on the implications of internally restricting retained earnings as a form of self-insurance reserve and rate stabilization fund, to restrict any future dividend payment until the 75:25 debt:equity ratio has been achieved and/or exceeded". Manitoba Hydro's response notes: "Manitoba Hydro believes the establishment of an internally restricted retained earnings account would serve no particular purpose".

Manitoba Hydro further noted in response to Coalition/MH-I-106(a) in its 2008/2009 General rates Application (see attachment 9) in this proceeding when asked about the pros and cons of a rate stabilization fund "There are no pros of establishing and maintaining a separate rate stabilization fund / drought protection fund for domestic customers".

Newfoundland

The Rate Stabilization Plan (RSP) in Newfoundland is a rate smoothing mechanism which was introduced in 1986 to limit volatility of customer rate impacts related to the cost of fuel used at the Holyrood Thermal Electric Generating Station built by Newfoundland and Labrador Hydro Corporation that is located near the community of Holyrood. The RSP also takes into account the effect on oil use due to the amount of water available in N&L Hydro's system for hydroelectric generation.

Through the use of the annual RSP, electricity rates for most customers are adjusted each July to reflect an updated cost of electricity generation after the regulator's review of a related application. Newfoundland Power and Industrial Customers rates are adjusted for variations between actual results and test year cost of service estimates relating to fuel. The purpose of the RSP is to protect electricity consumers from the volatility of oil prices where the cost of oil is a direct pass through to consumers and neither utility receives any profits or benefits financially from changes in oil prices.

Since its inception in 1986, the RSP rules have prescribed the use of future electricity consumption to refund to customers, or collect from customers, balances which accumulated in the RSP. For the period from 1986 until 2002, the payment / recovery period for RSP balances was a rolling 3-year period. For example, at June 30, 1988 there was a balance owing to retail customers of \$4.6 million as a result of fuel cost savings.

Throughout the 1989-2013 period, there were changes in the 1988 customer base such that some customers would have received benefit in 1989 and future years, who were not customers in 1988, and some customers would not receive benefit, though they were customers in 1988. On this basis, the original design of the RSP rules gave primary focus to customer class to collect or refund RSP balances, rather than to individual customers who were on the electrical grid in 1988 and were due refunds based on reduced fuel costs at Holyrood. Commencing in 2002, RSP rules were modified such that there was a two year amortization period for the RSP Balance, excluding hydrology, and in 2004, the amortization period was set to one year.

As a result of Newfoundland Hydro's General Rates Application in 2001/2002, in Order P.U. 7(2002-2003) (see attachment 10), the Board of Commissioners of Public Utilities ordered that, because of the

magnitude of anticipated rate increases, the August 31, 2002 balance in the RSP be “fixed”, and that its recovery be spread over a five year period commencing in 2003. In Order P.U. 40(2003) (see attachment 11), the Board further ordered that the RSP balance at December 31, 2003 also be consolidated with the August 2002 Historical RSP Balance for rate setting purposes. In total, at December 31, 2003, the RSP balance was \$156 million to be recovered from customers over the period 2004 to 2008.

In its September 2013 RSP Surplus Refund Plan Evidence, Newfoundland and Labrador Hydro proposed that the RSP Surplus be refunded to Newfoundland Power customers on their April 2014 electricity bills and be based on their total electricity consumption on bills issued during the period January 2013 to December 2013.

In its Order No. P.U. 9(2014) (see attachment 12), the Board of Commissioners of Public Utilities directed that the Newfoundland Power Rate Stabilization Plan Surplus shall be refunded to all ratepayers, with the exception of the Island Industrial customers, in the form of direct payment or rebate and in a manner to be approved by the Board. This order also provides details on the issues debated regarding the mechanics of the RSP.

Nova Scotia

Nova Scotia Power provides 95% of the generation, transmission and distribution of electrical power to 500,000 customers in the province.

In its Decision 2012 NSUARB 227 dated December 21, 2012 (see attachment 13), the Nova Scotia Utility and Review Board approved a Rate Stabilization Plan for Nova Scotia Power which included the deferral of any portion of the Board-approved revenue requirement not recovered by an average 3% annual rate increases.

A year prior to submitting the proposed Rate Stabilization Plan to the regulator for approval, Nova Scotia Power met with customer representatives to discuss the proposal. A May 5, 2011 new release (see attachment 14) indicates that Nova Scotia Power initiated a public discussion with customer representatives months in advance of applying for approval of the proposed multi-year approach to smooth increases in electricity rates.

This Decision also reiterated the pre-requisites identified in the Board's Rate Decision dated February 5, 2007 prior to the implementation of a fuel adjustment mechanism which included:

- an adequate and appropriate fuel procurement policy at Nova Scotia Power in which the Board has confidence;
- timely disclosure of complete and adequate information by Nova Scotia Power so as to ensure confidence that the procurement policy is being appropriately administered;
- disclosure and transparency with respect to the administration of the fuel adjustment mechanism; and
- a meaningful audit process under the administration of the Board.

Since the Nova Scotia Utility and Review Board approved a two-year Rate Stabilization Plan in 2012, Nova Scotia Power has implemented internal productivity initiatives to significantly reduce operating costs.

On April 1, 2014, Nova Scotia Power announced that it did not plan to file a general rate application in 2014 for higher electricity rates in 2015 and proposed no fuel rate increase for 2015. As indicated in a news release dated April 1, 2014 (see attachment 15), since January 2013, Nova Scotia Power has incurred approximately \$95 million more in fuel costs than those estimated and included in rates

pursuant to the Fuel Adjustment Mechanism. Additional fuel costs have been primarily driven by constraints in the supply of natural gas in Nova Scotia.

Electricity rate adjustments in Nova Scotia occur through either a general rate application or the Fuel Adjustment Mechanism process. The Fuel Adjustment Mechanism ensures that customers pay only the actual, prudently incurred costs of fuel used to make electricity. Applications under either mechanism are adjudicated by the Utility and Review Board through a public process.

Yours truly,

Roger Rondeau
Utilities Consumers' Group

TAB 1

**THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES**

DECISION 1-97

JANUARY 14, 1997

IN THE MATTER OF the Public Utilities Act being Chapter P-20 of the Revised Statutes of the Northwest Territories 1988, as amended.

AND IN THE MATTER OF an application by the Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided by the Northwest Territories Power Corporation to its customers within the Northwest Territories.

PUBLIC UTILITIES BOARD

BOARD MEMBERS

John E. Hill	Chairperson
Raymond Mercer	Vice-Chairperson
Peter Allen	Member
Gene Nikiforuk	Member

BOARD STAFF

Jamie Cameron	Board Secretary/Analyst
Craig Bell	Board Counsel
Rob Marshall	Board Consultant

APPEARANCES

D.R. Wright, Esq.	Counsel for Northwest Territories Power Corporation
L.J. Burgess, Esq.	Counsel for the City of Yellowknife and the Town of Inuvik
Loyola Keough, Esq.	Counsel for Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited

WITNESSES

For Northwest Territories Power Corporation

L. Courneya	President
R. Senko	Director, Rates and Regulatory Affairs
R. Blennerhassett	Vice-President, Operations
C. Jackson	Vice-President, Finance

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LIST OF SCHEDULES

A	-	Rate Base
B	-	Revenue Requirement
C	-	Capital Structure & Return on Rate Base
D	-	Working Capital Requirement
E	-	Amortization

ABBREVIATIONS

the Act	the Public Utilities Act being Chapter P-20 of the Revised Statutes of the Northwest Territories, 1988, as amended.
AFUDC	Allowance for Funds Used During Construction
the Board	the Public Utilities Board
CWIP	Construction Work In Process
DPC	Dogrib Power Corporation
Ex.	Exhibit
GRA or Application	General Rate Application
NWTPC or the Corporation	Northwest Territories Power Corporation
O&M	Operation and Maintenance
Test Year(s)	the Corporation's fiscal years ending March 31, 1996, 1997 and 1998, or any one of them
Tr.	Transcript - For example Transcript, page 50, line 4 is abbreviated to Tr., p. 50, l. 4.

1. BACKGROUND & APPLICATION

By letter dated December 20, 1995, the Northwest Territories Power Corporation ("**NWTPC, the Corporation**") submitted to the Public Utilities Board ("**the Board**"), a General Rate Application ("**GRA, Application**") for the test period consisting of the Corporation's fiscal years ending March 31, 1996 and March 31, 1997 ("**Test Years**").

In its Application (Ex.2), NWTPC requested that the Board:

1. determine a rate base for NWTPC's property that is used or required to be used in providing energy and related services to the public within the Northwest Territories, including the appropriate allowance for working capital, and fixing a fair return for the Test Years;
2. determine the revenue requirements for the Test Years;
3. fix and approve just and reasonable rates;
4. approve a deferral account for compensation that may be payable in accordance with Part C of Northwest Territories Water Board Licence N1L4-0154 respecting the Taltson River Basin;
5. approve a Rate Stabilization Fund to mitigate the adverse impact on rates of unanticipated changes in fuel prices and deviation in hydro conditions from average water levels;
6. approve the capitalization of the Power Acquisition Agreement dated March 8, 1993 between the Dogrib Power Corporation ("**DPC**") and NWTPC in respect of the Snare Cascades Hydro Project.

NWTPC, by letter dated July 16, 1996, amended its Application to incorporate a 1997/98 Test Year and also proposed that it enter into negotiations with the intervenors with a view to reaching a negotiated settlement regarding any or

all elements of the Application.

The Board responded to NWTPC on July 23, 1996 and advised that the Board was prepared to permit a negotiated settlement conference. The response required the Corporation to publish notice of the Negotiated Settlement Conference, and to provide the Board with a draft list of issues.

By letter dated September 20, 1996, NWTPC informed the Board that notice of the negotiated settlement meeting had been published in six territorial newspapers. NWTPC advised that there had been no response to the advertisements, and assumed that the parties who had registered as intervenors would participate in the negotiated settlement meeting. NWTPC advised that the days of October 28, 1996 through to November 1, 1996 had been scheduled for the settlement meeting and that Yellowknife had been selected as the location.

The Board, in a letter dated September 24, 1996, acknowledged that the conditions stipulated in its letter of July 23, 1996 had been met, and appointed Mr. John Donihee as facilitator for the negotiated settlement meeting.

In a letter dated November 13, 1996, NWTPC advised the Board that a negotiated settlement had been reached with the interested parties and filed a copy of the negotiated settlement, letters of endorsement from all interested parties and revised GRA schedules.

Subsequent to the Board receiving the Settlement Agreement from NWTPC, Board Counsel wrote to NWTPC on November 22, 1996 (Ex.9) requesting further detail and clarification of a number of items dealt with in the Settlement

Agreement. NWTPC replied to the Board on November 28, 1996 (Ex.12) supplying the requested information and explanations.

2. PUBLIC HEARING

Pursuant to the provisions of Section 22 of the Act, the Board, during the period January 2, 1996 to October 28, 1996, directed that notice of the public hearing of the GRA be published in newspapers "circulated in the Territories and in the locality affected by the hearing...". The notice included details of the GRA and the time and place of the public hearing of the GRA and invited interested persons to file a request with the Board for intervenor status (Ex.1).

Prior to the hearing, those persons who had requested intervenor status were provided the opportunity to make written information requests of NWTPC. The requests elicited written responses which were made available to all parties prior to the hearing. Written information requests by the Board, together with responses, were made available to all parties prior to the hearing. During the course of the hearing, members of the public who had not requested intervenor status were invited to participate in the proceedings.

The hearing was held in the Town of Hay River on December 3, 1996. At the commencement of the hearing, NWTPC explained the elements of the Settlement Agreement to the Board and requested that the Board review the settlement as a "package" that was not severable. Specifically, NWTPC requested that the Board accept and approve the Settlement Agreement in whole, or reject the settlement and send it back to the parties for further negotiation.

In this Decision, the Board will present its findings with respect to NWTPC's rate base, fair return on rate base and total revenue requirement for the provision of energy and related services for the 1995/96, 1996/97 and 1997/98 Test Years.

3. RATE BASE

The determination of a rate base, for the purpose of fixing just and reasonable rates, is governed by the provisions of Section 49 of the Act, which states:

"49 (1) In fixing just and reasonable rates, the Board shall determine a rate base for the property of a public utility used or required to be used to provide service to the public within the Territories.

- (2) In determining a rate base, the Board shall consider
 - (a) the cost of the property referred to in subsection (1) at the time that property was first devoted to public use, and to the prudent acquisition cost to the public utility, less depreciation, amortization or depletion; and
 - (b) the necessary working capital of the public utility."

NWTPC's computation of rate base, accumulated amortization and necessary working capital was set out in schedules 2.1 to 2.7 under Tab 2 of its Application.

The Board notes that the intervenors examined the elements of rate base through written interrogatories and the settlement process.

NWTPC and the intervenors participating in the negotiated settlement meetings agreed that the elements of rate base for each of the three Test Years should be approved as applied for, subject to specific adjustments to capital additions and retirements, accumulated amortization and working capital.

The Board's comments with respect to certain of these adjustments are

contained in the following sections.

3.1 Capital Additions

In its July 16, 1996 revision to its Application, NWTPC forecast capital additions of \$23,696,000, \$38,588,000 and \$8,094,000 respectively for 1995/96, 1996/97 and 1997/98.

As a consequence of the Settlement Agreement, forecast capital additions were adjusted to \$23,154,000, \$38,476,000 and \$6,350,000 for each of three Test Years. The significant adjustments are described below.

3.1.1 Snare Cascades Hydro Project

The Snare Cascades project, a 4.3 MW hydro power plant located on the Lower Snare River, is 100% owned by the DPC. Construction of the plant was completed in the summer of 1996 and it was placed into service on August 10, 1996. The plant is forecast to provide an average annual energy output of 27.3 GW.h based on long term average water flows and a firm capacity of 3.8 MW.

NWTPC will lease and operate the plant according to the commercial arrangement between DPC and NWTPC as described in the Dogrib Power Project Agreement and the Power Acquisition Agreement. The Power Acquisition Agreement is a capital lease which provides NWTPC with all of the benefits and risks incidental to ownership of the Snare Cascades plant. NWTPC proposed to capitalize the lease in accordance with its capitalization policy and the proper accounting treatment of a long-term lease.

Specifically, NWTPC requested that the Board approve the rent payable under the Power Acquisition Agreement and the costs incurred by NWTPC in relation to the Agreement by approving the capitalization of total costs of \$27,350,213.

The project is the largest single capital project entered into by NWTPC and was subjected to considerable scrutiny by all parties in terms of interrogatories and intervenor evidence. In particular, concerns were raised with respect to the immediate need for the project in relation to the existing capacity on the Snare Yellowknife system and the effect of the proposed rate base treatment on rates over the next several years.

In his prepared testimony, filed on behalf of the Municipal Intervenors, William Marcus summarized the concern the intervenors had with the project when he stated:

" ...the costs of Snare Cascades are front-loaded for ratemaking purposes. Thus, in the next several years, the plant will cost more than the fuel and variable operation and maintenance costs of diesel generation. This creates generational inequities. Ratepayers today who do not need capacity from Snare Cascades, would be required to pay more than the variable costs of diesel generation which the plant avoids. (Ex.5, p.10, // 11-16)"

In the Settlement Agreement, NWTPC and the intervenors agreed that the Snare Cascades project should be approved as applied for, subject to a phase-in of the project in a manner that would keep NWTPC whole with respect to its costs yet smooth out the rate increase experienced by customers as a result of the addition of the project to rate base.

Specifically, the following terms of the phase-in were agreed to:

- a) the entire Snare Cascades project would be placed into rate base in 1996/97;
- b) NWTPC would collect the difference between the full revenue requirement for the project and the annual variable savings resulting from the project for five years (1996/97 to 2000/01) in a deferral account;
- c) the balance in the deferral account would earn a return similar to AFUDC;
- d) the amount in the deferral account would be amortized over ten years commencing April 1, 2001;
- e) the balance in the deferral account would earn a cash return during the ten year amortization period.

During the course of its presentation of the Settlement Agreement to the Board, witnesses for NWTPC indicated that the effect of the proposed phase-in would reduce the revenue requirement by approximately \$700,000 over the three Test Years (Tr., p. 33, ll. 15-18).

As part of the settlement, NWTPC and the intervenors also requested that the Board approve the phase-in and the rider that would go into effect on April 1, 2001 in this Decision, subject to NWTPC filing a detailed reconciliation of the deferral account and the resulting rider sufficiently in advance of April 1, 2001 to allow the Board and interested parties to review NWTPC's calculation of the rider.

The Board has reviewed the evidence with respect to the project and is satisfied that the project is needed over the long term and has been incurred at prudent cost. Further, the Board is of the view that the proposed phase-in

is reasonable and fairly balances the interests of NWTPC and the ratepayers in the Snare Yellowknife system. The Board approves the proposed phase-in and rider as described in the Settlement Agreement and directs NWTPC to provide the Board and interested parties with a reconciliation of the deferral account on an annual basis.

3.1.2 Other Capital Expenditures - Snare Yellowknife System

The Settlement Agreement contained the following adjustments to capital additions for the Snare Yellowknife system:

3.1.2.1 Snare Rapids Upgrade

The project involved the rehabilitation of 3 km of the Snare Rapids to Snare Falls transmission line and the installation of a "sky wire". The line, originally installed in 1960/61, is used to transmit power from the Snare Rapids hydro station to the Snare Falls Tie Sub.

The Settlement Agreement proposes to reduce by \$100,000 the amount originally requested to be added to rate base in the 1996/97 Test Year, in recognition of the AFUDC accumulated by the project during the unusually long time period that it remained in CWIP.

3.1.2.2 Ruston Engine

The project involved the relocation of a 2.0 MW diesel engine from the abandoned Pine Point diesel back-up station to the Jackfish diesel plant in Yellowknife. The relocation was undertaken to provide back-up capacity at

Jackfish during the recent low water period on the Snare hydro system.

The Settlement Agreement proposes to add only \$500,000 of the total cost of the project to rate base in 1995/96. The balance of the cost would remain in CWIP and accumulate AFUDC, pending a review of the project by the Capacity/Reliability Planning Working Group. The group is being established to develop a capacity/reliability planning formula to be utilized by NWTPC in future General Rate Applications.

3.1.2.3. Yellowknife Storage Tank

The project involves the construction of a 4 million litre fuel storage tank at the Jackfish diesel plant. In its replies to Information Requests BR-117 (g) and YK-176 (b), NWTPC indicated that its justification for the project was the savings of fuel price premiums paid to local suppliers because the existing fuel storage was insufficient to carry inventory over a typical spring break-up and to open the Jackfish fuel supply tender to more suppliers.

In accordance with the Settlement Agreement, the project is to be deferred until additional study can be performed into its need, given the additional hydro capacity now available.

The Board has reviewed the proposed adjustments to NWTPC's forecast capital additions and finds them to be reasonable and in the public interest.

3.1.3 Other Capital Expenditures - Diesel Communities

In addition to the expenditures made in the two hydro zones, significant

investment was made in the diesel communities as well. In particular the Board notes that NWTPC installed new diesel engines in a number of communities as well as constructing a new plant in the community of Fort Norman (Tulita).

While these projects were not itemized individually in the settlement document, the Board notes that the forecast capital expenditures were examined in detail by the Board and the intervenors in the form of interrogatories. The Board has examined the evidence and is of the view that these expenditures are prudent and in the public interest.

3.2 Depreciation and Amortization

The purpose of amortization/depreciation is to systematically recover the cost of depreciable assets over their estimated useful lives. In determining the amortization/depreciation for an asset, recognition is generally given to any positive or negative net salvage, including site restoration costs, applicable to the retirement or relocation of the asset.

If the service life chosen for an asset group is too short, the costs of the assets will be recovered too quickly, resulting in assets which are fully depreciated but have not reached the end of their useful lives. The result is that current ratepayers are obliged to pay now for assets which yield benefits to future ratepayers.

Conversely, if amortization rates are too low based on estimated service lives which are too long, assets will be retired at the end of their useful lives but will not have been fully depreciated. In this instance, future ratepayers are

required to pay for benefits enjoyed by current ratepayers.

In Decision 2-94, the Board directed NWTPC to conduct a detailed depreciation study to address the above concerns. The study was to provide detailed support for the service lives chosen for all asset classes and ensure that both NWTPC's accumulated depreciation balance and its ongoing expense charges were reasonable.

NWTPC retained Gannett Fleming Valuation and Rate Consultants Inc. to perform the depreciation study. The results of the study, conducted under the direction of Mr. William Stout, were contained under Tab 5 and Appendix 3 of the Application. The depreciation study consisted of two phases: one, the estimation of survivor curves and net salvage percents for each depreciable group and two, the calculation of annual and accrued depreciation as of March 31, 1995.

A comparison of the calculated accrued depreciation to the booked accumulated depreciation indicated a depreciation reserve variance of \$28,897,218. NWTPC proposed to dispose of the variance over a ten-year period by reducing the amount of the annual depreciation expense. The net annual depreciation expense, as shown in Schedule 6.1 of the Application, was \$9,074,000, \$10,135,000 and \$10,600,000 respectively for the 1995/96, 1996/97 and 1997/98 Test Years.

The Municipal Intervenors retained the services of Mr. Jacob Pous of Diversified Utility Consultants Inc. to review the Study.

As a result of the interrogatory process, the recommendations of Mr. Stout and

Mr. Pous, and the settlement negotiations, significant changes in the depreciation parameters were agreed to by the parties and set out in Appendix D of the Settlement Agreement. It was also agreed to dispose of the amortization reserve variance over 10 years on a straight-line basis and that Miramar would receive a \$50,000 one-time adjustment to its 1996/97 reconciliation in recognition of its past contribution to the reserve, with such monies to be taken out of the amortization reserve variance account.

In total, these adjustments resulted in a revised annual depreciation expense of \$7,899,125 in 1995/96, \$8,833,696 in 1996/97 and \$9,195,766 in 1997/98 as shown in Table 5.2 in Appendix E of the Settlement Agreement. The Board's findings with respect to the annual depreciation expense are contained in section 5.2 of the Decision.

Schedules showing a detailed breakdown, by asset class, of the Calculated Accumulated Depreciation Reserve, Depreciation expense, and the excess depreciation reserve were supplied by NWTPC in Exhibit #12, and are attached to this Decision as Schedule E.

3.3 Working Capital

The mid-year working capital component of rate base, shown in Schedule 2.1 of the Application, was forecast at \$16,795,000 for 1995/96, \$16,869,000 for 1996/97 and \$18,226,000 for 1997/98.

Working Capital was accepted by the parties as forecast by NWTPC, with the exception of a change to the lead/lag study. The parties agreed that the nine days allowed for GST expenditure lag, illustrated in information request YK-15,

should be removed. The adjustment reduces the total GST lag from 57.5 to 48.5 days. The effect of this adjustment reduces the mid-year working capital to \$16,753,000, \$16,744,000 and \$17,046,000 respectively for the three Test Years. These amounts are reflected in Schedule D attached to this Decision.

3.4 Conclusion

The Board has considered the interrogatory process that took place prior to the negotiated settlement meeting, the elements of the Settlement Agreement, and is satisfied that the participating intervenors have fully examined the components of rate base.

The Board has reviewed the filed evidence and finds no reason to disturb the elements of the Settlement Agreement, as summarized above, with respect to rate base.

The Board, pursuant to the requirements of Section 49 of the Act, has determined the following rate base for each of the Test Years:

1995/96	\$182,027,000
1996/97	\$204,079,000
1997/98	\$218,066,000

Schedules supporting the above amounts are attached to this Decision as Schedule A.

4. RETURN ON RATE BASE

Having determined the rate base for NWTPC for the Test Years, the Board is required, pursuant to section 50 of the Act, to "fix a fair return on the rate base". Section 50 of the Act provides as follows:

"50. (1) The Board shall fix a fair return on the rate base of a public utility.

(2) In fixing a fair return, the Board shall consider all the facts that it considers relevant."

The Board's objective in fixing a fair return on rate base is to enable a utility to recover its cost of servicing those portions of the rate base deemed to be financed by debt and preferred equity, and to provide an opportunity to earn a fair return on the portion of rate base deemed to be financed by common equity.

4.1 Capital Structure

NWTPC's capital structure for the three Test Years included short term debt, long term debt, common equity, and in the Test Years 1996/97 and 1997/98 a capital lease obligation with respect to the Snare Cascades project.

The capital structure as agreed to by the parties is set out in Table 3-1 of the settlement package (Ex.8) and is not materially different from that forecast by NWTPC in Table 3-1, contained in its revised Application of July 16, 1996 (Ex.2).

In 1995/96, the capital structure comprises 46% equity, 53% long term debt,

and 1% short term debt. In 1996/97, the capitalization of the Snare Cascades lease results in a capital structure of 43% equity, 49% long term debt, 6% for the lease obligation and 2% short term debt. In 1997/98, when the lease is fully included in rate base, the equity component remains at 43%, long term debt is 45%, the lease obligation 11%, and short term debt 1%.

The Board has examined the evidence before it and agrees with the parties that the capital structure as proposed in the agreement is reasonable. The capital structure is illustrated in Schedule C and is approved by the Board.

4.2 Short Term Debt

In Table 3.1 of its Application, NWTPC forecast short term debt rates of 7.5% for each of the three Test Years. During the settlement negotiations, the parties agreed on short term debt rates of 7.5% for 1995/96, 6.8% for 1996/97 and 6.9% for 1997/98, in recognition of information that would likely have been placed into evidence at the Hearing.

Subsequent to the filing of the agreement, Counsel for the Board requested the information that would likely have been placed into evidence with respect to short term debt rates. In response NWTPC provided a copy of the June, 1996 Consensus Forecast, and advised that the information in the forecast was used in setting short term interest rates.

The Board has examined the evidence before it and agrees with the parties that the short term interest rates proposed in the agreement are reasonable. The Board approves short term rates of 7.5%, 6.8%, and 6.9% for the three Test Years 1995/96, 1996/97, and 1997/98 respectively.

4.3 Long Term Debt

In Table 3.1 of its Application, NWTPC forecast long term debt rates of 10.745% for 1995/96, 10.442% for 1996/97 and 10.404% for 1997/98.

As a result of the settlement negotiations, the parties agreed that the embedded cost of long term debt should remain at 10.745% for the 1995/96 Test Year and at 10.442% for the 1996/97 Test Year.

In recognition of information available at the time NWTPC amended its Application to include the 1997/98 Test Year (Tr., p. 28, // 9-13), the cost of new debt borrowing for the 1997/98 Test Year was set at 8.41%. This yielded an embedded rate for all long term debt for the 1997/98 Test Year of 10.287%.

The Board has examined the evidence before it and agrees with the parties that the long term debt rates proposed in the agreement are reasonable. The Board approves long term rates of 10.745%, 10.442%, and 10.287% for the three Test Years 1995/96, 1996/97, and 1997/98 respectively.

4.4 Capital Lease Obligation

As noted above the Snare Cascades hydro project has been allowed into rate base for the 1996/97 Test Year and subsequent years. The project is financed by a long term capital lease which forms part of the capital structure. An interest rate must also be determined for this portion of the capital structure.

The parties have agreed upon an interest rate of 10.063% for the 1996/97 Test Year and 10.044% for the 1997/98 Test Year.

The Board has examined the evidence before it and agrees with the parties that the above interest rates are reasonable for this portion of the capital structure. The Board approves lease interest rates of 10.063% and 10.044% for the Test Years 1996/97 and 1997/98 respectively.

4.5 Return on Common Equity

In Table 3.1 of its Application, NWTPC's forecast return on common equity was 12.625% for 1995/96, 12.50% for 1996/97 and 12.75% for 1997/98.

As part of the Settlement Agreement, NWTPC and the intervenors agreed that the return on common equity for 1995/96 and 1996/97 would be set at 11.75%, and for 1997/98 would be set at 11.5%.

Mr. Courneya summarized the rationale for the proposed rates of return when he stated in his presentation at the hearing:

"Some of the rationale for these changes:
Probably the most important one was looking at the whole negotiated settlement package. It also, I think, reflects the fact that we are one (1) year later from when we originally applied; the economy of the country has changed; as well as decisions that have been handed by both this Utility Board and other Utility Board in the south. (Tr., p. 48, ll. 1-8)"

The Board has reviewed the evidence before it and agrees with the parties that the proposed rates of return on the equity portion of the capital structure are reasonable. The Board approves a cost rate for common equity capital of 11.75% for 1995/96, 11.75% for 1996/97 and 11.5% for 1997/98.

4.6 Conclusion - Fair Return on Rate Base

Having determined the capital structure which is appropriate for the purpose of fixing the fair return on rate base, and having determined the dollar amounts and the cost rates for the components of the capital structure deemed to be financing the rate base, the Board approves the fair return on rate base for each of the Test Years, as follows in Schedule C attached:

1995/96	\$ 20,324,000
1996/97	\$ 22,444,000
1997/98	\$ 22,613,000

5. UTILITY REVENUE REQUIREMENT

Utility revenue requirement is composed of the following categories of cost:

- Cash Operation and Maintenance Expenses
- Non-Cash Operating Expenses
- Fair Return on Rate Base

As part of the settlement package the parties agreed on matters pertaining to cash operation and maintenance ("O&M") expenses and non-cash operating expenses. The fair return on rate base has been dealt with in a previous section.

5.1 Cash Operating Expenses

As part of the Settlement Agreement, the parties accepted the O&M expenses as forecast by NWTPC in its revised Application of July 16, 1996 with the exception of forecast fuel efficiencies for the 1997/98 Test Year for the communities of Yellowknife and Inuvik, and the consequent effect upon fuel expense.

It was agreed that the actual fuel efficiencies for 1995/96 would be used in the calculation determining the 1997/98 forecast efficiencies for these two communities and fuel expense adjusted accordingly. As part of the package, NWTPC has also proposed to make the same adjustment for all communities for the 1997/98 Test Year.

In Decision 2-94, Directive 11, the Board indicated its concerns with respect

to fuel efficiency. In response, NWTPC provided a detailed answer respecting the problems faced by the Corporation in tracking fuel efficiency, indicated that it is continually trying to improve efficiency, and that it continues to investigate opportunities to find an economic fuel metering system.

Upon its review of the settlement, the Board questioned whether the adjustment to fuel expense, to cap line losses at 8%, had been properly carried forward, as required under Directive 13 of Board Decision 9-95 (Phase II, 1993/94) and the Corporation's undertakings thereto. It was adduced in evidence that the Corporation had not. The Board will therefore make reductions in forecast fuel expense of \$89,900, \$95,600 and \$104,300 for the Test Years 1995/96, 1996/97 and 1997/98 respectively.

All other O&M expenses were accepted as forecast.

The Board has reviewed the evidence before it and believes the O&M expenses agreed to by the parties in the agreement, adjusted for the capping of line losses at 8%, to be reasonable and appropriate. The Board fixes the following amounts for O&M expenses for the Test Years:

1995/96	\$75,302,000
1996/97	\$72,290,000
1997/98	\$74,168,000

The above amounts are detailed in Schedule B attached.

5.2 Amortization Expense

Pursuant to section 51.(3) of the Act, the Board is required to fix proper and adequate rates and methods of depreciation, amortization and depletion in respect of the property of a public utility.

The results of the depreciation study undertaken by NWTPC and the amendments agreed to in the Settlement Agreement result in significant changes to the depreciation parameters used by NWTPC. The highlights of the depreciation study, as agreed to in the Settlement Agreement, were discussed in section 3.2. The revised depreciation parameters to be used by NWTPC, detailed by asset class, are illustrated in Schedule E. The Board agrees with the parties that these proposed depreciation rates and expenses are reasonable and appropriate.

The Board also notes that this is the first comprehensive depreciation study undertaken by NWTPC and that NWTPC has undertaken to conduct a further review of the issue within the next five years.

The Board has reviewed the evidence before it and fixes and approves the following amortization expenses, net of adjustments for customer contributions and the excess reserve variance, for the Test Years:

1995/96	\$7,899,000
1996/97	\$8,834,000
1997/98	\$9,196,000

5.3 Total Utility Revenue Requirement

The Board has reviewed the evidence contained in NWTPC's Application and the responses to interrogatories and, with the exception of the minor adjustment to fuel expense to adjust for line losses, finds no reason to disturb the settlement package with respect to the determination of NWTPC's revenue requirements for the three Test Years.

Based on its findings, the Board determines the total revenue requirements for the three Test Years to be as follows:

1995/96	\$103,525,000
1996/97	\$103,568,000
1997/98	\$105,977,000

The above amounts are detailed in Schedule B.

6. UTILITY REVENUE

6.1 Forecast Revenues

In Table 6-1 of the settlement package, NWTPC forecasts its revenues, at existing rates, for the three Test Years to be as follows:

1995/96	\$ 100,342,000
1996/97	\$ 100,873,000
1997/98	\$ 102,530,000

The intervenors have agreed with these forecast amounts and the Board sees no reason to disturb this element of the settlement package.

The Board has examined the evidence before it and approves the forecast revenue for the three Test Years.

6.2 Revenue/Surplus Deficiency

In section 5.3 of this Decision, the Board has determined NWTPC's revenue requirements for the three Test Years 1995/96, 1996/97 and 1997/98 to be \$103,525,000, \$103,568,000 and \$105,977, 000 respectively.

Based on approved revenues at existing rates of \$100,342,000, \$100,873,000 and \$102,530,000 for the three Test Years, the Board determines NWTPC's deficiency to be \$3,183,000 for the 1995/96 Test Year, \$2,695,000 for the 1996/97 Test Year and \$3,447,000 for the 1997/97 Test Year. The disposition of these deficiencies will be dealt with in the Phase II proceeding of the current

Application.

In addition to forecast revenues from existing base rates for the 1995/96 Test Year, NWTPC is also forecasting to collect \$3,983,000 under an interim refundable rider approved by the Board in Decision 14-95. The purpose of the rider was to compensate NWTPC for higher than anticipated fuel costs resulting from the ongoing low water problem in the Snare/Yellowknife zone. The disposition of the funds collected pursuant to the rider will also be dealt with in the Phase II proceeding.

7. OTHER ISSUES

7.1 Stabilization Funds

In its original Application, NWTPC proposed the implementation of Rate Stabilization Funds to mitigate the adverse impact on rates of unanticipated changes in fuel prices and deviations of hydro conditions from normal. The proposed operation of these funds is fully explained in Chapter 9 of the Application and will not be repeated in detail here. Briefly however the proposal called for the creation of four funds - one for each of the hydro zones which would cover variations in both fuel price and water levels for each zone, one large fund to cover fuel price fluctuations for all the diesel communities, and a fourth fund for the Town of Norman Wells to cover primarily fluctuations in the cost of purchased power. In all of the zones, except the Taltson, a surcharge would be implemented to build up a cash balance in the fund. There would also be a "trigger" mechanism whereby NWTPC would be at risk, or receive the benefit, for the first \$450,000 deviation from forecast conditions.

As part of the Settlement Agreement, the parties agreed to the establishment of stabilization funds but have proposed different parameters for their operation. The significant parameters are as follows:

- a) there would be no "trigger" mechanism;
- b) there would be no surcharge implemented to build up the funds;
- c) as the balance in each fund moved within its range there would be an imputed return to the customer if the fund were in a positive position or an imputed cost to the customer if the fund should be in a negative position;

- d) a separate water fund and a separate fuel fund would be set up in each of the hydro zones;
- e) the range for the Snare Yellowknife zone water fund would be plus or minus \$3 million and \$0 for Taltson with NWTPC being able to implement a rider once the range was exceeded. However, while the fund would have a \$0 target balance based on long term average water levels, the rider would only remain in effect until the fund balance was brought back to its upper or lower range limit, not to a zero balance; and
- f) the fuel fund ranges would be \$1 million for the Snare Yellowknife zone, \$2 million for the diesel communities (as with the original proposal there would be only one fund for all diesel communities), \$100,000 for Norman Wells, and \$0 for Taltson. NWTPC would be able to implement a rider once the fund's upper or lower range limit was reached but, unlike the water funds, a fuel rider would remain in effect until the zonal fund balance had returned to \$0.

Upon reviewing the proposal, the Board questioned why riders for the water funds would only return the funds to their upper or lower range while riders for the fuel funds would return them to a zero balance. In his reply to Board Counsel (Ex.12), Mr. Courneya explained that the use of long term average water levels would have the effect of self adjusting these funds to a zero balance while the same was not expected of the fuel funds as fuel prices were expected to rise over the long term. The Board accepts this explanation as reasonable.

The Board also considered the prudence of having only one fund for all diesel communities. The Board appreciates that while there are significant differences in fuel prices among communities it believes that any incremental rise or fall in fuel prices would affect all communities equally. The Board therefore accepts this parameter of the proposal as being reasonable as well.

In consideration of the evidence before it, the Board approves the establishment of water and fuel stabilization funds as detailed in the Settlement Agreement.

7.2 Taltson Deferral Account

In its Application, NWTPC requested Board approval of a deferral account in respect of compensation that may be payable in accordance with Part C of Northwest Territories Water Board Licence N1L4-0154 respecting the Taltson River Basin.

Part C of the licence identifies a number of claimants, with whom NWTPC was directed by the Water Board to negotiate to determine the validity and nature of any potential claim pursuant to the Water Act.

The deferral account was not included in the negotiated Settlement Agreement nor was any additional evidence provided to the Board with respect to the status of the negotiations with the claimants.

The Board will defer any decision with respect to this element of the Application until the matter of compensation is finally resolved.

7.3 Fort Smith Interruptible Power Sale

In Decision 3-96, the Board approved on an interim basis an interruptible power rate for the Town of Fort Smith. The energy was to be used in hydrogen demonstration projects.

The Board noted that it was required to hold a public hearing with respect to the setting of an interruptible power rate and stated that it would hear the matter prior to the Phase I hearing. The Board has deferred the matter of the interim rate approved in Decision 3-96 until the commencement of the Phase II hearing, when it will be heard in conjunction with the application for further interruptible power sales to service a district heating system in Fort Smith.

8. BOARD DIRECTIVE

1. The Board, as outlined in Section 3.1.1 of this Decision, approves the proposed phase-in and rider as described in the Settlement Agreement and directs NWTPC to provide the Board and interested parties with a reconciliation of the deferral account on an annual basis.
2. The Board directs NWTPC to provide particulars of any further measures taken to improve fuel efficiency, at the next GRA.

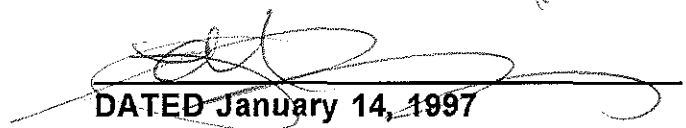
9. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. The Board determines the Northwest Territories Power Corporation's rate base to be \$182,027,000, \$204,079,000 and \$218,066,000 for the Test Years 1995/96, 1996/97 and 1997/98 respectively.
2. The Board determines the Northwest Territories Power Corporation's revenue requirements to be \$103,525,000, \$103,568,000 and \$105,977,000 for the Test Years 1995/96, 1996/97 and 1997/98 respectively.
3. The Board approves the capitalization of the rent payable under, and other costs incurred in relation to, the Power Acquisition Agreement dated March 18, 1993, as amended, between the Dogrib Power Corporation and the Northwest Territories Power Corporation in respect of the Snare Cascades Hydro Project agreed to in the Negotiated Settlement Agreement.
4. The Board approves the establishment of water and fuel stabilization funds as detailed in the Negotiated Settlement Agreement.

5. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

**ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES**



DATED January 14, 1997

**John E. Hill
Chairman**

FOLLOWING IS

SCHEDULES A, B, C, D AND E

ATTACHED TO AND FORMING PART OF

THE PUBLIC UTILITIES BOARD

OF THE NORTHWEST TERRITORIES

DECISION 1-97

DATED January 14, 1997

Northwest Territories Power Corporation
Schedule of Rate Base (\$000s)
As submitted in Settlement Agreement & Approved by Board

Schedule A

	<u>1995/96</u>	<u>1996/97</u>	<u>1997/98</u>
Gross Plant in Service			
Beginning of Year	288,935	308,489	346,965
Add: Additions	23,154	38,476	6,350
Add: Assets Retired from Service	2,651	0	0
Less: Disposals	6,251	0	0
End of Year	308,489	346,965	353,315
Mid Year Balance	298,712	327,727	350,140
 Amortization			
Beginning of Year	122,354	126,665	135,489
Add: Amortization	7,569	8,420	9,036
Add: Customer Contributions	381	404	404
Add: Assets Retired from Service	2,120	0	0
Less: Disposals	5,759	0	0
End of Year	126,665	135,489	144,929
Mid Year Balance	124,510	131,077	140,209
 Mid Year Net Plant in Service	174,202	196,650	209,930
 Add: Working Capital (Mid Year)	16,753	16,744	17,046
 Less: Customer Contributions (Mid Year)	8,928	9,315	8,910
 Mid-Year Rate Base	<u>182,027</u>	<u>204,079</u>	<u>218,066</u>

Northwest Territories Power Corporation
Revenue Requirement (000s)
As Submitted in Settlement Agreement & Approved by Board

Schedule B

Expense Category	<u>1995/96</u>	<u>1996/97</u>	<u>1997/98</u>
Operation and Maintenance			
Salaries and Wages	16,868	16,985	17,462
Fuel and Lubricants	36,261	32,696	33,354
Purchased Power	887	837	950
Supplies and Services	10,913	11,618	11,868
Reserve for Injuries and Damages	350	350	350
Travel and Accommodation	1,772	1,577	1,609
Water and Sewerage O&M	(1,433)	(1,361)	(1,388)
Head Office	9,684	9,588	9,963
Total O & M Expenses	<u>75,302</u>	<u>72,290</u>	<u>74,168</u>
Amortization net of Non-Utility Items			
Fixed Asset Amortization	7,569	8,420	9,036
Other Amortization	330	414	160
Total Amortization	<u>7,899</u>	<u>8,834</u>	<u>9,196</u>
Total Expenses	83,201	81,124	83,364
 Return on Rate Base	 20,324	 22,444	 22,613
 Total Revenue Requirement	 <u><u>103,525</u></u>	 <u><u>103,568</u></u>	 <u><u>105,977</u></u>

Northwest Territories Power Corporation
Capital Structure & Return on Rate Base (000s)
As submitted in Settlement Agreement & Approved by Board

Schedule C

	Mid-Year Capitalization	Mid-Year Capital Ratios	Mid-Year Rate Base	Mid-Year Cost Rate	Return
<u>1995/96</u>					
Common Equity	89,658	45.796%	83,361	11.750%	9,795
Long Term Debt	103,725	52.981%	96,440	10.745%	10,362
Short Term Debt	2,394	1.223%	2,226	7.500%	167
Total	195,777	100.000%	182,027		<u>20,324</u>
<u>1996/97</u>					
Common Equity	95,007	43.213%	88,188	11.750%	10,362
Long Term Debt	108,375	49.293%	100,597	10.442%	10,504
Capital Lease Obligation	13,226	6.016%	12,277	10.063%	1,235
Short Term Debt	3,250	1.478%	3,017	6.800%	205
sub-total	219,858	100.000%	204,079		22,307
Add/(Deduct): Snare Cascades Deferral					137
Total					<u>22,444</u>
<u>1997/98</u>					
Common Equity	98,919	43.017%	93,806	11.500%	10,788
Long Term Debt	103,025	44.803%	97,700	10.287%	10,050
Capital Lease Obligation	26,257	11.419%	24,900	10.044%	2,501
Short Term Debt	1,750	0.761%	1,660	6.900%	115
sub-total	229,951	100.000%	218,066		23,454
Add/(Deduct): Snare Cascades Deferral					(841)
Total					<u>22,613</u>

Northwest Territories Power Corporation
Working Capital Requirement (000s)
As Submitted in Settlement Agreement & Approved by Board

Schedule D

	<u>1995/96</u>	<u>1996/97</u>	<u>1997/98</u>
Cash Working Capital			
Salaries and Wages	437	440	452
Fuel and Lubricants	941	849	866
Purchased Power	23	22	25
Regulatory Costs	9	11	4
Supplies and Services	282	300	307
Reserve for Injuries and Damages	9	9	9
Travel and Accommodation	46	41	42
Water and Sewerage O&M	(37)	(35)	(36)
Head Office	251	248	258
GST Expenditure Lag	215	202	207
GST Remittance Lag	<u>(211)</u>	<u>(213)</u>	<u>(217)</u>
Total Cash Working Capital	1,965	1,874	1,917
Deposits	(770)	(793)	(813)
Supplies Inventory	2,954	3,037	3,347
Fuel & Lube Inventory	11,147	11,314	11,485
Deferred Charges	350	270	163
Prepaid Expenses	416	429	439
Housing Loans	691	613	508
Total Working Capital Requirement	<u><u>16,753</u></u>	<u><u>16,744</u></u>	<u><u>17,046</u></u>

NORTHWEST TERRITORIES POWER CORPORATION

Schedule E page 1 of 6

1995/96 AMORTIZATION PROVISION

DESCRIPTION	(\$'s)									
	Original Cost at March 31, 1995	1995/96 Capital Additions	Annual Rate	Annual Amount Plus 1/2 Year On Additions	Add: Amortization On Other Utility General	Less: Customer Contributions	Less: Water and Sewerage	Less: Taitson Intertie Provision	Less: Accumulated Reserve Variance	Net Amortization Provision on Fixed Assets
DEPRECIABLE PLANT										
Hydro Plant										
331 Structures and Improvements	11,240,777	40,567	2.78	313,057		0			(2,672)	315,729
332 Reservoirs, Dams and Waterways	17,749,924	731,356	1.65	298,907		0			(268,706)	567,613
333 Waterwheels, Turbines and Generators	6,441,482	0	1.93	124,321		0			(15,353)	139,674
334 Accessory Electric Equipment	5,742,806	48,289	2.38	137,253		0			4,944	132,310
335 Miscellaneous Power Plant Equipment	2,256,538	42,604	5.04	114,803		1,565			(12,060)	125,297
336 Road, Railroads and Bridges	5,554,914	9,962	1.33	73,947		0			89,168	(15,222)
Total Hydro Plant	48,986,441	872,776		1,062,289		1,565			(204,678)	1,265,401
Diesel Plant										
341 Structures and Improvements	39,629,620	2,398,386	2.88	1,175,870		57,833			916,553	201,484
342 Fuel Holders Producers and Accessories	16,381,903	2,635,538	5.21	922,153		12,426			(15,344)	925,071
343 Prime Movers	76,530,898	6,396,279	4.52	3,603,753		81,860			1,115,059	2,406,834
344 Generators	6,867,200	2,325,662	3.33	267,400		8,903			71,014	187,483
345 Accessory Electric Equipment	19,506,831	2,107,127	3.70	760,735		29,723			312,356	418,656
346 Miscellaneous Power Plant Equipment	1,590,312	489,525	5.00	91,754		208			28,499	63,047
Total Diesel Plant	160,506,764	16,352,518		6,821,664		190,952			2,428,137	4,202,575
Transmission Plant										
351 Clearing Land and Land Rights	2,534,118	0	1.91	48,402		0			24,924	23,478
352 Structures and Improvements	2,842,032	0	2.62	74,461		0			22,321	52,140
353 Station Equipment	6,709,224	228,506	2.63	179,431		1,723			159,058	18,652
354 Towers and Fixtures	13,247,395	0	2.68	355,030		0			40,180	314,850
355 Poles and Fixtures	359,765	0	3.78	13,599		0			(661)	14,261
356 Overhead Conductors and Devices	7,919,101	0	2.90	229,654		0			10,807	218,847
359 Roads and Trails	550,543	0	4.00	22,022		0			501	21,521
Total Transmission Plant	34,162,178	226,506		922,599		1,723			257,128	663,748
Distribution Plant										
361 Structures and Improvements	312,577	475,031	2.63	14,467		3,487			1,366	9,614
362 Station Equipment	1,175,236	59,017	3.33	40,118		329			23,156	16,633
363 Storage Battery Equipment	9,973	0	4.66	465		410			(7)	62
364 Poles, Towers and Fixtures	13,255,937	1,323,419	4.66	648,562		232,464			(126,056)	542,154
365 Overhead Conductors and Devices	5,676,932	289,570	4.00	232,869		84,560			(35,642)	183,951
366 Underground Conduit	35,502	20,566	5.00	2,289		2,114			(5)	180
367 Underground Conductor and Devices	191,292	0	4.97	9,507		4,610			784	4,113
368 Line Transformers	3,438,132	585,347	4.00	149,232		23,407			(1,912)	127,737
369 Services	2,365,971	0	3.43	81,153		29,597			3,052	48,504
370 Meters	1,138,055	91,683	4.00	47,356		1,279			(5,763)	51,839
371 Installations on Customer Premises	7,226	419	4.00	297		294			0	4
373 Street Lighting and Signal Systems	392,292	32,726	3.15	12,873		1,382			2,018	9,472
Total Distribution Plant	27,999,125	2,877,778		1,239,189		383,933			(139,008)	994,264

NORTHWEST TERRITORIES POWER CORPORATION

Schedule E, page 2 of 6

1995/96 AMORTIZATION PROVISION

		(\$'s)									
DESCRIPTION		Original Cost at March 31, 1995	1995/96 Capital Additions	Annual Rate	Annual Amount Plus 1/2 Year On Additions	Add: Amortization On Other Utility General	Less: Customer Contributions	Less: Water and Sewerage	Less: Taitson Intertie Provision	Less: Accumulated Reserve Variance	Net Amortization Provision on Fixed Assets
DEPRECIABLE PLANT											
General Plant											
303	Feasibility Studies/ In-house Course Develop.	0	173,634	20.00	17,363		0		111,057	0	(93,693)
390	Structures and Improvements	12,905,910	255,864	2.62	341,487		118,972			152,526	69,989
391	Office Furniture and Equipment	2,840,171	274,735	7.49	223,018		0			72,146	150,871
392	Transportation Equipment	3,135,419	168,000	8.91	286,850		0	1,549		87,045	198,256
393	Stores Equipment	148,218	0	9.89	14,659		0			(2,838)	17,496
394	Tools, Shop and Garage Equipment	99,340	0	8.52	8,464		714			(735)	8,485
395	Laboratory Equipment	265,885	0	5.26	13,986		0			3,185	10,800
396	Power Operated Equipment	875,867	0	5.00	43,793		0			43,102	692
397	Communication Equipment	670,208	218,000	6.67	51,973		0			7,464	44,510
398	Miscellaneous Equipment	53,696	75,330	6.67	6,094		984			(609)	5,719
118	Other Utility General	2,070,359	0			32,544		2,591		0	29,953
Total General Plant		20,994,714	1,165,562		1,007,686	32,544	120,669	4,140	111,057	361,286	443,079
Total Depreciable Plant		292,649,222	21,495,141		11,053,426	32,544	698,842	4,140	111,057	2,702,864	7,569,068
330	Land and Land Rights	777,814	49,874	0.00	0		0			0	0
340	Land and Land Rights	123,518	1,600,334	0.00	0		0			0	0
389	Land and Land Rights	167,354	9,068	0.00	0		0			0	0
Total Non Depreciable Plant		1,068,686	1,659,276		0		0			0	0
Total Electric Plant		293,717,908	23,154,417		11,053,426	32,544	698,842	4,140	111,057	2,702,864	7,569,068

NORTHWEST TERRITORIES POWER CORPORATION

Schedule E, page 3 of 6

1996/97 AMORTIZATION PROVISION

DESCRIPTION	Original Cost at March 31, 1996 Prior to Disposal	1995/96 Retirements & Disposals	1996/97 Capital Additions	Annual Rate	(\$'s)		Add: 1996/97 Snare Cascades Adjustment	Add: Amortization On Other Utility General	Less: Customer Contributions	Less: Water and Sewerage	Less: Taitson Intertie Provision	Less: Accumulated Reserve Variance	Net Amortization Provision on Fixed Assets
					Annual Amount Plus 1/2 Year On Additions								
DEPRECIABLE PLANT													
Hydro Plant													
331 Structures and Improvements	11,281,344	0	5,773,172	2.78	393,868		38,162		0			(2,672)	434,702
332 Reservoirs, Dams and Waterways	18,481,280	0	4,775,558	1.65	344,339		19,699		0			(268,706)	632,744
333 Waterwheels, Turbines and Generators	6,441,482	0	10,386,267	1.93	224,548		38,246		0			(15,353)	278,147
334 Accessory Electric Equipment	5,791,095	0	3,930,501	2.38	184,601		21,309		0			4,944	200,966
335 Miscellaneous Power Plant Equipment	2,299,142	0	3,162,881	5.04	195,581		39,559		1,565			(12,060)	245,635
336 Road, Railroads and Bridges	5,564,876	0	2,436,163	1.33	90,213		8,100		0			89,168	9,145
Total Hydro Plant	49,859,217	0	30,464,542		1,433,152		165,075		1,565			(204,678)	1,801,340
Diesel Plant													
341 Structures and Improvements	42,028,006	185,359	785,615	2.88	1,216,381				57,833			916,553	241,995
342 Fuel Holders Producers and Accessories	19,017,441	236,798	397,084	5.21	988,816				12,426			(15,344)	991,733
343 Prime Movers	82,927,177	5,257,387	1,018,957	4.52	3,533,703				81,860			1,115,059	2,336,784
344 Generators	9,192,862	19,451	66,480	3.33	306,581				8,903			71,014	226,665
345 Accessory Electric Equipment	21,613,958	0	2,297,088	3.70	842,213				29,723			312,356	500,134
346 Miscellaneous Power Plant Equipment	2,079,837	0	653,812	5.00	120,337				208			28,499	91,630
Total Diesel Plant	176,859,282	5,698,996	5,219,036		7,008,031				190,952			2,428,137	4,388,942
Transmission Plant													
351 Clearing Land and Land Rights	2,534,118	4,089	0	1.91	48,324				0			24,924	23,400
352 Structures and Improvements	2,842,032	0	0	2.62	74,461				0			22,321	52,140
353 Station Equipment	6,935,730	21,066	90,655	2.63	183,048				1,723			159,056	22,269
354 Towers and Fixtures	13,247,395	24,700	0	2.68	354,368				0			40,180	314,188
355 Poles and Fixtures	359,765	0	0	3.78	13,599				0			(661)	14,261
356 Overhead Conductors and Devices	7,919,101	12,268	0	2.90	229,298				0			10,807	218,491
359 Roads and Trails	550,543	0	0	4.00	22,022				0			501	21,521
Total Transmission Plant	34,388,684	62,123	90,655		925,120				1,723			257,128	666,269
Distribution Plant													
361 Structures and Improvements	787,608	0	0	2.63	20,714				4,747			1,366	14,601
362 Station Equipment	1,234,253	0	38,438	3.33	41,741				613			23,156	17,971
363 Storage Battery Equipment	9,973	0	0	4.66	465				410			(7)	62
364 Poles, Towers and Fixtures	14,579,356	101,474	725,525	4.66	691,574				244,716			(126,056)	572,914
365 Overhead Conductors and Devices	5,966,502	34,550	216,362	4.00	241,605				87,394			(35,642)	189,853
366 Underground Conduit	56,068	0	0	5.00	2,803				2,581			(5)	228
367 Underground Conductor and Devices	191,292	0	0	4.97	9,507				4,610			784	4,113
368 Line Transformers	4,023,479	8,834	124,922	4.00	163,084				29,458			(1,912)	135,538
369 Services	2,365,971	0	86,484	3.43	82,036				29,597			3,052	49,988
370 Meters	1,229,738	3,892	164,613	4.00	52,326				1,384			(5,763)	56,705
371 Installations on Customer Premises	7,645	0	0	4.00	306				299			0	7
373 Street Lighting and Signal Systems	425,018	0	19,219	3.15	13,691				1,388			2,018	10,285
Total Distribution Plant	30,876,903	148,750	1,375,563		1,320,452				407,197			(139,008)	1,052,264

NORTHWEST TERRITORIES POWER CORPORATION

Schedule E, page 4 of 6

1996/97 AMORTIZATION PROVISION

		(\$'s)											
DESCRIPTION		Original Cost at March 31, 1996 Prior to Disposal	1995/96 Retirements & Disposals	1996/97 Capital Additions	Annual Rate	Annual Amount Plus 1/2 Year On Additions	Add: 1996/97 Share Cascades Adjustment	Add: Amortization On Other Utility General	Less: Customer Contributions	Less: Water and Sewerage	Less: Taitson Intertie Provision	Less: Accumulated Reserve Variance	Net Amortization Provision on Fixed Assets
DEPRECIABLE PLANT													
General Plant													
303	Feasibility Studies/ In-house Course Develop.	173,634	0	0	20.00	34,727			0		111,057	0	(76,330)
390	Structures and Improvements	13,161,774	308,685	392,836	2.62	341,897			118,972			152,526	70,399
391	Office Furniture and Equipment	3,114,906	5,726	452,000	7.49	249,805			0			72,146	177,659
392	Transportation Equipment	3,303,419	8,601	300,000	8.91	306,933			0	1,549		87,045	218,339
393	Stores Equipment	148,218	0	0	9.89	14,659			0			(2,838)	17,496
394	Tools, Shop and Garage Equipment	99,340	0	0	8.52	8,464			714			(735)	8,485
395	Laboratory Equipment	265,885	0	0	5.26	13,986			0			3,185	10,800
396	Power Operated Equipment	875,867	18,342	0	5.00	42,876			0			43,102	(225)
397	Communication Equipment	888,208	0	0	6.67	59,243			0			7,464	51,780
398	Miscellaneous Equipment	129,028	0	181,309	6.67	14,653			984			(609)	14,278
118	Other Utility General	2,070,359	0	0				20,733		2,591		0	18,142
Total General Plant		22,160,276	341,354	1,326,145		1,087,243		20,733	120,669	4,140	111,057	361,286	510,824
Total Depreciable Plant		314,144,363	6,251,222	38,475,941		11,773,997	165,075	20,733	722,106	4,140	111,057	2,702,864	8,419,639
330	Land and Land Rights	827,688	0	0	0.00	0			0			0	0
340	Land and Land Rights	1,723,852	0	0	0.00	0			0			0	0
389	Land and Land Rights	176,422	0	0	0.00	0			0			0	0
Total Non Depreciable Plant		2,727,962	0	0		0			0			0	0
Total Electric Plant		316,872,325	6,251,222	38,475,941		11,773,997	165,075	20,733	722,106	4,140	111,057	2,702,864	8,419,639

NORTHWEST TERRITORIES POWER CORPORATION

Schedule E, page 5 of 6

1997/98 AMORTIZATION PROVISION

		(\$'s)				Add:		Less:	Less:	Less:	Net
DESCRIPTION		Original Cost	1997/98	Annual	Annual Amount	Amortization	On Other	Customer	Water and	Accumulated	Amortization
		at	Capital	Rate	Plus 1/2 Year	On Other	Utility General	Contributions	Sewerage	Reserve	Provision on
		March 31, 1997	Additions		On Additions					Variance	Fixed Assets
DEPRECIABLE PLANT											
Hydro Plant											
331	Structures and Improvements	17,054,516	0	2.78	474,116			0		(2,672)	476,788
332	Reservoirs, Dams and Waterways	23,256,837	0	1.65	383,738			0		(268,706)	652,443
333	Waterwheels, Turbines and Generators	16,827,749	0	1.93	324,776			0		(15,353)	340,128
334	Accessory Electric Equipment	9,721,595	0	2.38	231,374			0		4,944	226,430
335	Miscellaneous Power Plant Equipment	5,462,023	0	5.04	275,286			1,565		(12,060)	285,780
336	Road, Railroads and Bridges	8,001,038	0	1.33	106,414			0		89,168	17,245
Total Hydro Plant		80,323,759	0		1,795,703			1,565		(204,678)	1,998,815
Diesel Plant											
341	Structures and Improvements	42,628,262	0	2.88	1,227,694			57,833		916,553	253,308
342	Fuel Holders Producers and Accessories	19,177,727	69,467	5.21	1,000,969			12,426		(15,344)	1,003,887
343	Prime Movers	78,688,747	0	4.52	3,556,731			81,860		1,115,059	2,359,813
344	Generators	9,239,891	0	3.33	307,688			8,903		71,014	227,772
345	Accessory Electric Equipment	23,911,046	3,191,790	3.70	943,757			29,723		312,356	601,678
346	Miscellaneous Power Plant Equipment	2,733,649	68,247	5.00	138,389			208		28,499	109,682
Total Diesel Plant		176,379,323	3,329,504		7,175,228			190,952		2,428,137	4,556,139
Transmission Plant											
351	Clearing Land and Land Rights	2,530,029	0	1.91	48,324			0		24,924	23,400
352	Structures and Improvements	2,842,032	0	2.62	74,461			0		22,321	52,140
353	Station Equipment	7,005,319	1,027,366	2.63	197,750			1,723		159,056	36,971
354	Towers and Fixtures	13,222,695	342,455	2.68	358,957			0		40,180	318,777
355	Poles and Fixtures	359,765	0	3.78	13,599			0		(661)	14,281
356	Overhead Conductors and Devices	7,906,833	0	2.90	229,298			0		10,807	218,491
359	Roads and Trails	550,543	0	4.00	22,022			0		501	21,521
Total Transmission Plant		34,417,215	1,369,822		944,411			1,723		257,128	685,560
Distribution Plant											
361	Structures and Improvements	787,608	0	2.63	20,714			4,747		1,366	14,601
362	Station Equipment	1,272,691	26,000	3.33	42,814			613		23,156	19,044
363	Storage Battery Equipment	9,973	0	4.66	465			410		(7)	62
364	Poles, Towers and Fixtures	15,203,408	517,453	4.66	720,535			244,716		(126,056)	601,876
365	Overhead Conductors and Devices	6,148,315	130,000	4.00	248,533			87,394		(35,642)	196,780
366	Underground Conduit	56,068	0	5.00	2,803			2,581		(5)	228
367	Underground Conductor and Devices	191,292	0	4.97	9,507			4,610		784	4,113
368	Line Transformers	4,139,567	84,500	4.00	167,273			29,458		(1,912)	139,726
369	Services	2,452,455	58,500	3.43	85,122			29,597		3,052	52,474
370	Meters	1,390,459	121,000	4.00	58,038			1,384		(5,763)	62,417
371	Installations on Customer Premises	7,645	0	4.00	306			299		0	7
373	Street Lighting and Signal Systems	444,237	13,000	3.15	14,198			1,388		2,018	10,792
Total Distribution Plant		32,103,716	950,453		1,370,309			407,197		(139,008)	1,102,120

NORTHWEST TERRITORIES POWER CORPORATION

Schedule E, page 6 of 6

1997/98 AMORTIZATION PROVISION

		(\$'s)			Add:	Less:	Less:	Less:	Net	
DESCRIPTION		Original Cost	1997/98		Annual Amount	Amortization	Customer	Water and	Accumulated	Amortization
		at	Capital	Annual	Plus 1/2 Year	On Other	Contributions	Sewerage	Reserve	Provision on
		March 31, 1997	Additions	Rate	On Additions	Utility General			Variance	Fixed Assets
DEPRECIABLE PLANT										
General Plant										
303	Feasibility Studies/ In-house Course Develop.	173,634	0	20.00	34,727		0		0	34,727
390	Structures and Improvements	13,245,925	0	2.62	347,043		118,972		152,526	75,545
391	Office Furniture and Equipment	3,561,180	200,000	7.49	274,222		0		72,146	202,076
392	Transportation Equipment	3,594,818	500,000	8.91	342,573		0	1,549	87,045	253,979
393	Stores Equipment	148,218	0	9.89	14,659		0		(2,838)	17,496
394	Tools, Shop and Garage Equipment	99,340	0	8.52	8,464		714		(735)	8,485
395	Laboratory Equipment	265,885	0	5.26	13,986		0		3,185	10,800
396	Power Operated Equipment	857,525	0	5.00	42,876		0		43,102	(225)
397	Communication Equipment	888,208	0	6.67	59,243		0		7,464	51,780
398	Miscellaneous Equipment	310,335	0	6.67	20,699		984		(609)	20,325
118	Other Utility General	2,070,359	0			20,733		2,591	0	18,142
Total General Plant		23,145,068	700,000		1,158,493	20,733	120,669	4,140	361,286	693,131
Total Depreciable Plant		346,369,082	6,349,779		12,444,143	20,733	722,106	4,140	2,702,864	9,035,766
330	Land and Land Rights	827,688	0	0.00	0		0		0	0
340	Land and Land Rights	1,723,852	0	0.00	0		0		0	0
389	Land and Land Rights	176,422	0	0.00	0		0		0	0
Total Non Depreciable Plant		2,727,962	0		0		0		0	0
Total Electric Plant		349,097,044	6,349,779		12,444,143	20,733	722,106	4,140	2,702,864	9,035,766

CV 06852

SUPREME COURT

**IN THE SUPREME COURT
OF THE NORTHWEST TERRITORIES**

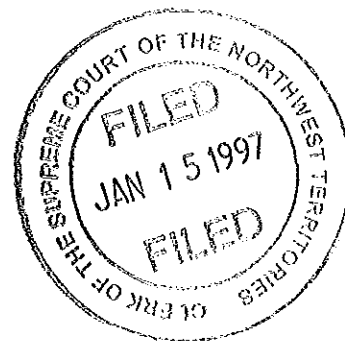
NORTHWEST TERRITORIES
POWER CORPORATION
Applicant

- and -

PUBLIC UTILITIES BOARD
Respondent

BOARD ORDER 1-97

**PUBLIC UTILITIES BOARD
203 - 62 WOODLAND DRIVE
BOX 4211
HAY RIVER NT X0E 1G1**



**THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES**

DECISION 26-2008

October 27, 2008

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided to its customers within the Northwest Territories, by seeking approval of the Phase 2 General Rate Application.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS

Joe Acorn	Chairman
John Hill	Vice-Chairman
William Koe	Member
Sandra Jaque	Member

BOARD STAFF

Louise Larocque	Board Secretary
Raj Retnanandan	Board Consultant
John Donihee	Board Counsel

ABBREVIATIONS

Application	Phase 2 General Rate Application
Board	Northwest Territories Public Utilities Board
BR	Board Information Request
Corporation	Northwest Territories Power Corporation
CSA	Customer Service Agreement
GNWT	Government of the Northwest Territories
GRA	Phase 2 General Rate Application
Hydro Communities	City of Yellowknife, Town of Hay River & Town of Fort Smith
HC	City of Yellowknife, Town of Hay River & Town of Fort Smith
IR	Information Request
kWh	Kilowatt-Hour
/.	Line
NTPC	Northwest Territories Power Corporation
p.	Page
R.S.N.W.T.	Revised Statutes of the Northwest Territories
TGC	Town of Inuvik, Village of Fort Simpson & Hamlet of Fort Liard
Thermal Generation	
Communities	Town of Inuvik, Village of Fort Simpson & Hamlet of Fort Liard
TPSP	Territorial Power Support Program

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1. BACKGROUND

By letter dated November 24, 2006, the Northwest Territories Power Corporation ("**NTPC, the Corporation**") submitted to the Northwest Territories Public Utilities Board ("**the Board**") its Phase 1 General Rate Application ("**Phase 1 Application**") for the fiscal years April 1, 2006 to March 31, 2007 and April 1, 2007 to March 31, 2008.

In its Phase 1 Application, the Corporation requested an order or orders of the Board to approve the 2006/07 and 2007/08 Revenue Requirement at \$79.909 million and \$84.331 million, respectively, including approval as required of the operating and maintenance expenses, amortization expenses and return on rate base. NTPC is also requesting an order or orders of the Board to approve the forecast 2006/07 and 2007/08 Rate Base, approve revised Terms and Conditions of Service, approve revised Maximum Corporation Investment levels, stabilization funds and accounting provisions.

The Board issued Decision 13-2007 dated August 29, 2007 addressing all matters arising from NTPC's Phase 1 Application. In this Decision, NTPC was requested to respond to a number of Board Directives.

By letter dated October 1, 2007, NTPC filed a response to Board Decision 13-2007 ("**Phase 1 Refiling**").

The Phase 1 Refiling was examined through a written process and the Board received written submissions from interested parties following NTPC's responses to interrogatories.

NTPC was directed to file its second Phase 1 refiling in accordance with the directions and approvals in Decision 17-2007 by November 30, 2007 together with rate schedules resulting from the Phase 1 second refiling.

By letter dated November 27, 2007, NTPC submitted responses to Decision 17-2007 addressing certain Board directives in Decisions 13-2007 and 17-2007, including the refiling schedules.

By letter dated December 5, 2007, the Board requested that interested parties provide their submissions by December 14, 2007 and NTPC will be allowed to respond by December 21, 2007.

The City of Yellowknife and the Towns of Hay River and Fort Smith ("**Hydro Communities**", "**HC**") filed their submission, by letter dated December 14, 2007 and the Town of Inuvik, Village of Fort Simpson and Hamlet of Fort Liard ("**Thermal Generation Communities**", "**TGC**") filed their submission, by letter dated December 17, 2007.

By letter dated December 21, 2007, NTPC filed a response to the interested parties' submission.

The Board had reviewed the information filed by NTPC and interested parties. The directions in Decisions 13-2007 and 17-2007 have been carried out to the Board's satisfaction. The Board issued Decision 19-2007 dated December 31, 2007 addressing all matters arising from NTPC's second Phase 1 refiling.

2. APPLICATION

On August 15, 2008, NTPC filed its Phase 2 General Rate Application ("**Application**", "**GRA**") for the fiscal year April 1, 2006 to March 31, 2007 and April 1, 2007 to March 31, 2008 to determine appropriate rates for their customers.

In its Application, NTPC requested order or orders of the Board to:

- a) Approving as final the Corporation's interim retail, wholesale and industrial rates for 2006/07 and all previous periods.
- b) Approving as final the Corporation's proposed 2007/08 retail, wholesale and industrial energy rates. The Corporation proposes to maintain the existing customer and demand charges for all rate classes.
- c) Approving the consolidation of the 2006/07 and 2007/08 General Rate Application shortfalls after transfers from the Diesel Communities Stabilization Fund; the Inuvik Stabilization Fund; the Norman Wells Stabilization Fund and the Taltson Fuel Stabilization Fund to offset the GRA Shortfall amounts.
- d) Approving the adjusted shortfall collection riders.
- e) Approving a change in the interest rate applicable to any outstanding shortfall balances in place beyond October 1, 2009. If the interest rate change is not approved then the Corporation is seeking to recover the shortfall balances over a 12-month period.
- f) Approving automatic fuel stabilization fund and automatic water stabilization fund riders.
- g) Approving standardized dates for stabilization fund applications.
- h) Approving the Stand-by Rate proposal.

- i) Approving the revisions to the Corporation's Terms and Conditions of Service.

NTPC stated the following in its Application:

The Corporation has developed its Phase II Application using a simplified approach. The Corporation has prioritized collecting outstanding balances related to the 2006/07 and 2007/08 GRA Shortfalls and the Stabilization Funds. The Corporation is proposing this simplified approach to Phase II in consideration of the 15% cap on base rate and shortfall rider increases; to reduce regulatory and administrative costs in light of the limited ability to rebalance rates between communities and rate classes and for reasons of intergenerational equity related to collecting shortfall and stabilization fund balances relating to costs already incurred to provide service to customers. Following the implementation of these rider adjustments, there would be very little ability for the Corporation to adjust base rates for most communities and rate classes. Therefore the Corporation is proposing only a very limited scope of base rate rebalancing.

(GRA, Executive Summary, p. ES-V)

Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letter dated August 19, 2008, directed NTPC to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories. The notice provided details of the GRA and invited interested persons to file a request with the Board for intervenor status. The notice also stated that any party already listed on the Phase 1 list will automatically be placed on the Phase 2 list.

The interested parties automatically placed on the Phase 2 list are the Hydro Communities, Thermal Generation Communities and Northland Utilities.

By letter dated August 19, 2008, the Board requested comments from NTPC and the interveners as to the required extent of the review process, including the need for an oral public hearing. In addition, the Board intends to combine the Phase 2 review with the review of NTPC's inter-affiliate code of conduct and conflict of interest guidelines (Directives 49 and 50 of Decision 13-2007).

After reviewing comments from all parties regarding the review process, the Board, by letter dated August 28, 2008, prepared a review schedule and requested comments. The Board received submission from HC, TGC and NTPC, all of which expressed no concerns with the schedule.

The Board, HC and TGC submitted information requests, to which NTPC responded on September 26, 2008.

On October 14, 2008, the Hydro Communities, the Thermal Generation Communities and NTPC filed their written argument. On October 21, 2008, HC, TGC and NTPC filed their written reply argument.

In this Decision, the Board will address all outstanding matters arising from NTPC's Phase 2 Application. The Board will issue a separate subsequent decision on the NTPC's proposed code of conduct.

3. FINALIZATION OF INTERIM RATES FOR 2006/07 AND ALL PREVIOUS PERIODS

In its Application, NTPC stated that it was seeking approval as final the NTPC's interim retail, wholesale and industrial rates for 2006/07 and all previous periods. NTPC provided a more detailed explanation of what it was seeking in its argument.

"Wholesale, retail and industrial rates for 2006/07 effective February 1, 2007 were granted interim approval in Board Decision 2-2007. The Corporation's Application notes that it is seeking final approval for interim retail, wholesale and industrial rates for 2006/07 and all previous periods.

Through an interrogatory to the Corporation, the HC inquired about the intent of the phrase "and all previous periods" in the Corporation's requested approval on page 1-1 of the Application. The Corporation's response noted that the statement was intended to ensure that there remain no outstanding matters related to rates charged in previous periods including final approval for industrial rates effective January 1, 2005 as approved on an interim basis in Board Order 4-2005.

The Corporation notes that the interim rates approved in Decision 2-2007 were subsequently adjusted, on an interim basis, by Order 20-2007. The Corporation also notes that variances between 2006/07 revenues at rates in place and approved 2006/07 test year revenue requirement will be addressed by way of shortfall riders. Therefore, the Corporation submits that its request for final approval of interim wholesale, retail and industrial rates for 2006/07 and all previous periods is prudent and reasonable, and should be approved by the Board." (NTPC Argument, p. 6)

In their reply argument, the HC stated that they do not object to final approval of the 2006/07 interim rates that were in effect during that period.

Views of the Board

The Board approves as final the NTPC's interim retail, wholesale and industrial rates for 2006/07 and all previous periods

4. FINALIZATION OF 2007/2008 BASE RATES

The NTPC is seeking approval as final the Corporation's proposed 2007/08 retail, wholesale and industrial rates as outlined in Appendix A and Schedule A.2 of the Application. The Corporation proposes to maintain the existing customer and demand charges for all rate classes.

"In Appendix 2 to Board Order 20-2007, the Board provided a determination of interim base rate adjustments effective January 1, 2008. The interim base rate adjustments were designed to allow the Corporation to fully collect the 2007/08 revenue requirement of \$81.389 million approved in Board Decision 19-2007. In Decision 17-2007 the Board approved the Corporation's 2007/08 miscellaneous revenues of \$0.862 million. As a result, the revenues to be collected through base rate adjustments effective January 1, 2008 were designed to collect \$80.527 million at approved 2007/08 sales volumes.

In Decision 4-2008, the Board varied Directive 14 of Decision 13-2007 and directed the Corporation to calculate its total 06/07 and 07/08 supplies and services expenses using forecast brushing expenses of \$126,000 for 06/07 and \$129,000 for 07/08.

By letter dated March 31, 2008 the Corporation submitted an application that requested approval of a method for allocating the brushing expenditure reductions amongst the communities in the test years 2006/07 and 2007/08. These adjustments were outlined in Schedule 1 to that application. The Board approved this method in Decision 16-2008.

As a result of the brushing adjustments, the interim base rates effective January 1, 2008 that were approved in Decision 20-2007 overcollect the 2007/08 revenue requirement (as adjusted for the reduction to brushing expense) by approximately \$0.272 million. Therefore, the Corporation is applying to adjust the base rates in place effective January 1, 2008 to reflect the revised brushing expense." (GRA, p. A-1 and A-2)

In addition to the brushing adjustment, the NTPC is also applying for a limited amount of rate rebalancing between certain communities and customer classes

in the Hydro zones. The NTPC's explanation for just limited rate rebalancing is as follows.

"As a result of the considerable rate pressures facing the Corporation and its customers related to diesel fuel prices and the GRA shortfalls, there is little if any ability at present for the Corporation to propose rate rebalancing between communities and customers classes. As such, the Corporation has not completed a full analytical cost-of-service study for the 2007/08 test year as would typically be included in NTPC's Phase II GRAs. Preparing and reviewing a cost-of-service study when there is virtually no ability to propose rate rebalancing between communities and customer classes would be expensive and not in the best interests of ratepayers. In the Corporation's view, customers are better off with a rate design focusing on collecting outstanding amounts related to costs that have already been incurred and a more simplified approach to rate rebalancing between communities. This approach also saves the considerable costs of undertaking a full Phase II proceeding when there is limited ability to rebalance rates. Further, the GNWT is currently conducting a review of rate regulation and subsidies that may impact future rate rebalancing directions between customer classes and communities." (GRA, p. 1-6 and 1-7)

The NTPC described the extent of the rate rebalancing.

"Following the calculation of the Shortfall rider, a very limited set of rate rebalancing was undertaken. The base energy rates for the communities of Dettah and Fort Resolution were raised as these communities had RCC ratios substantially below 95% while other customers on the Snare Yellowknife and Taltson systems had RCC ratios higher than 100%. Energy rates in Dettah and Fort Resolution were increased so that in combination with the shortfall riders in those communities there was a 15% increase over the base rates plus shortfall riders in place effective January 1, 2008.(Schedule 1.1)." (GRA, p. 1-6)

The HC stated the following in their argument.

"The January 1, 2008 Interim Rates as shown in Schedule 1.1 were adjusted downward by \$0.272 million to reflect the reduction to brushing

expenses approved by the Board in Decision 4-2008 and as shown in Schedule A.1. The proposed 2007/2008 base rates after the adjustments are also shown in Schedule 1.1. NTPC has applied for approval of these adjusted rates effective January 1, 2008. The Hydro Communities accept the adjusted base rates as shown in Schedule A.2.1 as reasonable.” (HC Argument, p. 4)

With regards to the rate rebalancing, the HC stated:

“Following the calculation of the shortfall riders, NTPC carried out a limited amount of rate rebalancing within the hydro communities to give effect to revenue to cost ratios for certain communities that were below the 95% target subject to the 15% cap based on a preliminary cost of service study that reflected the 2002/03 Board approved methods. In agreeing to a simplified process, the Hydro Communities had acknowledged in its letter of August 26, 2008 that a full review of the cost of service would provide little latitude for rate rebalancing between rate classes and communities. The limited rebalancing which NTPC has carried out appears reasonable to the Hydro Communities.” (HC Argument, p. 5)

The TGC did not comment on this matter in their argument or reply argument.

Views of the Board

The Board approves as final the Corporation’s proposed 2007/08 retail, wholesale and industrial rates as outlined in Appendix A and Schedule A.2 of the Application.

5. FINALIZATION OF SHORTFALL BALANCES AND RIDERS

5.1 Shortfall Balance

In compliance with a directive in Decision 20-2007, the NTPC is applying to consolidate the 2006/07 and 2007/08 shortfall balances into a single shortfall balance to be collected by community.

The calculation of the shortfall balances as of March. 31, 2008 is shown in Schedule B.1. The 2006/07 shortfall balance was \$1.462 million and the 2007/08 shortfall balance was \$7.877 million for a total combined shortfall of \$9.339 million.

Through the combined effect of the rider collections, the brushing adjustment and the interest, the forecast consolidated 2006/07 and 2007/08 balance by community as at September. 30, 2008 had declined to \$8.383 million, as shown by Schedule B.2.

In its argument, the NTPC stated the following.

“No intervenors posed interrogatories to the Corporation with respect to the consolidation of the 2006/07 and 2007/08 shortfalls or the calculation of the balance in the consolidated shortfall receivable at March 31, 2008. The Corporation submits that its calculation of the consolidated shortfall balance as at March 31, 2008 is consistent with the methods approved in Decision 16-2008 and should be approved.” (NTPC Argument, p. 7, /, 26-30)

Regarding the consolidated shortfall balance, the HC simply stated the following in its argument.

“The 2006/07 shortfall including interest to March 31, 2008 and the 2007/08 shortfall including interest to March 31, 2008 by community is shown in Schedule B.1 and the balances as at September 30, 2008 by community are shown in Schedule B.2. ...” (HC Argument, p. 4-5)

The HC did not express an opinion on the NTPC’s calculation of the consolidated shortfall rider however, since the shortfall riders flow directly from the shortfall balance; the HC seemed to implicitly approve the consolidated shortfall balance when they stated that they accept the shortfall riders as reasonable.

The TGC did not comment upon the consolidated shortfall balance.

Views of the Board

The Board approves the consolidation of the 2006/07 and 2007/08 shortfall balances into a single shortfall balance by community as calculated in Schedules B.1 and B.2 of the Application.

5.2 Shortfall Riders

The NTPC states in the Application that the shortfall riders currently in place, effective January 1, 2008, have been collecting revenue at a rate of about \$0.225 million/month. At that rate, it would take over three years to collect the consolidated shortfall balance plus approved interest. The NTPC states that this would lead to excessive intergenerational equity issues for the ratepayers.

The NTPC is applying for an increase to the existing shortfall rider to allow the recovery of the entire shortfall balance over an 18-month period from October 1,

2008 to March 31, 2010. The 18-month period was selected so that these riders would not overlap with the implementation of interim rates for the next GRA. Following the collection of the shortfall, the NTPC will file a reconciliation of rider collections and shortfall balances by community.

The calculation of the shortfall riders by community are shown in Schedule B.3.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule B.3: Proposed Shortfall Rider at October 1, 2008

Plant Number	Community	Forecast Sales From		Shortfall Rider with No Cap (¢/kWh)	Proposed Shortfall Rider at Oct. 1, 2008 with 15% Cap (¢/kWh)	Current Shortfall Rider per Board Order 20-2007 (¢/kWh)
		Shortfall Balance at Oct. 1, 2008 ¹ (\$000's)	Oct. 1, 2008 - Mar. 31, 2010 (MWh)			
		A	B	C	D	E
101/106/109	YK Snare System	3,306	301,607	1.10	1.15	0.50
104	Wha Ti	-92	2,303	(4.01)	(3.96)	(1.97)
105	Gameti	120	1,260	9.49	9.55	3.58
110	Lutzel K'e	-13	2,280	(0.57)	(0.52)	0.31
201/203	Taltson System	914	98,247	0.93	0.98	0.58
205	Fort Simpson	1,753	11,978	14.63	13.37	5.00
206	Fort Liard	410	3,166	12.96	13.02	5.02
207	Wrigley	286	864	33.15	28.50	11.01
208	Nahanni Butte	240	538	44.52	39.77	19.11
209	Jean Marie River	194	362	53.56	38.32	19.00
301	Inuvik	2,127	46,857	4.54	4.59	1.91
304	Norman Wells	-309	15,548	(1.99)	(1.93)	(1.03)
305	Tuktoyaktuk	-186	5,453	(3.40)	(3.35)	(2.19)
306	Fort McPherson	170	4,482	3.78	3.84	1.79
307	Aklavik	-191	4,088	(4.67)	(4.61)	(5.34)
308	Deline	74	3,751	1.98	2.03	0.22
309	Fort Good Hope	-141	4,191	(3.36)	(3.30)	(1.17)
310	Tulit'a	-121	2,132	(5.67)	(5.61)	(2.00)
311	Paulatuk	46	1,145	4.00	4.06	1.80
312	Sachs Harbour	118	1,023	11.58	11.63	2.97
313	Tsiigehtchic	-25	491	(5.13)	(5.08)	(1.22)
314	Colville Lake	-104	2,721	(3.83)	(3.77)	(14.48)
315	Ulukhaktok	-194	3,476	(5.57)	(5.51)	(2.28)
Total		8,383	517,964			

Notes:

1. From Schedule B.2

The NTPC applied a 15% rate cap on the combined impact of the base rate adjustments and the shortfall rider increases. The non-recovered shortfall in those communities that reached the 15% cap was then distributed across the

other communities by means of a 0.05 cent/kwh increase to the shortfall riders in those communities that were below the cap.

The HC stated the following in their argument.

“...NTPC designed rate riders to recover/refund these shortfalls/surpluses over 18 months. In order to limit the increases in existing base rates to 15%, the deficiency was then spread among the remaining communities who did not exceed the 15% cap. As shown in Schedule B.3, the amount of subsidy to limit the maximum increase in the shortfall rider for any one community was 0.05 cents per kWh. The Hydro Communities do not consider this to be an unreasonable amount to limit the cap on base rate increases at 15% for all communities.

...

The Hydro Communities accept ... the GRA shortfall riders as reasonable.” (HC Argument, p. 5)

The TGC did not comment upon the calculation or magnitude of the shortfall riders as applied for in the Application.

Views of the Board

Effective November 1st, 2008, the Board directs the NTPC to apply the shortfall riders as calculated in Schedule B-3 of the Application subject to an adjustment to account for the reduced 17-month collection period from November 1, 2008 to March 31, 2010 as well as an update to the applicable interest rate to October 27th, 2008. The NTPC is to continue to apply the 15% rate cap on the combined impacts of adjustments to the base rates and the shortfall riders.

5.3 Shortfall Interest Rate

The NTPC has applied for an increase in the interest rate that it is allowed to apply to the shortfall balance from 50% of the Bank of Canada Prime Business interest rate, as approved in Decision 16-2008, to Prime less 50 basis points.

“It is important to note that this reflects a very low short-term interest rate. As a result, it is not reasonable to customers or the Corporation for these outstanding balances to remain in place for extended periods. One of the implications of allowing these balances to persist beyond the next 12 months is that the Corporation has a limited ability to obtain financing at short-term interest rates. Allowing these balances to continue indefinitely may impact the Corporation’s ability to manage its short-term financing and put pressure on other uses of short-term financing, including the Corporation’s capital program. This would ultimately threaten the ability of the Corporation to earn its approved return on ratebase. Accordingly, the Corporation is applying for approval to charge an interest rate of prime less 50 basis points on any shortfall balances outstanding beyond October 1, 2009. This is the same interest rate presently applied to the stabilization funds. In the event that the interest rate change after 12 months is not approved, the Corporation will seek to collect the outstanding shortfall amounts over a 12 month period instead of an 18 month period.” (GRA, p. B-2, /, 1-13)

The NTPC provided a more substantial explanation in its argument.

“...The 18-month collection period already strains the Corporation's access to short-term financing and without an adjustment to the interest rate effective October 1, 2009, the Corporation cannot propose to carry the GRA shortfall receivable beyond that period.

In response to an interrogatory from the TGC, the Corporation provided additional information related to its access to short-term financing. The Corporation noted that it has an unsecured \$20 million operating credit line with its financial institution. The Corporation also noted that if it were to increase its operating line it would likely be subject to standby fees for any funds not used. This would increase the Corporation's finance expense and overall cost of borrowing to the detriment of customers.

The Corporation's application noted that it is applying to collect approximately \$15.430 million in receivables related to the GRA shortfall and stabilization funds as at October 1, 2008. If three quarters of the credit line is being used to finance a regulatory shortfall, the Corporation's ability to use the operating line to fund capital investment (pending conversion to long-term debt) is limited. This could hinder the Corporation's ability to deliver capital investment that is required to maintain and improve the Corporation's infrastructure. Without access to the necessary level of short-term financing, the Corporation would have to delay, defer or forego capital projects it would otherwise pursue to maintain its service level to customers. Clearly this outcome would adversely affect customers and not be consistent with the guiding principles of utility regulation.

The Corporation respectfully submits that its proposal to collect the outstanding shortfalls over an 18 month period and change the interest rate applicable to the shortfall to a level equal to the Bank of Canada Prime Business rate less 50 basis points effective October 1, 2009 is a reasonable proposal. This proposal balances the rate impact of the shortfall collection with the limitations on the Corporation's access to short-term financing and should be approved." (NTPC Argument, p. 13, / 32 – p. 14, / 27)

The TGC stated in its argument that the basis upon which the Board applied the current interest rate has not changed and the Board should reject the requested interest rate increase.

The NTPC responded to the TGC in its reply argument.

"...The Corporation acknowledges the concern expressed by the Board in relation to the existence and size of the 2007/08 shortfall. However, contrary to TGC's assertion, NTPC is not attempting to undo the Board's direction. Whereas normally the collection period would be over 12 months, NTPC has applied to collect the shortfall balances over 18 months in order to mitigate the rate impacts on customers. However, that collection period is reasonable only with an increase in the interest rate. If the interest rate increase for months 13 through 18 is not approved, then NTPC is seeking to collect the balances over a 12 month period at the lower interest rate.

The Corporation is applying to collect approximately \$15.430 million in receivables related to the GRA shortfall and stabilization funds as at October 1, 2008 (which amounts to approximately three quarters of its operating line of credit). The present interest rate reflects a short-term interest rate, however NTPC has a limited ability to obtain financing at short-term interest rates and that access continues to tighten in the current financial market. When three quarters of NTPC's operating line is used to finance the regulatory shortfall, the Corporation has limited ability to use the operating line to fund capital investment." (NTPC Reply, p. 8, /, 21-35)

The HC also commented on this matter in its reply argument.

"It is clear that the Board reduced the interest rate on outstanding balances by one-half due to the late filing of the 2006/07/08 GRA. It should be further noted that the recovery of the remaining balances in the GRA shortfall represents one of the major reasons why some communities exceed the 15% cap on rate and rider increases and has led to the BR-NTPC-1 Proposal to recover the Balance Remaining Fuel Rider from all communities. The Hydro Communities submit that the shortfalls would have been materially less had the 2006/07/08 GRA been filed earlier thus avoiding the compounding collection of GRA and Fuel/Water shortfalls.

NTPC goes on to suggest that it ought to receive interest on outstanding shortfall balances at a rate of the Prime Business Rate less 50 basis points because the 18 month collection period strains its access to short term financing. NTPC exaggerates this situation when it claims that it is applying to collect \$15.4 million of short term receivables as at October 1, 2008. The decrease in diesel fuel prices will virtually eliminate the \$5.8 million required to "keep-up" with fuel price increases. Further, the HC have disputed the inclusion of the fuel costs related to the Bluefish capital improvements in the amount of about \$1.8 million. These two adjustments would significantly reduce the October 1, 2008 short term receivables. Finally, the remaining balances after these adjustments will have been reduced to about one-third by October 2009 assuming an 18 month shortfall recovery period for most communities." (HC Reply, Section 6)

Views of the Board

Given the extended 17-month collection period for the GRA shortfall, the Board approves the NTPC request to apply interest at the rate of Prime minus 50 basis points for the remaining shortfall balance after October 1, 2009.

6. ADJUSTMENTS TO STABILIZATION FUND BALANCES AND RIDERS

6.1 Rider Design

As described in Appendix B of the Application, the NTPC operates 6 stabilization funds, 5 for fuel and 1 for water. The 6 funds are listed below.

<u>Stabilization Fund</u>	<u>Balance at Oct. 1, 2008</u>	<u>Trigger</u>
Diesel Communities Fuel	\$2.375 million	\$1 million
Inuvik Fuel	\$0.859 million	\$0.250 million
Norman Wells Fuel	\$0.740 million	\$0.100 million
Fort Smith Fuel	\$0.050 million	\$0
Snare Fuel	\$1.369 million	\$1 million
Snare Water	\$4.654 million	\$3 million

The funds had all accumulated balances due to the increases in the cost of fuel and these balances would continue increasing unless the fund riders were adjusted to account for the higher fuel costs. The NTPC proposed increasing the fund riders with both “catch up” and “keep up” components. The “catch up” components would be designed to retire the existing fund balances (with the exception of the Snare water fund which was only to be brought down to its \$3 million trigger) by March 31, 2010 while the “keep up” components would track the differences between those assumed in the 2007/08 test year and current fuel prices.

The NTPC's intention was that the stabilization fund riders would be applied over and above the 15% cap for the rate base adjustment and shortfall riders. The total combined rate impact on a percentage basis was shown in Schedule 1.2.

NTPC 2006/07 and 2007/08 Phase II GRA Rate Finalization Application
Schedule 1.2: Rate and Rider Change Summary

Plant Number	Community	% Changes without stab fund riders					% Changes with stab fund riders				
		Residential	General Service	Lighting	Wholesale	Industrial	Residential	General Service	Lighting	Wholesale	Industrial
		A	B	C	D	E	F	G	H	I	J
101	Yellowknife				4.17%	1.88%				11.31%	10.78%
108	Behchoko	2.54%	2.03%	0.84%			6.79%	5.44%	2.27%		
109	Dettah	15.00%	15.00%	15.00%			19.25%	18.41%	16.90%		
104	Wha Ti	-2.43%	-2.64%	-1.46%			10.31%	11.11%	6.25%		
105	Gameti	5.07%	4.36%	3.86%			14.75%	12.70%	11.27%		
110	Lutsel K'e	-1.11%	-1.20%	-0.69%			12.91%	13.92%	8.03%		
201	Fort Smith	1.29%	1.60%	0.85%	0.21%		2.04%	2.56%	1.35%	1.64%	
203	Fort Resolution	15.00%	15.00%	15.00%			15.67%	15.77%	15.41%		
205	Fort Simpson	12.76%	15.00%	11.12%			29.07%	33.99%	25.44%		
206	Fort Liard	11.65%	13.22%	7.04%			27.07%	30.60%	16.58%		
207	Wrigley	15.00%	13.85%	10.20%			24.39%	22.55%	16.69%		
208	Nahanni Butte	15.00%	11.11%	9.11%			26.23%	19.55%	16.08%		
209	Jean Marie River	15.00%	10.55%	7.61%			26.49%	18.76%	13.60%		
301	Inuvik	4.65%	5.32%	3.91%			14.88%	16.89%	12.56%		
304	Norman Wells	-0.76%	-0.89%	-0.56%			60.84%	68.12%	43.66%		
305	Tuktoyaktuk	-1.74%	-1.97%	-1.26%			14.34%	16.21%	10.49%		
306	Fort McPherson	2.77%	3.05%	2.46%			17.04%	18.75%	15.15%		
307	Aklavik	1.24%	1.31%	0.90%			20.11%	21.11%	14.67%		
308	Deline	2.40%	2.55%	2.84%			16.69%	17.75%	19.68%		
309	Fort Good Hope	-3.08%	-3.55%	-2.63%			12.45%	14.24%	10.66%		
310	Tulita	-4.22%	-4.39%	-3.64%			8.74%	9.05%	7.56%		
311	Paulatuk	1.88%	1.99%	1.69%			11.54%	12.24%	10.40%		
312	Sachs Harbour	6.27%	6.74%	5.81%			15.18%	16.29%	14.09%		
313	Tsigehtohic	-3.56%	-4.03%	-2.78%			6.92%	7.84%	5.44%		
314	Colville Lake	4.64%	5.33%	1.87%			10.26%	11.77%	4.16%		
315	Ulukhaktok	-4.60%	-5.07%	-3.47%			10.58%	11.67%	8.06%		

The Board was concerned about the high proposed increases with the extreme case being Norman Wells with total increases of over 60%. For the Diesel Communities, Inuvik and Norman Wells fuel funds, the largest components of the rate rider increases related to the "keep up" portion of the riders, as shown below, so the bulk of the increases were driven by current fuel prices as opposed to the accumulated balances.

<u>Stabilization Fund</u>	<u>Keep Up</u>	<u>Catch Up</u>	<u>Total Rider</u>
Diesel Communities	8.58 cents/kwh	4.04 cents/kwh	12.62 cents/kwh
Inuvik	5.86 cents/kwh	1.83 cents/kwh	7.70 cents/kwh
Norman Wells	18.75 cents/kwh	4.76 cents/kwh	23.51 cents/kwh

The Board sent the NTPC a number of information requests concerning alternative rate design options with the most significant being the question of whether or not the increase in fuel prices in 2008 could be considered an extraordinary event that would justify deviating from strict community-based ratemaking by sharing some costs equally (on a cents/kwh basis) across all NTPC communities and customer classes.

The NTPC responded by combining the various design options in the Board's IRs into a new alternative rate design for the Phase 2 GRA. The NTPC described this alternative option in its response to IR BR-NTPC-1.

"The Application seeks to address a major rate adjustment requirement that faces NTPC and its customers. The scale of adjustment required is such that the rate design criteria traditionally applied by NTPC and the Board could not all be met simultaneously. As a result, NTPC applied rate design criteria based on the following sequence:

- 1) **Collect utility costs within a reasonable period of time:** In this regard, rates were designed to include the following amounts:
 - a. Approximately \$5.8 million in annualized riders related to increases in fuel prices since the last NTPC GRA to the present time (the "keep up" component of the diesel communities, Inuvik and Norman Wells fuel funds (the "primary power fuel funds")); plus
 - b. One time amounts of approximately \$15.4 million comprised of \$8.4 million for GRA shortfalls per Schedule B.2, \$2.4 million for the Diesel Communities Fuel Fund, \$0.9 million for the Inuvik Fuel Fund, \$0.8 million for the Norman Wells Fuel

Fund, \$1.4 million for the Yellowknife Fuel Fund, \$0.05 million for the Ft. Smith Fuel Fund, plus \$1.7 million to bring the Snare-Yellowknife Water Fund to the trigger level.

All of which yields an annualized amount of approximately \$16.065 million. While this does not precisely yield \$0 balances for each of the funds 18 months out (due to both interest being charged, as well as: i) for the primary power fuel funds, forecast changes to fuel prices over the coming 18 months, and ii) for the water and standby fuel funds, anticipated charges to the funds over the coming 18 months) it does provide a reasonable basis to begin to implement the rolling 6 months stabilization fund revision process proposed by NTPC.

- 2) **Must avoid inter-community cross-subsidization where possible:** NTPC proposes to recover all noted amounts from the communities or groups of communities where the costs arise, consistent with the strict interpretation of community-based rates applied in NWT to date.
- 3) **Within the above two constraints, must seek to not raise rates to any given customer class by more than 15%:** While this criteria could be met for the shortfall component of the application, it was not possible to achieve this rate impact constraint with respect to fuel fund riders.

In response to BR.NTPC-2, a number of alternative scenarios are provided that set out variations in respect of the management of the stabilization funds.

A comprehensive alternative approach to the application can be developed to reprioritize the above rate design criteria plus adopt certain key variations in the rate design methodologies for implementation as at November 1, 2008, as follows (in sequence):

- 1) **Base Rate Adjustments:** Implement the required base rate adjustments for the brushing expense adjustment, as set out in the GRA Phase II Application.
- 2) **Stabilization Funds:** Per BR.NTPC-2(b) and BR.NTPC-4 (update for new fuel prices, Nov 1 implementation, and other adjustments

as described in that response), implement two stabilization fund adjustment mechanisms:

- a. **Crystallized “Catch-up”:** Per BR.NTPC-2(b), crystallize all fuel fund balances as at October 31, 2008, as well as the amounts to which the Snare-YK water fund exceeds the trigger levels as of that date, and charge to all customers on the system (including industrial and wholesale including NUL(NWT)) on an equal cents/kW.h basis over 17 months (now must assume November 1, 2008 rate implementation date through approximately March 31, 2010, or until fully collected). The levelized rider to be applied is 1.62 cents/kW.h.
 - b. **“Keep up”:** Adopt an “iterative” approach to stabilization funds to target approximately \$0 balances 17 months out (March 31, 2010) for all funds except the Snare-YK water fund, which would target approximately the \$3 million trigger level. In preparing this forecast, use updated fuel price forecasts for current price levels (effective as of September 19, 2008) which are approximately US\$103/bbl (approximately US\$19/bbl lower than in the Application).
- 3) **GRA Shortfall Riders:** Implement GRA shortfall riders as per the application with the exception of those communities and customer classes which would see cumulative rate changes in excess of 15% at the time of implementation (November 1, 2008) including all riders and stabilization fund amounts – those customer classes and communities would be:
- a. **At November 1, 2008,** have their GRA shortfall rider set such that their overall rate change is capped at 15%.
 - b. **At April 1, 2009,** implement a further increase as needed to target collection of the full shortfall within 12 months from that date, but in any event no more than 10%, (consistent with Board Decision 11-2008). Maintain all the shortfall riders in place until the full NTPC companywide GRA shortfall balance is collected (i.e., do not turn off riders community by community).

This alternative scenario exhibits some areas of significant benefit compared to the NTPC Application, with the exception that it does not

strictly adhere to the “no cross-subsidization between communities” criteria. In any event, it is an approach that can be readily implemented if preferred by the Board, and deserves due consideration in this regard.” (IR Response BR-NTPC-1)

The driving factor behind this alternative rate design scenario is the NTPC’s response to IR BR-NTPC-2(a):

“In the Corporation’s view it would be reasonable to consider the significant increase in diesel cost in the past 12 months to be an extraordinary event with the impacts shared across all NTPC communities and rate classes.”(IR Response BR-NTPC-2(a))

The impact of the new alternative scenario versus the original Application was shown In Table 1 from NTPC’s September 26, 2008 IR cover letter.

Table 1: Rate Impacts - percentage change including all riders and rate changes

	Original Application			BR-1 Scenario					
	Oct 1, 2008 Rate Impact			Nov 1, 2008 Rate Impact			Add'l Apr 1, 2009 Rate Impact		
	Resid	GS	Streetlig	Resid	GS	Streetlig	Resid	GS	Streetlig
Behchoko	6.8%	5.4%	2.3%	11.4%	9.1%	3.8%			
Dettah	19.3%	18.4%	16.9%	11.3%	9.1%	5.1%			
Wha Ti	10.3%	11.1%	6.2%	1.8%	1.9%	1.1%			
Gameti	14.8%	12.7%	11.3%	8.0%	6.9%	6.1%			
Lutsel K'e	12.9%	13.9%	8.0%	3.5%	3.7%	2.2%			
Fort Smith	2.0%	2.6%	1.4%	11.5%	14.7%	7.7%			
Fort Resolution	15.7%	15.8%	15.4%	10.2%	11.8%	6.2%			
Fort Simpson	29.1%	34.0%	25.4%	15.0%	15.0%	15.0%	6.1%	10.0%	3.0%
Fort Liard	27.1%	30.6%	16.6%	15.0%	15.0%	10.1%	1.8%	4.4%	
Wrigley	24.4%	22.6%	16.7%	15.0%	15.0%	14.9%	8.4%	6.3%	
Nahanni Butte	26.2%	19.5%	16.1%	15.0%	15.0%	13.0%	7.7%	1.0%	
Jean Marie River	26.5%	18.8%	13.6%	15.0%	15.0%	15.0%	10.0%	7.8%	0.6%
Inuvik	14.9%	16.9%	12.6%	9.7%	11.0%	8.2%			
Norman Wells	60.8%	68.1%	43.7%	15.0%	15.0%	12.8%	3.5%	6.1%	
Tuktoyaktuk	14.3%	16.2%	10.5%	3.5%	3.9%	2.5%			
Fort McPherson	17.0%	18.7%	15.1%	7.3%	8.0%	6.5%			
Aklavik	20.1%	21.1%	14.7%	7.1%	7.5%	5.2%			
Deline	16.7%	17.7%	19.7%	6.9%	7.3%	8.1%			
Fort Good Hope	12.5%	14.2%	10.7%	2.0%	2.2%	1.7%			
Tulita	8.7%	9.0%	7.6%	0.0%	0.0%	0.0%			
Paulatuk	11.5%	12.2%	10.4%	4.9%	5.2%	4.4%			
Sachs Harbour	15.2%	16.3%	14.1%	8.9%	9.5%	8.2%			
Tsiigehtchic	6.9%	7.8%	5.4%	-0.2%	-0.2%	-0.2%			
Colville Lake	10.3%	11.8%	4.2%	6.3%	7.2%	2.5%			
Ulukhaktok	10.6%	11.7%	8.1%	0.4%	0.4%	0.3%			
Yellowknife Wholesale		11.3%			15.0%			5.0%	
NUL (NWT) Wholesale		10.8%			15.0%			10.0%	
Industrial		1.6%			15.0%			8.6%	

In preparing the original Application and this alternative scenario, the NTPC used forecast fuel prices for January 2009. In developing the alternative scenario, the NTPC updated that January 2009 forecast from August 5th (oil at \$122/bbl) to September 26th (oil at \$103/bbl). The 2007/08 test year forecast was \$75/bbl.

In its argument, the NTPC stated the following.

“Although it does not strictly adhere to the longstanding “no cross-subsidization between communities” rate design criterion normally employed in the NWT, this alternative scenario exhibits some areas of significant merit. In particular, this rate design option recognizes the extraordinary circumstances surrounding fuel price increases in 2008 and implements an equal cents per kilowatt-hour for all communities and rate classes to retire existing balances in all fuel stabilization funds and to return the Snare-Yellowknife water stabilization fund to the trigger level. In situations where fuel costs have increased to this degree, maintaining a 15% cap on rate increases requires a mechanism to share some fuel costs across systems. Further, as the Corporation noted in its Application, the magnitude of cost pressures related to fuel price increases and the 2007/08 shortfall indicates that there is little to no ability to undertake rate rebalancing between communities and rate classes. This places pressure on the long-standing rate design objective to move toward revenue to cost coverage ratios of 95% to 105%. However, in the current circumstances the Corporation believes there is merit in the approach described in BR.NTPC-1. Rate design is always an exercise in achieving balance between sometimes competing rate objectives.

The Corporation notes that other utility regulators faced with extraordinary circumstances have implemented rates that do not necessarily conform to the normal rate design criteria employed in the jurisdiction. In its Application the Corporation provided an example from the Manitoba Public Utilities Board where that Board implemented an across the board rate increase to all rate classes in recognition of an unusually severe drought.

In the Corporation's view, the alternative rate design approach summarised in BR.NTPC-1 is preferable to the approach included in the Application. The Corporation submits that the rates summarised in Table 1 and Table 2 can be readily implemented if preferred by the Board, and deserve due consideration in this regard.” (NTPC Argument, p. 12, *l.* 5 – p. 13, *l.* 7)

The HC stated the following in their argument.

“While the changes in fuel prices as noted in the original Application may have constituted an “extraordinary event,” the changes in fuel prices must now be evaluated in the extraordinary circumstances of the financial markets and oil prices that have occurred over the last couple of weeks. NTPC states that “World oil prices and diesel fuel prices have risen

substantially since the 2006/07 and 2007/08 test year. This places further pressure on rates.” The footnote to this statement says “As an example, the 2007/08 fuel forecast assumed a NYMEX price of \$75/bbl (\$US) for the 2007/08 summer resupply season. NYMEX forecasts available August 5, 2008 are approximately \$120/bbl (\$US).” It must be noted at this point that the NYMEX price for crude oil by the September 26, 2008 update had decreased to \$107/bbl (\$US) and on October 13, 2008 was \$81.40 for November, \$81.89 for December, averaged \$82.93bbl (\$US) for January-June 2009 or several dollars above the GRA forecast levels.

...

The Hydro Communities submit that recent events (oil prices) have dramatically reduced the “keep-up” portion of the proposed Stabilization Fund Riders as shown in Schedule C.1 to the point where the fuel price changes from the GRA should no longer be considered to be an “extraordinary event.” The HC consider that the “Balance Retirement Component” may be reasonably reflective of costs incurred up to September 30, 2008 but should still be updated and designed for recovery over 18 months. However, the updated “Keep-Up” or Fuel Price Variance component of the shortfalls and rider amounts no longer warrant the averaging or sharing concepts reflected in the examples provided in BR-NTPC-1, 2 and 4. The Hydro Communities submit that it is essential that Schedule C.1 be updated by way of a compliance filing to reflect the latest actual and forecast fuel costs.

The Hydro Communities are strongly opposed to the “collective” or “crystallized” proposals outlined in BR-NTPC-1, 2 and 4 and submit that much of the rationale for such an approach has been eliminated due to recent drastic reductions in world crude oil and diesel fuel prices.

...

In conclusion, the Hydro Communities submit that each Stabilization Fund should continue to be treated on a stand-alone basis, the Balance Retirement Component in each fund should be recovered the 17 month period November 2008 through March 2009 and the Price Variance Component in each fund should be designed to bring the Fuel Stabilization Funds to zero and the Water Stabilization Funds to the trigger amount over the 17 month period November 2008 through March 2009 based on the latest diesel fuel price information available at the time of a compliance filing...” (HC Argument, p. 6-9)

The TGC stated the following in its argument.

“The TGC note NTPC has addressed in detail how it can adhere to the above noted Board determination and keep the total rate increase limited to 15% i.e. by way of a “comprehensive alternative approach to the application”.

The TGC recommend NTPC be directed to re-file in compliance with Decision 11-2008 such that the total rate increase is limited to 15%, using the “comprehensive alternative approach to the application.” As part of this exercise, the TGC recommend the Board direct the Corporation to use the most recent fuel price forecasts to compute the “keep up” amounts; the current fuel prices are significantly lower than the US \$103/bbl cited by NTPC.” (TGC Argument, p. 12)

The NTPC responded to the HC by acknowledging that the alternative rate design would increase rates in Yellowknife from what had originally been proposed in the Application and so the ratepayers under the Territorial Power Support Program (“**TPSP**”) would be affected. The NTPC estimates that the TPSP ratepayers who use 700 kwh/month would see their rates increase from \$12 in the Application to \$16 in the alternative design. The NTPC points out however, that residential users above 700 kwh and many commercial customers would not be protected from the high rate increases in the Application. Commercial ratepayers would likely pass the increases on to their customers in these communities.

The NTPC also points out that the City of Yellowknife has in the past supported sharing costs across rate zones and refers specifically to Decision 12-94 in which the City argued in favor of costs being spread across the Northwest Territories to avoid rate shock in Yellowknife.

The NTPC concluded by stating:

“NTPC continues to seek approval of its Application. However, as noted in its Written Argument, in the Corporation's view, the rate design approach illustrated in BR.NTPC-1 has considerable merit and should be given due consideration by the Board. Further, a combination of NTPC's proposal and the scenario outlined in NTPC's response in BR.NTPC-1 may also be a reasonable alternative.

NTPC reiterates its position that the extreme volatility in fuel prices constitutes an extraordinary event. However, NTPC does not believe that further updates to the price of fuel are warranted at this time for several reasons. Approximately 73% of the annual re-supply prices have already been set and were set when fuel prices were higher. Further, NTPC updated its fuel prices during the IR process. Those prices were updated to September 26, 2008 based upon the best information available to the Corporation at the time. NTPC submits that continual updating is impractical and gives no certainty. In addition, changes in world fuel price are not immediately reflected in costs to NTPC but are subject to a time lag.” (NTPC Reply, p. 3, /, 13-26)

In its reply argument, the HC devotes considerable discussion to the unfairness of the Board's consideration and potential implementation of the alternative rate design when the HC had agreed to participate in this simplified process with no knowledge that it would be faced with such a proposal.

The HC reinforces its earlier argument that the declining price of fuel has decreased, and perhaps now eliminated, the “keep up” portion of the fund riders with the price of oil dropping close to or below the reference price of \$75/bbl for the 2007/08 test year. The HC argues again that the fuel prices need to be updated to give a true evaluation of the current situation and provide some sample calculations to support its position.

The HC also suggests that perhaps the 15% rate cap can be maintained for all communities by spreading out the combined increased of all adjustments and riders to a longer period such as 24 months instead of the 17 months now available to March 31, 2010.

The HC summarizes its position as follows:

“The question that must be asked is whether these reduced shortfalls still constitute an “extraordinary event” or whether there is a viable alternative solution. The Hydro Communities submit that the updated pricing shows that the extraordinary event has been largely mitigated by the recent reductions in crude oil and diesel fuel prices. Further, the existing TPSP will largely mitigate these increases for most residential customers and mitigate it to some degree for general service customers. However, if the Board does not wish to recognize the subsidy programs that will be in place at least until the GNWT Rate Review is completed then it could consider a longer recovery period of say 24 months to limit increases to 15% or less. The Hydro Communities submit that cross-subsidies between rate zones can and should be avoided at least until such time as the GNWT has completed its Rate Review in 2009.” (HC Reply, Section 5)

The TGC argue in their reply in favor of the alternative rate design. They point out that although prices are currently low, the price is volatile and subject to large swings that are difficult to predict.

The TGC also argue that the Board and other regulators have deviated from their normal rate design criteria when faced with extraordinary circumstances.

Views of the Board

In Decision 20-2008, the Board stated the following:

“Beyond the concepts of rate stability and intergenerational equity, there must also be a general fairness to the method of determining rates. It is the Board’s view that, under certain circumstances, maintaining a fair regulatory system could require deviating from the Board’s current practice of community-based rates in favor of sharing costs across all communities and customer classes in the event of extraordinary conditions or events.” (Board Decision 20-2008, p. 4)

It is the Board's view that the significant increase in the cost of fuel from late 2007 to the summer of 2008 constitutes just such an extraordinary event as was contemplated by the Board in Decision 20-2008. Had fuel prices stayed where they were in the summer of 2008, the Board would be fully justified in deviating from its normal practice of community-based rates in favor of sharing costs across all communities and customer classes in an effort to retire the existing fuel fund balances and ease the burden upon the highly impacted communities.

However, the Board cannot ignore more recent world events. The extraordinary crisis in the world economy has produced swift and large decreases in the cost of fuel as well as decreases in interest rates. Essentially one extraordinary event has been overtaken, and substantially mitigated, by another.

The Board agrees with the HC that the large decreases in the price of fuel will significantly decrease or even eliminate the "keep up" components of the fuel riders. As the "keep up" components constituted the majority of the proposed fuel rider increases, the impacts upon those communities have been substantially lessened to the point that the total percent increases will have declined to much more reasonable levels than was proposed in the Application.

In light of the improved situation, the Board cannot now justify deviating from its normal practice of community-based rate design in favor of sharing costs across all communities and customer classes. The Board will not approve the alternative rate design as proposed by the NTPC in its response to IR BR-NTPC-1.

Having made that decision, the Board still needs to deal with the fact that some communities would still be faced with total rate increases on November 1st which exceed the 15% rate increase cap that the Board has adopted. The HC

suggested extending the collection period beyond March 31, 2010 to allow a longer period of collection such as 24 months to keep the rate increase lower.

Having removed cost sharing as an option, the Board is faced with either increasing the collection period or increasing the allowed rate cap. The Board would prefer for the full collection of all shortfalls to occur prior to any new interim rate riders coming into effect from the next Phase 1 GRA so the Board would prefer to maintain the March 31, 2010 target. To accommodate this desire, the Board is prepared this time to allow the total combined rate increase on November 1st for any community or customer class to be 20%.

Another factor in favor of increasing the rate cap to 20% is that the decreased cost of fuel and the reduction/elimination of the “keep up” component of the riders provides an opportune time to try to reduce/eliminate the stabilization fund balances. Fuel costs will inevitably rise again and it would be best if the stabilization fund balances had been significantly reduced or eliminated before this occurs.

While maintaining the 15% cap on adjustments to base rates and the shortfall riders, the Board directs NTPC to apply a 20% total cap to the combined impact of adjustments to base rates, shortfall riders and stabilization fund riders.

The Board agrees with the HC and directs the NTPC to design the stabilization fund riders to bring the fuel fund balances to \$0 and the Snare water fund balance to its trigger amount by March 31, 2010.

The Board notes that the price of oil has now dropped below \$70/bbl and agrees with the HC and the TGC that more recent forecast should be used by the NTPC. The Board directs the NTPC to use an updated oil price and interest rate from

October 27, 2008 when designing the stabilization fund rate riders for implementation on November 1, 2008.

While the Board has not approved cost sharing in this instance, that does not mean that this matter will not be considered by the Board again. The Board recognizes that this decision is taking advantage of the currently lower prices of fuel. Given the volatile state of the world economy, fuel prices might just as quickly start rising and again place some of the communities into the very difficult position of trying to eliminate fuel fund balances while at the same time trying to keep up with rising fuel prices. The Board expects the NTPC to closely watch this situation and, if necessary and regardless of any schedule, to come back to the Board with suggested rate designs, potentially including cost sharing, should the situation start getting out of hand again.

6.2 Standardized Dates for Rider Adjustments

The NTPC is requesting approval to file applications by February 15 and August 15 for stabilization rider adjustments to be effective April 1 and October 1. The NTPC states:

“In the Corporation’s view, this will benefit customers by providing more regular and predictable price changes. It will also ensure fairness to future customers by improving the timing between when fuel cost increases are incurred and when those costs are collected from customers. Further, the proposed timing of the rider changes avoid the summer and winter holiday periods. Finally, in the Corporation’s view this is consistent with the intent of the 1995/98 Phase I negotiated settlement that the rider adjustments be automatic, with Board review of the calculation of proposed riders as necessary.” (GRA, p. C-8, I. 1-7)

The NTPC provided additional information in its argument.

“Through interrogatories to the Corporation, intervenors requested additional information and clarification with respect to NTPC's proposal for future rider adjustments. The Corporation provided additional information in this regard, stating:

To be specific, the Corporation's proposal with respect to future revisions to stabilization funds is to make the process as routine and automatic as possible, as follows:

1) For the diesel communities, Inuvik and Norman Wells stabilization funds: Each 6 months (April 1 and October 1) implement new stabilization fund riders that comprise 2 components: 1) for the "keep up" (or fuel price variance) component, ensure the base riders in place (1.000 index) recovers the difference between the weighted average price for fuel (as at the date of application) and the most recent GRA price (and based on forecast 12 month generation and weighted average GRA plant efficiencies); and, 2) for the "catch up" (or balance retirement) component, take the full fund balance and divide by the forecast 12 months sales to determine the base rider (1.000 index). These values would be updated on a rolling basis at each 6 month update.

2) For the standby fuel funds (Fort Smith and Yellowknife): Each 6 months (April 1 and October 1) implement new stabilization fund riders that comprise only a "catch up" (balance retirement) component, based on recovering the full fund balance at the time of the application divided by the forecast 12 months sales to determine the base rider. These values would be updated on a rolling basis at each 6 month update.

3) For the Snare Yellowknife Water Stabilization Fund: Each 6 months (April 1 and October 1) implement new stabilization fund riders that comprise only a "catch up" (balance retirement) component, based on recovering the amount by which the fund exceeds the \$3 million trigger (plus or minus) at the time of the application divided by the forecast 12 months sales to determine the base rider. These values would be updated on a rolling basis at each 6 month update.

The approach proposed by NTPC under (3) above could lead to water stabilization fund riders being reduced, for example, if the fund was not used within a 6 month period, but the sales were higher than forecast so

collections were ahead of forecast.” (NTPC Argument, p. 15, / 22- p. 16, / 29)

The HC stated in its argument that fuel prices, fund balances and updated riders should be reviewed on a regular 6 month basis.

The TGC do not oppose the regular adjustment applications but recommend that the Board no longer permit the NTPC to collect interest of outstanding balances.

The NTPC responded to the TGC in its reply argument.

“The TGC appear to misunderstand the Corporation's proposal. The Corporation is simply proposing to review the status of the stabilization fund balances and riders every six months. This may lead to increases or decreases to riders or no change to the riders. It will not eliminate the lag between when fuel expenses are incurred and when the stabilization fund balances are collected or refunded. NTPC has not applied to change the trigger for these funds, therefore, even with a six month review of the stabilization fund riders there will still be material balances in the funds at times. This is demonstrated by a review of the stabilization fund balances using the iterative approach to calculating the stabilization fund riders in the Corporation's response to BR.NTPC-2. This clearly indicates the need for the Corporation to have access to financing for the balances in the stabilization funds.” (NTPC Reply, p. 9, / 7-16)

Views of the Board

The Board will not accept the TGC recommendation regarding interest. The Board does not see how 6-month adjustments warrants removing the collection (or paying) of interest by the NTPC.

The Board approves the NTPC's request to file applications by February 15 and August 15 of each year for stabilization rider adjustments to be effective April 1 and October 1 of each year.

6.3 Yellowknife Fuel and Water Stabilization Funds

6.3.1 Fuel Stabilization Fund

The NTPC stated the forecast balance in the Snare/Yellowknife Fuel Stabilization Fund is \$1.369 million at October 1, 2008. The established trigger for the fund is \$1 million. The NTPC noted there was no diesel fuel expense built into the revenue requirement for the Snare/Yellowknife system in the 2006/07 & 2007/08 Phase I GRA. Since the primary generation source for this system is hydro generation, and rate changes in Yellowknife ultimately affect all residential customer through the TPSP, the Corporation proposed only a “catch-up” component to the rider to retire the balance in the fund.

The HC noted the primary cause for diesel generation in the months of October to December 2007 was due to capital projects work on the Bluefish generating station headgate. The HC considered that this work should have been carried out earlier in the year when system load was lower in order to minimize the amount of diesel generation during construction. The HC submitted that the incremental diesel generation attributable to the timing of the Bluefish capital work should be excluded from the Yellowknife Fuel Stabilization Fund, which captured the price variance component of this event.

In reply to the HC’s comments, the NTPC submitted that the Bluefish generating station headgate project was in fact planned and executed to minimize diesel generation and commenced as soon as practicable in the spring. The NTPC submitted that if the fuel costs related to the Bluefish headgate project are not included in the stabilization fund, these costs need to be added to the capital project. The NTPC submitted the HC’s request should be dismissed.

Views of the Board

The Board notes the NTPC's views, as set out in Decision 17-2007, that diesel generation expenses during outages related to hydro and transmission capital projects would be capitalized as part of project costs on an individual project-by-project basis. [Decision 17-2007; P. 20] Consistent with this view, the Board considers that the diesel fuel costs associated with the Bluefish generating station headgate project should be capitalized. The NTPC is directed to adjust the Snare/Yellowknife Fuel Stabilization Fund balance and rider accordingly.

6.3.2 Water Stabilization Fund

The NTPC stated that in addition to a rider for the Snare/Yellowknife Fuel Stabilization fund, a rider is also required to address the current balance in the Snare/Yellowknife Water Stabilization fund. The fund balance is forecast to be \$4.654 million at October 1, 2008. The established trigger for this fund is \$3 million. The NTPC's proposed rider was designed to bring the water stabilization balance to the \$3 million threshold. The NTPC indicated charges to the water stabilization fund arise as a result of the unavailability of hydro generation due to low water or other factors.

The HC expressed concern that the Water Stabilization Fund incorporates low water conditions for the period October 2008 to March 2009. The HC submitted that absent evidence to the contrary, the normal water flows should be relied upon for the months of October 2008 through March 2009. In any event, the HC submitted, this would be subject to review again in 6 months under the NTPC's proposal.

The HC also submitted that the diesel fuel costs (at the forecast diesel fuel prices), associated with the timing of the Bluefish generating station headgate project should be disallowed from the water stabilization fund. The HC considered that this work should have been carried out earlier in the year when system load was lower in order to minimize the amount of diesel generation during construction.

The NTPC submitted that the diesel generation forecasts included in the water stabilization fund reflect not only water conditions but also expected loads and other requirements for diesel generation. It would be inappropriate to update water flows without also updating load forecasts. The NTPC submitted that, with the current load levels in the Snare/Yellowknife system, higher water levels do not necessarily lead to reductions in diesel requirements.

Views of the Board

In view of the Board's determination in the preceding section (Section 6.3.1), the NTPC is directed to adjust the Snare/Yellowknife Water Stabilization Fund balance and rider to reflect capitalization of the diesel fuel costs associated with the Bluefish generating station headgate project.

The Board notes the NTPC's view that it would be inappropriate to update water flows without also updating load forecasts. The NTPC also indicates, with the current load levels in the Snare/Yellowknife system, higher water levels do not necessarily lead to reductions in diesel requirements. Given the Board's decision to review fund balances every six months and given the NTPC's explanations respecting the minimal impact of adjusting water levels, the Board accepts the NTPC's forecast of water levels for the purposes of calculating the water stabilization rider for this Decision.

7. STAND-BY RATE PROPOSAL

The NTPC proposed a rate of \$24/kW each month for standby service for all communities. The NTPC also requested final approval of the interconnection guidelines which were approved on an interim basis in Decision 13-2007.

The NTPC established the standby rate proposal based on the following rate design considerations:

1. The full-cost demand charge related to generation functions in the thermal communities. The full cost generation demand component is approximately \$24 each month.
2. The same demand charge in each community for reasons of customer understandability and ease of administration. This is consistent with the demand charges for general service customers, which are levelized across communities.

The HC submitted that the community of Fort Smith does not consider that ease of understanding and ease of administration are sufficient or compelling reasons to vary from the generation demand cost component by a factor of 4. The HC submitted that a charge of \$6/kW/month for standby would be more appropriate for General Service customers in Fort Smith regardless of whether they are expected to request stand-by service.

The NTPC submitted the \$24 per kW charge has been determined considering a number of factors including that the NTPC must have the capability of serving the full standby load during system peak. Further a significant amount of demand

related costs are recovered through the energy charge to general service customers.

Views of the Board

The Board considers the proposed standby charge to be a reasonable proxy for the cost of peaking generation. The Board accepts the proposed standby rate for purposes of this Decision.

There were no comments from parties respecting the proposed interconnection guidelines. The Board approves as final the interconnection guidelines that were approved on an interim basis in Decision 13-2007.

8. TERMS AND CONDITIONS OF SERVICE

As described in Appendix F, the NTPC applied to have changes to Clauses 4.1, 13.2 and 14.1 of its Terms and Conditions of Service. The NTPC later withdrew its proposed change to 14.1.

The change to 4.1 was to remove the provision to allow the NTPC to refuse to provide service if a former customer residing at the premises has existing arrears.

The change to 13.2 was to restate the limitations on the NTPC's limitation of liability.

The HC agrees with the proposed change to Clause 4.1. The HC also accept the proposed change to Clause 13.2 as long at that change is also reflected in the NTPC's Customer Service Agreement ("**CSA**").

Views of the Board

The Board approves the proposed changes to Clauses 4.1 and 13.2 of the Terms and Conditions of Service. The Board also expects the proposed change to Clause 13.2 to be mirrored in the NTPC's CSA.

9. OTHER MATTERS

9.1 Time of Use Rates

The NTPC indicated that the Corporation has considered the potential benefits of time of use rates on its own systems and determined that it would not be beneficial to pursue time of use rates at this time for the following reasons:

- At present, both the Snare/Yellowknife and Taltson hydro systems have very limited diesel generation requirements, related largely to times of hydro unavailability. These times are hard to predict and are not related to seasonal or daily use patterns, therefore there is little or no benefit to customers of shifting loads between daily or season periods. When diesel generation is required more frequently, a time-of-use rate structure might have more potential benefits.
- Similarly, in the thermal communities the Corporation's generation costs do not vary by daily or seasonal periods as they might in an interconnected system. Generation facilities are planned to meet the annual system peak. As a result there is little to no benefit in the thermal communities of shifting load between daily or seasonal periods.

The NTPC submitted that while there would be little to no cost savings as a result of time-of-use rates, there would be added costs including:

- More advanced metering technology to accommodate time-of-use rates.

- Writing a new billing software script to enable the Corporation's current billing system to accommodate time-of-use rates.

The NTPC indicated that it is not proposing time-of-use rates at this time. The NTPC submitted it is more prudent for its customers to focus on general conservation efforts, to reduce bills and generation requirements at any time of the day or season of the year, rather than develop a new rate structure that would be difficult or costly to implement. The Corporation indicated that it believes there are substantial benefits to customers, given the current rate structure, to pursue these types of conservation initiatives.

With respect to future directions on the topic of time-of-use rates, the Corporation indicated it, together with Northland Utilities has proposed a meeting with the Board to discuss the future directions on this topic

Views of the Board

The Board views the adoption of time of use rates to be one among a number of approaches for managing customer demands with a view to either avoiding or forestalling new plant additions needed to meet growth in peak demands. In the Board's view, peak demand drives the need for new plant and if measures can be adopted to mitigate demands during periods of peak usage, costs may be avoided or postponed. The Board recognizes that while it is desirable to mitigate peak demands, the benefits of measures designed to achieve demand management must be weighed against the costs of implementing such measures.

The NTPC as well as Northland Utilities have requested a meeting with the Board to address matters such as time of use rates. A determination on future

processes involving time of use rates or other demand management measures will therefore have to await the outcome of this meeting.

9.2 Revenue to Cost Ratios

In IR BR-NTPC-5, the Board asked the NTPC to comment on a potential Board direction to the NTPC on revenue to cost ratios for the next Phase 2 GRA. The NTPC discussed this matter in its argument.

“...The Corporation notes that many of the communities with revenue to cost ratios below 95%, including for example Fort Resolution, Jean Marie River and Nahanni Butte, received 15% rate increases as approved in Decision 8-2003 as well as substantial rate increases effective February 1,2007 and January 1,2008.

The Corporation's response indicated that such a direction could be issued by the Board as a future rate design criteria that NTPC could seek to meet. At that time, NTPC's proposals could be assessed by the Board based on the extent to which the proposed rates meet this criteria in light of other relevant criteria. The Corporation noted that it was likely that this new criteria could not be met simultaneously with the Board's other rate design criteria including a 15% cap on rate increases but that the balance between different rate design criteria was a suitable matter to be addressed at the time of the next GRA.

The Corporation also notes that many of the communities it serves have very small customer numbers and energy sales. When major capital projects are required, such as a new power plant or an extensive distribution upgrade, this can have an extreme impact on the community's revenue requirement and rates cannot be increased enough with a 15% cap to make up this revenue requirement shortfall. Further, when one community's rates are lower than 100% revenue to cost coverage it creates upward pressure on other community revenue to cost coverage ratios. Therefore, maintaining a 15% cap on rate increases in the future will mean that some communities will be outside of the 95% to 105% revenue to cost coverage ratio.” (NTPC Argument, p. 23, / 14-34)

The TGC also discussed this matter in its argument.

“The TGC also note the results presented in Appendix E are not based on a current cost of service study and therefore, such results could vary materially if a proper cost of service reflecting cost causation is filed and tested. As well, there is currently a review by the GNWT of rate regulation and subsidies that may impact future rate rebalancing directions between customer classes and communities. Such review may have some significant impact on rate design and the ensuing RC ratios. **For these reasons, the TGC respectfully submit it may be premature to provide any direction to NTPC to transition communities to a 95-105% RC range in each of the years in the next Test Period.**” (TGC Argument, p. 15)

Views of the Board

The Board accepts that requiring communities with lower revenue to cost ratios to be brought to within the 95% to 105% range more quickly might require exceeding the 15% rate cap. However, it is the Board’s view that it is taking too long to get some communities within the appropriate range to the detriment of other communities that must cover the shortfalls. In particular, the Board is eager to end the situation in which higher cost communities are subsidizing lower cost communities.

The Board directs the NTPC, in its next Phase 2 GRA, to consider the following table, in conjunction with other rate design criteria, in setting the base rates.

Community/Customer	Present	Test Year 1	Test Year 2	Test Year 3
Fort Resolution	51.7%	70% minimum	90% minimum	95% minimum
Jean Marie River	69.2%	80% minimum	90% minimum	95% minimum
Nahanni Butte	75.2%	85% minimum	90% minimum	95% minimum
Fort Simpson	77.9%	85% minimum	90% minimum	95% minimum
Wrigley	80.6%	90% minimum	95% minimum	95% minimum

Dettah	85.9%	95% minimum	95% minimum	95% minimum
NUL(NWT)	130.2%	120% maximum	110% maximum	105% maximum
All Others	Various	Within 95% to 105% range		

9.3 Government of the Northwest Territories (“GNWT”) Electricity Review

The TGC recommends that the Board require the NTPC to quickly come forward with a new GRA to reflect the outcome of the GNWT electrical review if that review is completed prior to the NTPC’s next Phase 1 application.

Views of the Board

The Board expects that both it and the NTPC will be expected by the GNWT to quickly implement whatever recommendations are produced by the electrical review. The Board does not think that any direction is required.

9.4 Plant Efficiency

The TGC recommends that the Board require the NTPC to use actual plant heat rates to compute the fuel volumes for purposes of the stabilization funds.

Views of the Board

The Board considers this to be a Phase 1 matter that was already dealt with in Decision 13-2007. The Board will not consider this matter in this Decision.

10. SUMMARY OF BOARD DIRECTIONS

November 1, 2008 Implementation

1. The Board directs the NTPC to apply the shortfall riders as calculated in Schedule B-3 of the Application subject to an adjustment to account for the reduced 17-month collection period from November 1, 2008 to March 31, 2010 as well as an update to the applicable interest rate to October 27th, 2008. The NTPC is to continue to apply the 15% rate cap on the combined impacts of adjustments to the base rates and the shortfall riders.
2. While maintaining the 15% cap on adjustments to base rates and the shortfall riders, the Board directs NTPC to apply a 20% total cap to the combined impact of adjustments to base rates, shortfall riders and stabilization fund riders.
3. The Board directs the NTPC to design the stabilization fund riders to bring the fuel fund balances to \$0 and the Snare water fund balance to its trigger amount by March 31, 2010.
4. The Board directs the NTPC to use an updated oil price and interest rate from October 27, 2008 when designing the stabilization fund rate riders for implementation on November 1, 2008.
5. The Board considers that the diesel fuel costs associated with the Bluefish generating station headgate project should be capitalized. The NTPC is directed to adjust the Snare/Yellowknife Fuel Stabilization Fund balance and rider accordingly.

6. The NTPC is directed to adjust the Snare/Yellowknife Water Stabilization Fund balance and rider to reflect capitalization of the diesel fuel costs associated with the Bluefish generating station headgate project.

Next Phase 2 GRA

7. The Board directs the NTPC, in its next Phase 2 GRA, to consider the following table, in conjunction with other rate design criteria, in setting the base rates.

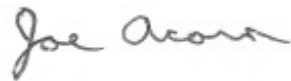
Community/Customer	Present	Test Year 1	Test Year 2	Test Year 3
Fort Resolution	51.7%	70% minimum	90% minimum	95% minimum
Jean Marie River	69.2%	80% minimum	90% minimum	95% minimum
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Wrigley	80.6%	90% minimum	95% minimum	95% minimum
Dettah	85.9%	95% minimum	95% minimum	95% minimum
NUL(NWT)	130.2%	120% maximum	110% maximum	105% maximum
All Others	Various	Within 95% to 105% range		

11. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. The Board directs NTPC to implement the rate changes, as approved and directed in this Decision, on November 1, 2008.
2. The Board directs NTPC to provide the Board and other parties by Oct. 30, 2008 with a working model, in Excel format, of all Phase 2 GRA tables and schedules relating to the rate changes approved and directed by this Decision. The NTPC is also to provide the Board and other parties with an updated set of rate schedules.
3. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northland Utilities (Yellowknife) Limited.

**ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES**



**Joe Acorn
Chairman**

Dated October 27, 2008

**THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES**

DECISION 11-2009

APRIL 17, 2009

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF a review of the Northwest Territories Power Corporation's update on its Rate Stabilization Fund Riders.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS

Joe Acorn	Chairman
John Hill	Vice-Chairman
William Koe	Member
Sandra Jaque	Member
Jake Heron	Member

BOARD STAFF

Louise Larocque	Board Secretary
Raj Retnanandan	Board Consultant
John Donihee	Board Counsel

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1. BACKGROUND

On August 15, 2008, the Northwest Territories Power Corporation (“**NTPC**”) filed its Phase 2 General Rate Application (“**Application**”, “**GRA**”) for the fiscal year April 1, 2006 to March 31, 2007 and April 1, 2007 to March 31, 2008 to determine appropriate rates for their customers.

As part of its Application, NTPC requested approval to file applications by February 15 and August 15 for stabilization rider adjustments to be effective April 1 and October 1. NTPC stated the following:

“In the Corporation’s view, this will benefit customers by providing more regular and predictable price changes. It will also ensure fairness to future customers by improving the timing between when fuel cost increases are incurred and when those costs are collected from customers. Further, the proposed timing of the rider changes avoid the summer and winter holiday periods. Finally, in the Corporation’s view this is consistent with the intent of the 1995/98 Phase I negotiated settlement that the rider adjustments be automatic, with Board review of the calculation of proposed riders as necessary.” (GRA, p. C-8, I. 1-7)

The NTPC provided additional information in its argument.

“Through interrogatories to the Corporation, intervenors requested additional information and clarification with respect to NTPCs proposal for future rider adjustments. The Corporation provided additional information in this regard, stating:

To be specific, the Corporation's proposal with respect to future revisions to stabilization funds is to make the process as routine and automatic as possible, as follows:

1) For the diesel communities, Inuvik and Norman Wells stabilization funds: Each 6 months (April 1 and October 1) implement new stabilization fund riders that comprise 2 components: 1) for the

"keep up" (or fuel price variance) component, ensure the base riders in place (1.000 index) recovers the difference between the weighted average price for fuel (as at the date of application) and the most recent GRA price (and based on forecast 12 month generation and weighted average GRA plant efficiencies); and, 2) for the "catch up" (or balance retirement) component, take the full fund balance and divide by the forecast 12 months sales to determine the base rider (1.000 index). These values would be updated on a rolling basis at each 6 month update.

2) For the standby fuel funds (Fort Smith and Yellowknife): Each 6 months (April 1 and October 1) implement new stabilization fund riders that comprise only a "catch up" (balance retirement) component, based on recovering the full fund balance at the time of the application divided by the forecast 12 months sales to determine the base rider. These values would be updated on a rolling basis at each 6 month update.

3) For the Snare Yellowknife Water Stabilization Fund: Each 6 months (April 1 and October 1) implement new stabilization fund riders that comprise only a "catch up" (balance retirement) component, based on recovering the amount by which the fund exceeds the \$3 million trigger (plus or minus) at the time of the application divided by the forecast 12 months sales to determine the base rider. These values would be updated on a rolling basis at each 6 month update.

The approach proposed by NTPC under (3) above could lead to water stabilization fund riders being reduced, for example, if the fund was not used within a 6 month period, but the sales were higher than forecast so collections were ahead of forecast." (NTPC Argument, p. 15, / 22- p. 16, / 29)

The Hydro Communities stated in argument that fuel prices, fund balances and updated riders should be reviewed on a regular 6 month basis.

The Thermal Generation Communities ("TGC") did not oppose the regular adjustment applications but recommended that the Board no longer permit the NTPC to collect interest on outstanding balances.

The NTPC responded to the TGC in its reply argument.

“The TGC appear to misunderstand the Corporation's proposal. The Corporation is simply proposing to review the status of the stabilization fund balances and riders every six months. This may lead to increases or decreases to riders or no change to the riders. It will not eliminate the lag between when fuel expenses are incurred and when the stabilization fund balances are collected or refunded. NTPC has not applied to change the trigger for these funds, therefore, even with a six month review of the stabilization fund riders there will still be material balances in the funds at times. This is demonstrated by a review of the stabilization fund balances using the iterative approach to calculating the stabilization fund riders in the Corporation's response to BR.NTPC-2. This clearly indicates the need for the Corporation to have access to financing for the balances in the stabilization funds.” (NTPC Reply, p. 9, /, 7-16)

The Board did not accept the TGC recommendation regarding interest. The Board did not see how 6-month adjustments warranted removing the collection (or paying) of interest by the NTPC.

The Board issued Decision 26-2008, dated October 27, 2008 addressing all matters arising from NTPC's GRA and also approved the NTPC's request to file applications by February 15 and August 15 of each year for stabilization rider adjustments to be effective April 1 and October 1 of each year.

2. STABILIZATION FUND UPDATE

By letter dated February 20, 2009, NTPC filed its stabilization fund updates, as per Decision 26-2008. NTPC stated that it was not proposing adjustment to any of the stabilization fund riders at this time.

NTPC noted that although the fuel funds might not be projected to achieve zero balances by March 31, 2010, all of the funds are making progress towards that target. NTPC stated that it will be in a better position to propose adjustments to the funds based on actual winter resupply prices and updated summer resupply price forecasts at the time of its August 2009 application.

With respect to the Snare/Yellowknife water stabilization fund, NTPC noted that at present the balance is expected to be slightly higher than the \$3 million trigger by March 31, 2010. NTPC stated, at the current load levels, the requirement for diesel generation is dependent largely on the water availability on the hydro system and NTPC would be in a better position to forecast the water levels at the time of the August 2009 stabilization fund update filing, following the spring run-off period.

NTPC will file its next stabilization fund update in August 2009, at which time fuel prices, water availability and rider collections will be updated.

In a letter dated February 25, 2009, the Board stated that it wanted to examine NTPC's updated filing in more detail and provided a schedule for the review.

On March 11, 2009, NTPC provided responses to the Board's information requests. No argument or reply argument was filed with the Board.

3. DECISION

The Board has reviewed the stabilization fund update and the responses to IRs from NTPC. The Board considers NTPC to have provided satisfactory explanations to questions raised by the Board. NTPC has also made corrections to the stabilizations funds where required.

While world oil prices had been in the \$35-\$45/barrel (US dollars) range earlier this winter, oil prices have now increased back into the \$50-\$55/barrel range. It is preferable for as much as possible of the outstanding fund balances to be collected prior to further increases in oil prices above the price (about \$64/barrel) that is currently established in the rates. The Board is concerned about the potential need for significant “keep up” collections on top of the current “catch up” components of the fund riders.

It is the Board’s view that decreases to the stabilization fund riders at this time could hinder the collection of the outstanding balances and make it less likely that the stabilization fund balances will achieve the targets that have been set for March 31, 2010.

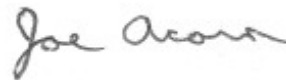
Therefore, the Board accepts the NTPC suggestion that there be no changes to the stabilization fund riders until NTPC files its next stabilization funds update with the Board by August 15th with potential changes to the stabilization fund riders for October 1st.

4. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. As proposed by the NTPC, the Board directs NTPC to file its next stabilization funds update by August 15th with proposed changes to the stabilization fund riders effective October 1st.
2. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

**ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES**



**Joe Acorn
Chairman**

Dated April 17, 2009

TAB 4

**THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES**

DECISION 16-2010

NOVEMBER 12, 2010

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided by the Northwest Territories Power Corporation to their customers within the Northwest Territories, in accordance with the Government of the Northwest Territories Electricity Rate Policy Guidelines.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS

Joe Acorn	Chairman
Sandra Jaque	Vice-Chairman
William Koe	Member
Jake Heron	Member

BOARD STAFF

Louise Larocque	Board Secretary
Raj Retnanandan	Board Consultant
John Donihee	Board Counsel

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1. BACKGROUND

In December 2008, the Government of the Northwest Territories ("**GNWT**") released a discussion paper that set the context for the Review of the Electricity Regulation, Rates and Subsidy Programs in the Northwest Territories ("**NWT**"). The GNWT then appointed an independent Electricity Review Team to publicly discuss electricity system issues and provide the GNWT with recommendations. The panel conducted an extensive public hearing process and released a report called *"Creating A Brighter Future: A Review of Electricity Regulation, Rates and Subsidy Programs in the Northwest Territories"* that presented 39 recommendations regarding the future approach to the NWT electricity system.

On May 14, 2010, the GNWT released a report entitled *"Efficient, Affordable and Equitable: Creating a Brighter Future for the Northwest Territories' Electricity System"* ("**Electricity Review**"). The report is intended to guide policy with respect to the future approach to the NWT electricity system.

On July 9, 2010, the Board received a letter from the Minister Responsible for the Public Utilities Board ("**Board**"), Robert R. McLeod, indicating the Executive Council has approved the following Electricity Rate Policy Guidelines ("**Guidelines**") for consideration by the Board.

The Minister's letter states inter alia:

"A key action identified in the Electricity Review is the issuance of formal policy guidance by the Minister Responsible for the Public Utilities Board to the NWT Public Utilities Board regarding the approach to electricity regulation and the establishment of electricity rates in the NWT. The Electricity Review should be considered as broad direction.

The following Guidelines are intended as primarily applicable to the electricity rates of the Northwest Territories Power Corporation (NTPC), recognizing that there are implications for electricity rates in communities where NTPC provides wholesale power that is distributed by Northland Utilities (Yellowknife) Limited (NUL(YK)) and Northland Utilities (NWT) Limited (NUL(NWT)). These guidelines may be amended at a later date for NUL (NWT).

In reviewing the electricity rates for the Northwest Territories Power Corporation (NTPC), the Public Utilities Board (PUB) should ensure:

- (1) The electricity rates for each utility are set on a zoned basis. In determining the composition of zones for each utility:
 - a. Each interconnected system served primarily by hydro should form a zone, by utility.
 - b. All non-interconnected communities served primarily by thermal generation should form a single zone, by utility.
- (2) Electricity rates for the same class of customers of a utility should be the same throughout each zone, with the exception of Government customers whose electricity rates will be set based on principles outlined in Clause (3).
 - a. In those communities where a franchise fee is levied, that fee shall apply only those communities.
- (3) Electricity rates for government customers shall be set based on the following principles:
 - a. Government customers can have higher electricity Base Rates than non-government customers in the same community for the same type of service, but not lower than non-government customers.
 - b. Government customer Base Rates will continue to vary by community.
 - c. If general service rates in a zone or community decrease as a result of this rate rebalancing exercise then government rates will stay at the current level, pending the next General Rate Application (GRA). The calculation of government rates in the next GRA is an issue for further discussion.

- (4) All costs included in a utility's revenue requirement that do not relate specifically to providing service in a single community or zone, referred to as head office and general operational costs, should be shared among all of the utility's zones, equally weighted by energy sales (per kWh).
- (5) In assessing the fair return on the rate base of NTPC, the Board should permit NTPC to request a downward adjustment to the return on equity in the thermal zone ("Return Adjustment") as compared to a fair level of return on equity.
- (6) The Board should consider establishing territorial fuel and low water riders on a per utility basis, in accordance with the following:
 - a. The Base Fuel Price shall be the levels approved in each utility's most recent GRA as of the implementation of this policy, and shall not vary unless otherwise directed by GNWT. The calculation and application of the Base Fuel Price in the next GRA is an issue for further discussion.
- (7) In implementing the Electricity Rate Policy Guidelines, should the Board find it necessary to deviate from the Guidelines, the Board should provide such recommendation to the Minister Responsible for the Public Utilities Board.
- (8) Transition provisions:
 - a. The Board should implement the Electricity Rate Policy Guidelines by October, 2010.
 - b. In implementing the electricity rate policy transition, the Board should ensure electricity Base Rates for all NTPC customers following the initial electricity rate adjustments will not exceed the levels of electricity Base Rates plus Rate Riders applicable for the same level of consumption effective on October 1, 2009.
 - c. Until such time as NTPC's next GRA, Norman Wells should remain as its own zone and not part of the thermal zone. The Board should ensure electricity base rates for Norman Wells customer classes following the initial electricity rate adjustments will equal the levels of electricity Base Rates plus Rate Riders applicable for the same level of consumption effective on October 1, 2009

- d. In implementing the electricity rate policy transition, the Board should seek to target an Interest Coverage Ratio of 1.5 on NTPC's Thermal Zone rate base."

In a letter dated July 26, 2010 to the Northwest Territories Power Corporation ("**NTPC**" or "**Corporation**"), the Board stated that it accepted the Guidelines as directives from the Executive Council under Section 14(1) of the *Public Utilities Act* ("**PUA**") and will implement these directives in accordance with s. 14(2). The Board also stated that it is using the authority it holds under Sections 20 to 22 of the *PUA* to initiate a hearing and directed NTPC to file with the Board an application to implement the directives from the GNWT. To assist in developing its application, the Board provided the following notes for NTPC with respect to the guidelines:

Guideline 1: Although not shown in the table, NUL(YK), as a wholesale customer, is part of the NTPC Snare zone and similarly NUL(NWT) Hydro is part of the NTPC Taltson zone.

Guideline 4: To be consistent, head office and general operational costs are to be apportioned to customer classes within a zone according to the same per kwh method as used to allocate these costs to the zones.

Guideline 6: NTPC is to propose a threshold for activation of the new territorial fuel and water rider. NTPC is also to use the new threshold, the base fuel prices and updated fuel forecasts for the next year to assess whether or not the territorial fuel and water rider will need to be active as of the implementation date of the new rates. If yes, at what level (cents/kwh).

Guideline 7: If the implementation of these guidelines creates a revenue shortfall or other issues such that compliance cannot be achieved then the NTPC is to inform the Board in the application and propose possible alternatives to establish a clear track record of the changes in revenues and rates. This could include establishing rate rebalancing accounts, by rate zone, which would reflect shortfalls, if any, arising in each community and rate class as a result of the rate rebalancing exercise.

The Board stated this proceeding is only a rate rebalancing exercise, with the exception of updated forecast fuel costs for the new territorial fuel and water rider. The Board indicated it is not requesting or seeking updated forecasts on items such as sales, costs, revenues, capital projects, etc. Further, the Board also indicated it is not seeking or expecting a comparison of actuals to forecasts since the previous General Rate Application (“**GRA**”). The Board instructed NTPC to use its approved revenue requirement and forecasts from the previous GRA to rebalance the rates in accordance with these guidelines; standards limiting the magnitude of rate changes do not apply in setting rates. NTPC was also required to set the rates such that each zone and customer class has rates set to 100% of the revenue cost ratio for each zone and for each customer class within that zone.

The Board published notice of the written hearing of the Application to implement the Guidelines in newspapers that circulate in the NWT. The notice provided details of the Application and invited interested persons to file a request with the Board for intervener status. The notice also provided a schedule of the proceeding.

By letter dated August 13, 2010, NTPC filed an Application with the Board to implement the Guidelines. NTPC advised that due to the unavailability of key

personnel during the proposed Information Request (“**IR**”) process, an alternative schedule for the process be considered.

By letter dated August 17, 2010, the Board requested comments from any party regarding NTPC’s proposed schedule. Since there were no comments received from the interested parties, the Board, by letter dated August 23, 2010, approved the proposed schedule as requested by NTPC.

The Board, the Hydro Communities (“**HC**”) (City of Yellowknife, Towns of Fort Smith and Hay River), the Thermal Generation Communities (“**TGC**”) (Town of Inuvik, Village of Fort Simpson and Hamlet of Fort Providence) and Northland Utilities Limited (“**NUL**” or “**Northland**”) submitted IRs, to which NTPC responded on September 15, 2010.

In a letter dated September 22, 2010, HC advised the Board that it does not intend to file intervenor evidence. However, HC indicated that it has come to the conclusion that the evidentiary record is not complete because one of the IRs did not receive an adequate response and had therefore submitted a follow up IR. By letter dated September 24, 2010, NTPC provided a response to HC’s follow up IR.

Since no intervenor evidence was filed, the Board, by letter dated September 27, 2010, revised the schedule for Argument and Reply Argument.

On October 6, 2010, NTPC and Northland filed written Argument.

By letter dated October 7, 2010, TGC requested an extension of the dates for Argument and Reply Argument. HC also submitted a letter dated, October 7, 2010 indicating their preference to file their Argument and Reply Argument

contemporaneously with the TGC. The Board, by letter dated October 7, 2010, granted the extension of the date for filing of Argument by TGC and HC to October 8, 2010 and the filing of Reply Argument by all parties to October 15, 2010.

On October 8, 2010, TGC and HC filed their written Argument.

By letters, dated October 15, 2010, the HC, TGC and NTPC submitted their Reply Argument. NUL did not file Reply Argument.

2. APPLICATION

In its Application, NTPC set out the proposed approach to implementing the Guidelines. The Application addresses the following approval requests:

- Adjustments to Base Rates.
- Terminate Existing Shortfall Riders.
- Rate Stabilization Fund Adjustments and Termination of Riders.
- Confirmation of Accounting Treatment for Rate Stabilization Fund.

NTPC states it has attempted to satisfy all of the GNWT and Board guidelines in developing its proposals. NTPC also states, where the Corporation was unable to completely implement a guideline, further details are provided in the Application.

On October 27, 2010, NTPC filed an amendment to its Application. NTPC states in the course of preparing for the implementation of revised rates, the Corporation has identified an error in the revenue forecast included with its August 13, 2010 Application. NTPC states in preparing Schedule 1.8 of that Application, the Corporation incorrectly included forecast sales to NWT Housing Corporation accounts as Non-government residential sales instead of Government residential sales.

NTPC states the error has implications for the calculation of the proposed non-government Residential and non-government General Service customer rates in the Thermal zones. Proposed rates for all other customer classes and zones are not affected. NTPC states, as a result of correcting the revenue forecast error, the proposed rates for Thermal Non-Government Residential and General Service Customers are 4.08 cents/kW.h lower than in the August filing.

The Board's consideration of NTPC's Application, as amended, is set out in this Decision.

3. GOVERNMENT RATE CLASSES

Guideline 3 required the Board to create government rate classes which could have rates that are higher than non-government customers in the same community for the same type of service. While government rates could be higher, they could not be lower than non-government rates and the government rates would continue to vary by community.

Board Findings:

It is the Board's view that Guideline 3 (b) was an unnecessary complication to this rate rebalancing exercise. The setting of many different government rates within the zones runs directly counter to the stated objective of the Government of making the electrical rate system less complex.

It is the Board's view that the government rates in a zone should have been set by just calculating the total government revenue from a zone using the October 2009 rates and then calculating a flat rate to apply to each of the government residential and general service customer classes across the zone. The same level of revenue would have been obtained with a simpler rate design. However, since Guideline 3 (b) did not create a fairness issue for any other ratepayers, the Board has proceeded with implementing Guideline 3 (b) as written.

If, however, the existence of government rate classes continues into the next GRA, it is the view of the Board that government rates should be set the same across a zone in the same manner as for non-government rate classes.

Guideline 3 (c) should also have been written to apply to both residential and general service rate classes instead of just general service. NTPC based its

application upon 3 (c) applying to both rate classes and the Board has proceeded on that basis.

The Board will recommend an amendment to Guideline 3 (c).

4. HEAD OFFICE AND GENERAL OPERATING COSTS

Several parties commented on the fairness and impact of adopting Guideline 4 which states that costs that do not relate specifically to providing service in a single community or zone, referred to as head office and general operational costs, should be shared among all of the utility's rate zones equally weighted by energy sales.

NUL states that Guideline 4 imposes new additional costs of approximately \$4 million on the hydro communities. In NUL's view, it is highly likely that a portion of the costs being allocated from NTPC communities are actually for distribution services and should not be allocated to communities served by Northland where those same type of headquarter functions are provided by Northland. In other words, hydro communities are being charged for the same services twice. NUL explained NTPC has a human resource function that provides service to the generation, transmission and distribution functions of its company. It would be logical to assume that Northland customers should pay for a portion of the costs associated with the generation and transmission functions; however they should not pay for the distribution component as Northland's customers receive human resource services from Northland already. NUL states this same example can be illustrated for all activities from billing, health and safety, and finance costs to name but a few.

In NUL's view, until a full disclosure of costs is provided by activity and those costs are clearly functionalized by Generation, Transmission and Distribution, just arbitrarily assigning all head office and general costs on an energy basis is not prudent or acceptable. Until such time as this information can be fully understood and tested, Northland states that the method of allocating head office

and general operational costs should remain status quo based on past Board practice. NUL states that if this cannot be accommodated then in the interest of fairness and equity to all NWT customers, headquarter and general operational costs from both NTPC and Northlands should be combined and then allocated to all rate zones. [NUL Argument, P. 2]

HC submits that the kilowatt-hour (“**kWh**”) basis totally fails to recognize customer accounting, collections, meter reading, public information, marketing expenses, human resources, employee benefits and any other functional categories needed to track or allocate expenses on a rational cost causation basis. HC submits that the Board should determine whether Guideline 4 exceeds a directive dealing with general performance of the duties of the Board and, in fact, may fetter the Board's discretion under Section 48(1) and (2) of the PUA to ensure that rates are not unjustly discriminatory or unduly preferential. HC submits the Board should recommend changes respecting Guideline 4 in order that it comports with the Board's previous findings in 1995 and 2003. Alternatively, the HC submits NUL's headquarter and general costs should be combined with those of NTPC and then allocated to all rate zones. [HC Argument, Paragraph 7, 8]

In its Reply Argument, NTPC states it has implemented the Guideline and the Board's direction in its treatment of the head office costs in the Application. NTPC submits, in balancing all the issues considered by the Review Commission, this proposed method represents an appropriate head office cost allocation method. NTPC recognizes that no allocation method will be perfect. However, the three member review team heard from residents and communities seeking changes to the electricity system and the approach to electricity rates. Based upon its extensive consultation with those residents, communities and

with experts, the review team proposed a number of recommendations that provide the basis for the Electricity Guidelines.

NTPC notes the July 9, 2010 letter from the Minister states “*There may be revisions to these guidelines as the Electricity Review is implemented and the Government of the Northwest Territories (GNWT) would very much appreciate the Board’s views on how these guidelines might be improved.*” NTPC states that in the event the policy Guidelines with respect to the Head Office cost allocation method are revised in the future, NTPC is open to exploring alternative allocation methods at some future date, including the possibility of combining the head office costs of NUL and NTPC as suggested by intervenors. [NTPC Reply, P. 1, 2]

The TGC submits that in the absence of directly identifiable driver(s) respecting HO-type overhead costs, the use of a broad-based allocator such as kWhs recommended in the Brighter Futures Report is just and reasonable. It will also end the needless acrimonious debate in regulatory proceedings on this issue, once and for all.

With respect to HC’s submission that the overhead costs of NTPC and NUL be combined, TGC states the customers in thermal communities served by NTPC obtain no value from NUL’s HO and G&A costs and the HC has not provided evidence to the contrary. TGC submits the approach recommended by HC lacks a justifiable cost causation basis and the Board should reject the HC’s argument on this issue. [TGC Reply, P. 6 & 10]

Board Findings:

The Board notes NUL’s and HC’s concern that the head office and general operating costs include distribution-related functions. HC indicates such

distribution-related functions might include some or all of customer accounting, collections, meter reading public information, marketing expenses and human resources.

The Board agrees, in principle, that the recovery of NTPC's head office and general operating costs from the Snare Yellowknife and Taltson system wholesale rate classes should not include distribution-related costs or overheads. Including NTPC's distribution-related head office and general operating costs in the Snare Yellowknife and Taltson wholesale rate classes would result in double counting because NUL has its own distribution related overheads that are being recovered through NUL's rates. It would also be inconsistent with cost causation. The blanket application to NTPC of the per kWh methodology required by Guideline 4 is too simplistic and blunt an instrument to produce an equitable result in the NWT electrical system.

Accordingly, the Board considers the distribution component of NTPC's head office and general operating costs should not be allocated to the Snare Yellowknife and Taltson wholesale rate classes. The Board will recommend an amendment to Guideline 4.

However, there is no evidence in these proceedings respecting the amount of any NTPC head office and general operating costs that are distribution-related. To identify these costs, NTPC needs to undertake a functional analysis to split these costs into the generation, transmission and distribution functions.

There is very limited time however to conduct a thorough, accurate and reviewed functional analysis prior to the expected December 1, 2010 implementation date for the new zonal rate system. Therefore, the Board directs NTPC in its refiling application to provide the Board with its best estimate total of head office and

general operating costs which are associated with the distribution function. The Board expects that NTPC would be able to provide this estimate based upon previous cost of service studies.

The Board directs NTPC in the refiling application to share amongst all of the utility's rate zones the head office and general operational costs related to generation and transmission, equally weighted by energy sales (per kWh). Any distribution-related head office and general operational costs should be shared amongst all of the utility's rate zones, equally weighted by energy sales (per kWh), with the exception of the Snare Yellowknife and Taltson wholesale rate classes which will not be allocated or assigned any distribution-related costs of NTPC.

Given that the refiling application will contain only a best estimates functional analysis, the Board will only approve the proposed head office and general operating costs methodology on an interim basis. Consequently, the rates arising from the use of this interim methodology, subject to directions elsewhere in this Decision, will also only be approved by the Board as interim rates commencing December 1, 2010.

The Board directs NTPC to conduct a thorough and final functional analysis on its head office and general operating costs. The purpose of this analysis is to identify the portion of head office and general operating costs that are related to the generation, transmission and distribution functions by reference to each of the expense elements shown in Attachment NUL NTPC 1(a-b) including details of direct assignments, allocations and the basis of the allocations.

The Board directs NTPC to file an application with the Board by January 14, 2011 to convert all of the interim rates to final rates with an implementation date

of April 1, 2011. That application is to include and incorporate the results of the final functional analysis, the results of which are to be presented in the application in a transparent manner.

The Board also directs NTPC, in that application, to provide an accounting and reconciliation on the revenue differences for each of the zones and classes, for the period from December 1, 2010 and April 1, 2011, between the interim best estimates approach on assigning head office and general operating costs and the final functional analysis approach described by the Board in this Decision.

As an alternative, if by January 14, 2011, NTPC is able to conclude an agreement with NUL on mechanisms to combine NTPC's and NUL's head office and general operating costs and then allocate these costs to all rate zones and rate classes of NTPC and NUL, then that agreement, instead of the functional analysis approach on NTPC's costs, can be the basis for the final rates going forward from April 1, 2011.

5. RATE STABILIZATION FUND RIDER MECHANISM

Guideline 6 provides that the Board consider establishing territorial fuel and low water riders on a per utility basis.

In response to Guideline 6, NTPC proposed a consolidated rate stabilization fund. The appropriate trigger level for the rate stabilization fund is discussed in Section 6. NTPC states, in the event a rider related to the consolidated fund is required in the future, NTPC would calculate the required rider on an equal cents per kWh basis for all customers, with the exception of Northland Utilities (NWT) Limited (“**NUL-NWT**”). NTPC states, at present, there is no Taltson water stabilization fund and NUL-NWT provides its own diesel generation. In the future, if a Taltson water stabilization aspect of the overall stabilization fund becomes necessary, the Corporation would revisit the inclusion of sales to NUL-NWT in the calculation of the stabilization fund rider. [Application, P. 8]

With respect to Guideline 6, NUL submits the Government is proposing that territorial fuel and low water riders be established on a per utility basis and allocated on a kilowatt hour basis. This methodology potentially has the same negative impact on communities served by Northlands.

NUL states that, through its IR responses, NTPC has clarified that Hay River was excluded from sharing in fuel costs incurred in NTPC thermal communities through the proposed Territorial wide fuel/low water rider concept. Northland agrees with this, however believes that further discussion is warranted to determine if a territorial wide approach towards sharing fuel/low water costs by all customers is appropriate and what mechanism could be implemented to accomplish this. [NUL Argument, P. 2]

HC submits, since Fort Smith also provides its own backup diesel generation and there is no Taltson water stabilization fund, it follows that Fort Smith should not participate in any future Territory Wide Water Stabilization Fund for the same reasons. [HC Argument, Paragraph 6]

Board Findings:

The Board notes that under NTPC's proposal the fuel and low water stabilization fund rider, when it is triggered, would apply to all customers who receive generation service from NTPC, on a per kWh basis. The only exception to this rule is NUL-NWT which purchases interruptible power from NTPC's Taltson hydro system for supply to Hay River. NTPC states that in the future, if a Taltson water stabilization fund became necessary, the Corporation would revisit the inclusion of sales to NUL-NWT in the calculation of the overall stabilization fund rider.

The Board considers the proposed exemption of NUL-NWT from the fuel and low water stabilization fund rider, due to the absence of a Taltson water stabilization fund at the present time, is appropriate. Accordingly, the Board approves the proposed sharing of fuel and water stabilization amounts for purposes of these proceedings.

The Board notes that if a Taltson water stabilization component were to be required as part of the overall stabilization fund in the future, under the per utility sharing approach, NUL-NWT customers would share in NTPC's fuel and low water rider amounts but NTPC's customers would not share in the NUL-NWT fuel rider amounts. This might not be equitable to NUL-NWT customers.

The per utility sharing of fuel and low water stabilization amounts could also result in significant differences in rider amounts for customers in NUL's service area and in NTPC's service area. Creating the potential for wide rate disparities between neighboring communities is not consistent with the principle of comparability of rates.

Accordingly, the Board directs NTPC to work with NUL to develop a mechanism for Northwest Territories-wide sharing of fuel and low water costs, on a combined utility basis. If an agreement is reached between the utilities, the details and implementation of the proposed mechanism should be included in the January 14, 2011 application to the Board for implementation on April 1, 2011. If there is agreement with NUL respecting territory-wide sharing of fuel and water costs, that proposal should address the appropriate territory-wide rate stabilization fund threshold and the corresponding rider taking the Board's comments in Section 6 into account.

Guideline 6 should be amended to respect the potential for the utilities reaching an agreement on a single territory-wide fuel and water fund that would cover both NTPC and NUL.

A further issue for the Board is Part (a) of Guideline 6 which places restrictions on the Board regarding the base fuel price which is included in the base rates. The Board appreciates that Part (a) was put in place for this rate rebalancing proceeding to ensure that base fuel price increases did not undermine the GNWT political commitment that as of the implementation date of the rate policy guidelines the base rates for any customer would be no higher than that customer's base rates plus riders from October 2009.

However, it is the Board's view that Part (a) serves no practical value. If fuel prices increase or decrease relative to the base fuel prices, the differences will be captured and applied by the territorial fuel and water rider. The rate payers, as a whole, will pay full value for the fuel regardless.

What the Board is concerned about is that the artificial manipulation of the base fuel prices by Part (a) could become a back-door mechanism from transferring dollars from ratepayers in one zone to ratepayers in another zone. For instance, if base fuel prices are set artificially low for a zone then the effect would be that ratepayers in that zone would appear to be paying their 100% revenue cost ratio but in actuality they would not be as the calculation of the 100% revenue cost ratio would be based upon artificially low base fuel prices. What could have the appearance of fairness would not be fair as the shortfall in revenue that would rightfully be earned in that zone would have to then be earned in other zones. Through the territorial fuel and water rider, those other zones could end up consistently paying significantly more than their 100% revenue to cost ratio.

It is the Board's view that base fuel prices should be set based solely upon the best available forecast pricing information available at the time that new base rates are established. The Board will recommend that Part (a) be deleted from Guideline 6.

6. RATE STABILIZATION FUND RIDER THRESHOLD

NTPC states that the Corporation currently maintains six rate stabilization funds: the Diesel Communities Fuel Fund, Inuvik Fuel Fund, Norman Wells Fuel Fund, the Fort Smith Fuel Fund, the Snare-Yellowknife Fuel Fund, and the Snare-Yellowknife Water Fund. There are rate riders in place for each fund that were approved in Decision 26-2008

The forecast balances in the funds effective December 1, 2010 are set out in Schedule 3.1. NTPC is proposing the following revisions to the Stabilization Funds:

1. Effective December 1, 2010, establish one NTPC Territory-wide Fuel and Water Stabilization Fund. The balance in the fund would continue to be calculated based on approved fuel prices, fuel efficiencies and long-term average hydro generation.
2. Effective December 1, 2010, transfer the surplus in the shortfall rider account to the NTPC Territory-wide Stabilization Fund.
3. Establish a new trigger level for the NTPC Territory-wide Stabilization Fund of +/- \$5 million. NTPC will monitor the effects of the proposed trigger level and review at the next GRA.

In BR NTPC 6, the Corporation was requested to comment on whether there would be merit in maintaining two separate stabilization funds, one for water stabilization (which presently has a \$3 million threshold) and the other for fuel

stabilization for all zones, with each stabilization fund trigger set so as to facilitate rate stability when the trigger level is reached.

In response, NTPC stated that rate stability related to the stabilization funds involves balancing the frequency with which the trigger levels are reached and the magnitude of the riders that are implemented when the funds are triggered. Maintaining separate fuel and water funds would tend to lead to riders being triggered more frequently (due to lower trigger levels and the fact that positive balances in one fund would not be available to offset negative balances in the other fund). However, the magnitude of the riders for separate fuel and water stabilization funds would tend to be lower, all other things being equal.

NTPC states, from an administrative perspective, the Corporation could maintain either one consolidated fund or two separate fuel and water funds, each associated with Territory wide riders when triggered.

In its Argument, TGC supported the creation of two separate funds in the interest of rate stability. [TGC Argument, Paragraphs 8, 9]

In its Reply Argument, NTPC submits it is of the view that a single Territory wide Fuel and Water Stabilization Fund is a more transparent and predictable method of managing stabilization funds. [NTPC Reply, P. 3]

NTPC confirmed it has received confirmation from the GNWT in relation to its commitment to provide \$6 million in funding to offset balances in the stabilization funds. [NTPC Reply, P. 4]

Board Findings:

The Board notes that under the existing rate stabilization funds, the largest trigger point applies to the water stabilization fund in the amount of plus or minus \$3 million. The Board notes from Attachment BR NTPC 6 (b) that the rate impact on certain communities such as Fort Smith and Fort Resolution could be significant with a \$5 million threshold for the consolidated rate stabilization fund.

It is also the Board's view that much of the public and political concern regarding electrical rates over the past two years was a result of NTPC allowing the stabilization funds amounts to get too high and then seeking recovery of those amounts on top of base rate increases. More timely activation of the current stabilization funds through lower and firm thresholds could have prevented much of this concern and produced more consistent and stable rates for NTPC ratepayers.

Having regard to rate stability and public concern considerations, it is the view of the Board that the proposed trigger of \$5 million for the territorial fuel and low water fund is too high. The Board directs NTPC to set the trigger point for the consolidated rate stabilization fund at \$2.5 million.

The Board recognizes that the reduction of the trigger to \$2.5 million would immediately require the activation of the territorial fuel and low water rider as the current forecast balance for March 31, 2011 is about \$3.2 million.

However, in consideration of the limited time available before December 1, 2010 as well as the Board's direction to NTPC regarding the negotiation of an agreement for the sharing of fuel and water costs with NUL, the Board is not directing NTPC to activate the territorial fuel and water rider as of December 1, 2010.

The Board is directing NTPC that, in the absence of an agreement with NUL for the sharing of territory-wide fuel and water costs being included in the already-directed January 14, 2011 application to be submitted to the Board, NTPC is to file a separate application with the Board by January 14th for activation of the NTPC territorial fuel and water rider for February 1, 2011 taking into consideration the latest fuel and water forecasts and the \$2.5 million trigger.

Other than the change in the trigger point for the consolidated rate stabilization fund, NTPC's other proposals respecting the stabilization funds and the shortfall fund as outlined in this Section 6 are approved.

7. REVENUE TO COST RATIOS

In its notes to the implementation of the Guidelines, the Board requested NTPC to set the rates to 100% of the revenue to cost ratio for each zone and for each customer class within that zone.

The revenue to cost ratios proposed by NTPC in Schedule 1.8 (Oct. 27th version) are shown in the following table.

Rate Zone	Revenue Comparison			
	07/08 GRA Revenue Requirement	Application Total Revenue	Surplus (Shortfall) Revenue at Revised Rates	Cost of Coverage Percentage for Revised Revenue
	\$000	\$000	\$000	%
	A	B	C	D
			A-B	B/A
Snare Zone	30,743	31,438	696	102.26%
Taltson Zone	7,441	7,181	-260	96.51%
Norman Wells	3,210	3,664	454	114.14%
Thermal Zone	37,742	36,852	-890	97.64%
Total	79,135	79,135	0	100.00%

NTPC stated that the Corporation was not able to achieve the Board's request that rates for each zone and customer class be at 100% revenue to cost ratios. This outcome could not be achieved due to the restrictions of Guidelines 8 (b) and 8 (c).

Board Findings:

Guideline 8 (b) states:

“In implementing the electricity rate policy transition, the Board should ensure electricity Base Rates for all NTPC customers following the initial electricity rate adjustments will not exceed the levels of electricity Base Rates plus Rate Riders applicable for the same level of consumption effective October 1, 2009.”

For the Taltson Zone, the Board accepts that the \$260,000 shortfall cannot be avoided as to raise the additional revenue from the zone would require raising most of the Taltson rate classes above what they were in October 2009.

However, Guideline 8 (b) does not prevent NTPC from acquiring additional revenue from the Thermal Zone to eliminate that \$890,000 shortfall. With Inuvik being the low rate community as of October 2009 (residential – 60.35 cents/kWh and general service – 53.68 cents/kWh), there is room to raise the proposed non-government residential rate (43.98 cents/kWh) and non-government general service rate (37.31 cents/kWh) and eliminate the shortfall.

Guideline 8 (c) states:

“Until such time as NTPC’s next GRA, Norman Wells should remain as its own zone and not part of the thermal zone. The Board should ensure electricity base rates for Norman Wells customer classes following the initial electricity rate adjustments will equal the levels

of electricity Base Rates plus Rate Riders applicable for the same level of consumption effective October 1, 2009.”

In NTPC’s view, Guideline 8 (c) prevents it from reducing the rates in Norman Wells thereby producing a surplus of \$454,000. This surplus represents a revenue to cost ratio of 114.14% for Norman Wells. This is unacceptable to the Board as such a sizable surplus cannot be considered to be fair and equitable to the ratepayers of Norman Wells.

In the Board’s view, Guideline 8 (c) needs to be changed from “*rate adjustments will equal the levels*” to “*rate adjustments will not exceed the levels*”. It is the Board’s view that the Guidelines were intended by the GNWT to be protective against rate increases, not against rate decreases. The requirement in Guideline 8 (c) that Norman Wells rates cannot be decreased is likely an oversight by the GNWT and the Board will recommend that this guideline be amended.

With the findings by the Board regarding Guidelines 8 (b) and (c), the Board examined the data to determine that the revenue to cost ratios for the Snare Zone, Norman Wells Zone and the Thermal Zone could all be set to 100.36% while still achieving the total required revenue of \$79.135 million. The Board’s calculations are in the following table.

Rate Zone	Revenue Comparison				Revised Revenues and Cost Ratios					
	07/08 GRA Revenue Requirement	Application Total Revenue	Surplus (Shortfall) Revenue at Revised Rates	Revenue Cost Ratios	Increase Snare and Thermal to 114.14% revenue cost ratio	Revised Surplus at 114.14%	Proportional Reductions to Surplus	Final Surplus by Zone	Revised Final Revenue Requirements by Zone	Revised Revenue Cost Ratios
	\$000	\$000	\$000	%	\$000	\$000	\$000	\$000	\$000	%
	A	B	C	D	E	F	G	H	I	J
			A-B	B/A	A*114.14%	E-A	F Total * (E / E Total)	F-G	A+H	I/A
Snare Zone	30,743	31,438	696	102.26%	35,090	4347	4236	111	30,854	100.36%
Taltson Zone	7,441	7,181	-260	96.51%		-260		-260	7,181	96.51%
Norman Wells	3,210	3,664	454	114.14%	3,664	454	442	12	3,222	100.37%
Thermal Zone	37,742	36,852	-890	97.64%	43,079	5337	5200	137	37,879	100.36%
Total	79,135	79,135	0	100.00%	81,833	9,878		0	79,136	100.00%

Accordingly, the Board directs NTPC that in its refiling application the revenue to cost ratios for the Snare Zone, Norman Wells Zone and the Thermal Zone should be equal and brought as close as possible to 100%.

Recognizing that the government rate classes will be producing revenues equal to or greater than a 100% revenue to cost ratio, the revenue to cost ratios for non-government rate classes will be equal to or less than 100%. Where the government rate classes are producing revenue at greater than 100%, the Board directs NTPC to share the benefit of the higher government rates equally amongst the non-government rate classes in a particular zone by setting the revenue to cost ratios for the non-government rate classes in the zone at equal levels. The refiling application is to demonstrate how the Board's directions on this matter have been met or cannot be met due to other considerations. To be clear, the Board is not expecting the development of new zonal cost of service studies to meet this direction for the refiling application. The Board expects that NTPC will be able to use its existing community cost of service studies to determine zonal revenue to cost ratios on a per class basis and to make any necessary revenue and rate adjustments for the non-government rate classes to equalize their revenue to cost ratios.

In the Board's view the current restriction on increasing revenue from the Taltson zone will not apply when NTPC applies to convert the interim rates to final rates on April 1, 2011. The Board directs NTPC that in the January 14th application to convert the interim rates to final rates, NTPC is to make further adjustments to the rates to bring each rate zone to a revenue to cost ratio of 100% on a go-forward basis by eliminating the shortfall from the Taltson zone.

The Board recognizes that moving to 100% revenue to cost ratios for each rate class within each zone is not possible as long as government rates are not being set based on cost causation principles and are collecting revenue in amounts that are higher than 100% revenue to cost ratios. If at some point in the future the government rate classes are either terminated or set based upon cost causation principles then the Board expects NTPC, from that point forward, to target each rate class within each zone to 100% revenue to cost ratios, subject to other rate design considerations.

The Board considers the 95% to 105% range used by the Board in setting revenue to cost ratios in previous GRAs is no longer relevant with respect to this application. The 95% to 105% was used as a small buffer against high rates in some communities in the community-based rate system. With the creation of rate zones such a buffer is no longer necessary or desirable. For future General Rate Applications, NTPC is to target 100% revenue to cost ratios for each zone and for each rate class within each zone unless there is some other restriction or over-riding rate design principle that would compel moving away from 100%.

8. REDUCTION OF RETURN ON EQUITY FOR NORMAN WELLS

TGC submits that while it concurs with NTPC's proposal for Norman Wells to remain its own zone on a transition basis, the eventual intent is to have Norman Wells *"as part of the Thermal Zone at the time of the next Phase II GRA."* To be consistent with the intent to make Norman Wells part of the Thermal zone and consistent at least directionally with the manner in which the rates in the next Phase 2 are to be set, the TGC submit it would be consistent with the intent of the Government Policy directions, for purposes of this rate rebalancing exercise, to compute the adjustment to ROE as if Norman Wells was effectively part of the Thermal Zone [TGC Argument, Paragraphs 4, 5]

In its Reply Argument, NTPC submits that while the TGC apparently recognizes the transitional nature of the proposed treatment of Norman Wells in its argument, it nonetheless seeks to eliminate the transition period for the purposes of computing the ROE. NTPC submits there is no principled basis to deviate from the Electricity Guidelines on this point at this time in anticipation of the next GRA. [NTPC Reply, P. 3]

Board Findings:

Guideline 8 (c) states until such time as NTPC's next GRA, Norman Wells should remain as its own zone and not part of the thermal zone.

In view of the foregoing Guideline, the Board considers no adjustment to the proposed return on equity should be made for Norman Wells at this time.

9. IMPLEMENTATION DATE

TGC submits that the July 2010 Electricity Rate Policy Guidelines provided that the “*Board should implement the Electricity Rate Policy Guidelines by October, 2010.*” Notwithstanding this very specific provision, NTPC proposes an implementation date of December 1, 2010 for “*new base rates and Territory wide Stabilization Fund.*”

TGC submits, practically, given that the October 1, 2010 date implementation is not feasible, the December 1, 2010 implementation date is reasonable. However, the TGC recommend NTPC address, in its Compliance Filing, the merits of having the Board-approved “re-balanced” rates in effect as of October 1, 2010 such that the difference in the collections between the period October 1, 2010 and December 1, 2010 is charged or refunded, as appropriate, as part of the Corporation’s next GRA.[TGC Argument, Paragraphs 14, 15]

In reply to TGC, NTPC states, its Application was prepared consistent with the guidance from the PUB on the implementation date contained in the Board’s letter dated July 26, 2010. NTPC takes issue with the TGC’s request for two reasons. First, seeking commentary from NTPC at the Argument stage is inappropriate. If TGC felt that further information was necessary with respect to the December 1, 2010 implementation date directed by the Board, then the proper recourse was an Information Request to that effect. Further, and in any event, the suggestion of what would effectively be a rider for an interim two month period is without merit. NTPC submits, any benefit to the customers would be more than offset by the increased administrative costs to manage such a charge or refund system including any implications related to shortfall or stabilization fund balances. [NTPC Reply, P. 4]

Board Findings:

The electricity policy guidelines and the consequent restructuring of rates is the result of policy decisions and directions by the GNWT. Unlike in a General Rate Application where the effective date of new rates including restructured rates has a cost causation relationship to the beginning of a test period, the dates set out in the Guidelines are those based entirely on process considerations. Accordingly, the December 1, 2010 effective date for new rates is consistent with the revised process established by the Board for these proceedings. Further, the rates that are in effect from October 1, 2010 to December 1, 2010 are final, not interim, rates and are not subject to retroactive change.

The Board will not require adjustment of rates retroactive to October 1, 2010.

10. RECOMMENDATIONS TO MINISTER

The Minister's letter dated July 9, 2010 to the Board states:

"There may be revisions to these guidelines as the Electricity Review is implemented and the Government of the Northwest Territories (GNWT) would very much appreciate the Board's views on how these guidelines might be improved. The GNWT would also be interested in learning of the Board's thoughts on matters not specifically addressed in these guidelines, including standardized filing requirements for general rate applications, establishment of cost recovery guidelines outlining eligible costs and standard reimbursement rates associated with the regulatory process, and whether additional guidelines should be considered."

In Section 3 of this Decision, the Board discussed its concerns regarding the calculation of rates for the government customer classes. Accordingly, the Board recommends Guideline 3 (c) be amended as follows:

If residential or general service rates in a zone or community decrease as a result of this rate rebalancing exercise then government rates will stay at the current level. The continued existence of government rate classes in the next GRA is a matter to be discussed. If government rate classes persist into the next GRA, then government rate classes will have flat rates across a zone with no variation by community. The GNWT will provide the Board with direction as to the revenue to cost ratios to be used for the government rate classes recognizing that there is no value to other rate payers to continuing with government rates classes if the revenue to cost ratio for the government rate classes is not targeted higher than 100%.

In Section 4 of this Decision, the Board made the determination that the distribution component of NTPC's head office and general operating costs should

not be allocated to the Snare Yellowknife and Taltson wholesale rate classes. Accordingly, the Board recommends Guideline 4 be amended as follows:

All generation and transmission related costs included in a utility's revenue requirement that do not relate specifically to providing service in a single community or zone, referred to as head office and general operational costs, should be shared among all of the utility's rate zones, equally weighted by energy sales (per kWh). Any distribution related head office and general operational costs should be shared among all of the utility's rate zones, with the exception of the Snare Yellowknife and Taltson wholesale rate classes, equally weighted by energy sales (per kWh).

In Section 5 of this Decision, the Board determined that if a Taltson water stabilization fund were to be initiated in the future, under the per utility sharing approach, NUL-NWT customers would share in NTPC's fuel and low water rider amounts but NTPC's customers would not share in the NUL-NWT fuel rider amounts. This might not be equitable to NUL-NWT customers. The per utility sharing of fuel and low water stabilization amounts could also result in different rider rates for customers in NUL's service area and in NTPC's service area. Creating the potential for wide rate disparities between neighbouring communities is not consistent with the principle of comparability of rates.

The Board also stated its concerns with having the base fuel prices set artificially rather than being based upon the best pricing information available at the time that new base rates are set.

Accordingly, the Board recommends Guideline 6 be amended as follows:

The Board should consider establishing Northwest Territories wide fuel and low water riders on a per utility or combined utility basis as dictated by the applicable rate making principles. The Base Fuel Prices shall be the levels approved in each utility's most recent GRA as of the implementation of this policy. This condition may be set-aside if necessary should an agreement be reached between the utilities regarding the implementation of a single territory-wide fuel and water fund that would cover both NTPC and NUL.

In Section 7 of this Decision, the Board identified a concern with Guideline 8 (c) in that it prevented a justifiable decrease in the rates in Norman Wells. It is the Board's view that the Guidelines were intended by the GNWT to be protective against rate increases, not against rate decreases. The requirement in Guideline 8 (c) that Norman Wells rates cannot be decreased is likely an oversight by the GNWT. Accordingly, the Board recommends that Guideline 8 (c) be amended as follows:

Until such time as NTPC's next GRA, Norman Wells should remain as its own zone and not part of the thermal zone. The Board should ensure electricity base rates for Norman Wells customer classes following the initial electricity rate adjustments will not exceed the levels of electricity Base Rates plus Rate Riders applicable for the same level of consumption effective October 1, 2009.

11. BOARD DIRECTIONS

The following is a summary of the Board directions to NTPC:

1. The Board directs NTPC in its refiling application to provide the Board with its best estimate total of head office and general operating costs which are associated with the distribution function. The Board expects that NTPC would be able to provide this estimate based upon previous cost of service studies.
2. The Board directs NTPC in the refiling application to share amongst all of the utility's rate zones the head office and general operational costs related to generation and transmission, equally weighted by energy sales (per kWh). Any distribution-related head office and general operational costs should be shared amongst all of the utility's rate zones, equally weighted by energy sales (per kWh), with the exception of the Snare Yellowknife and Taltson wholesale rate classes which will not be allocated or assigned any distribution-related costs of NTPC.
3. The Board directs NTPC to conduct a thorough and final functional analysis on its head office and general operating costs. The purpose of this analysis is to identify the portion of head office and general operating costs that are related to the generation, transmission and distribution functions by reference to each of the expense elements shown in Attachment NUL NTPC 1(a-b) including details of direct assignments, allocations and the basis of the allocations.
4. The Board directs NTPC to file an application with the Board by January 14, 2011 to convert all of the interim rates to final rates with an

implementation date of April 1, 2011. That application is to include and incorporate the results of the final functional analysis, the results of which are to be presented in the application in a transparent manner.

5. The Board also directs NTPC, in that application, to provide an accounting and reconciliation on the revenue differences for the Snare and Taltson wholesale rate classes, for the period from December 1, 2010 and April 1, 2011, between the interim best estimates approach on assigning head office and general operating costs and the final functional analysis approach described by the Board in this Decision.
6. As an alternative, if by January 14, 2011, NTPC is able to conclude an agreement with NUL on mechanisms to combine NTPC's and NUL's head office and general operating costs and then allocate these costs to all rate zones and rate classes of NTPC and NUL, then that agreement, instead of the functional analysis approach on NTPC's costs, can be the basis for the final rates going forward from April 1, 2011.
7. The Board directs NTPC to work with NUL to develop a mechanism for Northwest Territories-wide sharing of fuel and low water costs, on a combined utility basis. If an agreement is reached between the utilities, the details and implementation of the proposed mechanism should be included in the January 14th application to the Board for implementation on April 1, 2011.
8. The Board directs NTPC to set the trigger point for the consolidated rate stabilization fund at \$2.5 million.

9. The Board is directing NTPC that, in the absence of an agreement with NUL for the sharing of territory-wide fuel and water costs being included in the already-directed January 14th application to be submitted to the Board, NTPC is to file a separate application with the Board by January 14th for activation of the NTPC territorial fuel and water rider for February 1, 2011 taking into consideration the latest fuel and water forecasts and the \$2.5 million trigger.
10. The Board directs NTPC that in its refiling application the revenue to cost ratios for the Snare Zone, Norman Wells Zone and the Thermal Zone should be equal and brought as close as possible to 100%.
11. Where the government rate classes are producing revenue at greater than 100%, the Board directs NTPC to share the benefit of the higher government rates equally amongst the non-government rate classes in a particular zone by setting the revenue to cost ratios for the non-government rate classes in the zone at equal levels. The refiling application is to demonstrate how the Board's directions on this matter have been met or cannot be met due to other considerations.
12. The Board directs NTPC that in the January 14th application to convert the interim rates to final rates, NTPC is to make further adjustments to the rates to bring each rate zone to revenue to cost ratios of 100% on a go-forward basis by eliminating the shortfall from the Taltson zone.
13. If at some point in the future the government rate classes are either terminated or set based upon cost causation principles then the Board expects NTPC, from that point forward, to target each rate class within

each zone to 100% revenue to cost ratios, subject to other rate design considerations.

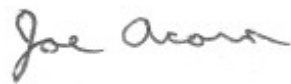
14. For future General Rate Applications, NTPC is to target 100% revenue to cost ratios for each zone and for each rate class within each zone unless there is some other restriction or over-riding rate design principle that would compel moving away from 100%.

12. BOARD ORDER

NOW THEREFORE, IT IS ORDERED THAT:

1. The Northwest Territories Power Corporation is to re-file its Application to implement the Electricity Rate Policy Guidelines, as approved and/or directed in this Decision, by November 22, 2010.
2. The Northwest Territories Power Corporation is to provide the Board and other parties with an updated set of rate schedules at the time of the refiling Application.
3. Nothing in this Decision and order shall bind, affect or prejudice the Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

**ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES**



**Joe Acorn
Chairman**

Dated November 12, 2010

TAB 5

**THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES**

DECISION 1-2013

JANUARY 21, 2013

IN THE MATTER OF the Public Utilities Act, being Chapter 110 of the Revised Statutes of the Northwest Territories, 1988(Supp.), as amended.

AND IN THE MATTER OF an application by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided to its customers within the Northwest Territories for the Test Years 2012/13 and 2013/14.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS

Joe Acorn	Chairman
Sandra Jaque	Vice-Chairman
William Koe	Member

BOARD STAFF

Louise Larocque	Board Secretary
Raj Retnanandan	Board Consultant
Evan W. Dixon	Board Counsel

APPEARANCES

Karen Salmon	Counsel for the Northwest Territories Power Corporation
Thomas D. Marriott	Counsel for the City of Yellowknife & Town of Hay River
G. Rangi Jeerakathil.	Counsel for the Thermal Generation Communities

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Northwest Territories Power Corporation

Judith Goucher	Chief Financial Officer
Terence Courtoreille	Manager, Budgeting & Regulatory Affairs
Daniel Roberts	Director of Engineering & Asset Management
Patrick Bowman	Consultant

WITNESSES cont...

City of Yellowknife & Town of Hay River

Russ Bell

Consultant

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1. BACKGROUND & APPLICATION

By letter dated March 23, 2012, the Northwest Territories Power Corporation ("**NTPC**" or the "**Corporation**") submitted to the Northwest Territories Public Utilities Board ("**the Board**") its General Rate Application ("**GRA, Application**"). The Application outlines forecast costs for providing electricity service for the 2012/13 and 2013/14 fiscal years (the "**Test Years**") [Ex 2].

In conjunction with its GRA and pursuant to Section 44 of the *Public Utilities Act* ("**the Act**"), NTPC also filed an Interim Rate Application ("**IRA**") dated March 23, 2012 wherein it requested approval of interim rates to increase all energy charges for all customer classes, in all communities, except Norman Wells, by 7% and for interim rates to increase all energy charges for all customer classes in Norman Wells by 15%. NTPC also requested that all interim rates be effective April 1, 2012. NTPC stated that to be consistent with the 2012/14 GRA, NTPC was not seeking to adjust customer charges or demand charges.

In previous interim rate applications, NTPC has proposed interim rate riders to collect approximately 80% of the Corporation's shortfall that would result from fully implementing the proposed revenue requirement in the GRA, subject to a maximum overall rate increase of 15%. In the current GRA, NTPC proposed to transition to rates that fully recover the Corporation's revenue requirement over a four-year period.

For the 2012/13 Test Year, NTPC requested approval of final rates that are 7% higher than current rates for all communities and rate classes except Norman Wells, where 15% energy rate increases are proposed to assist with the transition of Norman Wells into the Thermal zone as per Provision (9)(a) of the February 10, 2011 Rate Policy Guidelines.

Despite the additional revenue from interim rates, NTPC still expects to incur a substantial shortfall in the 2012/13 Test Year. As a result, NTPC indicates, the Corporation and its shareholder, the Government of the Northwest Territories (“GNWT”), have implemented financial funding measures which will mitigate the rate impact for customers during this transition. With these measures NTPC indicates, it can continue to provide safe and reliable service, while maintaining its financial viability for 2012/13.

By letter, dated March 28, 2012, the Corporation stated that it wished to amend its IRA to reduce the requested increase for all customer classes in Norman Wells from 15% to 7%, effective April 1, 2012. This amendment will bring Norman Wells’ proposed increases in line with the increases in energy charges sought for all customers in all other communities.

The Board issued Decision 11-2012, dated May 1, 2012, approving rates on an interim refundable basis, effective May 1, 2012 for the 2012/13 year. In its Order, the Board directed that all revenues collected by the interim rates are to be tracked by zone and rate class to allow reconciliation and true-up in accordance with the final GRA Decision.

In its GRA, the Corporation requested an order or orders of the Board:

1. **Approving the Test Year Revenue Requirements** at \$102.506 million and \$107.544 million in 2012/13 and 2013/14 respectively, including approval as required of the following costs and revenues:
 - a. **Operating and Maintenance Expenses** of \$37.280 million and \$38.634 million for non-fuel expenses in 2012/13 and 2013/14 respectively.

- b. **Fuel Expenses** of \$27.538 million and \$27.879 million for fuel and purchased power expenses in 2012/13 and 2013/14 respectively, including approvals to establish fuel prices at forecast levels for the two test years at the most recent prices charged by the GNWT Petroleum Products Division (“PPD”) as of February 2012, with actual variances from forecast being charged to or credited to NTPC’s territory-wide Stabilization Fund.
- c. **Amortization Expenses** (net of customer contributions) of \$13.298 million and \$13.363 million in 2012/13 and 2013/14 respectively for fixed assets, plus \$2.584 million in 2013/14 for the fixed asset true-up, plus \$5.280 million and \$5.747 million in 2012/13 and 2013/14 respectively for other amortization, including approvals:
 - i. To adopt new asset amortization rates as determined in NTPC’s 2011 Depreciation Study performed by Gannett Fleming for all asset classes.
 - ii. To amortize all variances arising as a result of the new depreciation rates over the average remaining life of the respective asset class, with a minimum period of 5 years.
 - iii. To implement a pause in accruals for future removal and site restoration (“net salvage”) until such time as a future depreciation study indicates the balance in the provision equals the expected future spending requirements.
 - iv. To decrease the annual appropriation for regulatory hearing costs from the \$0.600 million per year level set at the 2006/08 GRA, to \$0.243 million per year, reflecting the full recovery of the costs of all past GRAs, and the assumed costs for preparation and regulatory review of the 2012/13 and 2013/14 GRA on a simplified basis (total assumed incremental cost to NTPC of \$1.3 million).

- v. To increase the annual amortization of the normalized overhaul deferral account from an annual level of \$1.693 million per year approved in the 2006/08 GRA to \$3.046 million per year to reflect increases in the balance and in the forecast ongoing costs of overhauls primarily in the thermal zone.
- vi. To increase the annual amortization of the water licencing deferral account from an annual level of \$0.137 million per year approved in the 2006/08 GRA to \$0.751 million per year in 2012/13 and \$1.175 million per year in 2013/14 to reflect material increases in the balance in the account and in the forecast level of effort and spending required to maintain and renew NTPC's water licences including regulatory reviews, compensation, environmental and dam safety studies, Aquatic Effects Monitoring Program ("AEMP") costs and all related activities (except capital works).
- vii. Continuation of the Reserve for Injuries and Damages, at the same \$0.670 million per year appropriation approved in the 2006/08 GRA.
- viii. A new annual amortization of \$0.348 million per year to begin to discharge the balance in the regulatory Employee Future Benefits deferral, established as part of the 2001/03 GRA Negotiated Settlement. This account has previously had no annual accrual pending a full draw down of the balance that was established in the 2001/03 GRA, which has now occurred.
- ix. A new brushing deferral approach to amortize all brushing costs in a given year over the following 10 years, including approval to amortize \$0.088 million in 2012/13 and \$0.132 million in 2013/14.
- x. Amortization of all remaining deferred charges over 5 years except in cases where the anticipated benefits exceed this level

(specifically, 10 year amortization for IFRS conversion project costs, and for the Enterprise Resource Planning exercise).

d. **Return on Rate Base** of \$19.111 million and \$19.337 million in 2012/13 and 2013/14 respectively, reflecting an underlying forecast capital structure financing rate base of approximately 40% equity and 60% longterm debt and capital lease, including the following proposed costs of capital:

- i. Mid-Year Cost of Long-Term Debt of 6.54% and 5.77% in 2012/13 and 2013/14 respectively.
- ii. Average Cost of Capital Lease of 9.62% in each test year. Return on Equity in the Thermal Zone of 0% consistent with the Guidelines.
- iii. A requested Return on Equity for all assets outside the Thermal Zone of 8.5% determined on a simplified basis given the requested rate is below market standards recently set for utilities in Canada, such as the 8.75% low risk benchmark approved by the Alberta Utilities Commission for lower-risk large southern electric utilities (2011 and 2012 and interim 2013), and the 9.3% approved for NUL(YK) and NUL(NWT) (2011, 2012, and 2013).
- iv. An interest coverage ratio in the thermal zone of 1.5.

2. **Approving the Forecast Test Year Rate Base** at \$273.522 million and \$296.125 million in 2012/13 and 2013/14 mid-years respectively (Chapter 4), reflecting the net book value of assets in service, customer contributions, other deferred charges, and an allowance for working capital, including additions made to rate base pursuant to the following projects subject to PUB Project Permits:

- a. **Bluefish Dam Replacement Project** in 2012/13, at a forecast cost of \$37.4 million consistent with Board Decision 15-2011.
 - b. **Inuvik Diesel Conversion Project** at an estimated \$8 million, not yet in receipt of a PUB Project Permit, to address the extenuating circumstances arising from the shortfall in gas supply.
3. **Approving final GRA rates to be charged to customers** covering the rate transition period (including the 2 Test Years plus 2014/15 and 2015/16) as needed to achieve the full calculated level of rates.
- a. **Residential Non-Government:** Increases to all energy rates, other than Norman Wells, totalling 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. For Norman Wells increases to energy rates of 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 2015/16. No changes are proposed to fixed monthly charges.
 - b. **Residential Government:** Increases to customer energy rates equal to the same percentage as the increase in non-government customer energy rates in the same community. No changes are proposed to fixed monthly charges.
 - c. **General Service Non-Government:** Increases to all energy rates, other than Norman Wells, totalling 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. For Norman Wells increases to energy rates totalling 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 2015/16. No changes are proposed to demand charges.
 - d. **General Service Government:** Increases to customer energy rates equal to the same percentage as the increase in non-government General

- Service customer energy rates in the same community. No changes are proposed to demand charges.
- e. **Wholesale:** Increases to customer energy rates of 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. No changes to demand charges.
 - f. **Industrial:** Increases to customer energy rates of 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. No changes to demand charges.
 - g. **Lighting:** Increases to lighting rates equal to the same percentage applied to Government General Service in the same community.
4. **Approving revised Terms and Conditions of Service** primarily focused on standardizing the Corporation's terms with normal utility provisions (including provisions with respect to liability and indemnity), to address potential safety issues with respect to reconnections, to improve the clarity and consistency of the terms, as well as general housekeeping updates.

Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letter dated April 12, 2012, directed NTPC to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories ("**NWT**"). The notices published in April 2012 included details and schedules of the GRA, and invited interested persons to file a request with the Board for intervener status. [Ex 1]

The City of Yellowknife and Town of Hay River (collectively referred to as "**YK/HR**") registered to participate as interveners in the Board's process as did the Thermal Generation Communities, comprised of the Town of Inuvik, Hamlet of Fort Providence and Village of Fort Simpson (hereinafter the "**TGC**").

The Board's hearing process provided interveners with the opportunity to request further information of NTPC through an information request process as well as the ability to file evidence.

In accordance with the schedule set by the Board, NTPC provided written responses to the information requests [Ex 3] from the Board and interested parties. Written evidence was filed on behalf of YK/HR, by letter dated June 29, 2012 [Ex 6]. The TGC did not provide written evidence but were active in the information request process and the public hearing. Information requests were issued by the Board and NTPC to YK/HR in response to their written evidence [Ex 7]. All written information requests by the Board and interveners together with the responses were made available to all parties before the hearing and form part of the public record of this hearing.

By letter dated September 19, 2012, NTPC provided an updated filing package with respect to NTPC's GRA pursuant to its letter of June 8, 2012 and Board Decisions 16-2012 and 22-2012. The package included updated GRA schedules and updated information on Norman Wells transitioning to the Thermal Zone rates [Ex 13].

The update requested the following approvals:

- "1. **Approving the Test Year Revenue Requirements** at \$102.225 million and \$107.304 million in 2012/13 and 2013/14 respectively (Chapter 3), including approval as required of the following costs and revenues:
 - a. **Operating and Maintenance Expenses** of \$37.064 million and \$38.597 million for non-fuel expenses in 2012/13 and 2013/14 respectively.
 - b. **Fuel Expenses** of \$27.817 million and \$28.172 million for fuel and purchased power expenses in 2012/13 and 2013/14 respectively, including approvals to establish fuel prices at forecast levels for the two test years at the most recent prices charged by the GNWT Petroleum Products Division ("PPD") as of August 2012 February 2012, with actual variances from forecast being charged to or credited to NTPC's territory-wide Stabilization Fund.

- c. **Amortization Expenses** (net of customer contributions) of \$13.240 million and \$13.503 million in 2012/13 and 2013/14 respectively for fixed assets, plus \$2.584 million in 2013/14 for the fixed asset true-up, plus \$5.170 million and \$5.287 million in 2012/13 and 2013/14 respectively for other amortization, including approvals:
- i. To adopt new asset amortization rates as determined in NTPC's 2011 Depreciation Study performed by Gannett Fleming (Appendix A) for all asset classes.
 - ii. To amortize all variances arising as a result of the new depreciation rates over the average remaining life of the respective asset class, with a minimum period of 5 years.
 - iii. To implement a pause in accruals for future removal and site restoration ("net salvage") until such time as a future depreciation study indicates the balance in the provision equals the expected future spending requirements.
 - iv. To decrease the annual appropriation for regulatory hearing costs from the \$0.600 million per year level set at the 2006/08 GRA, to \$0.243 million per year, reflecting the full recovery of the costs of all past GRAs, and the assumed costs for preparation and regulatory review of the 2012/13 and 2013/14 GRA on a simplified basis (total assumed incremental cost to NTPC of \$1.3 million).
 - v. To increase the annual amortization of the normalized overhaul deferral account from an annual level of \$1.693 million per year approved in the 2006/08 GRA to \$2.936 million per year to reflect increases in the balance and in the forecast ongoing costs of overhauls primarily in the thermal zone.
 - vi. To increase the annual amortization of the water licencing deferral account from an annual level of \$0.137 million per year approved in the 2006/08 GRA to \$0.751 million per year in 2012/13 and \$0.825 million in 2013/14 to reflect material increases in the balance in the account and in the forecast level of effort and spending required to maintain and renew NTPC's water licences including regulatory reviews, compensation, environmental and dam safety studies, Aquatic Effects Monitoring Program ("AEMP") costs and all related activities (except capital works).
 - vii. Continuation of the Reserve for Injuries and Damages, at the same \$0.670 million per year appropriation approved in the 2006/08 GRA.
 - viii. A new annual amortization of \$0.348 million per year to begin to discharge the balance in the regulatory Employee Future Benefits deferral, established as part of the 2001/03 GRA Negotiated Settlement. This account has previously had no annual accrual pending a full draw down of the balance that was established in the 2001/03 GRA, which has now occurred.
 - ix. A new brushing deferral approach to amortize all brushing costs in a given year over the following 10 years, including approval to amortize \$0.088 million in 2012/13 and \$0.132 million in 2013/14.
 - x. Amortization of all remaining deferred charges over 5 years except in cases where the anticipated benefits exceed this level (specifically, 10 year amortization for IFRS conversion project costs, and for the Enterprise Resource Planning exercise).
- d. **Return on Rate Base** of \$18.934 million and \$19.161 million in 2012/13 and 2013/14 respectively, reflecting an underlying forecast capital structure financing

rate base of approximately 40% equity and 60% long-term debt and capital lease, including the following proposed costs of capital:

- i. Mid-Year Cost of Long-Term Debt of 6.47% 6.54% and 5.68% 5.77% in 2012/13 and 2013/14 respectively.
 - ii. Average Cost of Capital Lease of 9.62% in each test year.
 - iii. Return on Equity in the Thermal Zone of 0% consistent with the Guidelines.
 - iv. A requested Return on Equity for all assets outside the Thermal Zone of 8.5% determined on a simplified basis given the requested rate is below market standards recently set for utilities in Canada, such as the 8.75% low risk benchmark approved by the Alberta Utilities Commission for lower-risk large southern electric utilities (2011 and 2012 and interim 2013), and the 9.3% approved for NUL(YK) and NUL(NWT) (2011, 2012, and 2013).
 - v. An interest coverage ratio in the thermal zone of 1.5.
2. **Approving the Forecast Test Year Rate Base** at \$272.778 million and \$296.592 million in 2012/13 and 2013/14 mid-years respectively (Chapter 4), reflecting the net book value of assets in service, customer contributions, other deferred charges, and an allowance for working capital, including additions made to rate base pursuant to the following projects subject to PUB Project Permits:
- a) **Bluefish Dam Replacement Project** in 2012/13, at a forecast cost of \$37.4 million consistent with Board Decision 15-2011.
 - b) **Inuvik Diesel Conversion Project** at an estimated \$10.3 million, including \$7.7 million approved via PUB Project Permit, to address the extenuating circumstances arising from the shortfall in gas supply.
3. **Approving final GRA rates to be charged to customers** covering the rate transition period (including the 2 Test Years plus 2014/15 and 2015/16) as needed to achieve the full calculated level of rates (Chapter 4).
- a) **Residential Non-Government:** Increases to all energy rates, other than Norman Wells, totaling 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. For Norman Wells increases to energy rates of 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 2015/16. No changes are proposed to fixed monthly charges.
 - b) **Residential Government:** Increases to customer energy rates equal to the same percentage as the increase in non-government customer energy rates in the same community. No changes are proposed to fixed monthly charges.
 - c) **General Service Non-Government:** Increases to all energy rates, other than Norman Wells, totaling 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. For Norman Wells increases to energy rates totaling 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 2015/16. No changes are proposed to demand charges.
 - d) **General Service Government:** Increases to customer energy rates equal to the same percentage as the increase in non-government General Service customer energy rates in the same community. No changes are proposed to demand charges.
 - e) **Wholesale:** Increases to customer energy rates of 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. No changes to demand charges.

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2. PUBLIC HEARING

The hearing was held in the City of Yellowknife on September 26 and 27, 2012. During the course of the hearing, members of the public who had not requested intervener status were invited to participate. During the hearing, NTPC undertook to provide responses to a number of undertakings provided at the hearing.

Following the hearing, undertaking responses and Argument/Reply were filed on the following dates:

Responses to Undertakings	October 9, 2012
Information Requests on Undertakings	October 11, 2012
Responses to Information Requests	October 15, 2012
Written Argument	October 24, 2012
Written Reply Argument	November 7, 2012

3. RATE BASE

NTPC's mid-year rate base for the Test Years 2012/13 and 2013/14 includes:

- Gross plant in service, including capital additions and disposals
- Accumulated amortization
- Customer contributions
- Working capital
- Deferral accounts

The calculation of the mid-year rate base is set out in Schedule 5.1

3.1 Gross Plant In Service

NTPC's calculation of gross plant in service is shown in Schedule 5.1.

TGC requested that the 2012/13 Test Year opening balances for gross plant in service be updated to reflect the 2011/12 actual closing balances for plant. The Board will deal with this matter in Section 13.1 of this Decision.

3.2 Accumulated Amortization

NTPC's calculation of accumulated amortization is set out in Schedule 5.1.

TGC requested that the 2012/13 Test Year opening balances for Accumulated Amortization be updated to reflect the 2011/12 actual closing balances. The Board will deal with this matter in Section 13.1 of this Decision.

3.3 Capital Additions

NTPC summarized capital spending for 2010/11 and forecasts for 2011/12, 2012/13 and 2013/14 in Appendix B of the Application. In Appendix B, the Corporation provided additional detail for those projects over \$150,000 including those projects previously approved by the Board through Major Project Permit Applications.

The issues respecting capital additions that were raised during the proceedings are discussed below.

3.3.1 Capital Budgeting and Business Cases

NTPC acknowledged that its record in the years leading up to the 2009/10 NTPC Review conducted by a Panel of Experts, had not been acceptable with respect to project scoping, cost estimating and budgeting. In this regard, NTPC quotes the Panel's comments as follows:

"Cost estimates and project scope do not appear to be as well planned as one could reasonably expect. For example, with the Snare Rapids Upgrade, the original budget was targeted at \$4.92 million, but eight years later expenditures had risen to \$9.5 million. The first 5 years of work consumed most of the original budget. Better scoping at the outset should have allowed for, among other reasonable projections, a better estimate of the condition of the facility and its parts." [Ex 8; P2]

During hearing examination NTPC's witness, Mr. Roberts, indicated several changes designed to address project scoping and accuracy of cost estimating have been put in place since the Panel Review. First, a reorganized structure has been put in place:

"So under the reorganization structure the first thing that will be addressed is the estimates and the accuracy of the estimates. To achieve that, we have asset managers who are responsible for the planning. And we have a dedicated asset manager now for the hydro and a dedicated asset manager position for the Thermal plants and also for the T&D. And where it refers to the team approach, what that means is they'll be assessing the projects and looking at the condition of the assets, but they'll be working in conjunction with our design team so that we can have better estimates for the -- upfront. So there was clearly some problems with using estimates that were weren't up-to-date. So that's the first thing that will be addressed." [T264; L9-25]

Second, there will be more emphasis on scoping of projects:

"...So where it says scope creep, it's not really, it's the fact that the project should have included all this at the start if it's evaluated correctly. So the projects will be -recent estimates which I saw -- like I say, not just this project, I saw quite a few projects that we were using estimates significantly out-of-date. And also there will be more emphasis put on the scoping of these projects." [T265; L12-20]

Third, the issue of completeness of cost estimates is to be addressed:

"And the third issue that I saw is around the completeness, I'll call it, of the estimates themselves. Quite often the estimates that were put forward in our capital plan would have included estimates for contractors and materials which --excepting they want were out of date, they were --but there were also -- I would say weren't complete, they didn't fully include costs like construction supervision or travel to site wasn't accurate -- wasn't accurate enough, design, engineering costs were underestimated. So it's pretty clear that we have to address these issues to up come up with more realistic budgets." [T265, L21 – T266, L8]

Mr. Roberts confirmed that there will be ongoing monitoring of projects and if a larger project in the \$50,000 to \$75,000 range looks like it is going over budget it is flagged at an early stage. [T269, L5-9] Where project costs are expected to be \$100,000 over the budget they are required to be brought to the attention of the Board of Directors. [T269, L17-22]

In terms of accountability tools, NTPC was questioned as to whether post-completion reports are prepared when projects are completed, looking at

variances and lessons learned for future budgeting purposes. Mr. Roberts indicated: "I haven't seen them but we will be doing them." [T268, L11]

Ms. Goucher referred to other accountability tools used by NTPC:

"...We do have also some specific accountability tools in terms of adherence to budget targets. In terms of the management team, I believe it was Mr. Courtoreille who identified that one of the criteria of the at-risk performance pay is that our capital program be delivered overall within certain budget tolerances, otherwise the entire management team could have -- could lose any at-risk compensation for that fiscal year.

In terms of the individual project managers and other employees within the engineering group or other groups who are responsible for project management, we also complete, as an organization, annual performance reviews. Those reviews speak to specific skills gaps and performance deficiencies, and we identify training programs out of those. So that would be another tool that's available to the management team in terms of making sure that we reach the success level that we're seeking in terms of project management." [T271, L18 – T272, L13]

YK/HR expressed concern that the Corporation did not provide business cases in support of certain major capital projects. YK/HR noted that businesses cases for the Snare/Jackfish Transient Stability Upgrade project and the Distribution System Upgrade project, the land use database, and the computerized maintenance system had not been provided by NTPC. YK/HR recommended, on the basis of NTPC having not identified any tangible benefits to the land use data base project with a cost of \$430,000, and the computerized maintenance system at a cost of \$413,000, that the Board deny the inclusion of these projects in approved rate base. [YK/HR Argument, P7, Para 26]

YK/HR also recommended that NTPC provide business cases in support of capital programs, to include the following:

- A full and complete discussion of the business need that is being addressed.
- A list of all assumptions made, including the source and basis for the assumptions.
- An analysis of all reasonable options that could be pursued, including the do nothing option.

- Cost projections over the life of the project, for each option to allow the assessment of the total lifecycle cost of the project. This should include all costs of the project.
- Appendices that provide the calculation of costs included in the business case.
- Projected tangible benefits, along with the basis for the projected benefits.
- Scenarios for reasonable sensitivities, to allow the testing of changing cost or benefit levels on the outcome.
- Present value of revenue requirement.
- Traditional cash flow analysis.
- A discussion of all intangible benefits.
- A complete discussion of risks and mitigation strategies related to the project and the recommended option. [YK/HR Argument Para 11]

YK/HR noted that NTPC has additional information, and conducts a more detailed analysis for internal management purposes. As such, and in order to enhance the efficiency and transparency of the regulatory process, YK/HR suggested that NTPC should be directed to provide complete business cases to support capital expenditures for a GRA as part of the minimum filing requirements [YK/HR Argument, P3, Para 12]. YK/HR recommended a materiality threshold of \$400,000 for filing of business cases. [Ex 6, P13, Para A11]

YK/HR submitted, expenditures that are a part of a larger program should be analysed and justified together. In this regard, YK/HR noted that NTPC is forecasting to spend over \$500,000 per year on IT projects for each of 2012/13 and 2013/14, yet has not provided a business case or its internal IT policy, nor evidence that its policies and practices result in the least cost option for customers. [YK/HR Argument, P1, Para 5]

With respect to the proposed Remote Terminal Unit (“RTU”) replacement, YK/HR submitted:

“..NTPC is forecasting to spend \$876,000 in 2012/13 and \$1,491,000 in 2013/14, yet has provided limited explanations for its forecast. NTPC has not provided a business case in support of the level of spending forecast for 2013/14. While NTPC has explained what the expenditures are for, NTPC has not explained why the increased spending in 2014 is

required. In fact, YK/HR notes that the original budget for the entire project was \$2.5 million, and the revised budget is \$4.2 million. Further, NTPC indicates it has spent \$3.4 million of the \$4.2 million. Given that NTPC has spent \$3.4 million of the \$4.2 million budget, YK/HR does not understand why an additional \$2,367,000 is to be spent over the 2012/13 2013/14 period. According to NTPC, there is only \$0.8" million left to be spent. Given the history of spending and the fact that NTPC's own budget indicates that there is only \$0.8 million left in the project, YK/HR submits that the forecast spending on RTU replacement be reduced to \$0.8 million to represent the level of spending left to in the project budget." [YK/HR Argument, P7, Para 27]

NTPC responded to the positions taken by YK/HR in its Rebuttal and in Reply Argument.

With respect to YK/HR's recommendation that the computerized maintenance system costs and the land use data base costs be disallowed, NTPC submitted that business cases are only relevant where an optional project is being pursued for reasons of a positive financial return. NTPC submitted that neither project cited by YK/HR meets these criteria. NTPC further submitted that the referenced projects are essential core utility functions which cannot be properly portrayed by a business case focused on return on investment or cash flows.

With specific reference to the Computerized Maintenance System, NTPC submitted that the existing maintenance control system has 3 fundamental issues:

- It is no longer supported by the software producer;
- It is no longer compatible with current computer operating systems; and
- It is limited in functionality in that it does not track any auxiliary equipment outside the main engines in a plant.

With respect to the electronic land use data base, NTPC identified the following benefits:

- Employees can quickly resolve property right issues with customers;
- Identify missing or unclear property rights;
- Ensure new distribution extensions have correct property rights;
- Reduced management time resolving property rights issues allowing management to concentrate on core functions;
- Increased customer service as property rights issues will be resolved in a timely manner. [NTPC Reply, P17-19]

With respect to expenditures on RTUs, NTPC stated that YK/HR appeared to misunderstand the distinction between capital spending and capitalization. When the Corporation spends money on an active capital project, the spending is captured in Capital Work in Progress (“**CWIP**”). These funds earn interest until such time as the project is completed and/or the assets become used or useful, at which time the spending is capitalized. Capitalized assets are built into rate base and amortized accordingly. RTU capital additions to rate base are provided in Schedules B-1 through B-4 of the Application, and total \$2.7 million. Accordingly, while \$3.4 million has been spent, only \$2.7 million of this amount is proposed to be built into rate base, rather than the full amount as suggested by YK/HR. [NTPC Reply, P17, L9-16]

With respect to YK/HR's comments respecting business cases, NTPC stated that the framework for utility regulation in NWT already incorporates a provision for detailed review of project impacts on the business and on rates for all cases where a Major Project Permit is required under *the Act*. This threshold has been legislatively set at \$5 million or 10% of a utility's rate base. NTPC submitted the legislation does not provide for any similar detailed project specific reviews for projects below this threshold. [NTPC Reply, P35, L6-10]

Board Findings:

The Board is concerned by the budget cost overruns on certain larger projects executed by NTPC, some of which are listed in BR.NTPC-28. This is particularly a concern given NTPC's acknowledgement of a breakdown in process checks and balances which resulted in inadequate planning and scoping of projects and incorrect budget estimates during the years leading up to 2009/10.

In the Board's view the existence of appropriate process checks and balances and accountability tools provide the necessary assurance that capital budgets reflect prudent cost estimates and accountability for actual project costs in relation to capital budgets. The Board notes NTPC's comments with respect to process improvements and accountability tools for performance it has recently instituted and is encouraged by the steps the Corporation has taken to address this issue. The Board expects NTPC to demonstrate the operation and effectiveness of these checks and balances as part of the testing of capital additions in future proceedings.

Given this context, the Board considers the preparation of business cases as described in Mr. Bell's evidence and in YK/HR Argument would facilitate assessment of capital forecasts in the context of a GRA and would also provide the necessary discipline for NTPC to ensure capital budgets and forecasts take into account the best available information having reviewed alternatives and that the capital budgets and forecasts are reasonably accurate.

Accordingly, the Board directs NTPC to provide business cases in support of major capital projects forecast to be added to rate base, at the time of the next GRA. The Board finds the list of items to be addressed in business cases as set out by YK/HR provides a reasonable template for structuring business cases. For the purpose of preparing business cases, the Board accepts YK/HR

recommendation that the project cost threshold for business cases be set at \$400,000.

NTPC is directed to prepare business cases for capital projects meeting the above threshold which are scheduled to commence after March 31, 2013 and should be prepared to provide detailed explanations for variances between budget and actual costs based on post completion reports.

The Board notes YK/HR's position that NTPC did not identify any tangible benefits to the land use data base project and computerized maintenance system its recommendation that the Board deny the inclusion of these projects in approved rate base. The Board notes NTPC has provided reasons for going ahead with these projects as well as the specific benefits associated with these projects. Therefore, the Board denies YK/HR's request to disallow these items from rate base.

With respect to YK/HR's request that RTU replacement be reduced to \$0.8 million to represent the level of spending left in the project budget, the Board notes NTPC's explanation that the difference in spending referred to by YK/HR arises from not considering amounts included in CWIP. The Board accepts NTPC's explanation and will therefore not adjust the RTU additions for the Test Years.

3.3.2 Inuvik Diesel Conversion Project

NTPC indicated that the Inuvik conversion project is being undertaken entirely in response to the termination of natural gas availability for NTPC use. The project involves the conversion of two existing Wartsila engines (one 2.1MW and the other 2.8MW) to diesel use and, the installation of a 2.8 MW EMD diesel unit

relocated from Jackfish. The project also involves upgrading and re-commissioning of the diesel fuel tank at Inuvik. NTPC states the re-commissioning of the fuel tank was under consideration for future years even absent the conversion of Inuvik to diesel, but must now be advanced to permit a base load diesel operation.

Although in its Application [Ex 2], NTPC estimated the cost of conversion of the two Wartsila units and relocation of the EMD unit to be \$8 million, NTPC revised the \$8 million estimate to \$10.3 million in its update Application. [Ex 13] The proposed cost with respect to the Inuvik diesel conversion project is as follows:

Inuvik Diesel Conversion Project			
	2012/13	2013/14	Total
	\$M	\$M	\$M
Conversion of 2 Gas Wartsila Engines to Diesel	7.7		7.7
One 2.5MW EMD Diesel Unit	2.6		2.6
Sub Total	10.3	0	10.3
Recommissioning Diesel Fuel Tank	2.3	1.2	3.5
Total	12.6	1.2	13.8

In Argument, NTPC stated that the Corporation's August 17, 2012 Major Project Permit application discussed a large range of options that NTPC investigated as potential solutions to address the firm capacity issues of the Inuvik Power Plant. Options that related to the use of synthetic gas (propane-air) to supply the existing gas units were ruled out as they are technically challenging, propane fuel (including storage) is very expensive and the use of propane is not recommended by the engine manufacturer. Options that solely focused on temporary solutions (e.g., rented modules) were not considered appropriate for a solution over potentially 5 or more years. [NTPC Argument, P32, L37 - P33, L5]

NTPC stated, the key option identified focuses on a solution that provides reliable power over a period of no less than 5 years (and potentially up to the full asset life of diesel units, in the event natural gas supply is not re-established in the future for the town). NTPC stated, the alternative option was also identified and discussed in conjunction with overall community planning efforts being led by the Town and the GNWT. [NTPC Argument, P33, L6-10]

NTPC stated that the effect of the capital project is equivalent to a major overhaul on each of the units, which will defer the schedule for overhauls. NTPC indicates it is estimating that the deferral effect will be roughly equivalent to avoiding one year of average annual overhaul cost for the Inuvik units, or approximately \$1.1 million.

With regard to the third gas unit at Inuvik that is not proposed to be converted to diesel, NTPC's witness, Mr. Bowman, indicated there are potential future developments that are sufficiently on the horizon that one wouldn't necessarily want to rush to get rid of a gas engine in Inuvik at this point in time. [T160, L22 – T161, L1]

The TGC submitted it remains unclear to TGC why the failure in gas supply (which is the sole reason for this project) could not be predicted in a more timely fashion, if NTPC was in constant contact with the gas supplier. Further, the TGC stated it was not clear, given section 4.01(a) of the Gas Supply Agreement, whether the failure of gas supply for Inuvik may have had an economic component given the current turmoil in gas markets. [TGC Argument, P15, Para50]

In its Reply, NTPC confirmed its understanding that the loss of gas was unexpected and unforeseen and NTPC could not have completed any kind of

meaningful analysis that would have prevented this situation from happening again. [NTPC Reply, P 9, L4-6]

Board Findings:

The Board notes the conversion of the gas units at Inuvik arose as a result of the imminent depletion of gas supply to the Inuvik plant. The Board accepts NTPC's forecast capital addition with respect to the Inuvik diesel conversion project for the purposes of this Decision.

The Board directs NTPC to provide a post completion report with respect to the Inuvik Diesel Conversion project at the time of the next GRA, including a narrative report evaluating the strengths and weaknesses observed in the planning, budgeting and execution of the project and, providing detailed explanations for variances between budget and actual costs as well as variances related to project scheduling and achievement of expected standards of quality and performance in the final delivered plant.

3.3.3 Bluefish Dam Replacement Project

NTPC forecast an addition of \$37.398 million in 2012/13 with respect to the design and construction of a new dam at Bluefish Lake to replace the existing dam constructed in the early 1940s.

In Decision 20-2009, the Board approved the Corporation's application for a project permit for replacement of the Bluefish Lake Dam in an amount up to \$18.5 million. This budget estimate was later revised to \$37.4 million plus or minus 10% in Decision 15-2011.

NTPC stated that the revised cost reflects the considerable time and effort NTPC spent in refining the project cost estimates and logistics. The revised cost incorporates changes in the project design resulting from more detailed investigation of the sizing of the water conveyance structures and the geotechnical conditions, as well as the results of the collaborative work with the selected contractor on cost saving measures and improvements in the new dam construction. NTPC noted that the project cost to date is within the updated approved budget of \$37.4 million (+/- 10%) and the project implementation is on schedule.

Board Findings:

The Board is of the view that the Bluefish Dam is another project, in addition to those discussed in Section 3.3.1, where scoping and capital budgeting were not carried out with proper due diligence when the initial capital budget was prepared. This resulted in the revised budget estimate being more than double that in the initial budget.

The Board notes NTPC's statement that the project cost to date is within the updated approved budget of \$37.4 million (+/- 10%) and the project implementation is on schedule.

Having regard to the Board's earlier acceptance of this budget in Decision 15-2011, the Board accepts NTPC's forecast capital addition with respect to the Bluefish Dam replacement project for the purposes of this Decision.

The Board directs NTPC to provide a post completion report with respect to the Bluefish Dam replacement project at the time of the next GRA, including a narrative report evaluating the strengths and weaknesses observed in the planning, budgeting and execution of the project and, providing detailed

explanations for variances between budget and actual costs as well as variances related to project scheduling and achievement of expected standards of quality and performance in the final delivered plant.

3.4 Transmission Line Development Study

NTPC proposed to add \$693,000 to the rate base in 2011/12 with respect to the cost of a transmission line development study carried out in the 2003-2005 period. NTPC indicates the study was not capitalized by NTPC until 2011/12 as up to this time the study had been considered “on loan” to NWT Energy Corporation (03) Ltd (“**NTEC(03) Ltd**”), an affiliate of NTPC.

NTPC indicated that the study looked at procedures and technologies that are appropriate to building transmission infrastructure in the NWT, as well as specific options and routing that would apply to a transmission line from the existing Taltson generating station to the North Slave diamond mines. NTPC stated that the commitment of \$700,000 of regulated system capital investment ultimately enabled the following benefits for customers (both actual benefits, as well as further potential additional benefits had the project proceeded or if it proceeds in the future):

- *A new unregulated development company was formed (Northwest Territories Energy Corporation, 2003, or “NTEC(03) Ltd.”) which was able to secure well over \$5 million of government funding, at no cost to NTPC, with the largest component of this capital used for environmental studies at Taltson. These environmental studies were heavily relied upon by NTPC in its recent relicensing of the Taltson facility, and were specifically cited and provided for review by the Mackenzie Valley Land and Water Board (“MVLWB”). Absent the NTEC(03) Ltd. environmental work, NTPC’s costs for relicensing the Taltson facility would have been substantially higher.*
- *At the time the studies were conducted, there was very little information to assess whether any business case could be developed for trying to market the 60 GWh of existing annual surplus Taltson power to the diamond mines. No reasonable cost estimate could be prepared for the transmission needed, and little information was known about the technological options, the routing options and the feasibility of such a project*

- given challenging electrical characteristics related to long transmission lines at relatively low loading. Without such information no party could have moved the project concept forward. No project would ever have been developed without first “equity” being brought to the concept by NTPC.*
- The project had very high potential returns, given the scale of surplus power available. Even at a relatively low rate (as compared to the diamond mines’ costs of diesel power) averaging, for example, at only 10 cents/kWh this would equal \$6 million/year of new revenue with very little added operating costs. These revenues would have been available to help maintain lower rates for regulated ratepayers regardless as to the owner of the transmission line or any new generation.*
 - NTPC also expects ongoing value from the study, as it is the only updated assessment of the current best practices and available technology for transmission suitable for NWT. The conditions faced by NTPC in potential future transmission line construction are unique compared to southern utilities, and there was no updated information available specific to NWT. [TGC.NTPC-49]*

The TGC submitted that the study costs were incurred prior to the Test Years and thus are not proper capital for the Test Years. If the amounts benefited ratepayers as suggested by NTPC in cross-examination, NTPC should have forecast them in the rate applications applicable to the years it incurred the costs. NTPC did not receive prior approval of the Board to conduct these Capitalized Studies.

TGC submitted the Capitalized Studies related to utilizing excess capacity on the Taltson system, specifically for supplying electric energy to Diamond mines in the NWT. NTPC will not be the proponent of the project to which the studies relate. Rather, an unregulated affiliate of NTPC will ultimately gain the benefit of the Capitalized Studies and proceed with the project, likely with other private sector partners, as confirmed by Mr. Bowman in cross-examination. TGC submitted that many of the studies contained in BR.NTPC-23 were actually performed for parties other than NTPC, including Northwest Territories Energy Corporation, and Dèze Energy Corporation. The TGC submitted that the studies benefited other parties or unregulated affiliates of NTPC and as such, NTPC did not prudently incur the expenditures on the Capitalized Studies. On this basis the TGC submitted the capitalized studies should be denied in full.

TGC submitted that as a result of the proposed expansion project not proceeding, NTPC is now unable to recover the costs it expended on the Capitalized Studies from its unregulated affiliate which has resulted in it now seeking to recover these costs from customers, after the fact.

Furthermore, as NTPC does not have an approved deferral account for the costs related to the transmission line study these costs should be denied on the basis that approval of these costs would amount to retroactive ratemaking. [TGC Argument, P36, Para 128 – P38, Para 133]

TGC also argued that if the Board was inclined to accept any portion of the study costs, such costs should be allocated entirely to the Hydro Zone as no portion of the Taltson facility benefits the Thermal Zone. [TGC Reply, P4-5, Para 10]

In response to why the costs were not included in the period incurred, NTPC indicated that the study was loaned to the affiliate with an interest cost at prime less 50 basis points. Therefore, NTPC states spending on this study over that period of years was being compensated through that route. [T141, L9-16]

Board Findings:

The Board notes the primary purpose of the study was for the future transmission development to be undertaken by an affiliate of NTPC. The Board accepts that there may have been some anticipated benefits to NTPC's customers had the transmission development gone ahead. However, the benefit to NTPC does not appear to be the primary intent of the study. This finding is supported by the fact NTPC treated the study cost as a recoverable from NTEC (03) Ltd until 2011/12. Although the costs were incurred during the 2003-2005 period NTPC did not seek to include the cost in rate base even in the 2006-2008 GRA, but rather treated the amounts as a recoverable from NTEC (03) Ltd.

Since the primary purpose of the study was not related to providing electricity service to NTPC's customers, the Board denies the proposed inclusion of the study cost in the 2012/13 and 2013/14 rate base. Accordingly, NTPC is directed to remove the cost of the transmission line development study from each Test Year rate base, in its Compliance Filing Application.

3.5 Treatment of Capitalized Studies and Disallowed Assets Included in Plant in Service

The Board notes from Schedules 5.2 and 5.3 that the following amounts with respect to unamortized costs of feasibility studies are included in plant in service:

Feasibility Studies				
	2010/11	2011/12	2012/13	2013/14
Gross Plant	\$000	\$000	\$000	
Beginning of Year	5179	5864	6557	6557
Additions	685	693		
End of Year	5864	6557	6557	6557
Accumulated Amortization				
Beginning of Year	4457	4702	5047	5379
Additions	245	345	332	332
End of Year	4702	5047	5379	5711
Net Plant	1162	1510	1178	846

The Board has dealt with the disallowance of the transmission line study addition in the amount of \$693,000 in Section 3.4. This Section deals with the remaining costs included as unamortized costs of feasibility studies.

Board Findings:

With regard to the remaining costs included as unamortized costs of feasibility studies, the Board is concerned by the insufficient justification for inclusion of the cost of these studies in rate base and the amortization thereof in each Test Year.

In Decision 17-2007, Directive 18, the Board determined deferred cost items may typically include financing costs and any material costs incurred in conducting special studies. The Board noted in order for such expenditures to be considered eligible, NTPC should be able to demonstrate corresponding benefits that extend beyond a single year. Further, for deferred cost items that arise in non-test years the quantum of the expenditure proposed for deferred cost treatment should be material and NTPC should demonstrate why they are not considered part of the forecast variance in operations and maintenance expenses in that year. Accordingly, the Board directed NTPC to provide evidence showing how each item proposed for deferred cost treatment meets the conditions outlined above.

During hearing examination, NTPC's witness explained:

"..and that category is not one feasibility study, it's the sum gross plant total of all feasibility studies NTPC still carries on its books. And my recollection is many of those are even fully depreciated. But the full value of the study is on the books and the full value of the amortization is on the books, so it's a very long list of items. But one doesn't actually, the reason it's in the table, is one doesn't look at those studies and coming up with amortization and depreciation rate, they're fixed." [T286, L15-25]

Given the lack of support provided during the proceedings with respect to the cost of feasibility studies (other than the transmission study) and the amortization thereof, the Board directs NTPC to provide as part of the Compliance Filing Application, details of all studies included under the category of feasibility studies and provide justification for why any additions to the feasibility studies account in the 2007/08 to 2010/11 period should be capitalized based on the guidance provided in Directive 18 from Decision 17-2009. At the same time, NTPC should

also provide support showing how the amortization amounts in each Test Year were arrived at having regard to each study.

The Board also notes from Schedules 5.2 and 5.3 a category of costs referred to as disallowed and deferred regulatory assets included in gross plant in service and accumulated amortization as follows:

Disallowed and Deferred Regulatory Assets				
	2010/11	2011/12	2012/13	2013/14
	\$000	\$000	\$000	
Gross Plant				
Beginning of Year	163	163	163	163
Additions	0	0	0	0
End of Year	163	163	163	163
Accumulated Amortization				
Beginning of Year	93	99	106	112
Additions	7	7	7	7
End of Year	100	106	113	119

The Board considers disallowed assets should not be included in gross plant in service and in rate base. Accordingly, NTPC is directed to remove the net book value of disallowed assets from Test Year rate base in its Compliance Filing Application.

The Board is concerned that inclusion of deferred costs under the category of deferral accounts and under the category of plant in service can result in confusion and errors in the testing and evaluation of such costs. Accordingly, NTPC is directed to include deferred costs under an appropriate FERC account at the time of the next GRA.

3.6 Major Spares and Capital Inventory

NTPC stated that net General Plant increases of \$22.3 million in 2012/13 over 2007/08 reflect changes in accounting policy, which now includes major spare parts and capital inventory of approximately \$6.7 million in the gross plant. NTPC further advised that the accounting policy change with respect to major spare parts and capital inventory is consistent with the accounting standard issued in 2007 by the Canadian Institute of Chartered Accountants (“CICA”). The Corporation’s 2008/09 Financial Statement includes the following description respecting the change in accounting policy:

As a result of adopting Section 3031, NTPC reclassified its major spare parts and standby equipment previously included in inventories to property, plant and equipment. As these inventories are considered plant held for future use, no adjustment to amortization expense or accumulated amortization has been made for these assets. Prior period comparative amounts were restated in accordance with the transition provisions. The inventories reclassified as at March 31, 2009 were valued at \$685 (2008 - \$524) and have been identified in Note 8 as Assets held for future use.

NTPC stated that the impact of the change is zero. NTPC confirmed that the proposed major spare parts and capital inventory approach involves no amortization costs for the 2012/13 and 2013/14 Test Years consistent with the above accounting policy. [TGC.NTPC-37]

The TGC expressed concern with the significantly higher dollar levels associated with spare parts and capital inventory. The TGC indicated that the \$6.7M inventory is about 6 to 7 times higher than the average of about \$0.6M in the 2008-2009 timeframe. With respect to NTPC’s argument that diesel engines are “harder to spec”, TGC submitted that NTPC had not filed any evidence to support the growth in such inventory. More specifically, it had not explained why the

availability and increased magnitude of major parts and capital inventory had changed relative to the period prior to the change in its accounting policy in 2008/2009 to justify a significantly higher level of major spare parts and capital inventory.

The TGC also argued that there is no basis to use a change in GAAP as the exclusive rationale for a change in regulatory treatment. The TGC submitted the current Board-approved methodology has been in place for the last 20 years. The only difference between the current approved method and the proposed method is one of timing of cash flows. Under the existing Board-approved method, interest is capitalized and the inventory enters rate base at cost plus carrying costs (capitalized interest) when the inventory item is actually used or required to be used. The TGC submitted that the effect of NTPC's proposal is to build that carrying cost into rates today; such that it gets a cash return today as opposed to a "paper return" in the form of capitalized interest cost.

As such, the TGC recommended that the Board reject NTPC's proposed treatment and direct NTPC, in its Compliance Filing, to reflect continued adherence with the currently approved Board methodology. [TGC Argument, P18, Para 60 – P20, Para 66]

In its Reply submission, NTPC stated that the proposed method allows the Corporation to avoid maintaining two sets of financial statement records which would create a reconciling item and result in higher administration costs; and in the circumstances, given that the impact on the Revenue Requirement is zero, its proposed method is appropriate and should be approved. [NTPC Reply, P20, L9-13]

Board Findings:

NTPC explained that the increase reflects the holding in inventory of long delivery equipment items such as engines, transformers and breakers. NTPC explained that the inventory helps to avoid delays when replacements are needed and further helps to standardize the equipment that is installed. [T283, L4]

The Board notes TGC's argument that the \$6.7M inventory is much higher than the average of about \$0.6M in the 2008-2009 timeframe and NTPC has not filed any evidence to support the growth in such inventory. However, the Board is mindful of NTPC's position that the inventory helps to avoid delays when replacements are needed and further helps to standardize the equipment that is installed. The Board considers that NTPC has not provided any analysis that would weigh and evaluate the qualitative and quantitative benefits of holding the proposed level of inventory in relation to the carrying costs. In the absence of such evidence, the Board will approve the inclusion of 50% of the proposed inventory in rate base in 2012/13 and 2013/14. Therefore, NTPC is directed to remove 50% of the cost of major spares and capital inventory from Test Year rate base in its Compliance Filing Application.

If NTPC were to hold any portion of the disallowed inventory as plant held for future use, NTPC should be able to demonstrate the level of inventory on which Interest During Construction (“IDC”) is being added is justifiable based on a cost benefit analysis as described above.

3.7 Customer Contributions

NTPC's forecast of customer contributions is shown in schedule 5.4.

The TGC requested that the 2012/13 Test Year opening balances for customer contributions be updated to reflect the 2011/12 actual closing balances. The Board will deal with this matter in Section 13 .1 of this Decision.

Under cross examination NTPC was asked why there are no additions to customer contributions included in 2011/12 to 2013/14.

In response, NTPC's witness indicated that when a new customer is connected there is a cost to connect that customer, some of which is paid for by the customer as a recoverable and some of which is paid for by the Corporation as a non-recoverable. The portion that's paid for by the customer as a recoverable cost is what's recorded as customer contributions. [T354, L16-22]

The Corporation explained that the non-recoverable portion is referred to as type 6 non recoverable work in the capital additions schedule and is largely comprised of distribution extensions that the Corporation undertakes when it adds customers to the system. NTPC indicated that customers do have an allowable investment that pays for a portion of that investment, but there's also a portion that's non-recoverable. And those would be capital assets that are being recorded in the capital additions schedule. [T233, L1-9]

Board Findings:

The Board accepts NTPC's explanation for zero contribution additions in the Test Years.

3.8 Working Capital

NTPC's calculation of working capital is set out in Schedule 5.6. Working capital is made up of cash working capital as well as fuel and supplies inventory. The cash working capital calculation is based on an analysis of leads and lags associated with operating cash payments and receipts.

NTPC states the revenue lag for industrial and wholesale customers was calculated from the billing date to the date the collection was actually deposited to the Corporation's account. NTPC stated that in order to establish the payment lag associated with bills rendered to customers whose bills are computer generated, a comprehensive analysis of all utility revenues billed and collected through the Corporation's billing system for the period under study was performed using a computer program.

As an alternative to the sampling approach to determination of revenue lag NTPC also calculated the revenue lag based on when payments by customers for bills rendered is due. This was described as the normalized approach. NTPC states, the normalized approach uses the NTPC approved Terms and Conditions of Service to develop the overall revenue lag. This same normalized approach is used for the calculation of the expense lag and the overall payment lag is based on the Corporation's standard payment practices. NTPC states using the normalized approach for both revenue and expenses is appropriate as both calculations use the same normalized methodology. It would be incorrect to use a sampling methodology for the calculation of revenue and a normalized approach for the calculation of expenses.

The TGC submitted that the use of the sampling method results an increase in working capital lag by 9 days or \$0.115M in Revenue Requirement (\$1.651M

increase in rate base times 6.94%). However, NTPC would also have to include Interest on overdue accounts of \$0.153M as a revenue offset for a net reduction in 2012/13 and 2013/14 Revenue Requirement of about \$0.038M. TGC submitted it does not oppose the continued use of the normalized approach as long as it is corrected for the amount of the Interest on overdue accounts. The TGC therefore recommend the Revenue Requirement be reduced by \$0.038M in each of the Test Years. [TGC Argument, P31, Para 108 – P32, Para 109]

In its Reply, NTPC submitted TGC's acceptance of the normalized method with an adjustment for the calculation of the revenue lag only is one sided and should be rejected by the Board. As noted, the Directive only reviewed the revenue lag variance and not the expenditure variance. Adjustments for only one component of the cash working capital calculation are incorrect. Further, in NTPC's view it would be incorrect to lower revenue requirement based on the normalized approach and then further lower it by interest on overdue accounts as it would produce a "double counting" of revenue which the Board should reject. [NTPC Reply, P21, L5-15]

Board Findings:

The Board understands NTPC's working capital calculation in these proceedings is based on a normalized approach for both payment lag and revenue lag. The normalized approach reflects the Corporation's standard practices for payment of expenses as well as terms and conditions for receipt of revenues. The Board views the normalized approach as a theoretical approach for determination of cash working capital requirements.

Performing a lead lag study based on a sampling of actual transactions would have the added advantage that the Corporation will be alerted to any material deviations in the number of days lead or lag from the normalized approach.

Management then has the ability to take corrective action respecting any unplanned leads and lags, as necessary. Accordingly, the Board prefers a sampling approach to the development of a lead lag study and the determination of cash working capital.

The Board directs NTPC to provide a cash working capital calculation based on a sampling of leads and lags at the time of the next GRA. This means any revenues related to late payment charges should also be included in other revenues.

The Board accepts NTPC's calculation of cash working capital and total working capital for the purposes of this Decision.

3.9 Deferral Accounts

3.9.1 Regulatory and Other Deferral Accounts

As described in its Argument, NTPC is proposing to decrease the annual appropriation for the Regulatory and Other Deferral Account from \$0.672 million to \$0.377 million per year in the 2012/13 Test Year and \$0.376 million in the 2013/14 Test Year. The decrease is a result of NTPC's efforts to decrease the costs of filing a GRA, the benefits of regulatory reform and anticipated simplification of the review process.

Included as part of this deferral account are two new items – Enterprise Resource Planning (“**ERP**”) and International Financial Reporting Standards (“**IFRS**”) Conversion – that NTPC states meet the requirements for deferral cost treatment.

Enterprise Resource Planning

In 2010/11, a project was initiated to review the Great Plains system which is the core of NTPC's ERP system. The objective was to assess whether opportunities exist to optimize the system and increase effectiveness and efficiency throughout NTPC. The first phase of the project, which was completed in 2011/12 at a cost of \$136,000, was a gap analysis of the building blocks in NTPC's ERP (e.g. general accounting, customer processing, procure to pay/supply chain, human resources/payroll, projects and operations) against leading practice and common utility practice. The second phase of the project, to be completed in 2012/13 at a cost of \$308,000, will focus on organizational hierarchy and code block structure.

NTPC is proposing the total project cost of \$444,000 be included in the Regulatory and Other Deferral Account to be amortized over 10 years starting in 2012/13. NTPC states that this project will provide long-term benefits.

In addition to the \$444,000, the work completed to date has identified a Business Intelligence ("BI") tool, at a cost of \$60,000, which would be a valuable addition in terms of maximizing the reporting capabilities of the system. NTPC states that the extra \$60,000 will not be part of the deferral account – it will be treated as a capital project for 2012/13 and managed within the overall capital budget for 2012/13.

NTPC also states that any future improvements to the ERP will be assessed in terms of cost/benefit and the treatment of those expenses as current or deferred costs will be made in accordance with the principles established in the 2006/08 GRA.

In its Argument, TGC stated:

"The TGC has no position on whether or not the proposed \$444,000 is reasonable or prudent. In our view, there simply is not enough evidence on the record to make such a conclusion. NTPC refers to the elimination of a "number of manual processes that are taking place" that will "allow us to spend less time collecting and inputting the data and more time analyzing the data and making good business decisions of that analytic, yet NTPC will not eliminate any FTC positions." The TGC questions why, if this project has the potential to provide additional data management and capabilities to make more informed business decisions, did such a project have to wait until the commencement of a GRA?

Based on the foregoing, the TGC recommends the Board should deny the additional \$60,000 additional amount noted by NTPC in respect of the Business Intelligence (BI) tool. It would appear that if NTPC had done an appropriate business case, it should have anticipated this additional expenditure. Limiting the total project cost to the \$444,000 projected in this rate case will avoid the "scope creep" and exert the discipline necessary to control costs to the amounts initially budgeted. To this end, NTPC acknowledged it is willing to manage the Enterprise Resource project within the overall capital budget of \$444,000 put forward in this GRA for 2012/13. While the TGC is not opposed to this project, the TGC recommends that (i) the maximum amount approved for this project should be no more than \$444,000 forecast in this 2012-2014 GRA, and (ii) no portion of this cost should be deemed to be either part of a deferral account or deferred costs." [TGC Argument, P23, Para 78-79]

NTPC responded in its Reply:

"TGC takes no position on the reasonableness or prudence of NTPC's proposed \$444,000 Enterprise Resource Planning ("ERP") process (a deferred cost), but recommends the Board deny the complementary Business Intelligence tool, an estimated capital cost of \$60,000.

This Business Intelligence capital project is not, in fact, part of the GRA proposal from NTPC. NTPC witnesses identified that this project would be undertaken, but that it would occur as a normal intra-year adjustment to the overall capital plan and that the GRA capital plan budget would not be increased for this amount.

TGC also recommends the ERP cost should not be part of a deferral account or deferred cost. As TGC does not oppose the Enterprise Resource Planning project, but also does not want it included in a deferral account, this suggests the cost would need to be included in the Corporation's Operations & Maintenance budget as an annual expenditure. The Corporation does not agree with this proposal as the ERP project meets the guidelines of a deferral account, and further the TGC approach would increase overall Revenue Requirement 1 and rate impact for customers." [NTPC Reply, P21, L20 – P22, L2]

Board Findings:

Given that the \$60,000 for the BI Tool will be accommodated within the overall 2012/13 capital budget, the Board sees no reason to deny this expenditure.

As for the overall ERP project, the Board is satisfied that the project meets the criteria for treatment as a deferred cost and approves the inclusion of the \$444,000 ERP project cost in the Regulatory and Other Deferral Account to be amortized over a period of 10 years beginning in 2012/13.

IFRS Conversion

The IFRS Conversion project is budgeted for \$546,000 up to 2011/12 with amortization beginning in 2012/13 over 10 years. NTPC states that this project provides benefits that extend beyond the single year as the one-time IFRS conversion will apply to financial reporting in future periods.

Of the \$546,000, \$296,000 was spent in 2009/10 and 2010/11. The remaining \$250,000 was to be spent in 2011/12 but with the 1 year delay in the switch to IFRS, the \$250,000 will now be spent in 2012/13.

In its Argument, TGC stated:

"As discussed in Section 2.1 of this Argument, implementation of IFRS has now been deferred by a further 12 months to January 1, 2014, and the Corporation plans to adopt this deferral. NTPC confirmed that notwithstanding the additional year of deferral (to January 1, 2014), the total amount of \$541,000 in respect of consulting fees is still a reasonable forecast. Further, it has not spent the \$250,000 noted in the above table.

In our submission, now that the Canadian AcSB has allowed entities with rate regulated operations a further 1-year delay to implement IFRS, the TGC recommends the \$250,000 expenditure be further delayed from 2012/2013 to 2013/2014.

Further, it is noted that NTPC takes the position that a 100% of these costs should be on account of the regulated operations as they comprise 99% of the "reporting for that corporate entity."

The TGC submits it is inappropriate to deem 100% of IFRS conversion costs to regulated operations. While the unregulated operations may be rather limited at this time, it is possible they may become more sizeable at some future point and at that time such non-regulated entities will benefit from consulting and other related costs incurred with respect to IFRS conversion. To this end, the TGC recommends NTPC provide at the time of its Compliance Filing, the relative size of its unregulated operations (in terms of revenues, expenses, capital employed etc) in the last 5 years relative to the regulated operations. This ratio should be used to allocate the IFRS costs to regulated/unregulated entities.” [TGC Argument, P21, Para 68-71]

On the timing of the spending of the \$250,000, NTPC responded in its Reply:

“TGC recommends the Board delay the \$250,000 expenditure for the implementation of IFRS from 2012/13 to 2013/14. NTPC notes however that, Table 1 from BR.NTPC-26(b) shows the forecast \$250,000 expenditure not in 2012/13 but rather in 2011/12. The Corporation will implement IFRS for external reporting in January 2014 which is in the second test-year of this Application. As such these costs will be incurred before the transition into IFRS reporting in the 2013/14 test year. Accordingly, if the Board delays the \$250,000 expenditure, it should be delayed from 2011/12 to the 2012/13 and not 2013/14.” [NTPC Reply, P31, L27 – P32, L4]

On the matter of the sharing of IFRS conversion costs with NTPC’s unregulated affiliates, NTPC stated:

“Further, TGC incorrectly concluded these IFRS implementation costs are for both regulated and unregulated entities. The costs are required as the Corporation transitions into IFRS and are comprised of external consultants that specialize in transitioning utility companies into IFRS. The services provided by the external consultants are strictly for the regulated entities and not unregulated entities. IFRS implementation costs for unregulated operations are not being charged to regulated customers. In the circumstances, the TGC recommendation that IFRS implementation costs be shared between the regulated and unregulated entities should be rejected.” [NTPC Reply, P32, L13-20]

Board Findings:

On the matter of the \$250,000, the Board expects NTPC to spend this money in an appropriate and timely manner to meet the final IFRS implementation date, whatever that final date turns out to be. The Board sees no need to issue a direction on this matter.

Given NTPC's clarification that the IFRS conversion costs are solely to the benefit of the regulated entity and not NTPC's unregulated affiliates, the Board also sees no need to issue any direction on the matter of sharing the IFRS conversion costs.

3.9.2 Engine Overhaul Deferral Account

NTPC is seeking approval to increase the annual amortization of the normalized overhaul deferral account from an annual level of \$1.693 million per year approved in the 2006/08 GRA to \$2.936 million per year to reflect increases in the balance and in the forecasted ongoing costs of overhauls primarily in the Thermal zone. The \$2.936 million is an annual increase of \$1.243 million which breaks down into the zones as follows: an annual increase of \$0.095 million in the Taltson zone, an annual decrease of \$0.224 million for the Snare zone and an annual increase of \$1.372 million for the Thermal zone. The increase in the Thermal zone is being driven by increased overhaul costs for the larger generating units in the zone.

In response to Undertaking 23, NTPC described the parameters of the engine overhaul deferral account as follows:

"Diesel Engine Overhaul includes labour and materials for planned major maintenance, based on operating hours. Overhaul requirements vary with engine size, speed, make and operating conditions and typically are required at 5,000 hour intervals for minor overhaul, 15,000 hours for top overhauls and 30,000 hours for major overhauls. Engine Overhaul does not include minor routine maintenance carried out on a day-to-day basis (daily, weekly, monthly or hours based).

General Definitions (may vary with manufacturer):

- *Minor Overhaul - engine inspect, testing, tune-up, exchange turbocharger, lube oil/filters.*
- *Top Overhaul - minor overhaul, replace heads, fuel injectors, water pump and fuel pump.*

- *Major Overhaul - top overhaul, replace pistons, liners, connecting rods, oil pump, exchange oil cooler, clean aftercooler and inspect vibration dampers.*

Hydro Generating unit overhauls follow the same principle; that is they include labour and materials for planned major maintenance, as specified by the manufacturer or standard operating procedures."

NTPC states, consistent with the above definitions replacement of certain components of an asset as part of an overhaul is intended to replace consumable components of the engine, and the costs would be included in the overhaul deferral account. There is no disposal. The specific component would still be maintained in the fixed assets continuity schedule, until the underlying asset itself reaches the end of its useful life, at which point the replaced component will be disposed of as part of the associated asset.

In its Argument, TGC raised 2 issues – the cost of overhauls for the 3rd gas engine and the escalation of costs for the Inuvik overhauls.

On the costs of overhauls for the 3rd gas engine, TGC stated:

"The TGC has concerns about the magnitude of the cost of overhauls. For example, over the 3-year period 2008/09 to 2010/11, the average overhaul cost of the third engine is some \$0.515M. In comparison, the cost of the two other original gas engines amounted to \$0.793M, or about \$0.397 per year. The overhaul cost for the third gas engine, the newest of the three gas engines, is therefore on average some 30% higher [$\$0.515/\$0.397M$] than the other 2 gas engines. No evidence is provided to suggest there is something unusual or different about the newest third engine which would require more costs to overhaul.

As the newest engine, one would expect the overhaul costs to be similar to or lower than older gas engines. Nowhere is the higher expense more evident than in 2008/09, which is just two years after the third gas engine was installed in 2006/07. In this year, the newest engine cost \$645,000, about \$79,000 [$\$0.645-\$0.566M$] or 14% more than the combined cost of the other two gas engines which were installed back in 2000, some 6-7 years previously. Another way to look at it is that the third engine at \$0.645M cost some \$0.362M, or more than double the cost (127% more) of the average of the other two gas engines of \$0.283M.

NTPC has not provided any evidence why the cost of the third diesel engine is so high relative to the other 2 gas engines. It is our recommendation, therefore, that the overhaul

cost of the third diesel engine should be no more than the average cost of the other 2 diesel engines of \$0.397M noted above. As such, the TGC recommends disallowance of \$0.354M as shown on the following table:

Calculation of Excess Overhaul Costs for the Third Gas Engine in Inuvik for the Years 2008/09 through to 2010/11												
	2007/08	2008/09	2009/10	2010/11	2011/12	Total						
third engine	29	397	397	397	83	1,302	Deemed cost of \$0.397M/yr for 2008/09, 2009/10 and 2010/11					
original gas engines	839	566	938	876	349	3,568						
diesel engines	5	231	343			579						
total adds	873	1,194	1,678	1,273	432	5,449						
Reduction	-	(248)	185	(290)	-	(354)						

[TGC Argument, P25, Para 85-87]

NTPC responded in its Reply:

"TGC's argument in respect of the third gas engine includes a number of incorrect statements. In particular, TGC asserts that overhauls on the third gas engine are overly costly as they average \$0.515 million compared to \$0.793 million for the two older engines. TGC only arrives at this value by a selective interpretation of the data in Table 8 at page 24. Specifically, TGC ignores the year 2007/08 in calculating its long-term average numbers for no apparent reason. Had this year been included, the average costs for the third engine are almost identical to the costs per unit for the older 2 engines. As costs for overhauls are cyclical over a lengthy period that can be 5-7 years depending on the hours the units are used, the selective mathematics on 3 chosen years is an incorrect approach. Further, TGC notes that "No evidence is provided to suggest there is something unusual or different about the newest third engine which would require more costs to overhaul." NTPC would like to point out that, along with the clarification that the third gas engine has not been more costly, TGC did not put any questions to NTPC at the hearing to attempt to elicit any such facts about the third gas engine one way or the other." [NTPC Reply, P22, L14-26]

On the matter of the escalation of costs for the Inuvik overhauls, TGC states:

"The underlying problem appears to be the manner in which NTPC's contract with the OEM was structured. More specifically, if the OEM failed to satisfy maintenance requirements, the contract could be terminated. However, NTPC agreed not to sue the OEM in the event the OEM failed to live up to the maintenance requirements under the contract. It is surprising that any prudent person would agree to let the party failing to live up to the contractual terms off "scot free".

It is clear that NTPC experienced significant additional costs and expense as a result of the OEM not performing maintenance it was required to perform under contract with NTPC. NTPC now wishes to pass these additional costs to customers. In our view, had proper penalties for non-performance been built into the contract, NTPC would not have incurred the additional costs.

NTPC should have laid out penalties in the contract for "failure to perform". Not having such penalties obviously provided an incentive for the OEM to act at will in terms of its responsibilities with respect to maintenance requirements for the two gas generating units. NTPC. The result, it appears, is an additional cost to customers of \$2.246M shown in Table 8 of Exhibit 003, BR.NTPC-23 (g), page 14 of 15. In our view, this additional cost should be shared 50:50 with the shareholders. As such, the TGC recommend the Board disallow \$1.123M from the Overhaul Deferral Account for Thermal Zone." [TGC Argument, P26, Para 90 – P27, Para 92]

NTPC responded in its Reply:

"The facts that are in evidence in this proceeding are that NTPC had a contract with the gas engine OEM that provided overhauls at a very favourable price compared to market. That contract led to many years of overhauls in Inuvik at a consistent price dating back to before the 2001/03 GRA. At a particular point in the life of that contract, the service provided by the OEM become inferior, and NTPC was faced with a choice between reduced reliability or terminating the contract. NTPC sought for a number of years to find alternatives within the contract to have the contractor increase their performance quality. In the end that was not possible, and NTPC elected to terminate the contract as reliable service to the customers in Inuvik was more critical than below-market pricing.

In short, TGC's argument is not based in fact, and should be rejected by the Board. The maintenance contract in place had a minimum annual price and was based on the power production subject to a 4% annual escalation factor. These favorable pricing terms benefited customers from 2001 to 2006 but were subject to a termination clause where neither party would be liable to the other after the termination date.

TGC suggests if "proper penalties for non-performance [had] been built into the contract, NTPC would not have incurred additional cost." This suggestion incorrectly assumes that the same fixed pricing terms could have been achieved even if the contract imposed adverse non-performance penalties. It is unknown and unrealistic to retrospectively assume the same pricing terms could have been achieved with adverse performance penalties for the OEM. The contract signed by the Corporation contained good pricing terms for the Corporation and customers but ultimately did not protect against poor performance. TGC further suggests the Corporation should have sued the OEM based on the terms of the contract. However, on the terms of the contract, neither party would be liable to the other after the termination date, and the Corporation could not sue the OEM for poor performance.

The Corporation was aware that the contract was beneficial to the customers and it wanted to maintain the contract. Accordingly, from 2004 to 2007 the Corporation met with the OEM on several occasions and tried to resolve the issues. For three years the Corporation tried to resolve the issues as any prudent person would do. TGC is incorrect when they suggest the Corporation let the OEM off "scot free" or that the Corporation was not prudent. While the pricing terms were beneficial, the Corporation could not continue to reduce the reliability of the engines. TGC suggestion that the maintenance contract should have continued fails to recognize that reduced reliability and increased outages ultimately result in greater harm to customers." [NTPC Reply, P23, L6 – P24, L5]

Board Findings:

On the matter of the cost of overhauls for the 3rd Inuvik gas engine, the Board shares NTPC's concerns about TGC's selective use of 3 years of data. The Board notes that if the 5 year period from 2007/08 to 2011/12 were taken together, the average annual cost of overhauls for the 3rd engine is \$331,000, which is less than the annual average of \$356,800 for the first 2 engines.

On the matter of the escalating cost of overhauls in Inuvik, it is the view of the Board that it will not, over a decade after the fact, question the contents of the maintenance contract for the first 2 gas engines. It is apparent that the contract provided benefits to the ratepayers for a period of time and those benefits later ran out. The Board expects that this incident will be a lesson learned for NTPC when it negotiates future maintenance contracts but the Board will not retroactively try to figuratively renegotiate the terms of this contract to make it more favorable to the ratepayers.

The Board notes NTPC's statement that the replacement of certain components of an asset as part of an overhaul is intended to replace consumable components of the engine, and the costs would be included in the overhaul deferral account. In the Board's view there is lack of clarity as to what the consumable components are. More specifically, the consumables should not include components that are considered retirement units for amortization purposes. The Board's understanding of the treatment of replacements that fit the definition of retirement units is that they are retired from gross plant and the cost of the replacement capitalized. The Board directs NTPC to address the appropriate treatment and adjustments for any expenditures for components included in the Engine Overhaul Deferral Account, that are considered retirement units for amortization purposes, in its Compliance Filing Application.

3.9.3 Water License Deferral Account

As a part of the 2006/08 GRA, NTPC applied to establish a water license deferral account with a normalized annual appropriation. The water license deferral account captures the cost of all water licensing activities including regulatory costs, environmental and dam safety studies and related activities. The Board approved the water license deferral account in Decision 13-2007.

In this Application, NTPC is applying to increase the annual amortization of the water license deferral account from an annual level of \$0.137 million per year approved in the 2006/08 GRA to \$0.751 million per year in 2012/13 and \$0.825 million per year in 2013/14 to reflect material increases in the balance in the account and in the forecast level of effort and spending required to maintain and renew NTPC's water licenses including regulatory reviews, compensation, environmental and dam safety studies, Aquatic Effects Monitoring Program (AEMP) costs and all related activities (except capital works). The account mid-year balance is forecast at \$5.109 million in 2012/13 and \$5.094 million in 2013/14.

A major component added to the deferral account is \$3.2 million of Taltson re-licensing work that consisted of various studies that were used during the re-licensing process.

Regarding the \$3.2 million spent on studies used during the re-licensing process, the TGC stated the following in its Argument:

"The TGC submits that capital additions related to the \$700,000 transmission line development study and the \$3.5 million in studies capitalized to the Talston re-licensing account totaling 4.2 million ("Capitalized Studies") should be denied in full." [TGC Argument, P36, Para 127]

The TGC's explanation for this position is somewhat unclear as the TGC seems to be treating the \$3.2 million on environmental studies and the \$700,000 on the transmission line study the same in some places and differently in other places. The Board is of the view that TGC's argument would have been easier to follow had it discussed these issues separately.

The basis of the TGC's position on the \$3.2 million appears to be that 1) these studies were completed in previous years and so it would be retroactive ratemaking to capitalize them now; and 2) the studies were initially conducted for other parties and so should not now be paid for by NTPC's customers.

NTPC responded in its Reply:

"On the first of the two items listed, the \$3.2 million of Taltson Water Re-licencing costs, these costs were incurred by NTPC and performed by NTPC as a required component of re-licencing the Taltson dam. The re-licencing process was successful and NTPC is now in possession of a renewed water licence that permits it to operate the dam for the benefit of ratepayers. There is no alternative interpretation but that these studies are used, useful, and required to provide service to ratepayers in the test year period.

...

The irony of TGC's argument is that one of the reasons they cite for its recommendation to deny the \$3.2 million is that many of the studies contained in BR.NTPC-23 were performed FOR parties other than NTPC. TGC fails to understand the evidence that the studies they are citing, over \$10 million worth, were performed and paid for BY parties other than NTPC, but NTPC (and its ratepayers) still received the benefit of these studies as part of its re-licencing application. None of this \$10 million in studies is proposed to be included in rate base.

Had NTPC not triggered the initiation of the Taltson expansion program, it is expected that a substantial portion of the \$10 million in work that ratepayers are presently benefitting from (at no direct cost) would have had to be performed in any event, ultimately leading to higher rates to the Taltson zone than those required in the current GRA." [NTPC Reply, P27, L23 – P28, L10]

Board Findings:

The Board has no evidence to suggest that the ratepayers are not receiving full value for the forecast \$3.2 million in environmental studies used for the Taltson

re-licensing. Moreover, the Board notes that NTPC has provided compelling evidence that the studies are used and useful and necessary to provide service. The Board also notes that YK/HR, representing the Taltson Zone, did not comment on the study costs. Accordingly, the Board approves the addition of the environmental study costs related to Taltson re-licensing to the deferral account in 2011/12 and does not consider this to be retroactive ratemaking.

3.9.4 Reserve for Injuries and Damages

In its Application, NTPC stated:

"In the 2006/08 GRA consistent with previous GRA's the Corporation included the annual appropriation to the Reserve for Injuries and Damages account as part of its Operations and Maintenance expense. In this GRA to be consistent with other annual deferral provisions the Corporation is including the appropriation in amortization of deferred charges instead of Operations and Maintenance expenses. In the 2006/08 GRA, the Reserve for Injuries and Damages was included as no-cost capital. Subsequent to the 2006/08 GRA, these accounts are no longer sources of capital and are in positive balances owed to the Corporation. As the Reserve is no longer a source of capital it is moved into the deferral accounts portion of Rate Base." [Ex 2, P5-13, L6 – 14]

NTPC is seeking approval for a continuation of the Reserve for Injuries and Damages ("**RFID**") at the same \$0.670 million per year appropriation approved in the 2006/08 GRA.

In its Argument, the TGC stated:

"The RID balance forecast at March 31, 2014 is \$0.851. Hence, at an annual amortization of \$670,000, and based on NTPC's evidence it does not expect any further additions/events to the RID Account. The TGC notes the RID balance will be in an over-funded in 2 years,...

...

The TGC submits that the funding amount should be such that on a forecast basis, the balance should be zero over the course of the 4-year transition period ending 2015/16 for

rates proposed by NTPC in this Application. The TGC therefore recommends reduction in the RID amortization expense in each year by \$122,000,...

...

The TGC makes the observation that in the case of the Employee Future Benefits Deferral Account, NTPC has proposed the 2012 balance be collected (i.e. the "catch-up" amount) over a period of 10 years. A similar approach has been taken for brushing expense. Using such an approach for the RID would result in an amortization of \$0.219/year i.e. the 2012 balance of \$2.191M/10 years. To be consistent with these other deferral accounts, the TGC submits the Board could, as an alternative to the recommendation noted earlier i.e. a 4-year amortization, reduce RID amortization costs from \$670,000 to \$219,000 for each of the Test Years." [TGC Argument, P27, Para 95 – P28, Para 97]

NTPC responded in its Reply:

"The Application does not include any forecast additions to the RFID account. However this does not mean the Corporation will be protected from events that would meet the criteria of the RFID policy for the eventual inclusion in the RFID Deferral Account. For example, in the hearing, the Corporation discussed the flooding of Nahanni Butte which occurred after the Application was filed. At the time of the hearing the Corporation was still investigating the total damage and the costs were being tracked by a separate code. Once the total costs are known the Corporation may apply the costs to the RFID account if the event meets all the criteria of the policy. Based on the forgoing, TGC incorrectly concludes there is no future requirement for a "keep up" portion of the RFID account.

Using TGC's approach and to be consistent with the other deferral accounts, the RFID account should have a catch up portion and a keep up portion. As suggested by TGC, with a 10 year amortization the catch up portion would be \$0.219 million per year. Similar to the overhaul keep up, the RFID keep up would be based on the annual expenditures over a certain time period. Table 11 from BR.NTPC-23 shows the total charges to the RFID account of \$2.944 million over a 5 year time period from 2007/08 to 2011/12. This is an annual keep up of \$0.589 million. Under the TGC approach to be consistent with the other deferral accounts, the RFID amortization would be \$0.808 million (\$0.219 million + \$0.589 million).

The Corporation does not agree the annual RFID amortization should be increased to \$0.808 million. Nor should it be decreased to only a catch up portion, given that external events such as the Nahanni Butte situation will continue to occur. The Corporation recommends that it be maintained at the approved level of \$0.670 million." [NTPC Reply, P24, L16 – P25, L4]

Board Findings:

While there are no forecast additions to the RFID, it is the Board's view that setting the annual appropriation based on there being no additions would not be

prudent. The Board is satisfied with continuing the RFID with the current annual appropriation of \$0.670 million. If the RFID ends up in an over-funded position the Board expects the Corporation to come forward with a suitable adjustment at the next GRA.

3.9.5 Employee Future Benefits

NTPC is seeking approval for a new annual amortization of \$0.348 million per year to begin to discharge the balance in the regulatory Employee Future Benefits deferral account. The account has previously had no annual accrual pending a full drawdown of the balance that was established in the 2001/03 GRA, which has now occurred.

No parties submitted comments on the Employee Future Benefits deferral account in Argument or Reply Argument.

Board Findings:

The Board approves the new annual amortization of \$0.348 million for the Employee Future Benefits deferral account.

3.9.6 Brushing Deferral Account

NTPC proposed the establishment of a Brushing Deferral Account, based on the principles of deferred costs. NTPC states brushing costs incurred each year will be deferred over 10 years starting 2011/12, leading to annual amortization costs of \$0.132 million by 2013/14.

TGC submits, contrary to NTPC's Argument that brushing expenses provide some type of enduring value, these costs are not similar to capital assets which have a life of more than one year and can be said to provide some enduring value. The TGC submits NTPC's brushing proposal advanced in this GRA should be rejected.

The TGC stated, based on the history of brushing expenses provided in TGC.NTPC-44 (a), the average actual brushing costs for the period 2007/08 through to 2010/11 amounts to \$0.306M. TGC submitted an appropriate forecast for the Test Years should reflect the actual brushing expenses incurred in the last few years. NTPC is free to manage its brushing program within the budgeted costs, without a need for true-up. Accordingly, the TGC recommended the Board reduce the forecast brushing expenses from \$0.444M to \$0.306M, a reduction of \$0.138M for each of the Test Years 2012/13 and 2013/14. [TGC Argument, P29, Para 101- P30, Para. 102]

In its Reply submission, NTPC states recent past practice (including past averages) is not a good indicator of the future requirement for brushing, or for the expected individual annual level of brushing expense in any given year. Starting from 2010/11, NTPC implemented a higher level modern brushing program with average annual cost exceeding \$0.400 million. This estimate is based on the review of actual competitive tender pricings and the expected required scale and frequency of brushing work to be completed on NTPC's transmission and distribution lines.

NTPC submits, past history gives no evidence of the required future level of activity and the scale of spending in any zone is "lumpy". In addition, there should be no debate that brushing expenses are similar to capital assets in terms of providing enduring value, because brushing in any particular area will only be

done on either a 6, 10 or 20-year cycle. Implementation of a deferred treatment for brushing expenses would result in smoothing out of the year to year fluctuations in actual expenses. NTPC submits the TGC's proposal would not provide a reasonable matching of costs with the rate periods in which they provide benefits, and would not promote rate stability. [NTPC Reply, P25-26]

Board Findings:

The Board recognizes the treatment of brushing expense as a deferred cost can result in smoothing out the lumpiness of these expenditures by zone. However, the Board is concerned that treatment of brushing on a deferred cost basis takes away the incentive to be efficient in terms of the scope and type of the brushing programs and the corresponding costs. The Board agrees with the TGC that NTPC is free to manage its brushing program within the budgeted costs, without a need for true-up. Accordingly, the Board is not prepared to approve NTPC's request for deferred cost treatment of brushing costs.

The Board directs NTPC to include, in its Compliance Filing Application, annual brushing costs for each zone based on the 5 actual year average brushing costs with due adjustment for inflation and any forecast scope changes.

3.10 Conversion to International Financial Reporting Standards

NTPC states, in February 2008, the CICA Accounting Standards Board ("**AcSB**") confirmed that the transition to IFRS from Canadian GAAP would be required for publicly accountable entities for interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011, and would include comparatives for fiscal periods beginning on or after January 1, 2010. NTPC states, in July 2010, the AcSB proposed (and subsequently approved), a one

year implementation deferral for rate-regulated entities. As such, the Corporation will be required to issue its first IFRS financial statements in fiscal year ending March 31, 2013 with comparative figures for the year ending March 31, 2012. NTPC indicates the conversion project is on-going and includes determining the key accounting differences between Canadian GAAP and IFRS as well as finalizing and implementing changes in policies and procedures throughout the Corporation to comply with IFRS.

Exhibit 21, response to Undertaking #1, indicates the AcSB has decided to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2014.

The TGC noted NTPC's acknowledgement that for both financial accounting purposes as well as for regulatory accounting purposes, NTPC will elect to take the deferral of IFRS changeover until such time as it is in a position where there are no further deferrals available. The TGC submits, notwithstanding the decision to defer the implementation of IFRS to January 1, 2014, for financial accounting and regulatory purposes, NTPC has decided to adopt certain aspects of accounting prescribed by IFRS.

In this regard, the TGC states NTPC is applying an IDC charge to capital projects based solely on the embedded cost of long-term debt. This means that, in effect, a portion of the Corporation's long-term debt is not available to finance general rate base (i.e., assets in service) as it is applied as a "first call" against assets under construction. In 2013/14 the average cost of capital under the IDC "first allocation" of long term debt, versus the Allowance for Funds Used During Construction ("**AFUDC**") approach of equally distributing equity and debt is less than 1 basis point (average cost of capital changes from 6.530% to 6.537%) or about \$0.020 million on the overall revenue requirement.

The TGC recommended that the Board reject the proposed change over to IDC in light of the deferral of the implementation of IFRS to January 1, 2014 adopted by NTPC and in light of the immaterial impact of the proposed change as noted above. [TGC Argument, P4, Para 9]

In its Reply submission, the TGC stated IDC charges debt only, whereas AFUDC requires the calculation of the average cost of debt and equity. As equity generally has a lower cost than debt for NTPC, the AFUDC cost is lower than the debt cost alone. Further, as NTPC has applied for a nil cost of equity for the Thermal Zone and augmented the interest cost by 50% according to the GNWT Guidelines, the resulting IDC cost for the Thermal Zone is significantly higher than that for the Hydro Zone. The TGC submits the Board should deny NTPC's proposal to adopt IDC in view of higher carrying cost capitalized to assets under construction in the Thermal Zone relative to those under construction in the Hydro Zone. [TGC Reply, P5, Paras 12-14]

The TGC also submits that any potential changes arising from the adoption of IFRS, including (Deferral Accounts, Deferred Costs, Asset Retirement Obligations, Future Removal and Site Restoration Costs and PPE) should not impact or affect the accounting for rate making purposes. As such, the TGC recommends the Board direct NTPC that the adoption of IFRS for external financial reporting purposes will not automatically drive the requirements for rate making purposes on the basis that the methods used by the Board to establish just and reasonable rates have not always been the same as those used for external financial reporting purposes. Rather the methods used by the Board have been based on historical, sound regulatory principles. [TGC Argument, P7, Para 21]

In its Reply submission, NTPC notes that the TGC's disagreement respecting IDC is with the timing of implementation rather than the treatment of IDC. NTPC submits, by adopting the IDC approach and implementing it in 2012/13, the Corporation is able to avoid two sets of asset databases which would create a reconciling item incurring higher costs and administration. With an implementation in 2012/13, the Corporation also avoids an application to the PUB in the very near future concerning the AFUDC/IDC methodology. [NTPC Reply, P32, Para 22-29]

Board Findings:

The Board notes, as a result of the deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities, the Corporation will be required to issue its first IFRS financial statements in fiscal year ending March 31, 2014. While further deferrals may be possible this is the current position of the AcSB and the target NTPC is working towards. Noting the relatively minor impact of the adoption of IDC in 2012/13, the Board will not require NTPC to defer the implementation of IDC from 2012/13 to 2013/14.

The Board considers, with the adoption of IDC, the interest rate used to calculate IDC on construction work in progress for each Zone will be the embedded cost of debt for that Zone. Accordingly, IDC that is capitalized as part of the cost of certain capital projects should not be impacted by the 1.5 interest rate multiplier applicable only to the calculation of return on rate base for the Thermal Zone.

The Board agrees with the TGC that any potential changes arising from the adoption of IFRS (including Deferral Accounts, Deferred Costs, Asset Retirement Obligations, Future Removal and Site Restoration Costs and PPE) should not necessarily impact or affect the accounting for rate making purposes. The Board will continue to require NTPC to maintain its regulatory records in accordance

with regulatory principles. To the extent there are any differences between regulatory treatment and accounting treatment of items, there could be potential increases in the cost of administering two sets of records. NTPC should take these matters into consideration when transitioning to IFRS.

4. RETURN ON RATE BASE

4.1 Rate Policy Guidelines and Adoption of IDC

NTPC indicates it has revised its approach to determining the cost of capital in this GRA as compared to past practice. NTPC states the Rate Policy Guidelines introduced a new reserve margin concept for the thermal zones. Using this approach, NTPC no longer seeks a return on its shareholder's equity from assets in the thermal zone. Rather, NTPC only seeks to recover the cost of debt in this zone, plus a reserve margin (measured as 1.5 times "interest coverage" ratio, which indicates the degree of flexibility NTPC has to meet its interest obligations due to variability in operating results).

To give effect to this policy, NTPC states it is necessary to divide the rate base between the two groups (thermal zone and all non-thermal) to apply the appropriate cost rates to each balance. NTPC states in order to give full effect to this zoned approach it is also applying the cost of the Snare-Cascades hydro lease against the non-thermal assets to reflect the role it plays in financing rate base.

NTPC states it is applying an IDC charge to capital projects based solely on the embedded cost of long-term debt. This means that, in effect, a portion of the Corporation's long-term debt is not available to finance general rate base (i.e., assets in service) as it is applied as a "first call" against assets under construction.

The revised approach to calculating the Corporation's return on rate base is set out in Schedule 3.5. Sources of financing specifically related to certain

components of rate base are addressed first including (long-term debt to finance work-in-progress, and capital lease to be applied 100% to non-thermal assets), leaving “general” capitalization (debt and equity) to finance the remaining components of rate base. The calculation of return on rate base for the non-thermal assets includes provision for debt, equity and the capital lease.

Board Findings:

The Board notes the assignment of the Snare Cascades capital lease to non-thermal rate base results in a debt to equity split of 61:39 for the non-thermal zone and 57:43 for the Thermal Zone. This means the debt interest subject to the 1.5 multiplier would be lower than would be the case if the 60:40 debt equity capital ratio, applicable to NTPC overall, were applied to the Thermal Zone. The Board notes the higher debt ratio (61% versus 60%) for the non-thermal rate base was necessitated by the need to assign the capital lease to the non-thermal rate base. Taking this into consideration the Board accepts NTPC proposed method of calculating the return on rate base to comply with the Rate Policy Guidelines and to reflect the transition to IDC as set out in Schedule 3.5.

4.2 Capital Structure

NTPC proposed a capital structure reflecting the financing of NTPC's rate base by approximately 40% equity and 60% long-term debt and capital lease, for 2012/13 and 2013/14.

Board Findings:

The Board notes NTPC's proposed capital structure together with a rate of return on equity of 8.5% on non-thermal rate base results in an interest coverage ratio of 1.69 in 2012/13 and 1.76 in 2013/14 as shown below:

Interest Coverage Ratios		
	2012/13	2013/14
	\$000	\$000
Debt Interest-Thermal Including Reserve	4682	4309
Debt Interest-Thermal	3121	2873
Debt Interest-Non Thermal	6285	6253
Interest on Capital Lease	1908	1869
Total Interest	11314	10995
Total Return	19111	19337
Interest Coverage Ratio	1.69	1.76
Source: Schedule 3.5		

The Board notes that the above ratios may change slightly following NTPC's update filing in Exhibit 13, which reflects a lower cost of debt.

None of the parties commented on the proposed capital structure. The Board considers the proposed capital structure and resulting interest coverage ratios are not unreasonable considering that NTPC's past coverage ratios were in the range of about 1.7. [Decision 13-2007, P32] Accordingly, the Board accepts NTPC's proposed capital structure for the purposes of this Decision.

4.3 Cost of Capital

In its Application, NTPC forecasts the issuance of long term debt in the amount of \$25 million in 2012/13 at a coupon rate of 4.29%. In its update filing, NTPC indicated this \$25 million debt will be issued at the interest rate of 3.818%, which will lower the cost of debt to the benefit of ratepayers. [Ex13; P3] As a result, the Mid-Year Cost of Long-Term Debt was revised to 6.47% and 5.68% in 2012/13 and 2013/14 respectively in Exhibit 13.

Consistent with the Rate Policy Guidelines, NTPC proposes a Return on Equity ("**ROE**") in the Thermal Zone of 0%. In place of an ROE for the Thermal Zone, NTPC proposed to increase the cost of debt by a multiple of 1.5 in order to provide an interest coverage ratio of 1.5.

For all assets outside the thermal zone, NTPC proposed an ROE of 8.5%. NTPC indicates the 8.5% ROE was determined on a simplified basis. NTPC states, the requested rate is below market standards recently set for utilities in Canada, such as the 8.75% low risk benchmark approved by the Alberta Utilities Commission for lower-risk large southern electric utilities (2011 and 2012 and interim 2013), and the 9.3% approved for Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited (collectively "**Northland**") (2011, 2012, and 2013).

During cross examination, Board staff questioned NTPC with regard to why the average rate of return on sinking fund investments during the Test Years are forecast to be less than the rate of return in prior years. In response, NTPC indicated the number of debt instruments with sinking fund requirements is decreasing. Considering the long term nature of the debt, NTPC states, the Board of Directors have elected to amend the sinking fund policy allowing management only to invest in fixed income type investments which results in lower earnings. [T301; L15-20]

Board Findings:

The Board accepts the 8.5% ROE applicable to the equity portion of non-thermal rate base as it results in an acceptable interest coverage ratio for the Corporation in each of the Test Years as discussed in Section 4.2. The Board also accepts NTPC's proposals respecting the cost of debt.

In BR.NTPC-7b), NTPC provided a detailed cost of debt calculation. NTPC is directed to file the calculation of the updated cost of debt (as updated in Exhibit 13) in the same format as in the BR.NTPC-7b) attachments, in Excel format, in support of its Compliance Filing Application.

4.4 Capital Lease

In 1996 the NWT Energy Corporation Ltd. ("**NTEC**"), pursuant to the authority of the Northwest Territories Power Corporation Act, financed the construction of a 4.3 MW hydro facility by the Dogrib Power Corporation ("**DPC**") [Ex 22; P19]. NTPC then leased the hydro facility from DPC under a 65 year lease agreement.

In Decision 13-2007 the Board noted that the capital costs that the Corporation incurs with respect to the lease represent DPC's costs of financing comprised of DPC's cost of debt raised to finance the construction of the project (9.6% on 93.26% of DPC's capital structure) and a return on DPC's equity position in the project (NTPC's allowed return on equity less 0.25% on 6.74% of DPC's capital structure). [Decision 13-2007; P 26]

DPC's cost of debt financing, in turn, reflects the actual cost rate of borrowing from NTEC an amount of \$22.9 million under a loan agreement between the two parties. To provide the debt financing to DPC, NTEC issued three series of debentures as follows:

Date of Issue	Amount of Issue	Due Date	Coupon Rate
May-95	\$8 million	May-25	10.00%
Oct-95	\$8 million	Oct-25	9.75%
Sep-96	\$9 Million	Sep-26	9.11%

In Decision 13-2007, the Board noted that DPC's cost of financing the lease is based on 93.26% debt owed to NTEC at 9.6% interest which is being repaid over 30 years and 6.74% equity at the allowed rate of return on equity minus 25 basis points. Further, the Board noted that given the mismatch in cash flow profiles, there may be potential for DPC to reduce its cost of capital by substituting some of the higher cost debt included in its capital structure with lower cost debt as the 9.6% debt is being amortized over 30 years.

Accordingly, the Board directed NTPC to address the potential for better matching the carrying cost of the lease to DPC with the cost of the lease to NTPC over the 65-year term of the lease, at the next GRA.

In response to this direction, NTPC states the matter of DPC's cost of financing is beyond the control of NTPC. As the lessee, NTPC's rights and obligations are set out in the lease agreement with DPC, which includes compensation to DPC for their costs related to financing the assets. DPC arranged for long-term financing in the late 1990s at market rates then applicable to long-term borrowings and this debt has been the underlying basis for calculation of the lease costs since that time (including approval by the Board for inclusion of these costs into rates). Given that DPC's debt is structured as long term debt, the same rules apply to NTPC long-term debt; that is, the rates cannot be readily adjusted and cannot be retroactively tested for reasonableness without recognizing the alternatives that existed at the time (including the lack of options for 65 year fixed-rate financing).
[Ex 2; P6-7]

Board Findings:

The Board notes the repayment of the loan to NTEC by DPC would be over a 30 year period whereas the lease obligation spans a period of 65 years. Consistent with this difference in timing of payments, the balance of the loan payable by

DPC to NTEC is \$18.191 million as of year-end 2011/12. [Exhibit 22, Note 13 to the 2011/12 Annual Report] while the lease obligation, on which interest is being calculated by NTPC, shows a balance of \$20.036 million as of year-end 2011/12. [Schedule 3.6]

Since the loan to NTEC is being paid at a faster rate than the 65 year term of the lease obligation, it would appear that DPC's cost related to the financing of the hydro facility lease may be changing since the time the initial terms of the lease were negotiated. In effect the faster repayment of the loan by DPC to NTEC would provide DPC the opportunity to substitute the high cost debt with lower cost debt at current borrowing rates in order to finance the lease.

While the Board does not consider it appropriate to test the reasonableness of the initial rates for financing that were negotiated, the Board notes the understanding at the time of the last GRA that the capital costs that the Corporation incurs with respect to the lease would represent DPC's costs of financing comprised of DPC's cost of debt raised to finance the construction of the project (9.6% on 93.26% of DPC's capital structure) and a return on DPC's equity position in the project. In view of this the Board considers that any change in DPC's cost of capital with respect to its financing of the lease over the 65 year term, should be reflected in customer rates. The intent of the Board's Directive 25 in Decision 13-2007 was to elicit a full discussion and estimates of any changes in DPC's cost of capital.

Having regard to the cost based nature of the lease; the Board is not persuaded by NTPC's statement that the same rules apply to the lease as for NTPC's long-term debt. The Board is also not persuaded, based on the evidence filed, why changes in DPC's cost of financing over the 65 year lease term may not be reflected in the lease rates paid by NTPC.

Accordingly, the Board directs NTPC to provide, at the time of the Compliance Filing Application, evidence to support NTPC's view that the same rules apply to the lease as for NTPC's long-term debt and to provide evidentiary support for the view that DPC's cost of financing over the 65 year lease term should remain unchanged, notwithstanding the cost based nature of the lease.

5. PRODUCTION FUEL AND PURCHASE POWER

In its September 19, 2012 update, NTPC revised its 2012/13 and 2013/14 production fuel forecasts. The 2012/13 forecast was increased by \$280,000 to \$24,824,000. The 2013/14 forecast was increased by \$293,000 to \$25,194,000. These two increases are due to the original fuel price forecasts in the application being updated to reflect the actual August 2012 fuel prices from the Petroleum Products Division, which are approximately 1 cent/litre higher on average than in the application.

The September 19, 2012 update did not change the purchased power forecasts of \$2,993,000 for 2012/13 and \$2,978,000 for 2013/14.

Intervenors raised concerns with fuel efficiencies and the Inuvik gas situation. Each topic is addressed in the following sections.

5.1 Fuel Efficiencies

In Argument, TGC recommended that NTPC be required to amend their method of forecasting fuel efficiencies when a new diesel engine is being installed in a community. TGC stated:

"The TGC does not object to the 3:2:1 ratio approved by the Board in prior rate cases. However, in order to avoid the deferral of improvements of fuel efficiencies in the Test Years to some future years beyond these Test Years, this ratio needs to be tweaked slightly. Where in a Test Year NTPC is forecasting the installation of a new engine to be installed in a particular community, the result of which is an improved overall fuel efficiency for that community, NTPC should be directed to reflect that fuel efficiency in the determination of the fuel heat rates." [TGC Argument, P33, Para 116]

NTPC responded in its Reply:

"NTPC readily acknowledged that the new diesel engines, scheduled to be installed during the test years in Nahanni Butte and Jean Marie River, would be more efficient than the historic efficiencies. However, there is no viable means of forecasting the efficiency improvements.

In the 2006/08 GRA, the issue of forecasting efficiency changes due to engine installations was extensively discussed in regards to the third Inuvik gas engine. The manufacturer's fuel efficiency ratings were examined as a means of forecasting efficiency improvements. These were largely ruled out as a viable proxy for GRA forecasts. As Mr. Kerr noted, manufacturer's ratings "...are based on one (1) hour of continuous operation at those loads, but it does not take into consideration any fuel consumed to warm up or cool down the engine." These ratings do not reflect real world conditions which a GRA forecast is intended to mirror as part of cost causation.

The resulting Board direction was prefaced on the generally upward trend in fuel efficiencies and the Board's concern that customers could forego a year's worth of fuel efficiency improvements if the test years forecast were not included within the 3-2-1 calculation. The Board's direction sought to provide an equitable means of forecasting test year fuel efficiencies improvements and NTPC followed the Board's direction in preparing its 2012/14 GRA.

The Corporation submits that its fuel efficiency forecasts for the test years are reasonable and should be approved." [NTPC Reply, P8, L3-20]

In its Reply, the TGC stated:

"The TGC recommendation that the Board should tweak the application of the 3-2-1 method to reflect the improved fuel efficiencies arising from a new engine installation is fair, and will result in a forecast of fuel costs more representative of the expected conditions. To this end, the Board should direct NTPC in its refiling to re-calculate the fuel efficiencies for the Test Years in each of the communities, including Inuvik, where NTPC forecasts a new engine installation.

Where in a Test Year NTPC forecasts the installation of a new engine in a particular community, which results in an improved overall fuel efficiency for that community, NTPC should be directed to reflect that fuel efficiency in the determination of the fuel heat rates." [TGC Reply, P4, Para 7-8]

Board Findings:

Attachment BR.NTPC-4(a-c) indicates that fuel costs are calculated at the community level using an average fuel efficiency rate for each community. Therefore changes in the fuel efficiencies due to the addition of new engines can

have an impact on the fuel efficiencies for the community and consequently impact the fuel costs for the relevant Zone.

The Board recognizes that in the normal course, any improved fuel efficiencies will make their way into the fuel forecasting system under the methodology that is currently in place in a short period of time, therefore, the Board sees no reason to deviate from the method of determining test year forecast fuel efficiencies.

However, for the community of Inuvik, there is a fundamental change in the configuration of engines, due to the conversion of gas engines to diesel and the base loading of diesel engines. NTPC acknowledged during hearing examination that the fuel efficiencies in Inuvik could improve significantly following the 2013/14 year:

So what I'm wondering is should the better fuel efficiencies resulting from the conversion as well as the installation of the new EMD engine be somehow captured in the forecast, at least for the 2013/14 year?

A. Yeah, the conversion of the Wartsila from gas to diesel will be completed June next year. What I expect to happen, based on what I've seen in many similar projects, the first year of operation there will be teething problems with that and we will inevitably be running a combination of EMDs and the Wartsilas for anywhere between 6 months and a year. I don't expect it to go that smooth. So the first year of operation I would expect the fuel efficiency to be still roundabout 3.5.

The Wartsilas are about -- after that I would expect the impact of the Wartsilas to come through and we'll see improved fuel efficiencies in the range between 5 and 8 percent depending on load factors. [T303, L20 – T304, L14]

Schedule 3.3.2 indicates the diesel generation in the Thermal Zone is 76,014 Mwh in 2013/14 and the corresponding cost is \$24.3 million. Schedule BR.NTPC-25a-4 indicates Inuvik generation constitutes approximately 44% of the total Thermal Zone diesel generation. The Board considers that a 5 to 8 percent improvement in the fuel efficiencies for Inuvik could potentially result in a material reduction in the diesel costs for the Thermal Zone.

Considering the materiality of the potential fuel cost reduction following the conversion of gas engines to diesel and the base loading of diesel generation, the Board considers, in this particular instance, the benefit of the fuel conversion should be reflected in customer rates without having to wait until the next GRA. Accordingly, NTPC is directed to address, at the time of the Compliance Filing Application, a method of recognizing the expected improvement in fuel efficiencies at Inuvik, in the rates for years commencing after the 2013/14 Test Year.

5.2 Inuvik Gas Supply

The TGC stated the following in Argument:

"Given the above, TGC submits that the Board should direct NTPC to prepare a comprehensive analysis of the issue surrounding the failure of gas supply in Inuvik, including the identification the basis for the failure, required reporting from the gas supplier and associated communications, and the analysis of any stranded costs (including prepaid gas not delivered), so that the situation is fully understood and similar events may be better avoided in the future." [TGC Argument, P14, Para 51]

NTPC responded in its Reply:

"The Corporation notes that it did obtain its own reserve report confirming the reserve estimates of the gas supply. However, NTPC would not possibly be able to complete the requested broad analysis surrounding the failure of the Inuvik Gas Supply as the Corporation is not privy to most of the information contemplated in such an analysis. Inuvik Gas Ltd. ("IGL") is the distributor of natural gas in Inuvik and the company from which NTPC purchased gas for generating electricity. As the owner of the gas, IGL has the proprietary information regarding the issues surrounding the gas well failure, including the identification and basis for the failure and any reporting obligations. In NTPC's experience, disclosure of this information is not typically contemplated under sales agreements such as the one in place between NTPC and IGL (provided in response NTPC.TGC-12(a)). As NTPC previously advised, NTPC understands that the loss of gas was unexpected and unforeseen and NTPC cannot complete any kind of meaningful analysis that would prevent this situation from happening again."

The Corporation is also puzzled by TGC's recommendation that it provide further analysis of any stranded costs including any "prepaid gas not delivered". As part of the Application the Corporation has fully disclosed all fuel costs related to its revenue requirement and confirmed there are no prepaid gas expenses that have not been delivered from IGL. Further, the Corporation filed a project permit application regarding the Inuvik plant conversion and provided further capital cost information supporting this project as part of the Application. TGC had ample opportunity to further test this issue within the regulatory schedule set out by the Board. It did not do so, but rather filed a letter stating "the TGC recommends the Board approve NTPC's application for the major project permit respecting the Inuvik Gas Engines Conversion to Diesel Project Application." As such, TGC's recommendation should be rejected." [NTPC Reply, P8, L27 – P9,L16]

Board Findings:

The Board agrees with NTPC that it does not have the information required to fulfill the recommendation from TGC. Moreover, the Board agrees with the views of NTPC that these matters would have been more appropriately raised by the TGC in other regulatory proceedings on earlier applications filed by NTPC and Inuvik Gas Ltd.

6. NON-PRODUCTION FUEL, OPERATIONS AND MAINTENANCE EXPENSES

In its September 19, 2012 update, NTPC revised its 2012/13 and 2013/14 non-production fuel, operations and maintenance forecasts.

The 2012/13 forecast was decreased by \$216,000 to \$37,064,000. The \$216,000 decrease consisted of a \$180,000 decrease in salaries and wages and a \$36,000 decrease in non-production fuel and lubricants.

The 2013/14 forecast was decreased by \$37,000 to \$38,597,000. The \$37,000 decrease was in non-production fuel and lubricants.

Intervenors raised concerns with NTPC's forecasts for salaries and wages and for supplies and services. Each topic is addressed in the following sections.

6.1 Salaries and Wages

In its September 19, 2012 update, NTPC revised its 2012/13 salaries and wages forecast to \$22,244,000, a reduction of \$180,000 from the application. The reduction was the result of the forecast of \$360,000 for the apprenticeship program being cut in half due to the program not being initiated as quickly as anticipated and actual hiring in the year being delayed.

The forecast for 2013/14 of \$23,492,000 was unchanged from the application.

In its Argument, YK/HR highlighted NTPC's response to BR-NTPC-4 by noting large fluctuations in the year-to-year level of spending on salaries and wages in the Snare Zone and in the Head Office and Regional Office. YK/HR indicates that NTPC did not provide a satisfactory response to explain the fluctuations and that this undermines the reliability of the information provided. The fluctuations lead YK/HR to question the accounting and management of costs. However, YK/HR did not make a recommendation to the Board on this matter.

YK/HR also raises the issue of an increasing ratio of fringe benefits in the Test Years (37.06% in 2011/12, 40.54% in 2012/13 and 41.74% in 2013/14). YK/HR states that the reasons provided by NTPC explain why salaries and wages would be increasing but do not explain why the ratio of fringe benefits are also increasing. YK/HR notes that NTPC has confirmed that it has not increased its benefits program so there is no reason for the ratio of benefits to be increasing. YK/HR recommends that the cost of employee benefits be limited to the forecast for 2011/12 of 37.06% of Total Regular Payroll for Distribution and Transmission. YK/HR states that this results in a reduction of \$92,000 in 2012/13 and \$136,000 in 2013/14.

In its Reply, NTPC responded to YK/HR comments on year-to-year salary fluctuations as follows:

"...The Corporation was specifically tested in this area during the course of the hearing. The Corporation explained, among other things, that salary allocations are not completed within rate zones during the intervening years in the same manner when calculating the Corporation's revenue requirement. This results in some "lumpiness" when comparing year over year results in salaries. However, the overall results are complete and reliable. As described at page 3-7 of the Corporation's Application, the average increase in salaries since 2007/08 is 3.4% per year, which reflects wage rate inflation over the intervening years. In addition, NTPC's employee compliment has been maintained at a level consistent with 2007/08 and was not challenged by YK/HR. As a result, the overall salary forecast is reasonable and should be approved." [NTPC Reply, P9, L22-31]

On the matter of the ratio of fringe benefits, NTPC responded as follows:

"YK/HR's recommended reduction is arbitrary and once again unsubstantiated by any evidence. Fringe benefits as described at page 3-6 of the Corporation's Application are prescribed amounts that the Corporation must incur either by legislation or its collective agreement with the Union of Northern Workers. As per Revised Attachment YK/HR.NTPC-2 (c) the ratio of fringe when compared to regular payroll for all other areas except distribution and transmission is forecast at 39%. The same ratio for the distribution and transmission areas is estimated at 41% which reasonably represents the levels of fringe benefits that the Corporation will incur during the test years. As a result, YK/HR's recommended reduction in salaries and wages should be rejected." [NTPC Reply, P10, L1-9]

In its Reply, YK/HR maintained its recommendation of a reduction to the ratio of fringe benefits.

Board Findings:

On the matter of the year-to-year fluctuations in salaries and wages, the Board shares the concern expressed by YK/HR. NTPC's explanation *"that salary allocations are not completed within rate zones during the intervening years in the same manner when calculating the Corporation's revenue requirement"* is a concern to the Board. NTPC is regulated on a rate zone basis. As such, the Board expects NTPC to be able to provide the Board and interveners with information at least down to a rate zone level.

It is the Board's view that NTPC should not be maintaining a different level of expense tracking in the intervening years as compared to the Test Years. For the forecasts in the Test Years to be considered accurate and reliable they need to be based upon accurate information from the non-test years. In the Board's view, confidence in the forecasts is somewhat undermined given NTPC's current practice. However the Board will not be issuing a direction on this matter within this Decision. The Board will address this matter further in its upcoming proceeding on minimum filing requirements.

On the matter of the ratio of fringe benefits, the Board agrees with YK/HR that NTPC has not provided a suitable explanation for the 3.48% (2012/13) and 1.20% (2013/14) increases in the fringe benefit ratio for distribution and transportation. The reasons provided by NTPC explain the increase in salaries and wages but do not explain the increasing ratio of fringe benefits.

The Board notes NTPC statement that YK/HR's recommendation on this matter is arbitrary and unsubstantiated by the evidence. The Board reminds NTPC that the onus is on it to provide the evidence to substantiate its requested revenue requirement. In this instance, it has not done so and on this basis, the recommendation from YK/HR cannot be anything but arbitrary given the lack of evidence filed by NTPC.

The Board directs NTPC that in its Compliance Filing Application, the ratio of fringe benefits for distribution and transmission is to be set at 37.06% for Test Years 2012/13 and 2013/14.

6.2 Supplies and Services

In its September 19, 2012 update, NTPC did not change its 2012/13 and 2013/14 supplies and services forecasts from the \$11,812,000 and \$12,049,000, respectively, that were in the original application.

In its Argument, NTPC highlighted that there are two major factors for the supplies and services expense increasing since the 2007/08 test year – 1) an increase of \$0.214 million in insurance premiums due to higher gross plant and 2) an increase in communication charges of \$0.279 million due to the remote

diesel SCADA systems that have been developed. It is NTPC's position that the remaining increase largely reflects inflation since the 2007/08 test year.

When questioned at the hearing as to why the supplies and services forecast increases in 2013/14 after having had yearly decreases in 2010/11, 2011/12 and 2012/13, NTPC responded as follows:

Q. If we look at several years we see that the supplies and services expense decreases for -in each of the years 2010/11, 2011/12 and 2012/13, and then in 2013/14 you're showing an increase. So we thought we saw a trend there and wondered why that trend would not continue into the 2013/14 year, can you help with us that?

A. Yes, for the purposes of calculating the 13/14 forecast we assume that inflation factor of 2 percent.

A. MS. GOUCHER: If I could add to that, Mr. Marriott. The Corporation over the last several years leading up to this rate application, as I mentioned in my opening comments, has committed to trying to reduce costs in those areas where it has active management. So we have made considerable strides, particularly in the area of supplies and services, because that is one of those controllable costs.

Having said that, we are a utility and the nature of our business has not changed materially from year to year. Although we have gone through a series of years where we've been able to reduce costs in this area. The second test year fiscal 2013 reflects the end of those adjustments and reflects instead an increase at inflation which, again, is – as I indicated, is a commitment of the management, the Board of directors and the shareholder on a go-forward basis. For those areas such as supplies and services where we are actively managing costs and they are more so in our control than perhaps some other areas, we have done what we can over the past several years to reduce costs in those areas and now what you're seeing on a go-forward basis is increases in line with inflation. [T192, L25 – T194, L10]

In its Argument, YK/HR stated:

“...There has been a steady decline in costs since 2009/10. In 2010/11, Supplies and Services expense decreases by \$711,000. In 2011/12, Supplies and Services expense are forecast to decrease by \$697,000. During those two fiscal years Supplies and Services expense decrease by \$1,408,000, yet NTPC only forecasts a reduction of \$171,000 for 2012/13, and an increase of \$236,000 in 2013/14. NTPC explains the 2012/13 reduction as due to stretch objectives and the increase in 2013/14 as due to inflation. Given the recent trend in declining Supplies and Services expenses, and the fact that NTPC imposes stretch targets, YK/HR submit that there is no need for an increase in 2013/14. As such, the forecast for Supplies and Services should be \$11,812,000 for 2013/14, a reduction of \$236,000.” [YK/HR Argument, P12, Para 47]

In its Reply, NTPC stated:

"As discussed, the intervening years had a number of one-time events and corrections that have skewed the year over year comparisons. As a result, the trend experienced during the intervening years cannot be expected to continue. In addition, the Corporation further explains the increase in supplies and services to be driven by two notable events; an increase in insurance premiums and communication charges. Absent these notable items, total supplies and services have increased 2.3% over the 2007/08 test year when rates were last set. YK/HR did not test or dispute these increases in insurance premiums or communication charges. Incorporating an inflation factor for 2013/14 supplies and service is reasonable as the Corporation is subject to inflationary pressures. As such YK/HR's proposal should be denied." [NTPC Reply, P10, L15-24]

Board Findings:

The Board accepts the explanation provided by NTPC for its 2012/13 and 2013/14 supplies and services forecasts, namely; the large decreases in the preceding years were due to cost-reduction efforts; and the forecasts for the 2 Test Years in question represent the effect of inflation.

As such, the Board will not issue any direction to NTPC on this matter.

7. AMORTIZATION

An amortization study was completed by Gannett Fleming, for purposes of the GRA, to determine the amortization parameters and rates. NTPC indicates on the basis that the study is not proposed to be implemented for Test Year 2012/13, there is no impact of the study on the first Test Year. The impact of the amortization study on the 2013/14 amortization expense is as follows:

- Increased rates for changes in lives - \$1.038 million (details provided in BR.NTPC-11(e) Table 3);
- Reduction arising from negative salvage pause approach – negative \$2.098 million (as compared to what was previously in rates);
- True-up - \$2.584 million (details provided at page A-52 to A-53 of the Application); and
- Total - \$1.534 million increase.

As part of the amortization study, NTPC proposed changes to the life parameters for a number of asset accounts. BR.NTPC-33, Table 1 shows the impact of the proposed changes to life parameters (excluding proposed changes to salvage) alone, including true up differences, contribute to an increase in amortization expense of \$2.2 million.

This increase is offset by NTPC's proposal to set all net salvage percentages equal to zero under a proposed pause approach for negative salvage.

7.1 Net Salvage and Implementation of Pause Approach

NTPC states due to a current accumulated amortization surplus in the net salvage accounts, it is proposing a “pause” in collection of new salvage amounts through rates until this balance is reduced.

NTPC states the reason for the pause approach is to permit the current \$20 million surplus in the salvage accounts to be drawn down. NTPC states, once this is complete, it is anticipated that the \$1.5 million annual accrual to the salvage reserve will need to be incorporated into rates (at a future GRA). NTPC states, given that the NTPC revenue requirement is in the order of \$100 million, the impact of the end of the pause approach is anticipated to be a rate pressure of 1.5%.

The determination that there is a surplus in the salvage accounts is based on a split of the total accumulated amortization balance between accumulated amortization for original cost of assets and negative salvage, performed in 1994/95 for the 1995/98 GRA. NTPC acknowledges that despite having split the balances for original cost of assets and negative salvage, depreciation studies performed in 1994/1995 (for the 1995/98 GRA) and in 2000 (for the 2001/03 GRA) did not separately analyze the balances, but rather treated accumulated amortization as a combined value for each asset class. NTPC states, as the split was performed almost 20 years ago, NTPC does not have detailed information on the approach and rationale for particular mathematical approach taken to perform the splits. NTPC states, Gannett Fleming was not involved in preparing the splits at the time.

The total accumulated amortization balance (for original cost of assets and negative salvage) as of year-end 2010/11 is \$146.04 million. NTPC's evidence

indicates, accumulated amortization applicable to original cost of assets is \$111.229 million while the accumulated amortization applicable to net salvage is \$40.831 million. Other reconciling items make up the balance of minus \$6.017. [BR.NTPC-16] As a result of the proposed allocation of total accumulated amortization there is a reserve deficiency applicable to the original cost of assets amounting to \$37.8 million as shown in Schedule 2 (page A-53) and a reserve surplus applicable to net salvage of \$20.223 million as shown in BR.NTPC-11, Table 2.

Board Findings:

The Board notes there are some uncertainties over the allocation of the accumulated amortization balance between accumulated amortization for original cost of assets and negative salvage. In this regard, the Board notes NTPC's acknowledgment the split of accumulated amortization (between accumulated amortization for original cost of assets and negative salvage) was performed almost 20 years ago and NTPC does not have detailed information on the approach and rationale for the particular mathematical approach taken to perform the splits. NTPC also states Gannett Fleming was not involved in preparing the splits at the time. The Board notes the proposed pause approach to the recovery of negative salvage is based on the assumption there is indeed a surplus in the accumulated amortization for negative salvage.

Notwithstanding the uncertainties associated with the split, the Board notes that the difference in true up for reserve differences is not materially different whether the split approach or the combined approach were adopted. More specifically, the true up for reserve differences amounts to \$2.584 million based on the assumption the accumulated amortization were split between accumulated amortization applicable to original cost of assets and accumulated amortization applicable to net salvage and if the pause approach for negative salvage is

implemented. However, from Table 1 of BR.NTPC-34, the Board notes that if the accumulated amortization were not split (between accumulated amortization applicable to original cost of assets and accumulated amortization applicable to net salvage) the true up amount would be \$2.361 million. Therefore the splitting of the accumulated amortization contributes to an increase in the true up amount of \$223,000.

Given the relatively small difference in the true up for reserve differences, the Board accepts the split between accumulated amortization applicable to original cost of assets and accumulated amortization applicable to net salvage as proposed by NTPC for the purposes of these proceedings. Further, given the surplus in the accumulated amortization for net salvage, the Board also accepts the pause approach for negative salvage for the purposes of this Decision.

Noting the uncertainties over the split in the accumulated amortization balance discussed above, the Board directs NTPC to provide evidence to support the split between accumulated amortization applicable to original cost of assets and accumulated amortization applicable to net salvage at the time of the next GRA.

7.2 Regulatory Treatment of Insurance Proceeds and Asset Retirement

NTPC indicates an amount of \$13.1 million, shown as a reconciling item between the gross plant in service as per Schedule 5.1 and the amortization study in BR.NTPC-16, representing total insurance proceeds received by NTPC in the past, was credited against assets [BR.NTPC-38b)]. This includes items such as insurance recoveries on the Fort McPherson fire (\$5.3 million) and the L199 splice failures (\$1.6 million). NTPC states the accumulated amortization balance

of \$6.810 million, also shown as a reconciling item in BR.NTPC-16, is simply the sum of amortization against each of these balances up to March 31, 2011.

NTPC states when it receives insurance proceeds towards an asset, NTPC records that asset in its appropriate FERC account, and records the insurance proceeds as an offset to that asset, in the same FERC account. These insurance proceeds are then amortized at the same rate as the underlying asset. This same “offset” approach (crediting the insurance proceeds against the asset) is used in the financial statements and in the GRA. The net effect is much like a customer contribution. [BR.NTPC-38b)]

NTPC states for the purposes of the depreciation study, it is necessary to use the true gross book value in determining the appropriate life and depreciation rate for the assets in each FERC account. This is why insurance proceeds are added back to the Gross Plant and Accumulated Amortization balances in coming up with the plant to be studied in the amortization study. NTPC states once the appropriate rate for each FERC account is determined, this same rate is applied to the asset gross book value, to any insurance proceeds against the asset, and to any customer contributions against the asset.

Board Findings:

The Board notes, from BR.NTPC-16, Tables 1 and 2, that the insurance proceeds and accumulated amortization are not reflected in the specific FERC accounts that include the relevant assets, by virtue of the fact they are treated as reconciling items. From the proposed treatment of insurance proceeds, It appears to the Board that the assets that were the subject of the insurance claim are remaining in the relevant plant account at original cost although the physical assets, such as the Fort McPherson plant, may no longer be in service. The Board is concerned that unless the insurance claim amounts exactly match the

original costs of the corresponding assets that were the subject of the insurance claim, the application of an amortization rate developed on the basis of an Iowa curve to a plant account that includes the original cost of assets that are no longer in service may result in the annual amortization expense being misstated.

This leads to a broader question concerning NTPC's practices regarding assets that are no longer in service. The Board has looked at Schedule 5.1 and neither the gross plant balance nor the accumulated amortization balance, reflect any asset retirements during the 2010/11 to 2013/14 period. Again, the Board is concerned the application of an amortization rate developed on the basis of an Iowa curve to a plant account that includes the original cost of assets that are no longer in service may result in the annual amortization expense being misstated.

NTPC is directed to address how its practices regarding treatment of insurance proceeds and retirement of assets that are no longer in service, from gross plant in service, results in the appropriate amortization expense and amortization of reserve differences for the Test Years. If the Board's comments give rise to any corrections to the gross plant used for calculation of amortization expense, NTPC is directed to provide the corrected amortization expense at the time of the Compliance Filing Application.

7.3 Individual Accounts

As indicated earlier in Section 7.0, NTPC proposed changes to life parameters which result in material increases in depreciation expense. The basis for changes in life parameters for some of the accounts were discussed through information requests and in Argument and Reply.

Account 341.00 – Diesel Plant - Structures and Improvements

NTPC proposed a change in the Average Service Life (“**ASL**”) for account 341.00, reflecting a change in the Iowa Curve, from 40R2 to 30S2.5.

NTPC's Depreciation expert, Gannett Fleming, states the mortality experience as witnessed in the retirement rate study for this account provides the basis for the development of the average service life estimate. The Iowa 30-S2.5 as recommended provides a good fit to the historic retirement pattern through the period of statistical reliance, is within the range of approved average service lives for comparable peer utilities, and is consistent with the expectation of the operational and management staff of NTPC. [Ex 2; Appendix A, P A33]

With respect to NTPC's proposal for Account 341.00, TGC submitted a review of the peer electric utilities reveals the following:

- Northlands uses an ASL of 50 years with a 50-S1.5 curve
- Yukon Electrical Corp uses an ASL of 40 years; with a curve of 40-R2.5
- Qulliq Energy Corporation an ASL of 35 years; with a curve of 35-R2.5
- Manitoba Hydro uses an ASL of 30 years; with a curve of 30-R3

The TGC submitted, at a proposed ASL of 30 years, NTPC is at the bottom end of the average ASL for the above noted peer utilities. The TGC submits greater weight should be given to the experience of the peer group of utilities and accordingly, recommended NTPC should be directed to use an ASL of 39 years, reflecting the average experience of the peer group.[TGC Argument, P40, Para 140]

Account 343.00 – Diesel Plant – Prime Movers

NTPC proposed a change in the depreciation parameters for account 343.00 reflecting a change in the Iowa Curve, from 25S2.5 to 20R3.

Gannett Fleming states, the original life table as provided indicates significant retirement ratios beginning in the first 10 years of the account's life and continues through to approximately age 25. By age 30 the plant exposed to retirement is less than 1% of the total plant exposed to retirement over the account's life. Therefore the Iowa curve fitting focused on the original life table through to age 30. The Iowa curve matching procedures employed by Gannett Fleming resulted in an Iowa 20-R3 being considered the best fit to the historic retirement trends. Gannett Fleming states, the Iowa 20-R3 represents a shorter life estimate than the currently used Iowa 25-S2.5, and is shorter than the peer range of 25 to 27 year estimates. However, the site reviews and operational staff reviews did not indicate any reason to believe that the plant currently in service should have any significant longer life indications than has been experienced in the past. [Ex 2, Appendix A, P32]

With respect to the NTPC proposal respecting Account 343.00, TGC submitted, a review of the peer electric utilities reveals the following:

- Northlands uses an ASL of 25 years with a 25-R1.5 curve
- Yukon Electrical Corp uses an ASL of 27 years; with a curve of 27-R2.5
- Quilliq Energy Corporation an ASL of 25 years; with a curve of 25-R1.5108

In TGC's view the foregoing shows NTPC, at a proposed ASL of 20 years, is well below the bottom end of the average ASL range of 25-27 years for the above noted peer utilities, and 6 years below the Average ASL of 26 years. In TGC's view, greater weight should be given to the experience of the peer group of

utilities. TGC submitted, given that 2 of the 3 peer group of companies have an ASL of 25 years, NTPC should be directed to use an ASL of 25 years, i.e. no change from the 25-S2.5 curve currently approved by the Board for Account 343.00. [TGC Argument, P41, Para 145]

In its Reply submission, NTPC stated the survivor curve estimates as recommended by Gannett Fleming for Accounts 341.00 and 343.00 considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined through conversations conducted as part of the study with operations and management personnel; incorporation of the knowledge that Gannett Fleming has gained through the completion of a number of NTPC assignments over a number of years; and survivor curve estimates from previous studies of this company and other electric generation, transmission and distribution companies. As such, the Gannett Fleming recommendations were based on significant review of a number of considerations, only one of which was the review of peer companies. To ignore all of the other factors, as is recommended by TGC, will result in a life estimate that is:

- Not consistent with 49 years of relevant retirement history;
- Not consistent with the views of the Corporations operations and management staff; and
- Not consistent with the operating practices and policies of the Corporation

The TGC submitted, in the event the Board is inclined to approve the revised depreciation rates as filed in this Application, the increases should be phased in over the 4-year period ending 2015/16 to coincide with NTPC rate design proposals. [TGC Argument, P41, Para 146]

In Reply, NTPC submitted:

During the transition years (2012/13, 2013/14 and 2014/15) the lowering of costs would solely serve to reduce the contribution from the GNWT (as customers would still face 7% increases). However, the entire value of this "savings" would have to be made up by depreciation expenses recorded in future regulatory accounts in years where GNWT contributions were not available, with the result that the ratepayers would pay higher rates in future than they would have paid. [NTPC Reply, P12, L29-34]

Board Findings:

The Board notes the NTPC proposed reductions in ASL and life parameters for the following major accounts have a significant impact on the depreciation expense:

Ac #	Description	Original Cost March 31, 2011	Existing Life Parameter	Proposed Life Parameter	Peer Group Average ASL	Impact of Life Changes
341	Diesel Plant Structures and Improvements	\$40,921,982	40-R2	30-S2.5	39 Years	\$772,141
343	Prime Movers	\$48,087,155	25-S2.5	20-R3	26 Years	\$609,957
345	Accessory Electrical Equipment	\$19,767,023	28-S2.5	21-L4	28 Years	\$541,892
	Source: BR NTPC 33 Table 1 and BR 33a					

The factors considered by Gannett Fleming in arriving at the proposed ASL and life parameters are set out in BR.NTPC-33d). This response indicates 60% reliance was placed on the historical retirements for account 341 while, 80% reliance was placed on historical retirements for accounts 343 and 345, in order to come up with the recommended parameters.

The Board notes the proposed ASLs for each of the above accounts are significantly lower than the peer group average ASLs. Given this information, the Board is not persuaded such a significant reduction in ASLs should be approved in a single move based primarily on the analysis of historical data reviewed by Gannett Fleming, as part of these proceedings. The Board considers a move that is about 50% of the way towards the ASLs proposed by NTPC would provide an

appropriate balance for the purposes of these proceedings. Accordingly, the Board directs NTPC to make a directional move in the Average Service Life parameter for the above noted accounts by reflecting ASLs of 35 years for account 341, 23 years for account 343 and 25 years for account 345, in its Compliance Filing Application.

7.4 Account 391.04 Office Furniture and Equipment – Gains and Losses

Schedule 2 of Appendix A shows a negative balance of \$2.079 million in the accumulated amortization for account 391.04. NTPC states, the \$2.079 million recorded in FERC 391.04 represents an accumulated amortization shortfall from past periods, largely due to retirements of computer hardware and software at a younger age than the “average” that was adopted for assets in FERC 391.

NTPC states, as part of first being regulated, it adopted the FERC system of accounts, which has a single account dedicated to “Office Furniture and Equipment”, account 391. NTPC has used this account to capture all office furniture and all general purpose computer hardware and software. In the 1995/98 GRA this account was given a 13 year life, adjusted in the 2001/03 GRA to a 10 year amortization period.

NTPC states, over time, it has become clear that NTPC needed a more complete breakdown of the assets contained in account 391, as computer hardware and software did not exhibit life profiles that were at all similar to office furniture. In this GRA, NTPC states it has proposed to create 3 sub-FERC codes; one for computer hardware (5 years), one for office furniture (15 years), and a third for computer software (5 years). To accomplish this change, the assets in FERC 391 were individually separated into the 3 noted groups.

NTPC states the result of failing to have these sub-FERC accounts in the past is that computer retirements have driven a substantial accumulated amortization “loss on disposal” in the account, as computers regularly do not last 10 years. [BR.NTPC-38a)]

Board Findings:

Having regard to the reasons provided by NTPC, the Board accepts NTPC's request to amortize the accumulated loss in account 394.04 over 10 years.

8. STABILIZATION FUNDS

NTPC states that in accordance with the Board Decision 16-2010, as of December 2010, Diesel, Inuvik, Norman Wells, Taltson, Snare-Yellowknife fuel and Snare-Yellowknife water funds have been consolidated into one NTPC Territory-wide Consolidated Fuel and Water Rate Stabilization Fund (“**RSF**”).

The operation of the RSF is described in BR.NTPC-10b) and in Section 3.6 of the Application. The purpose of the RSF is to flow through to customers, subject to a \$2.5 million threshold, variances in fuel prices and purchased power prices relative to the GRA forecast, and to flow through fuel mix variances in dual fuel communities.

NTPC’s proposal respecting the operation of the funds may be summarized as follows:

Thermal and Norman Wells Zones:

- i. The actual cost of diesel (and where relevant purchase power cost per kWh) is compared to the forecast cost of fuel reflected in the base rate (i.e., the fuel cost as approved by the Board for the latest GRA test year).
- ii. The difference is multiplied by the number of litres required to meet the load at the GRA approved efficiency factor (based on actual generation).
- iii. The total fuel cost variance will be charged / credited to the RSF.
- iv. For dual fuel communities, namely, Norman Wells, which uses purchased power and diesel generation and Inuvik, which uses diesel and gas generation, the cost impacts of changes in the mix of supply from the GRA forecast are flowed through to the RSF.

Snare Zone:

- v. For the Snare Zone, the kWh variance based on the following will be charged / credited to the RSF based on the GRA approved efficiency and fuel price:
 - a) Where the hydro generation exceeds 220 GWh/year, a kWh savings from above-average water will be calculated.
 - b) Where the hydro generation is below 220 GWh/year, but diesel is still required on an actual basis, any costs for diesel generation kWh in excess of that included in rates (1.2 GWh/year) will be charged to the RSF.

Taltson Zone:

- vi. For the Taltson zone, any diesel generation built into base rates will not be charged via the fund, but fuel for diesel generation which exceeds this level is charged to the fund.

With respect to the proposed inclusion of variances relative to the Taltson Zone in the RSF, NTPC states, it has long had an approved water stabilization mechanism for Taltson although this mechanism has been considered “inactive” due to the low level of loads on that system. However, with the initiation of a consistent principled Consolidated Stabilization Fund for all of NTPC’s customers across NWT, activation of this fund is now appropriate.

The TGC submitted, for communities where dual fuel sources are used, one as a primary source and the other as a backup, the costs of both should be shared across all of NWT, consistent with the GNWT Guideline 6, as approved in Decision 16-2010. [TGC Argument, P13, Para 43]

In its Reply submission, NTPC stated it is precisely NTPC's proposal that the Fuel and Water Stabilization Fund capture all variation from all fuel sources used for generation purposes. NTPC stated it has specifically sought approval to expand the RSF in three areas (Taltson hydro, Norman Wells fuel and Snare-Yellowknife base diesel) to achieve this precise objective.

The TGC also referred to Board Directive 7 from Decision 16-2010 requiring NTPC to work with Northland to develop a mechanism for territory wide sharing of the stabilization fund. TGC submitted NTPC should be directed to provide the results of its discussions with Northland at the earliest possible opportunity, and no later than the Compliance Filing in response to the Board Decision on this 2012-2014 GRA. Further, notwithstanding the passage of time, NTPC should address whether it can comply with the Directive to more broadly share the stabilization accounts across all NWT communities effective April 1, 2011 as anticipated by the Board in Decision 16-2010. [TGC Argument, P12, Para 37]

In its Reply submission, NTPC states the delay in fulfilling the Board Directive is largely due to other regulatory proceedings with both utilities. Imposing an aggressive deadline may not be practically achievable as the Corporation's resources will be fully engaged in completing the 2012/14 GRA compliance filing. Further, any directive would only bind NTPC. NTPC states, the Corporation fully intends to fulfill the requirements of this directive as soon as possible and intends to engage with Northland to advance this directive in the near future. However, NTPC submits a firm deadline is not practical or necessary in the circumstances. [NTPC Reply, P6, L33 - P7, L6]

Board Findings:

The Board has examined NTPC's proposed mechanics for operation of the RSF as applicable to the Thermal and Norman Wells Zones and accepts them as filed.

With respect to the Snare Zone, NTPC confirmed during the hearing, the cost of any diesel generation kWh in excess or less than that included in rates (1.2 GWh/year) will be charged or credited to the RSF. [T316, L24 – T317, L3]

NTPC also confirmed that the fund, as it applies to the Snare Zone, would operate to capture any variances in diesel costs relative to the GRA forecast and the operation of the fund is not intended to capture any efficiencies in terms of the optimization of water and diesel resources:

"What I'm wondering is, is there an incentive for the Corporation to optimize dispatch so that there is an optimum use of water and diesel resources?"

A. Well, there's absolutely an incentive for the Corporation to optimize the dispatch and to keep the diesels off. It's one of the driving factors in all of the considerations that go into the decisions that are made on the dispatch of this system. The Corporation has spent considerable effort and time and money to make sure that the hydro system can supply as much as possible beyond the next load. That's just a given.

The question about the incentives built into the fund was an item of considerable debate in the last GRA and a number of re-filings. And at the end of the day what seemed like a possible theory of saying: We'll include this type of fuel and not that type of fuel was -- ended up being more complicated in trying to apply than the advantages it might have brought.

And at the end of the day it was decided that the fund would operate to catch any variances in diesel rather than having to try to say: That kilowatt hour was due to peaking or that one was due to exercising or this extra bit of water I just used only arose because I peaked with my earlier kilowatt hour of diesel and I didn't use the water back then and so now it arose now and it saved me some diesel and do I get credit for that offsetting water, and all sorts of complexities that you start to get into when you try to label particular bits of generation." [T320, P320, L16 – P321, L23]

In view of NTPC's proposal that the fund, as applicable to the Snare Zone, would capture all diesel cost variances, the Board considers the reference to the long-

term average water forecast of 220 GWh per year, made by NTPC in its description of the fund operation, is redundant. Accordingly, the Board approves a revised wording for operation of the fund, as applicable to the Snare Zone, as follows:

For the Snare Zone, the fuel costs for diesel generation built into base rates will not be charged via the fund, but fuel costs for diesel generation which are greater or less than this level are charged or credited to the fund.

The Board notes NTPC's view that the recovery of both volume and price variances relative to diesel costs through the fund is the only practical approach in the Snare Zone and that every effort is being made to maximize the use of the hydro resource by the corporation. Accordingly, the Board approves the recovery of both volume and price variances relative to the diesel cost forecast for the purposes of this Decision.

The Board continues to be concerned by an RSF mechanism which allows pass through of all diesel costs as this may not provide the appropriate incentive for NTPC to maximize use of the hydro resource. The Board directs NTPC to address the feasibility of NTPC assuming forecast risk on diesel volume variances for the Snare Zone at the time of the next GRA.

With respect to the operation of the RSF as applicable to the Taltson zone, the Board notes the following observations by the Board in Decision 16-2010:

"The Board considers the proposed exemption of NUL-NWT from the fuel and low water stabilization fund rider, due to the absence of a Taltson water stabilization fund at the present time, is appropriate. Accordingly, the Board approves the proposed sharing of fuel and water stabilization amounts for purposes of these proceedings.

The Board notes that if a Taltson water stabilization component were to be required as part of the overall stabilization fund in the future, under the per utility sharing approach, NUL-NWT customers would share in NTPC's fuel and low water rider amounts but NTPC's customers would not share in the NUL-NWT fuel rider amounts. This might not be equitable to NUL-NWT customers.

The per utility sharing of fuel and low water stabilization amounts could also result in significant differences in rider amounts for customers in NUL's service area and in NTPC's service area. Creating the potential for wide rate disparities between neighboring communities is not consistent with the principle of comparability of rates.

Accordingly, the Board directs NTPC to work with NUL to develop a mechanism for Northwest Territories-wide sharing of fuel and low water costs, on a combined utility basis. [Decision 16-2010, P19-20]

While NTPC has requested inclusion of diesel cost variances relative to the Taltson Zone in the RSF, the issue of sharing of fuel cost variances on a combined utility basis has not been accomplished as yet. The Board notes NTPC's statement that the Corporation fully intends to fulfill the requirements of the Board directive requiring operation of the RSF on a combined utility basis as soon as possible and that it intends to engage with Northland to advance this directive in the near future. In view of this, the Board denies the inclusion of the fuel cost variances relative to the Taltson Zone in the RSF until there is agreement between NTPC and Northland to operate the RSF on a combined utility basis. This means, if the RSF is triggered at any time prior to implementation of the RSF on a combined utility basis, the recoveries and/or refunds of the balance in the RSF would not apply to the Taltson Zone customers.

9. AFFILIATE CHARGES

9.1 Overhead Charges to Affiliates

In Decision 13-2007, Directive 42, the Board directed NTPC, in its next Phase 1 GRA, to file with the Board details of all transactions with the Corporation's parent, other affiliates and non-regulated operations, including details of how the transfer pricing is determined (fair market value, allocated costs), the allocation drivers used, as well as identification of all amounts included in the Revenue Requirement with respect to costs or revenues related to parent, other affiliate and non-regulated operations.

In response to BR.NTPC-24a), NTPC provided Table 1 showing the transactions between NTPC and its affiliates from 2007/08 to 2011/12.

Table 1:
Affiliate Actual Costs 2007/08 to 2010/11 and Forecasts 2011/12 to 2013/14 (\$000s)

Transaction Description	2007/08	2008/09	2009/10	2010/11	2011/12 ¹	2012/13	2013/14
NTPC Direct Costs	235	216	213	283	193	228	233
NTPC Utility Bills	17	17	12	8	7	9	9
Overhead Costs	150	150	150	116	87	74	75
Shared Services	60	62	98	144	106	161	164
Interest Expense	492	342	185	227	164	133	136
Dividends declared to non-regulated entities	800	850	800	825	500	400	400
Dividends paid to non-regulated entities	-	1,271	1,163	812	402	400	400

Note:

1. Actual transactions from April 2011 to December 2011 shown.

NTPC states, the majority of affiliate transactions require very little resources to manage throughout the year and therefore do not have material overhead costs directly assigned to them. The Corporation allocates overhead costs to recover time spent on affiliate matters that are not directly assigned such as purchasing

and logistic matters, HR support, IT support and accounting assistance. All of which would include management time to supervise such activities. The costs for affiliate transactions are tracked with separate plant numbers and therefore are readily separated from regulated activities and not included in the Corporation's revenue requirement.

In order to fully comply with the foregoing direction, the TGC recommends that in all future general rate proceedings, NTPC should provide the full amount of costs incurred in running its utility operations (i.e. including costs incurred for affiliates) and provide separate line item(s) in the Revenue Requirement deducting costs incurred, either directly or indirectly, to support the operations of its affiliates. This would provide full and complete transparency of all costs incurred by NTPC, the regulated entity, and the nature and extent of costs charged or allocated to its affiliates. [TGC Argument, P35, Para 122]

With respect to interest on affiliate transactions, the TGC state NTPC has provided no evidence that the affiliates could actually avail themselves of a rate equal to prime less 50 basis points. On this basis, the TGC recommended that NTPC be directed to provide evidence at its next GRA to demonstrate the "prime less 50 bp" rate charged for loans to affiliates is in fact the same rate which NTPC incurs for such short term borrowings and to show both the costs of such debt as well as the offsetting recovery from the affiliates in the determination of its Revenue Requirement for the Test Year. [TGC Argument, P36, Para 126]

NTPC submits the process set out by the Board for the GRA Filing Manual is an appropriate means to address the recommendations made by TGC at paragraph 122, namely the presentation of costs ultimately charged to affiliates as opposed to regulated ratepayers. [NTPC Reply, P 35, L17-19]

Board Findings:

The Board agrees with the TGC that the information provided with respect to affiliates should provide the means for the Board and other parties to understand the accounting entries with respect to amounts recoverable from, or payable to affiliates, both on a forecast basis and on an actual basis. For example, with respect to shared services, response to TGC.NTPC-45(n)(vi) indicates costs for shared services include building leases, telecommunication costs and computer software costs. It is not clear in which regulatory account the costs/recoveries related to the shared services are reflected. Similarly it is not clear in which accounts interest payments/recoveries or overhead recoveries are reflected, both on a forecast and actual basis. Therefore, the Board directs NTPC to provide, at the time of the Compliance Filing Application, details explaining the accounting entries involved in recording each of the affiliate costs/revenues (other than dividends), for GRA forecast purposes and for recording actual results for financial statement purposes.

In response to Board Decision 13-2007, Directive 42, NTPC also did not explain the basis on which overheads, shared services and interest expense are priced. It is not clear whether the pricing method used is consistent with the affiliate transfer pricing policies as approved in Decision 6-2009:

Under the Cost Recovery Basis, the fully burdened cost of employees providing the shared service for the time period they are used by the Affiliate, including salary, benefits, vacation, materials, disbursements and all applicable overheads shall be used for determining shared employee costs. Where there are shared costs arising from the sharing of assets, an allocated share of capital and operating costs appropriate for the time period utilized by the Affiliate shall be used for determining shared asset costs.

When a utility provides to or takes from an Affiliate services, resources or products, that do not fit the description of Shared Services outlined above the Board considers these to be For Profit Affiliate Services. The Board considers the transfer price respecting For Profit Affiliate Services should reflect the fair market value. The onus is on the utility to demonstrate the transfer price of the services, resources or products reflects the fair market value. [Decision 6-2009, P20-21]

NTPC is directed to identify the transfer pricing policy and how it was used for pricing shared services including overheads and, interest expense/recoveries, at the time of the Compliance Filing Application.

10. SALES AND REVENUE FORECAST

NTPC indicates the forecast of customers for the Test Years were developed using the following approach.

For residential customers, 2011/12 customer count forecasts were forecast based on the 2010/11 average actual customer counts from December to March multiplied by the average annual population growth rate. 2012/13 and 2013/14 customer count forecasts were then estimated using the 2011/12 forecast customer counts multiplied by the population growth rates

For general service customers, the same method was used as described for residential customer counts with the exception that only 50% of the population growth rates were used. NTPC states a 50% factor was used because:

- General Service customer numbers tend not to change as frequently as residential customer numbers;
- There tend to be more residential customers in a community than general service customers.
- More of the growth in customer counts in the General Service customer class can be addressed from specific information

NTPC states, after a baseline customer count is developed, the Corporation checked, and where necessary adjusted the customer count to address new developments planned to have in-service dates in the forecast years for communities where the population growth percentage did not reflect similar patterns.

With respect to development of the usage forecasts, NTPC indicated the following approach was used:

"Monthly usage per customer (UPC) in actual years is calculated as actual sales for the month divided by the actual average annual customer number for each community. The forecast sales for each forecast year 2011/12, 2012/13 and 2013/14 are then calculated by averaging the last five years of monthly UPC and then multiplying by the forecast annual customer count. NTPC states, in 2013/14 additional UPC is added to Inuvik's general service and residential classes to account for a 5% increase in power demand as a result of the gas conversion, which subsequently raises UPC for the Thermal zone and Corporate wide, as a percentage of sales, compared to totals." [BR.NTPC-2]

NTPC states, the usage per customer ("**UPC**") method is not used for lighting, wholesale or industrial forecasts. Instead the following methods were used:

***"Lighting:** The load forecast for lighting uses 2010/11 actuals for each forecast year and makes adjustments, where applicable, when lighting will be changed to more efficient lamps.*

***Wholesale:** Snare zone wholesale forecasts assume a 0.7% increase over the preceding year, which is equivalent to the 2011/12 forecast growth rate over 2010/11 actual wholesale sales. The Taltson zone wholesale forecast assumes a 5-year average, per month, using five of the last seven years as a rolling average.*

***Industrial:** Considering that no new mining activities are expected during the 2012/13 and 2013/14 test years, forecast industrial sales for the test years was assumed to remain at the forecast 2011/12 level." [Ex 2; P2-14]*

YK/HR submitted, despite NTPC's assertion that it has complied with Board Directive 7, NTPC has not used normalized heating or cooling degree days. Instead, NTPC has used a simple average with no trending. Further the 2012/13 forecast includes the 2011/12 average in the five year average, and the 2013/14 forecast includes the 2011/12 and 2012/13 averages. This approach results in a disproportionate weighting being placed on recent years. [YK/HR Argument, P8, Para 31 – P9, Para 33]

YK/HR recommended that the forecast UPC should reflect the recent patterns. That is that Snare zone residential UPC should reflect the pattern of increases as

noted by YK/HR in Argument, and the Taltson zone residential and general service UPC should not decrease but remain constant at the 2011/12 average. YK/HR requested that the Board direct NTPC to provide evidence that its use of a five year average of UPC is a reasonable forecasting methodology and that the Board direct NTPC to investigate alternate forecasting methodologies and provide the results of the investigation at the next GRA. [YK/HR Argument, P10, Para 38 – P11, Para 39]

In its Reply submission, NTPC states the average UPC calculated over a five year period incorporates the effects of medium-term weather fluctuations, and thus represents a reasonable and practical approach to determining a temperature-normalized average UPC. Mr Bowman referred to some of the difficulties of developing weather normalized data:

"In NTPC's case, the loads are very diverse and distributed and very small. And loads can swing, particularly in the small communities, for many different reasons. [T164. L7-10]

...

In the case of NTPC, that is a very difficult thing to try to do because a lot of the weather data needed to do that is not available. And especially for the small communities. And also for small utilities the data that generates that line is often not very good at generating lines because it looks more like a scatter plot because there's a heck of a lot more going on in any small community than just the weather that's driving the changes in load. So you may have a cold winter but you may have had one house vacant and as a result -- or one -- your use per customer would be swung because that house is using much less power. And so you can see a lot of noise in there.

I have been involved in hearings in places like Yukon where the utility there, Yukon Electrical has tried to do this weather normalization process, worked through a large stack of data and produced a substantial section of their rate application, and at the end of the day the R-squared or the statistical term that tells you how well you are aligned -- a single line summarizes your data is very low, it's very poor match to weather." [T165, L6 – T166, L4]

With regard to the use of rolling averages including use of a given year forecast to develop subsequent year forecasts, NTPC submitted the same effect exists for

the fuel forecasting approach that was specifically directed by the Board, and presumably reflects a willingness or desire to more heavily weight the more recent years. In NTPC's view this is not an unreasonable approach to forecasting. NTPC also states the evidence in this proceeding does not support YK/HR's claim (a) that in the last GRA 2007/08 test year NTPC's methods under forecast the average UPC in the hydro zones, and (b) that the current GRA is forecasting reductions in average UPC that are not justified based on the data. [NTPC Reply, P3, L36 – P4, L12]

Board Findings:

The Board has examined NTPC's customer forecasts for the Test Years, as well as the methods used to develop such forecasts and accepts them as reasonable.

The Board notes YK/HR's observations respecting lack of temperature normalization and the heavier weighting placed by NTPC on more recent year UPC numbers in developing its forecasts of UPC. The Board recognizes the difficulties of obtaining temperature normalization data for certain communities. However, noting YK/HR's request that NTPC investigate alternate forecasting methodologies and provide the results of the investigation at the next GRA, the Board directs NTPC to examine the following refinements with respect to its UPS forecast methodology for the purposes of the next GRA:

- For those communities where temperature normalization data is available, NTPC is to carry out regression analyses for all temperature sensitive sales, using degree days, trend variable(s) and any other relevant variables to develop a reasonable estimate of forecast UPC.
- For those communities where temperature normalization data is not available, NTPC is to use a straight 5 year average UPC over the most

recent recorded (actual) years and use the actual growth rate over the same recorded years to project growth for the forecast years.

In the absence of any evidence to indicate, NTPC's forecast sales for the Test Years are not reasonable, the Board accepts NTPC's forecast sales as filed for the purposes of this Decision.

11. RATES

11.1 Rates Phase In Proposal

NTPC states the rate changes in this GRA are designed to achieve a level of rates that recover the full 2013/14 Revenue Requirement by the end of a four year transition period ("Full Rates"). NTPC states, during the transition period (2012/13, 2013/14 and 2014/15), rates will fail to achieve the full Revenue Requirement. Accordingly, NTPC and the GNWT have implemented funding measures to ensure the Corporation is able to continue to provide safe and reliable service and maintain financial viability during the transition period. As a result, GNWT funding in the amounts of \$13.63 million in 2012/13, \$11.484 million in 2013/14 and \$4.892 million in 2014/15 will be provided to NTPC based on forecasts reflected in its Application. [T331, L18-20]

On September 19, 2012, NTPC filed an update to its Application. [Ex 13] The following Table shows the rate increases and shortfalls for the Test Years and for the transition period:

	2012/13	2013/14	2014/15	2015/16
	\$000	\$000	\$000	\$000
Total Revenue Requirement	102,225	107,304		
Revenue at Existing Rates	82,132	83,123		
Other Revenue	1,029	1,058		
Total Revenue	83,161	84,181		
Shortfall	19,065	23,124		
Revenue at Proposed Rates	87,672	94,763	101,144	106,246
Other Revenue	1,029	1,058	1,058	1,058
Total Proposed Revenue	88,700	95,821	102,202	107,304
Shortfall	13,525	11,483	5,102	0
Percent Increase in Customer Rates Year Over Year	6.745%	6.636%	6.733%	5.044%

NTPC requested approval of rates covering the rate transition period (including the 2 Test Years plus 2014/15 and 2015/16) as needed to achieve the full calculated level of rates.

In its IRA, NTPC stated that that a lower Board-approved 2012/13 revenue requirement would simply reduce the amount of the GNWT financial support for 2012/13. [Interim Rate Application, P2]

NTPC proposed increases to all energy rates, other than Norman Wells, totaling 7% in each of 2012/13, 2013/14, 2014/15, and as required in 2015/16 to achieve Full Rates. For Norman Wells, NTPC proposed increases to energy rates of 15% in each year as needed to achieve transition into the thermal zone, as well as to achieve Full Rates by 2015/16. NTPC proposed no changes to fixed monthly or demand charges.

For the purposes of 2012/13 interim rates, Norman Wells customers saw a 7% energy rate increase as did other customers. NTPC indicated it consulted with the Norman Wells community and the GNWT about phasing in rate increases for that community. Following this, NTPC requested that the final rates for Norman Wells reflect an additional increase of 8% for 2012/13 and 15% in each subsequent year, as needed to transition Norman Wells into the Thermal Zone. NTPC indicated it is not requesting recovery of the shortfall relative to Norman Wells arising from the implementation of a 7% interim increase for 2012/13 instead of the 15% now being requested for that year.

TGC expressed concern about the proposed increases in rates for Norman Wells.

TGC notes, once the final rates take effect, customers in Norman Wells are proposed to receive an additional 8% increase for the balance of 2012/13, followed by a 15% increase in 2013/14 and another 15% increase in 2014/15. TGC states, the impact of the stacking of significant rate increases in Norman Wells over the next 4 years will lead to rate shock; an annual 15% increase over the next 4 year is an increase in rates of 75%. This is not in the best interests of customers. In TGC's view, any such rate increase to comply with the GNWT's Guidelines should be phased-in over an appropriate length of time. TGC recommended NTPC be directed to provide a proposal which would implement a rate increase of no more than 7% per year for Norman Wells until full cost recovery is attained. [TGC Argument, P14, Para 47 - P15, Para 49]

In its Reply submission, NTPC states keeping Norman Wells' rate increases to 7% as suggested would simply defer and create a larger rate impact for customers beyond 2015/16, a rate impact that will need to be dealt with in transitioning Norman Wells to the Thermal Zone. In addition, and with exception

to 2012/13, if Norman Wells' rate increases were limited to 7% for the next 4 years, additional revenue shortfalls will be created for every year that Norman Wells is not at full cost recovery. Once again, these shortfalls would have to be collected from customers by implementing additional shortfall riders in addition to any transitional rate increase to bring Norman Wells into the Thermal Zone.

NTPC submits its proposal to increase Norman Wells' rates 15% in each year as needed to achieve transition into the thermal zone as well as to achieve the full rates by 2015/16 is not rate shock. The Board has a long standing guideline that has allowed 15% as the maximum rate impact for customers. [NTPC Reply, P13, L23-26]

YK/HR submitted that any difference between NTPC's applied-for 2013/2014 revenue requirement and what is ultimately approved by the Board should be reflected in the rates for 2015/2016. For example, a decrease to NTPC's 2013/2014 revenue requirement should be reflected in a rate increase of less than 5% for most customers in 2015/2016.

YK/HR submitted, since NTPC is seeking approval of, *inter alia*, final rates for the 2012/2013, 2013/2014, 2014/2015 and 2015/2016 years, if the Board approves NTPC's Application, that it explicitly state that rates for all years shall be considered final. YK/HR submits in granting NTPC the relief requested, the Board should ensure that rates for the entire "transition period" are certain and not subject to further increases in addition to those approved in this Application. YK/HR submits, if NTPC's rates for the four years are approved as final, NTPC shall not be entitled to come back and ask for any further rate increases during the test period, nor should NTPC be entitled to collect any shortfall from the 2014/2015 and 2015/2016 years in future rates [YK/HR Argument, P13, Para 51 – P14, Para 52]

In its Reply submission, NTPC states it would appear that YK/HR is effectively requesting that the Board fetter its own discretion to carry out its statutory mandate in the future with respect to years that are presently not test-years. NTPC states, Sections 49 through 51 of *the Act* outline the powers and obligations of the Board, including the requirement to fix just and reasonable rates to be charged by NTPC with reference to the “fiscal year of the public utility in which a proceeding is initiated for fixing rates.” Although NTPC does not at this time anticipate requiring further rate adjustments for the years 2014/15 and/or 2015/16, a Board direction to this effect would fetter its discretion and prevent the Board from fulfilling its statutory duties outlined in *the Act* in the event NTPC was to bring a new GRA before it. [NTPC Reply, P15, L3-11]

Board Findings:

The Board approves in principle a phasing in of rate increases over a period of 4 years from 2012/13 to 2015/16, in view of the significant increases in Test Year revenue requirements over existing rates and in view of the arrangements made by NTPC for funding by the GNWT, in order to smooth out rate impacts to customers during the rates phase in period.

The Board notes NTPC's proposal that a lower Board-approved 2012/13 revenue requirement would simply reduce the amount of the GNWT financial support for 2012/13. The Board notes NTPC's confirmation that the GNWT maximum contributions to fund the shortfall amounts would be \$13.63 million in 2012/13, \$11.484 million in 2013/14 and \$4.892 million in 2014/15, as set out in TGC.NTPC-9. [T331, L12-22]

Given that the maximum contributions from the GNWT for 2012/13 and 2013/14 have been negotiated, the Board directs that the GNWT contributions for 2012/13

and 2013/14 be recognized in the determination of rates for those years in NTPC's Compliance Filing Application.

With respect to the rates phase in for the 2014/15 and 2015/16 years, the Board notes NTPC's statement that the shortfall in 2014/15 at \$5.102 million exceeds the available funding from the GNWT in the amount of \$4.892 million for that year and, that upon final approval of the 2013/14 revenue requirement, if the shortfall still exists, the Corporation will consider alternative approaches for addressing the shortfall and setting of final rates. [Ex 13] NTPC is directed to address the 2014/15 phase in rate increase after giving effect to the Board's determinations in this Decision, at the time of the Compliance Filing.

The Board considers the establishment of phased in rates for 2015/16 requires an approved cost of service study by rate zone to ensure rates for each zone reflect the corresponding Zone based allocated costs. The Board will deal with this matter in Section 11.2.

The Board agrees with NTPC's view that acceptance of YK/HR's recommendation that rates for the 2014/15 and 2015/16 years be considered final, would fetter the Board's discretion to establish just and reasonable rates for those years. Accordingly, the Board rejects YK/HR's recommendation that the rates for all years during the phase in period be established on a final basis.

With respect to the transitioning of the community of Norman Wells into the Thermal Zone, the Board, in the interest of rate stability, considers it appropriate to phase in rate increases for Norman Wells with annual increases of 7%, as may be required and, applicable to energy rates, until Norman Wells rates are fully transitioned to reflect the corresponding rates as the rest of the rates within the Thermal Zone. In order to achieve this, Norman Wells base rates should be

adjusted to equal the corresponding Thermal Zone base rates. The 7% increase per year for Norman Wells should be given effect to by way of a credit rider applicable only to Norman Wells customers. The annual shortfall in revenue due to the Norman Wells credit rider will be collected by NTPC from the Thermal Zone in its entirety, including Norman Wells, by application of a recovery rider to all of the Thermal Zone base rates. The Board directs NTPC to propose rates and riders for Norman Wells and the Thermal Zone in accordance with this finding in its Compliance Filing Application.

11.2 Cost Allocations by Rate Zone

NTPC states, in 2012/13 and 2013/14, customers as a whole are not fully covering NTPC's Revenue Requirement, and no zone is paying outside of the routinely recognized zone of reasonableness of 95%-105% for at least the next 3 years. In Tables 4.4 and 4.5 of the Application, NTPC indicates it is targeting revenue to cost ratios of 104.1% for the Hydro areas, which includes both the Snare and the Taltson Zone, and 96.7% for the Thermal Zone in 2015/16, which is the last year of the rate transition period.

In BR.NTPC-22, the Corporation provided a calculation of the revenue requirements by rate zone for 2011/12 and 2012/13. The allocated costs by rate zone are as follows:

Proportion of Costs by Rate Zone				
Zone	2012/13		2013/14	
	\$000	%	\$000	%
Hydro	35584	34.7%	37754	35.1%
Taltson	9973	9.7%	10714	10.0%
Thermal	56949	55.6%	59076	54.9%
Total	102506	100.0%	107544	100.0%

YK/HR raised issues respecting NTPC's proposed allocation of common costs by rate zone. Specifically, YK/HR submitted capital additions such as Line Tools, Hot Sticks, Truck equipment, and major tool purchases, Type 6 work as well as certain vehicle and machinery purchases are budgeted at corporate; yet the actual costs are eventually recorded in the communities that are served.

For example, with respect to Type 6 work, the majority of the work is in the thermal communities. However, using the last three years, which appears to be representative of the current spending patterns, YK/HR submits 93% of the Non recoverable Type 6 work, is attributable to thermal communities. With respect to vehicles and machinery purchases, YK/HR submits the cost of a pole trailer and off-road track digger included in vehicle and machinery purchases (estimated by YK/HR at \$350,000 to \$400,000) are designated for Inuvik; however these items are included under corporate. [YK/HR Argument, P6, Para 20-21]

YK/HR submitted, based on this sampling of costs that are misallocated, that it is concerned that the forecast methodology does not accurately reflect the tracking of actual results. For future rate applications, YK/HR recommends that the Board direct NTPC to implement a forecasting methodology that more accurately reflects how actual expenditures are recorded. This would include demonstration that the costs are allocated to the correct zone. [YK/HR Argument, P6, Para 22]

In its Reply submission, NTPC agreed in principle with YK/HR's submission and indicated it has endeavoured to provide proper allocations to zones where the costs can be so categorized during GRA preparation. However, NTPC submits this is not always possible given the dynamic nature of a capital plan, and the tendency of certain "blanket" budgets to be Corporate-wide prior to the actual money being spent. [NTPC Reply, P15, L28-31]

NTPC further noted that past spending does not adequately predict which zones the future additions will occur in. This can be seen in undertaking which provides Actual Non-Recoverable Type 6 Work by Zone for actual years 2007/08 to 2010/11. On a per zone basis, the majority of actual costs do incur in the Thermal Zone, but in any given year (such as 2007/08 where the majority of costs were in the Snare Zone) it is hard to predict where costs will be incurred.

NTPC submits in the instance where a forecast cost within one of these cost groupings can be allocated on a community or zone basis, such as the case with the Off-Road Track Digger to be purchased for Inuvik, there could be a step in the forecast process that first directly assigns known costs that would otherwise be allocated to head office. [NTPC Reply, P16, L12-21]

In its Reply submission TGC submitted the evidence supports including the costs of D Group - Vehicle and Machinery Purchases as Corporate or Head Office. While YK/HR may suggest there is precision as to location of the pole trailer and the off-road, tracked digger, the evidence at the hearing clearly suggests NTPC cannot be "precise about where it's going to be spent", [TGC Reply, P10, Para 29]

Board Findings:

NTPC was directed in Decision 16-2010, Directive 14, to target 100% revenue to cost ratios for each zone and for each rate class within each zone unless there is some other restriction or over-riding rate design principle that would compel moving away from 100%. The Board recognizes this cannot be achieved at the zone level during the rates phase in period from 2012/13 to 2014/15. However, the Board notes NTPC is targeting to achieve certain revenue to cost ratio targets within the revenue to cost tolerance range of 95% to 105%, by 2015/16.

The Board notes the information provided by NTPC on the target revenue to cost ratios for the hydro areas combines both the Taltson Zone and the Snare Zone. On the other hand, Directive 14 from Decision 16-2010 required the target revenue to cost ratio of 100% to be applied to each of the rate zones. This means Snare and Taltson Zones are to be considered separately. Further, consistent with Directive 14, the Board considers NTPC should target a 100% revenue to cost ratio for each of the rate zones subject to other rate design criteria by 2015/16 when the rates phase in would be completed.

In order to continue the rate phase in by rate zone, the Board considers it necessary for NTPC to conduct a fully allocated zone-based cost of service study and design the phase in rate changes for 2015/16 having regard to this study. Accordingly, NTPC is directed to file a zone-based, fully allocated cost of service study based on the 2013/14 approved revenue requirement together with proposed rates targeting 100% revenue to cost ratios by rate zone in 2015/16, subject to other rate design criteria. The Board will refer to this as the 2015/16 Phase 2 Application. This Phase 2 Application is to be filed by September 30, 2014 which would allow at least 6 months processing time prior to the commencement of the 2015/16 fiscal year.

The Board notes NTPC's cost allocation study by rate zone provided in BR.NTPC-22. For the purposes of the 2012/13 and 2013/14 Test Years, NTPC is directed to file, at the time of the Compliance Filing Application, an update to the cost allocations shown in BR.NTPC-22 for 2012/13 and 2013/14, in Excel format, reflecting the Board's determinations in this Decision and showing:

- How rate base, return, amortization expense and other components of revenue requirement were assigned or allocated by rate zone;

- The proposed allocation of revenues from GNWT support by rate zone;
- The proposed revenues to be recovered through customer rates, by rate zone;
- How the proposed revenues by rate class would dovetail into the 2014/15 and 2015/16 rates phase in increases, by rate zone.

For the purposes of this update to BR.NTPC-22, the Taltson Zone should be considered separate from the Snare Zone.

NTPC is also directed to file proposed rates designed to recover the proposed 2012/13 and 2013/14 revenues from customer rates reflecting the update to BR.NTPC-22 referred to above.

The Board notes YK/HR concern that capital additions such as Line Tools, Hot Sticks, Truck equipment, and major tool purchases, Type 6 work as well as certain vehicle and machinery purchases are budgeted at corporate; yet the actual costs are eventually recorded in the communities that are served. The Board agrees the type of costs referred to by YK/HR are not common costs but rather, zone specific costs and should be assigned to each zone on a forecast basis using reasonable assumptions. NTPC is directed to reflect this direction in future GRA filings.

The Board also notes NTPC's acknowledgement that an Off-Road Track Digger is assignable to Inuvik. Accordingly, NTPC is directed to assign the cost of the off-Road digger to the Thermal Zone in the update to the cost allocations as set out in BR.NTPC-22, to be filed as part of the Compliance Filing Application.

11.3 Requirement for Phase 2

NTPC indicates the GRA filing achieves the objectives targeted in this GRA in a single package, with no need for a segregated "Phase 1" and "Phase 2" process. Specifically, NTPC submits the GRA achieves the following outcomes without a separate Phase 2 filing:

- *Adopts a simplified rate design that shares cost increases across-the-board: This approach is consistent with the principles of the GNWT funding and is consistent with recent practice in many Canadian jurisdictions. This approach also does not get distracted with excessive analysis on specific components of the rates (such as tweaking demand charges) but focuses on the energy component, which is the component best understood by customers and provides the best signals for conservation.*
- *This GRA focuses mainly on rate transition and a simplified rate design to the benefit of customers. No customer class or zone is paying their full cost of service, which would otherwise justify a Phase II study, during the transition years through to 2015/16 fiscal year. Further, it is important to note that customers also benefit from the avoidance of the costs associated with a Phase 2 process.*
- *Rates proposed are well below costs in the Test Years: Due to the magnitude of the GNWT funding available, all zones will be paying well below the pure costs to serve them in the Test Years 2012/13 and 2013/14.*
- *Rates proposed are at or below costs over the full 4 years of transition: Over the full 4 year transition, even with the proposed sequential rate increases each year, each zone will be at or below the costs to serve them.*
- *No need for second hearing to complete GRA: The rate proposals contained in the GRA, along with detailed zonal cost allocation, provide all necessary information for the Board to conclude that the rate proposals meet the requirements of the Act (i.e., that rates are just and reasonable). [NTPC Argument, P8, L24 - P9, L7]*

During hearing examination, NTPC was asked to comment on its intent in relation to doing a Phase 2 where it may look at the rate components in relation to the cost. In response NTPC indicated since there are number of rate transition issues being dealt with in these proceedings and no community or rate class is paying its full cost at the moment, a full Phase 2 is not being contemplated until 2015/16 or beyond that date:

"What's been included in the responses in this filing is that there are a lot of issues to deal with today and a lot of transitions that need to occur. And no class, no community is paying their full cost at the moment. It's the government funding that's making up the

difference. So it's at least a number of years down the road before one would get to the point of needing to look at how precise we need to get, how close we're getting to the end goal. Probably 15/16 or beyond." [T342, L13-22]

NTPC also noted it has yet to address the question whether there should be separate rate classes for Government and Non-Government customers when a cost of service study is performed:

"I'm also not sure when we eventually get to the point, which in the Corporation's proposal is a number of years down the road -- that we run a next detailed Cost of Service study, whether we would actually run separate classes -- for example, general service government versus general service non-government, or whether it would just be run as a general service class, but then the rates would be different between government and non-government. It's just not a question we wrestled with." [T340, L21 – T341, L5]

Board Findings:

In Decision 16-2010, Directive 14, NTPC was directed to target 100% revenue to cost ratios for each zone and for each rate class within each zone unless there is some other restriction or over-riding rate design principle that would compel moving away from 100%.

In the preceding Section, the Board directed NTPC to file a 2015/16 Phase 2 Application in order to establish appropriate revenue to cost ratios by rate Zone. Consistent with Directive 14, the Board considers it appropriate to also target revenue to cost ratios of 100% by rate class, subject to other rate design criteria. Accordingly, NTPC is directed to file a cost of service study based on the 2013/14 approved revenue requirement, showing the allocation of costs by rate class and the design of proposed rates by rate class, for 2015/16, by September 30, 2014.

11.4 Government Customer Class

The GNWT's revised electricity policy guidelines dated February 11, 2011 require the Government rates move towards flat rates across each of the electricity rate zones, at the time of the next GRA. Pursuant to this requirement, NTPC was questioned as to when NTPC is targeting for Government rates to reflect the same rates by rate zone. [BR.NTPC-22h]

NTPC indicates it has not developed any specific transition plan within this Application for government rates to be moved to a levelized structure, given that the customers within this class almost entirely represent either direct or indirect purchases by the GNWT. Instead, the Corporation focused on dealing with other material rate pressures that required GNWT involvement, notably the transition funding committed by the GNWT. NTPC also notes that the GNWT, as the customer for these Government rate classes, has not indicated a desire for rate restructuring at this time. [NTPC Argument, P31, L2-8]

Board Findings:

The Board is not persuaded by NTPC's reasons for delaying the implementation of flat rates by zone for Government rate customer classes. The Board considers implementation of the revised electricity policy guidelines respecting flat rates, by zone, for Government customers, is not likely to impact NTPC's overall rate proposals or the rates for non-Government customers. Accordingly, NTPC is directed to propose, in the Compliance Filing Application, a flat Government rate by rate class and by zone that recovers the same revenue for the Government class as the proposed community based Government rates, for each zone. The Board considers this will accomplish the goal of simplified rates and a flat Government rate by class in each zone.

12. TERMS AND CONDITIONS OF SERVICE

NTPC's Application requested a number of revisions to the Corporation's Terms and Conditions of Service ("**T&Cs**"). NTPC indicated in its Application that the revisions were intended to provide greater clarity and consistency as well as make the document easier to understand for customers, as well as NTPC personnel.

The Board notes that the majority of the revisions are of the 'housekeeping' nature and do not fundamentally alter the nature or scope of the section. These changes are approved. The Board's conclusion on the substantive amendment pertaining to the treatment of unclaimed security deposits is considered below.

Unclaimed Security Deposits

NTPC's proposed section 5.11 provides that in those cases where the Corporation is unable to locate a former customer to whom a security deposit is payable; and the deposit remains unclaimed for six years from the date the customer was disconnected, the deposit becomes the property of the Corporation immediately after the six year period has expired.

Board Findings:

NTPC clarified that clause 5.11 would only apply to customers who no longer have an active account with the Corporation, who no longer owe money to the Corporation and are entitled to the return of a security deposit but cannot be located for any number of reasons. Under cross examination, NTPC confirmed that the situation it seeks to remedy through clause 5.11 is infrequent and has only occurred in 26 instances (T368, L18-25).

The Board accepts the proposed revision on the basis of NTPC's explanation that any such funds would in essence act as an offset against otherwise delinquent accounts. The Board expects that NTPC will continue to make every reasonable effort to locate former customers who are owed security deposits and directs NTPC to publish a notice in a newspaper with circulation in the NWT one month prior to the six year anniversary date prior to the unclaimed deposit becoming the property of the Corporation.

13. OTHER MATTERS

13.1 2012 Actual Results

TGC submitted not having reliable actual data for the most recently completed year casts a shadow of a doubt as to the reasonableness of the 2012-2014 Test Year Revenue Requirements. This is not to suggest that 2012 actual results should simply replace 2012 forecasts. Rather, the use of 2012 results of operations is to assess the nature and extent of changes, if any, which may be required to the costs and revenues included in the Test Year 2013-2014 Revenue Requirements. [TGC Argument, P8, Para 24]

The TGC submits, by not providing the March 31, 2012 actual balance sheet data, the forecast year-end balances of Property, Plant and Equipment accounts, Accumulated Amortization as well as Deferral accounts will be different than the actual values, and hence, the amount of return and depreciation for the Test Years will be either over or under-stated. Neither the Corporation, nor customers, should benefit from the use of erroneous opening continuity balances. [TGC Argument, P8, Para 25]

Accordingly, TGC recommended that the Board direct NTPC to reflect the following actual Opening balances as at April 1, 2012 in its 2012-2014 Compliance Filing:

- *Rate base data – including Property Plant and Equipment, Accumulated/Depreciation, Contributions in Aid of Construction;*
- *2012 actual debt and interest rates;*
- *2012 actual opening balances of all deferral accounts; and the impact of all load forecast and revenue and expense accounts which vary from the 2012 filed-forecasts by more*

than 10% and which would have a bearing on the filed-for forecasts for the Test Years.
[TGC Argument, P 10-11, Para 28]

In its Reply submission, the TGC stated that when a hearing occurs well into a Test Year, the forecast nature of the regulatory model is distorted. In effect, the utility has the benefit of actual data and the regulator does not. It serves the interests of the regulatory model that the utility provide this actual information when available and that it update forecast balances in the GRA and compliance filing. This practice is commonly accepted in other jurisdictions, including Alberta.
[TGC Reply, P6, Para 16]

In its Reply submission, NTPC submitted it does not support the TGC's request to update opening balances. NTPC states the premise of a GRA based on a future forward test year, particularly in light of the Board's direction that GRA's be filed as far as possible in advance of the actual test year starting, is inconsistent with incorporating actual data for the opening balances. Further, NTPC states, it has not completed this work to date; so, there is a time and cost implication for requiring these updates to be completed.

NTPC submitted that the actual opening balances are not expected to be materially different from the forecast test year opening balances used in the GRA. On the one item where a notable difference was expected, the long-term debt interest rate, NTPC states, it has already incorporated this update into the revised GRA numbers and requested approvals in Exhibit 13. [NTPC Reply, P31, L13-22]

Board Findings:

The Board notes NTPC's statement that incorporating actual data for the opening balances is not consistent with the premise of a GRA based on a future forward test year, particularly in light of the Board's direction that GRA's be filed as far as

possible in advance of the actual test year starting. The Board also notes TGC's view that as the proceedings progress, the utility has the benefit of actual data whereas the regulator does not, and it serves the interests of the regulatory model for the utility to provide actual opening balances, a practice that is commonly accepted in other jurisdictions, including Alberta.

In the Board's view the updating of actual information for opening balances should be assessed on a case by case basis. In this instance, the Board notes the opening balance for plant in service as reflected in note 7 of the 2011/12 financial statements is \$388.272 million. [Ex 22, Note 7] On the other hand, the opening balance for gross plant in Schedule 5.1 amounts to \$395.313 million. The difference of about \$7.0 million does not appear to bear out NTPC's submission that actual opening balances are not expected to be materially different from the forecast Test Year opening balances used in the GRA.

Given the foregoing difference in opening gross plant balance, the Board considers it appropriate, in this instance, to reflect the most current information in relation to actual balances for the period preceding the test period, in the Test Year forecasts in order to ensure the Test Year forecasts are not unduly misstated as a result of building upon incorrect balances.

The Board therefore, directs NTPC, at the time of the Compliance Filing Application, to update the opening balances for plant in service and accumulated amortization as well as the opening balances for deferral accounts and deferred cost balances, to reflect the recorded balances. If the updating of these balances results in the need to update any other related items, such as contributions or amortization expense, based on materiality considerations, NTPC should reflect such changes as well in the Compliance Filing Application. NTPC is directed, as part of its Compliance Filing Application, to provide reconciliations between the

regulatory schedules and the 2011/12 financial statements with respect to any updated opening balances.

13.2 Minimum Filing Requirements

YK/HR submitted, NTPC has continued its practise of providing schedules and tables in PDF format only. In order to improve regulatory efficiency, and avoid future processes to secure analysis in Excel format, NTPC should be directed to provide, in future proceedings, all tables and schedules included in filings with the Board, in Excel format with formulae and links intact, in addition to the PDF schedules and tables already provided. YK/HR recommended that this be identified as a minimum filing requirement. [YK/HR Argument, P4-5, Para 16]

With respect to determination of minimum filing requirements, NTPC stated it is attentive to the Board letter dated June 20, 2012, informing of the Board's intention to commence the GRA Filing Manual process upon the conclusion of the current NTPC GRA. This process is intended to help develop specific Minimum Filing Requirements for future GRAs. NTPC submitted that YK/HR recommendations in regards to future filing requirements are premature and should instead be addressed as part of the future process envisioned by the Board.

Board Findings:

The Board considers it more efficient to deal with the minimum filing requirements as part of the GRA filing Manual process. Accordingly, the Board will defer any consideration of minimum filing requirements to that proceeding.

14. SUMMARY OF BOARD DIRECTIONS

Compliance Filing Application

1. NTPC is directed to remove the cost of the transmission line development study from each Test Year rate base, in its Compliance Filing Application.
2. The Board directs NTPC to provide as part of the Compliance Filing Application; details of all studies included under the category of feasibility studies and provide justification for why any additions to the feasibility studies account in the 2007/08 to 2010/11 period should be capitalized based on the guidance provided in Directive 18 from Decision 17-2009. At the same time, NTPC should also provide support showing how the amortization amounts in each Test Year were arrived at having regard to each study.
3. The Board considers disallowed assets should not be included in gross plant in service and in rate base. Accordingly, NTPC is directed to remove the net book value of disallowed assets from Test Year rate base in its Compliance Filing Application.
4. The Board considers that NTPC has not provided any analysis that would weigh and evaluate the qualitative and quantitative benefits of holding the proposed level of inventory in relation to the carrying costs. In the absence of such evidence, the Board will approve the inclusion of 50% of the proposed inventory in rate base in 2012/13 and 2013/14. Therefore, NTPC is directed to remove 50% of the cost of major spares and capital inventory from Test Year rate base in its Compliance Filing Application.

5. The Board directs NTPC to address the appropriate treatment and adjustments for any expenditures for components included in the Engine Overhaul Deferral Account, that are considered retirement units for amortization purposes, in its Compliance Filing Application.
6. The Board directs NTPC to include, in its Compliance Filing Application, annual brushing costs for each zone calculated based on the 5 actual year average brushing costs with due adjustment for inflation and any forecast scope changes.
7. BR.NTPC-7b) provided a detailed cost of debt calculation. NTPC is directed to file the calculation of the updated cost of debt (as updated in Exhibit 13) in the same format as in the BR.NTPC-7b) attachments, in Excel format, in support of its Compliance Filing Application.
8. The Board directs NTPC to provide, at the time of the Compliance Filing Application, evidence to support NTPC's view that the same rules apply to the lease as for NTPC's long-term debt and to provide evidentiary support for the view that DPC's cost of financing over the 65 year lease term should remain unchanged, notwithstanding the cost based nature of the lease.
9. NTPC is directed to address, at the time of the Compliance Filing Application, a method of recognizing the improvement in fuel efficiencies at Inuvik, in the rates for years commencing after the 2013/14 Test Year.
10. The Board directs NTPC that in its Compliance Filing Application, the ratio of fringe benefits for distribution and transmission is to be set at 37.06% for Test Years 2012/13 and 2013/14.

11. NTPC is directed to address how its practices regarding treatment of insurance proceeds and retirement of assets that are no longer in service, from gross plant in service, results in the correct amortization expense and amortization of reserve differences for the Test Years. If the Board's comments give rise to any corrections to the gross plant used for calculation of amortization expense, NTPC is directed to provide the corrected amortization expense at the time of the Compliance Filing Application.
12. The Board considers a move that is about 50% of the way towards the ASLs proposed by NTPC would provide an appropriate balance for the purposes of these proceedings. Accordingly, the Board directs NTPC to make a directional move in the Average Service Life parameter for the above noted accounts by reflecting ASLs of 35 years for account 341, 23 years for account 343 and 25 years for account 345, in its Compliance Filing Application.
13. The Board directs NTPC to provide, at the time of the Compliance Filing Application, details explaining the accounting entries involved in recording each of the affiliate costs/revenues (other than dividends), for GRA forecast purposes and for recording actual results for financial statement purposes.
14. NTPC is directed to identify the transfer pricing policy and how it was used for pricing shared services including overheads and, interest expense/recoveries, at the time of the Compliance Filing Application.
15. The Board directs that the GNWT contributions for 2012/13 and 2013/14 be recognized in the determination of rates for those years in NTPC's Compliance Filing Application.

16. NTPC is directed to address the 2014/15 phase in rate increase after giving effect to the Board's determinations in this Decision, at the time of the Compliance Filing.

17. With respect to the transitioning of the community of Norman Wells into the Thermal Zone, the Board, in the interest of rate stability, considers it appropriate to phase in rate increases for Norman Wells with annual increases of 7%, as may be required and, applicable to energy rates, until Norman Wells rates are fully transitioned to reflect the corresponding rates as the rest of the rates within the Thermal Zone. In order to achieve this, Norman Wells base rates should be adjusted to equal the corresponding Thermal Zone base rates. The 7% increase per year for Norman Wells should be given effect to by way of a credit rider applicable only to Norman Wells customers. The annual shortfall in revenue due to the Norman Wells credit rider will be collected by NTPC from the Thermal Zone in its entirety, including Norman Wells, by application of a recovery rider to all of the Thermal Zone base rates. The Board directs NTPC to propose rates and riders for Norman Wells and the Thermal Zone in accordance with this finding in its Compliance Filing Application.

18. The Board notes NTPC's cost allocation study by rate zone provided in BR.NTPC-22. For the purposes of the 2012/13 and 2013/14 Test Years, NTPC is directed to file, at the time of the Compliance Filing Application, an update to the cost allocations shown in BR.NTPC-22 for 2012/13 and 2013/14, in Excel format, reflecting the Board's determinations in this Decisions and showing:

- How rate base, return, amortization expense and other components of revenue requirement were assigned or allocated by rate zone;
- The proposed allocation of revenues from GNWT support by rate zone;

- The proposed revenues to be recovered through customer rates, by rate zone;
- How the proposed revenues by rate class would dovetail into the 2014/15 and 2015/16 rates phase in increases, by rate zone.

For the purposes of this update to BR.NTPC-22, the Taltson Zone should be considered separate from the Snare Zone.

19.NTPC is directed to file proposed rates designed to recover the proposed 2012/13 and 2013/14 revenues from customer rates reflecting the update to BR.NTPC-22 referred to above.

20.The Board also notes NTPC's acknowledgement that an Off-Road Track Digger is assignable to Inuvik. Accordingly, NTPC is directed to assign the cost of the off-Road digger to the Thermal Zone in the update to the cost allocations as set out in BR.NTPC-22, to be filed as part of the Compliance Filing Application.

21.The Board is not persuaded by NTPC's reasons for delaying the implementation of flat rates by zone for Government rate customer classes. The Board considers implementation of the revised electricity policy guidelines is not likely to impact NTPC's overall rate proposals or the rates for non-Government customers. Accordingly, NTPC is directed to propose, in the Compliance Filing Application, a flat Government rate by rate class and by zone that recovers the same revenue for the Government class as the proposed community based Government rates, for each zone. The Board considers this will accomplish the goal of simplified rates and a flat Government rate by class in each zone.

22. The Board therefore directs NTPC, at the time of the Compliance Filing Application, to update the opening balances for plant in service and accumulated amortization as well as the opening balances for deferral accounts and deferred cost balances, to reflect the recorded balances. If the updating of these balances results in the need to update any other related items, such as contributions or amortization expense, based on materiality considerations, NTPC should reflect such changes as well in the Compliance Filing Application.

23. NTPC is directed, as part of its Compliance Filing Application, to provide reconciliations between the regulatory schedules and the 2011/12 financial statements with respect to any updated opening balances.

Next GRA

24. The Board directs NTPC to provide business cases in support of major capital projects forecast to be added to rate base, at the time of the next GRA. The Board finds the list of items to be addressed in business cases as set out by YK/HR provides a reasonable template for structuring business cases. For the purpose of preparing business cases, the Board accepts YK/HR recommendation that the project cost threshold for business cases be set at \$400,000.

25. NTPC is directed to prepare business cases for capital projects meeting the above threshold and are to commence after March 31, 2013 and, be prepared to provide detailed explanations for variances between budget and actual costs based on post completion reports.

26. The Board directs NTPC to provide a post completion report with respect to the Inuvik Diesel Conversion Project, at the time of the next GRA, including a narrative report evaluating the strengths and weaknesses observed in the planning, budgeting and execution of the project and, providing detailed explanations for variances between budget and actual costs as well as variances related to project scheduling and achievement of expected standards of quality and performance in the final delivered plant.
27. The Board directs NTPC to provide a post completion report with respect to the Bluefish Dam replacement project at the time of the next GRA, including a narrative report evaluating the strengths and weaknesses observed in the planning, budgeting and execution of the project and, providing detailed explanations for variances between budget and actual costs as well as variances related to project scheduling and achievement of expected standards of quality and performance in the final delivered plant.
28. The Board is concerned that inclusion of deferred costs under the category of deferral accounts and under the category of plant in service can result in confusion and errors in the testing and evaluation of such costs. Accordingly, NTPC is directed to include deferred costs under an appropriate FERC account at the time of the next GRA.
29. The Board directs NTPC to provide a cash working capital calculation based on a sampling of leads and lags at the time of the next GRA. This means any revenues related to late payment charges should also be included in other revenues.
30. Noting the uncertainties over the split in the accumulated amortization balance discussed above, the Board directs NTPC to provide evidence to support the split between accumulated amortization applicable to original cost

of assets and accumulated amortization applicable to net salvage at the time of the next GRA.

31. The Board continues to be concerned by an RSF mechanism which allows pass through of all diesel costs as this may not provide the appropriate incentive for NTPC to maximize use of the hydro resource. The Board directs NTPC to address the feasibility of NTPC assuming forecast risk on diesel volume variances for the Snare Zone at the time of the next GRA.

32. The Board directs NTPC to examine the following refinements with respect to its UPC forecast methodology for the purposes of the next GRA:

- For those communities where temperature normalization data is available, NTPC is to carry out regression analyses for all temperature sensitive sales, using degree days, trend variable(s) and any other relevant variables to develop a reasonable estimate of forecast UPC.
- For those communities where temperature normalization data is not available, NTPC is to use a straight 5 year average UPC over the most recent recorded (actual) years and use the actual growth rate over the same recorded years to project growth for the forecast years.

33. The Board notes YK/HR concern that capital additions such as Line Tools, Hot Sticks, Truck equipment, and major tool purchases, Type 6 work as well as certain vehicle and machinery purchases are budgeted at corporate; yet the actual costs are eventually recorded in the communities that are served. The Board agrees the type of costs referred to by YK/HR are not common costs but rather, zone specific costs and should be assigned to each zone on a forecast basis using reasonable assumptions. NTPC is directed to reflect this direction in future GRA filings.

September 30, 2014 Phase 2 GRA Filing

34. In order to continue the rate phase in by rate zone, the Board considers it necessary for NTPC to conduct a fully allocated zone based cost of service study and structure the increases in 2015/16 having regard to this study. Accordingly, NTPC is directed to file a zone-based, fully allocated cost of service study based on the 2013/14 approved revenue requirement together with proposed rates targeting 100% revenue to cost ratios by rate zone in 2015/16, subject to other rate design criteria. The Board will refer to this as the 2015/16 Phase 2 Application. This Phase 2 Application is to be filed by September 30, 2014 which would allow at least 6 months processing time prior to the commencement of the 2015/16 fiscal year.

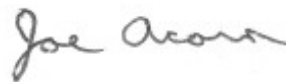
35. The Board directed NTPC to file a 2015/16 Phase 2 Application in order to establish appropriate revenue to cost ratios by rate zone. Consistent with Directive 14, the Board considers it appropriate to also target revenue to cost ratios of 100% by rate class, subject to other rate design criteria. Accordingly, NTPC is directed to file a cost of service study based on the 2013/14 approved revenue requirement, showing the allocation of costs by rate class and the design of proposed rates by rate class, for 2015/16, by September 30, 2014.

15. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. The Board directs NTPC to provide to the Board and interested parties a Compliance Filing Application reflecting the findings and directions in this Decision, including proposed revenue requirements for the 2012/13 and 2013/14 Test Years, rates designed to recover the customer portion of revenues for 2012/13, 2013/14 and 2014/15 and a rate rider to recover any shortfall arising from late implementation of interim rates in 2012/13, within 45 days of this Decision.
2. The Board directs NTPC to provide as part of the Compliance Filing Application a working model, in Excel format, of all GRA schedules relating to the establishment of rate base, return, revenue requirement, revenues and revenue deficiencies and all relevant supporting schedules.
3. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

**ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES**



**Joe Acorn
Chairman**

Dated January 21, 2013

TAB 6

MANITOBA
THE PUBLIC UTILITIES BOARD ACT
THE MANITOBA HYDRO ACT
THE CROWN CORPORATIONS PUBLIC
REVIEW AND ACCOUNTABILITY ACT

Edited for format and typographical errors only
August 25, 2008
Further amended September 4, 2008

Board Order 116/08

July 29, 2008

Before: Graham Lane CA, Chair
 Robert Mayer Q.C., Vice-Chair
 Susan Proven, P.H.Ec., Member

**AN ORDER SETTING OUT FURTHER DIRECTIONS, RATIONALE AND
BACKGROUND FOR OR RELATED TO THE DECISIONS IN BOARD
ORDER 90/08 WITH RESPECT TO AN APPLICATION BY MANITOBA
HYDRO FOR INCREASED RATES AND FOR RELATED MATTERS**

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Executive Summary

Executive Summary

Manitoba Hydro's (MH, the Corporation or the Utility) 2008/09 General Rate Application (GRA) was heard by the Public Utilities Board (Board) in the spring of 2008, with Board Order 90/08 released on June 30, 2008 to take effect July 1.

The Board further advised that Order 90/08 would be followed by another Order, one that would provide further direction on a number of other significant matters, and, as well, provide necessary background information and detailed rationale for the rate changes provided by Order 90/08.

Order 90/08 provided certain rate and other directions to the Corporation, as indicated elsewhere in this Order. Order 90/08 is available through the Board's office or by viewing its website, www.pub.gov.mb.ca.

With respect to "further direction", this Order contains various directives to provide new and revised information to the Board in respect of MH's:

- Integrated Financial Forecasts;
- Capital Expenditure Forecasts;
- Load Forecast and Power Resource Plan;
- Export Program;
- International Financial Reporting Standards Implementation;
- Benchmarking Study of Key Performance Metrics;
- Asset Condition Assessment Study;
- Terms of Reference for a Review of MH's Capital Program;
- Quantified Risk Analysis;
- Demand Side Management ("Power Smart" program enhancements);
- Green House Gas Reduction Strategy;
- Low-Income Programs, including a Bill Assistance Program;
- Cost of Service Study (COSS) Revisions;
- Rate Design Revisions;
- MH Diesel Rate Zone; and
- Energy Intensive Industry Rate Proposal.

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Detailed directives and recommendations are found in the last sections of this Order.

For all the reasons referred to in this Order and Order 90/08, the Board approved a 5% across-the-board rate increase as of July 1, 2008 that was larger than the Corporation sought, and, as well, indicated that a further 4% increase may be granted as of April 1, 2009 following the Board's review of additional information requested in this Order. As well, the Board accepted MH's forecast that its net income for the fiscal year 2007/08 will exceed \$300 million, and that water conditions into fiscal 2008/09 were excellent, suggesting that another reasonably good net income result may be expected for fiscal 2008/09.

Order 90/08 also advised of the Board's concern with the scale of capital expenditures and new debt now planned over the next 15 years. There is a risk that the Corporation may not be able to meet domestic and export requirements and commitments without having to resort to high-priced imported power or other higher-cost generation in years of lower than median water conditions. The risk of lower than median water conditions, (including a drought), creates a financial risk. The other financial risks include the potential for future interest rate increases, currency fluctuations, capital cost escalations, new accounting standards (IFRS) and other operational factors, some or all of which may well challenge the Corporation's future financial strength.

The Board will direct MH to propose to the Board by January 15, 2009 terms of reference for a regulatory review of the impact that MH's planned Capital program may have on consumer rates. The Board will also direct MH to quantify its risks in an effort to determine the appropriateness of the current financial stability targets.

Executive Summary

The Board also expresses concern with the Corporation's withholding of information related to its export transactions and projections, for stated confidentiality reasons, as that withholding made it difficult if not impossible for the Board to arrive at findings with respect to such matters as to what constitutes the Corporation's marginal cost rate, a final determination of the rules to govern the allocation of costs and revenues to customer classes, the weight to be given to marginal and environmental factors in future differentiation of customer class rates, and, perhaps most importantly, the likelihood of profitability with respect to its export commitments and the risk that these commitments will lead to years of either additional imports of power or thermal generation to avoid supply shortfalls. Accordingly, the Board has requested additional information related to MH's export forecasts.

In this Order, the Board notes that there are approximately 100,000 low-income households that are customers of MH (many, also being customers of Centra Gas), and the particular affordability pressures on these households arising from energy price increases (gasoline, diesel, natural gas and, though much more modest, electricity).

The Board has recently approved issuance of a single bill for consumers of electricity and natural gas and provided MH an ability to maintain natural gas and electricity services, when financial delinquency conditions exist. These efforts avoid disconnections through the availability of an electricity load-limiter and will assist with the health and safety of consumers through the coming winter. However, the Board seeks further actions by the Corporation to address the varied problems of low-income households, problems exacerbated by rising energy costs.

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Accordingly, by this Order the Board directs MH to increase its efforts to conserve domestic energy through far more aggressive DSM measures, including those particularly targeted at low-income households lacking the means to invest in energy efficiency measures without assistance from the Corporation.

The reduced consumption benefits expected to arise out of more successful DSM programs will assist low-income households in meeting their utility bills. It will also provide the Corporation with a higher level of supply security to meet future demand requirements.

There is a risk that if natural gas customers move in any significant way to electricity as the sole or supplementary space-heating source for their residences, (a growing risk given recent natural gas commodity price increases and volatility), MH will have less energy to export and may have to import power in some years to meet its commitments. MH's low rates for all of its customers, excluding "government accounts" in the diesel zone, are maintainable in part due to export profits.

Finally, herein, the Board suggests to government that it consider establishing a separate entity to manage the Corporation's DSM and low-income initiatives. The Board concludes that MH's full energies and focus should be placed on the effective implementation of its long-term expansion plans, towards meeting the demand for electricity and natural gas. The Board can envision MH establishing aggressive goals for the reduction of domestic energy consumption for such a new entity to target, together with providing funding to meet those targets. MH will benefit by being able to export the energy that is conserved.

1.0 Overview

1.0 Overview

1.1 History

Manitoba Hydro's last General Rate Application (GRA) was held in the spring of 2004, following a drought that contributed to a record loss of \$428 million for the Corporation's electric operations. That 2004 GRA led to Board Orders 101/04 and 143/04, and those Orders approved a 5% average rate increase, effective August 1, 2004, and two additional average rate increases of 2.25% each, to be effective April 1, 2005 and October 1, 2005 – the latter two increases conditional on MH filing additional information and justification.

Subsequently, by Order 34/05 the Board confirmed the first of the two conditional 2.25% average rate increases, the first one taking effect April 1, 2005. However, due to a reported "dramatic" rebound in water conditions following the drought that contributed to rate increases in Order 101/04, and a favourable financial forecast for MH's fiscal year 2005/06, the Board was advised by MH (on July 5, 2005) that the Corporation would not seek the second conditionally approved rate increase, tentatively scheduled for October 1, 2005.

Water conditions ebb and flow, and subsequently, due to a return to poor water conditions during most of MH's fiscal 2006/07 (not anticipated by MH when it decided to forego the last of the two conditional rate increases), MH applied to the Board to reinstate that foregone average rate increase of 2.25%. After a thorough review of information submitted by MH, and by way of Order 21/07, the Board granted MH's application, effective March 1, 2007, on an interim basis. Final approval of that rate increase was later sought by MH as part of its 2008 GRA, and provided by the Board by way of recent Order 90/08.

1.0 Overview

1.2 2008 General Rate Application

In the summer of 2007, and pursuant to *The Public Utilities Board Act* and *The Crown Corporation Public Review and Accountability Act*, MH applied to the Board for the following:

- a) Approval of rate schedules incorporating an across the board 2.9% increase in General Consumers' rates effective April 1, 2008 (with the exception of Area & Roadway Lighting which would receive a 1% increase);
- b) Final approval of General Consumers' interim rates approved in Order 21/07 effective March 1, 2007;
- c) Surplus Energy Program: immediate interim approval to extend the program (currently set to expire October 31, 2007) to October 31, 2008 together with final approval to extend the program to March 31, 2013;
- d) Final approval of all Surplus Energy Program (SEP) interim rate orders as set out in Appendix 10.6 of the GRA;
- e) Approval of modifications to the Curtailable Rate Program (CRP) as discussed in Tab 10, Section 10.2 of the Application, and final approval of all interim Curtailable Rate Program orders as set out in Appendix 10.6;
- f) Final approval of changes to the Limited Use of Billing Demand Rate (LUBD) as set out in Appendix 10.6;
- g) Contingent on final execution of the settlement agreement between Indian and Northern Affairs Canada (INAC), Manitoba Keewatinook Ininew Okimowin (MKO) and Manitoba Hydro, approval of interim *ex parte* Orders related to electricity service in the Diesel Rate Zone as set out in Appendix 10.6; and

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- h) Approval of a new General Service Large rate for new or expanding loads as set out in Tab 10, Section 10.3 of the GRA.

By Order 90/08 and following a public hearing of MH's GRA, the Board established an across-the-board rate increase of 5% effective July 1, 2008 for all MH customers, except for Area and Roadway Lighting customers, whose rates are not to change.

In addition, the Board approved:

- a) A further conditional across-the-board general rate increase of 4%, with the exception of Area and Roadway Lighting customers (for whom rates are again not to increase), provisionally to take effect April 1, 2009 (subject to the Board's further review, that, depending on developments, could result in the Board increasing or decreasing the 4% increase conditionally approved);
- b) An increase in the Basic Monthly Charge (BMC) for all customers of 5%, as of both July 1, 2008 and April 1, 2009;
- c) As indicated above, finalization of Order 21/07 which established an interim rate increase of 2.25% on March 1, 2007;
- d) A modest introduction of inverted rates for the "residential" class (SGS), establishing a precedent and indicating an intention to widen the differential in the future;
- e) As requested by MH, extension of the Surplus Energy Program (SEP), although only to October 31, 2008 ahead of conclusions yet to be reached and a possible further extension to follow this Order;
- f) Modifications to the Curtailable Rate Program, as proposed by MH;

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- g) Changes to the Limited Use of Billing Demand Rate, as proposed by MH;
and
- h) Final approval for various interim SEP Orders through to the date of the close of the hearing that led to Order 90/08.

Order 90/08 was issued on June 30, 2008, and also indicated that final approval of several Interim *Ex-Parte* Orders related to electricity service in the Diesel Rate Zone would be deferred until final execution of a Settlement Agreement between INAC, MKO and MH had occurred.

The Order also advised MH to re-file, "with any adjustments it may deem appropriate, a revised proposal for a new industrial rate for new and expanding industrial load".

Although the Corporation had sought a 2.9% across-the-board increase, excepting for a proposed 1% increase for Area and Roadway Lighting customers, and had indicated a need for further 2.9% across-the-board increases for each year through to 2017/18, the Board concluded that higher increases were required, at least for 2008 and 2009.

In Order 90/08, the Board noted:

"With MH's new export and construction commitments and plans, and with the increased risk that MH's Manitoba load forecasts may prove low given the large increase in the price of natural gas over the past year (yet to be fully reflected in natural gas bills), and providing the risk of energy switching, the Board is also concerned with the risk associated with advancing major new generation and transmission projects with industrial rates well below marginal cost."

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And,

“While the Board is now providing a 5% increase for 2008 and the prospect for a further 4% April 1, 2009, the latter subject to reconsideration following receipt and review of additional information, the electricity rate increases now set and contemplated pale in comparison to the increases being implemented or planned by other Canadian electricity utilities, and the cost increases now being experienced by consumers, businesses, institutions and governments with respect to other energy sources. “

And,

“Notwithstanding the Board’s appreciation of the negative implications of rate increases for MH’s customers, and the Board’s particular and on-going concern for low-income households, particularly, in this case, those relying on electricity for space heating, the Board will provide MH with a greater increase than the Corporation sought. This, because of a combination of concerns briefly cited below (to be) elaborate(d) on in more detail in a subsequent Order:

- a) In its application, MH advised that its proposed series of 2.9% increases were required to maintain progress towards the eventual attainment of the Corporation’s financial targets, primarily the achievement of the long-sought but not achieved target debt to equity ratio of 75:25. MH projected that notwithstanding its forecasts of annual rate increases and the assumption of continuing success with export markets, and taking into account forecast net income for 2007/09 to achieve or exceed \$300 million, it still did not expect to achieve the debt:equity financial target of 75:25 by 2017/18 (let alone the current or previous earlier target dates);
- b) MH’s plans for capital expenditures may involve the expenditure of \$18 billion or more over the next 15 years, expenditures predicated in part on what may or may not be overly optimistic export prices – this level of capital expenditure will result in significantly increased debt levels, export commitments and general business risks;
- c) MH’s reports and evidence of hyper-inflation with respect to construction and commodity costs, which are driving up the Utility’s projected costs for new generation and transmission projects and have lowered its estimates of the return to be expected for the first of its new generation projects (Wuskwatim), a project that will likely be followed by further major construction (Pointe du Bois, Bipole III, and the Keeyask and Conawapa generation stations);

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- d) While the Board shares some Intervener concerns as to an apparent acceleration of MH's OM&A costs (Operating, Maintenance and Administration), which MH attributes to labour shortages as well as increased needs for system maintenance, (both factors cited to be beyond the direct control of the Utility), the Board does not have enough information on whether current and forecast OM&A expenditures are fully supported, since no formal and in-depth benchmarking has yet been undertaken;
- e) The approaching adoption of International Financial Reporting Standards (IFRS), which will form the new Canadian Generally Accepted Accounting Principles (GAAP), with potentially materially significant and negative impacts for the Corporation's current forecasts of annual net income results through 2017/18;
- f) There has been a significant increase in the value of the Canadian dollar relative to American currency, and it has had the effect of reducing the value of electricity exports as expressed in Canadian dollars. The Canadian dollar has climbed from just above 60 cents U.S. dollar (USD) to near parity with the U.S. currency. With MISO imports (MH's exports) priced in USD, this has affected MH's export revenues. While MH forecasts the Canadian dollar falling back about 15 cents from its current level, the Board is not confident with that forecast, and if near parity remains MH's export price forecasts are in jeopardy;
- g) There appears to be a growing disconnect between electricity prices obtained from American markets and natural gas prices (in the past, when natural gas prices rose, the assumption and general experience was that MH's export prices rose as well); and
- h) Continuing business risks related to interest rates (now at recent historic lows), the risk of further currency fluctuations, drought, inflation, market access problems, and other concerns: "

"Interest rates are at very low levels in both an absolute and relative to inflation sense – the current prime rate of the Bank of Canada is approximately only one percentage point higher than the current national rate of inflation – and with hyper-inflation present with respect to commodities (including energy) and processed products such as chemicals, steel and concrete, the Board is concerned that interest rates will increase at some point during MH's expansion phase, placing increased pressure on the cost of the Corporation's operations."

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And,

“MH has benefited from 12 of the last 16 years being of above or near median water flows; statistically, poorer water conditions can be expected to occur at some point in the future and a drought, which has been experienced regularly through the Corporation’s history, could have a devastating impact on MH’s financial situation, as it recently did in fiscal 2003/04.”

And,

“MH’s export market is primarily American utilities within the MISO market, and transmission lines on both sides of the border are required to transport the power to MH’s export customers and carry power back to Manitoba when imports are required, and there are risks involved with reliance on a significantly predominant market. While a national east-west grid remains a worthy objective, there is no present indication that MH’s Canadian provincial customer list, particularly from a volume perspective, can be assured to strongly develop.”

The Board concluded its overview of the Corporation’s risks by stating in Order 90/08 that it “is focused on the risks that lie ahead and determined to ensure as reasonably as possible that MH has the financial strength to meet the risks”.

“The rate changes and comments of present and future risks associated with this Order should not be perceived as a challenge to the perspective that MH remains a tremendous asset for Manitoba, and that the Corporation continues to have and represent large growth opportunities. Even with the rate increases announced and forecast herein, Manitobans should continue to benefit from some of the lowest electricity rates in North America.

The Board also finds it important to recognize a present and growing disconnect between relatively stable and low electricity rates (set by a regulatory body with particular attention to historic costs) and other competing energy prices, the latter set by largely unregulated market forces little affected by the actual cost of production and distribution.

With respect to MH, while the costs of generation, transmission and distribution assets acquired decades ago have allowed for residential rates of 6 cents per kilowatt hour (kW.h) and 3.2 cents for major industry, the new generating stations and transmission facilities will demand much higher rates simply to break even, let alone produce the net income required to allow MH to move forward supported by a reasonable capital structure.

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As a comparison to electricity rates ... Combining actual and projected natural gas bill increases for 2008, it would not be surprising if natural gas customers end up paying 30% more for their natural gas this winter as opposed to the last. With respect to fuel oil, propane, gasoline and diesel, increases experienced are even more severe.

In 1999, when MH purchased Centra Gas, space heating by natural gas ... could be expected to come at half or less than half the cost of an electrically-heated home; this is no longer the case. (Now) ... space heating by electricity (is) cheaper than by natural gas for all residences other than those that heat by way of a high-efficiency gas furnace. If the trend continues more and more new and existing residences may select or convert to electric heating, driving up domestic electricity load and limiting export sales and profits."

The Board noted that Order 90/08 would be followed by a more detailed Order that would provide further direction, necessary background information and detailed rationale for the rate changes of Order 90/08. The Board also noted that the subsequent Order, which is this Order:

"... will also summarize and encapsulate the positions of Interveners and MH, the comments of presenters, and the evidence of witnesses all appearing before the Board at the public hearing of MH's GRA, a hearing held over 19 days in the Board's offices in the months of March, April and May 2008."

1.3 Previous Board Directives

In addition to MH's specific requests for Board approval in the Utility's GRA, MH reported on the status of various responses to previous Board Directives that were issued in Orders:

117/06 - A review of Manitoba Hydro's Cost of Service Study Methodology and other matters.

Order 117/06 followed a comprehensive public hearing which reviewed in depth MH's Cost of Service Study Methodology, and provided various directives to modify and refine the methodologies to be used in subsequent Cost of Services Studies. In the recent GRA, the Board and Interveners had the opportunity to

1.0 Overview

consider those modifications and refinements in MH's Prospective Cost of Service Study - 08 (PCOSS -08).

173/06 – Application by Manitoba Hydro for the extension of the approval of the Surplus Energy Program (SEP).

By 173/06, the Board approved the extension of SEP to the earlier of October 31, 2007 or a further application by MH, with the expectation that the SEP would be included for review in MH's 2008 GRA.

176/06 - An Interim ex parte Application by Manitoba Hydro for an Order approving new electricity rates in four communities served by diesel generation, to be effective January 1, 2007.

This was the fourth Order, in a series of Orders (17/04; 45/04; 159/04; and 176/06) that adjusted rates, each provided on an interim basis, in the four communities that Manitoba Hydro services by diesel generated electricity. The communities are:

Barrenlands First Nation (also known as Brochet)

Northlands Dene First Nation (also know as Lac Brochet)

Syisi Dene First Nation (also known as Tadoule Lake)

Shamattawa First Nation (also known as Shamattawa)

The interim rates approved in Order 176/06 (as well as the other interim orders) were predicated on MH filing an Application to finalize all outstanding Diesel Zone Interim Orders, as soon as the Settlement Agreement among MH, MKO, and INAC has been fully executed.

20/07 - Manitoba Hydro - Interim Rate Increase effective March 1, 2007.

1.0 Overview

This Order approved, on an interim basis, the 2.25% average rate increase that MH, in the most recent GRA sought to confirm, and which the Board has confirmed by way of Order 90/08.

By this Order, the Board also comments on MH's responses to previous directives and provides additional directives for the attention of the Utility.

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1.4 Board Findings

As was the case with Order 90/08, this Order addresses many complex issues and provides detailed analysis, discussion and decisions (in other sections of this Order) in support of not only the directed rate approvals provided by Order 90/08 but also with respect to other matters deferred to this Order.

For all of the reasons set out both above and in the Board's Findings sections included herein, the fiscal health of MH, along with the affordability of energy for low-income households, remain the Board's greatest concerns. While the Board's concern over MH's financial situation lies largely with the \$18 billion of capital expenditures likely to lie ahead, and the debt expected to be incurred to fund those expenditures, the Board's concern for low-income households is with their ability to pay seemingly "ever-increasing" energy bills (not just electricity, but also natural gas, gasoline, diesel, fuel oil and propane).

The Board also notes elsewhere in this Order, findings related to MH's OM&A expenses and the Corporation's efforts at expense control, and observes that the unprecedented planned increase in such capital expenditures are beyond the Board's statutory jurisdiction to approve or deny. Nonetheless, the impact on finance and depreciation expense arising from capital expenditures, along with the risks ever-present with a Corporation dependent in large part on weather and other matters not within its control – general inflation, interest rates, currency fluctuations, represent the largest component of the upward pressure on consumer rates.

In considering its directions and comments, the Board is mindful of past directions from the Manitoba Court of Appeal:

1.0 Overview

“The Board’s function is not only to protect consumers from unreasonable charges, but also to ensure the fiscal health of the corporation and fairness between different classes of consumer.”¹

1. Coalition of Manitoba Motorcycle Groups Inc. v. Manitoba (Public Utilities Board) [1995] M.J. No. 301 (C.A.).

Attention to the fiscal health of MH (as one factor in the Board’s determination of the public interest), has been supported by the Manitoba Court of Appeal.

The intent of the legislation is for the Board to approve fair rates, taking into account such considerations as cost and policy, or other factors as the Board may deem appropriate. Rate approval involves balancing the interests of multiple consumer groups (residential, commercial, institutional and industrial) with those of the utility. In the end, the long-term interests of consumers and the utility should coincide.

The Board’s decision in Order 90/08 to build retained earnings more rapidly than MH proposed, in order to better protect the utility and consumers from the potentially devastating financial impact of future drought and other identified risks, clearly meets the intent of the legislation and is within the jurisdiction afforded to the Board in s. 26 of *The Crown Corporations Public Review and Accountability Act*.

It should be clear for the reasons cited herein that the Board understood its role in this regard.

“The (Board) has two primary concerns when dealing with a rate application; the interests of the utility’s ratepayers and the financial health of the utility. Together, and in the broadest interpretation, these interests represent the general public interest.”²

2 Consumers’ Association of Canada (Man.) Inc. et al v. Manitoba Hydro Electric Board, 2005 MBCA 55

In arriving at its decision to grant MH rate increases as of July 1, 2008 and April 1, 2009 (the latter conditional), the Board took into account recent financial

1.0 Overview

results and forecasts which, particularly if the forecasts are met, will contribute in a meaningful way to improving MH's financial strength in the near term.

Financial results for fiscal 2007 were \$13 million better than projected and the current projection of \$300 million (or more) of net income for fiscal 2007/08 represents a gain of at least \$96 million over what had been anticipated given median water flows. The Board also understands that energy in storage (water in the reservoirs) was at record or near record levels going into 2008/09 and that water flow conditions remain favourable, both factors suggesting that the current forecasted net income of \$156 million for 2008/09, (which was again based on median water flows), may be exceeded.

If these projections prove out, MH will have enjoyed 14 of the last 18 years of above or near median water flows. While such a result would be very good news indeed, history has a habit of repeating itself, particularly when it comes to weather, and years of water flow better than median may very likely be followed by years of below median water flows.

Then, there are the significant concerns expressed over the forecasted increase in capital spending, concerns expressed not only by the Board, but also MIPUG, the Coalition and MKO. The concern is of particular importance as the capital program increases now forecast are, at least initially, driven by export sales commitments.

Intervenors suggest a capital justification hearing or, at least, a public dialogue on the appropriateness of the capital program, which brings risks as well as opportunities. The Board shares this view.

And, MH's intended capital program, unprecedented in the Corporation's history, and supported in large part by the expectation of large export sales, also has risks, the larger the commitments the larger the risks.

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The Board would be remiss if it did not acknowledge that a primary driver of the Board's decision to increase 2008 rates by 5%, 2.1% more than MH sought, was the Board's perspective that attention should be paid to not only reaching but also maintaining the 75:25 debt to equity financial target.

It is not as if MH is already at its 75:25 debt:equity target, or that MH has projected to the Board that it expects to reach and maintain that target. In fact, due to the planned acceleration in capital spending, driven primarily by export considerations, the Corporation is not expected to meet its 75:25 debt to equity ratio target during the current forecast period, which extends to 2017/18, and those forecasts already assume annual average rate increases of about 3% each year.

In addition, major new contracts are being contemplated for export sales that will require new generation and transmission facilities costing over \$6 billion, costs which have not yet been incorporated in the forecasts of the Corporation.

That said, the Board was reluctant to raise MH's rates by more than the Corporation sought. The Board is well aware that Manitoba's consumers are facing extraordinary increases in the cost of living caused largely by increases in petroleum prices. High petroleum costs are also translating into higher costs for staples: food, tires, gasoline and diesel prices, and heating oil, propane and natural gas heating costs.

For the Board, in meeting its mandate to serve the public interest, that interest includes the financial health of the Utility. A major capital program, combined with water, interest rate, accounting and currency risks, warrants larger rate increases than those sought by the Corporation, in order to improve the Utility's financial resilience.

1.0 Overview

The Board is encouraged by improved financial projections for fiscal 2008, noting that MH has indicated its financial results is likely to exceed \$300 million, an improvement from the \$264 million reflected in its previous forecast. The Board further notes that MH has indicated near record level energy in storage and favourable water flows at the outset of fiscal 2009, which bodes well for MH meeting if not exceeding its fiscal 2009 forecasted net income of \$156 million. Such improved financial results would also assist in enhancing the financial strength of MH.

The Board notes that the improvement is very much linked to higher volumes of hydraulic generation and is not reflective of increasing export prices or demonstrated cost reductions from previous forecasts.

While MH's fiscal health has significantly improved from the financial impact of the 2003/04 drought, where the loss incurred was the largest in the Utility's history, a future drought, one that could extend over several years, would result in larger generation reductions than the 2003/04 drought brought about, and would result in greater financial loss.

The Board is of the view that further improving the financial strength of MH, regardless of current improved results, is important to the future of the Utility, and that Manitobans, already enjoying electricity rates well below the average found on the continent, and cognizant of the rapid and hyper-inflationary increases for commodities generally (and energy in particular), will accept that an increase of 5% is now necessary.

MH financial strength has a significant influence on the finances of the Province, and MH's financial strength is a major consideration in the evaluation of the credit rating of the Province. In fact, the interest rates MH now enjoys are far below what would be required if not for the guarantee of the Province. The Board

1.0 Overview

further notes that MH has also indicated that the Corporations' debt to equity ratio would have to be similar to that of privately-owned utilities (i.e. 60:40) in order to borrow at rates comparable to the cost of funds received through the Province, without the Province's guarantee.

Any downward adjustment in the credit rating of the Province would likely result in higher borrowing costs for MH as well as the Province, and serve as a double blow against the interests of consumers and industry.

MH rates should gradually begin to recognize the rates required to support new generation and transmission. Given the economic benefits that flow to the current generation of Manitobans as a result of an extensive capital expenditure program and the maintenance of an efficient and effective electrical grid, it seems reasonable that (to some limited extent) the current generation should shoulder some of the rate burden possibly destined for future generations

Leaving aside the weather, maintenance and economic risks that the Corporation faces, there is also the matter of the adoption of IFRS and the consequences for the Corporation once IFRS becomes GAAP. The Board shares the concern expressed by MH's Vice President of Finance and Chief Financial Officer when he testified that IFRS accounting could reduce the Corporation's annual average forecast of net income through to 2017/18 by as much as \$120 million a year.

In fact, the Board needs to have MH's risks fully quantified to provide guidance on future rate requirements. And, while revenue alone will not be sufficient to support projected capital spending, MH needs sustained and repeated annual rate increases to support its financial position. Furthermore, the Board is concerned that the recently-announced new export contracts have not yet been reflected in the Corporation's Capital and Resource Requirements analysis, and the Board needs to see an updated Integrated Financial Forecast (IFF), Capital

1.0 Overview

Expenditure Forecast (CEF), Load Forecast & Power Resource Plan going out to 2028, this beyond the regular forecast period of 2018 to better gauge fully what lies ahead for ratepayers.

For the reasons cited above, and given the overall situation and prospects for additional rate increases as well as borrowings in the future, the Board confirmed as final, by way of Order 90/08, the interim rate increase of 2.25% granted March 1, 2007 on an interim basis. The Board believes that the initial interim increase, which took effect in fiscal 2007/08, was an integral part of the improved financial results for the year just completed.

In light of all the pressures on MH, it is acutely important that the financial strength of MH be improved. In the past MH has been striving to achieve a debt to equity target of 75:25. Although the target was deferred to 2011/12, it now appears that it will not be achieved and held to until well beyond 2017/18.

MH is evaluated by credit rating agencies that are interested in seeing MH making progress toward its financial targets. It is vital that progress continues to be made to ensure no negative implications for the credit rating of the Province. A strong credit rating results in access to capital at reasonable costs. Any deterioration in the credit rating of the Province attributable to MH would likely lead to higher borrowing costs for both the Province and MH.

All this said, the Board does not believe ratepayers alone should shoulder the obligation to maintain the utility's financial health. The Board expects the Corporation to demonstrate and provide evidence of tangible results in the management of OM&A costs and the Capital program, as well as addressing other issues and meeting directives discussed in detail in other sections of this Order.

1.0 Overview

Approval of the conditional 4% increase now slated for April 1, 2009 is dependent on MH addressing (to the Board's satisfaction) certain directives set out in this Order and filing additional financial information to allow the Board to assess whether the conditional increase is justified. The Board will direct MH to file (before January 15, 2009), supporting information for Board review of the 4% April 1, 2009 conditional increase. In addition to the information to be filed with the Board by that date, MH is to include:

- a) first, second and third quarter 2008/09 unaudited financial results and statements; and
- b) an updated forecast of net income for 2008/09, reflecting existing water energy in storage conditions.

2.0 Operating Results and Financial Projections

2.0 Operating Results and Financial Projections

2.1 MH's Forecasting Process

MH utilizes four main forecasting tools:

- a) The integrated financial forecast (IFF) projects MH's financial results over an 11 year period and includes an income statement, balance sheet and statement of cash flow.
- b) The System Load Forecast projects energy and capacity requirements for electricity in Manitoba over the next 20 years.
- c) The Power Resource Plan forecasts MH's supply capabilities under dependable flow conditions.
- c) The Capital Expenditure Forecast (CEF) includes the planned capital expenditures for a 10 year period including safety requirements, supply side enhancements major generation and transmission projects and investments in administrative assets.

2.2 Comparison of Actual Operating Results with Prior Forecast

The IFF reviewed at the last GRA was IFF03-1, presented at the Board's 2004 hearing of MH's GRA. At that time, MH had just endured a severe drought and was forecasting a loss of \$355 million for fiscal 2004. At the 2004 hearing MH provided an update to the Board indicating that the forecasted drought loss would be greater than that reflected in IFF03-1, projecting a loss falling between \$400 million and \$430 million, which ultimately settled at \$428 million.

2.0 Operating Results and Financial Projections

As directed in Order 101/04, MH filed IFF MH04-1 to justify implementation of the first 2.25% conditional increase, which was granted by the Board effective April 1, 2005.

As a result of the increases granted by the Board, more favourable water levels in fiscal 2005, and higher export sales in fiscal 2006, MH's financial position improved in the order of \$130 million over the forecasts of IFF03-1 and IFF04-1.

The favourable water conditions of 2005 and 2006 reversed in fiscal 2007. In January 2007, MH sought from the Board a 2.25% rate increase. In support of its application, MH filed IFF MH06-2, which forecast a \$108 million net income for fiscal 2006/07. The Board granted that increase on an interim basis by Order 21/07, and it took effect March 1, 2007.

2.3 Integrated Financial Forecast (MH07-1)

At the most recent GRA, MH filed its most current IFF (IFF MH 07-1) for its electricity operations, as well as its most current capital expenditure forecast (CEF 07-1), both for the eleven-year period 2008 to 2018. The IFF provides an indication of MH's view of its long-term financial direction in both absolute terms and as to achieving its financial targets, and is for use in future planning. MH's operating results since its 2004 GRA are compared to actual and prior forecasts as follows:

2.0 Operating Results and Financial Projections

Statement of Operations & Retained Earnings (\$ Millions)

Fiscal Year	Actual				IFF07-1	
	2004	2005	2006	2007	2008	2009
Revenue						
Domestic	936	954	1001	1,040	1,079	1,108
Requested Rate Increase	-	-	-	-	-	31
Export	351	554	827	592	582	468
Total Revenue	1,287	1,508	1,828	1,632	1,661	1,607
Expenses						
Finance	455	473	473	472	404	426
Depreciation	276	291	303	314	332	347
Operations & administrative	293	308	322	332	351	360
Water Rentals	71	111	131	112	121	112
Tax expense	51	52	54	55	57	64
Fuel & power purchases	569	135	125	226	132	143
Total Expenses	1,715	1,370	1,408	1,511	1,397	1,452
Net income [IFF 07 - 1]	(428)	138	420	121	264	155
Compared to Prior Forecasts						
Net income (loss) [IFF03-1]	(355)					
[IFF04-1]	-	147	208			
[IFF06-2]	-	-	-	108	174	127
Net income difference	(73)	(9)	212	13	90	28
Retained earnings Actual/IFF 07-1	707	845	1,265	1,386	1,650	1,805
Retained earnings from above IFF	759	854	1,061	1,398	1,572	1,699
Cumulative difference	(52)	(9)	204	12	78	106

Domestic electricity revenues are forecast to increase with load growth (usage) and approved rate increases. Export revenue forecasts are based on volumes and market prices, the former limited by water conditions and transmission capacity, the latter on demand and supply conditions in the MISO market (the marginal cost of the next unit of production).

2.0 Operating Results and Financial Projections

MH's projected net income for the three-year period 2006/07 to 2008/09 is projected to be \$131 million higher in IFF 07-1 than the aggregate result for that period forecast in the earlier IFF 06-2 forecast. Incorporating the changes from prior IFF's, as discussed above, MH's net income for the five year period 2003/04 to 2008/09 is now forecast to be over \$261 million higher than was the case with the previous forecast.

IFF MH07-1 reflects both the interim increase of 2.25% granted March 1, 2007, finalized by Order 90/08, and MH's requested 2.9% increase as of April 1, 2008, varied to 5% from July 1, 2008 by Order 90/08. The forecast also assumes annual increases of 2.9% for the years 2009/10 through 2017/18. While the Board has already indicated consideration of a 4% increase for 2009/10, later rate forecasts will be the subject of future applications and processes.

MH's decision to file the most current GRA was based on IFF MH06-4, a forecast which projected net income for fiscal 2007/08 to be \$249 million, with a further \$163 million for fiscal 2008/09. During the GRA, MH provided an oral update to IFF07-1, suggesting that net income for fiscal 2007/08 will be higher by at least a further \$36 million. Relative to IFF MH06-4, net income for 2007/08 was then expected to be at least \$51 million higher than that forecast. The most recent anticipated improved operating results for fiscal 2007/08 are not reflected in IFF MH07-1, and despite the oral update, MH did not revise its request for a 2.9% increase as of April 1, 2008.

MH advised that its actual financial results for fiscal 2007/08 would not be made available to the Board until mid-June 2008, and, then, only in confidence pursuant to normal legislative reporting requirements.

MH's operating results and forecasts compared to the forecast of the 2004 GRA were as follows:

2.0 Operating Results and Financial Projections

Statement of Operations & Retained Earnings (\$ Millions)

(\$ Millions)	Actual				IFF07-1		
Fiscal Year	2004	2005	2006	2007	2008	2009	Total 2004-2009
Revenue							
Domestic	936	933	929	965	985	1,014	
Estimated PUB Approved Increases	-	21	72	75	94	94	356
Export	351	554	827	592	582	468	
Total Revenue	1,287	1,508	1,828	1,632	1,661	1,576	
Expenses							
	1,715	1,370	1,408	1,511	1,397	1,452	
Net income (loss) [IFF 07 - 1]	(428)	138	420	121	264	124	
Compared to 2004 GRA Forecast							
Net income (loss) [IFF03-1]	(355)	40	31	30	17	29	
Net income difference	(73)	98	389	91	247	95	847
Retained earnings Actual/IFF 07-1	707	845	1,265	1,386	1,650	1,774	
Retained earnings IFF03-1	759	799	830	860	877	906	
Cumulative Retained Earnings difference							
2004 GRA vs. 2008 GRA	(52)	46	435	526	773	868	

Overall, since the 2004 GRA, MH's net income has been \$847 million higher than that forecast at that time. The increase in net income is due in part to improved water conditions, conditions better than the median results expected, which led to higher than forecast exports. As well, rate increases approved by the Board since the 2004 GRA have contributed approximately \$350 million in additional revenue for the fiscal years 2004/05 through 2008/09.

2.0 Operating Results and Financial Projections

2.4 Board Findings

There has been an improvement in MH's financial results from that forecast in IFF03-1 at the 2004 GRA, notwithstanding the severe drought experienced in 2003/04. The Board further notes that, aided by much better water conditions than expected, record export sales (provided not only by the water conditions but also by the prices obtained following hurricanes Katrina and Rita in the summer of 2005), along with rate increases, brought in approximately \$350 million in revenue, and further contributed to the improved results.

The Board would have expected such additional revenue to have significantly improved the financial strength of the utility, as displayed in its meeting its financial targets, compared with the original forecast. Yet it didn't, and the Board is concerned that MH is still not forecasting to achieve its debt:equity target within its forecast period, not by 2011/12 or throughout the entire 11 year forecast ending in 2017/18.

While the forecasts through to 2018 assume annual rate increases of 2.9%, and annual profits that appear to be very large, particularly to a province accustomed to narrow government budget surpluses and relatively modest returns from government enterprises, the Board not only notes the magnitude of the growing asset base on which these earnings are forecast to occur (restrained as it is by asset costs incurred decades ago at very much lower prices than replacement costs), the Board continues to question the "solidity" of the results and forecasts.

While MH advised that its fiscal 2008 net income would exceed \$300 million, due to higher than initially forecast water flows, risks abound with respect to MH's longer-term forecasts, particularly:

2.0 Operating Results and Financial Projections

- a) A decline in export contract sales, trending down to 145 GW.h by 2017/18 in the absence of new contracts [the recently announced sales to Minnesota and Wisconsin, if consummated, will reduce this risk];
- b) The limitations of the Corporation's ability to export until Conawapa, Keeyask and other Generating resources, including wind, come on line, in conjunction with the expected restrictions on the Brandon thermal plant commencing in 2009;
- c) MH's future domestic load growth forecast may prove low, with the risk of consumers switching to electricity from space heating by natural gas, which is now more expensive than electricity except in the case of high efficiency furnaces;
- d) MH's Canadian dollar exchange rate forecast assumptions;
- e) MH's future export price forecasts are predicated on imposition of a carbon tax, yet there is no current certainty of such a tax being implemented and having a materially beneficial effect within the immediate horizon of IFF07-1;
- f) Escalation in construction cost inflation over the past five years. Increases in commodity costs (iron, steel, concrete, copper and nickel for example) have been sharp and sustained;
- i) Based on recent experience, current capital expenditure forecasts related to future construction may prove to be low, and actual costs may exceed the forecasts;
- j) Recent or good water flow levels suggest an increased risk of a severe drought during a time when MH's capital expansion plans are significant; and

2.0 Operating Results and Financial Projections

- k) The required adoption of IFRS as of MH's 2012 fiscal year (with MH's 2011 fiscal year financial statements required to be IFRS based for comparison purposes).

A further discussion of each of these risk factors is provided later in this Order.

3.0 Forecast Revenues

3.0 Forecast Revenues

3.1 Domestic Revenues

In IFF 07-1, MH forecast that at pre-Order 90/08 rates domestic revenues would increase from \$1.057 billion (for fiscal 2008) to \$1.258 billion by fiscal 2018, a projected increase of \$201 million. Additional revenue forecast to arise from assumed 2.9% annual rate increases for each year from fiscal 2008/09 on to 2017/18 was projected to contribute a further \$395 million to MH's forecast revenue growth, with total revenue forecast for fiscal 2017/18 to be \$1.653 billion.

The forecast of \$200 million in additional domestic revenue at pre-Order 90/08 rates reflects projected net load growth of about 3,500 GW.h over the ten-year period. Of this, 2,200 GW.h, almost entirely expected to occur in the first three years of the forecast, relates to projected new industrial load. To the Board, it appears that MH has assumed that a new Energy Intensive Industry Rate, as initially proposed by MH to take effect in 2008/09, will be applied to almost all of the industrial load growth forecast in IFF 07-1.

3.2 Extra-Provincial Revenues

3.2.1 Energy Available for Export

MH's hydraulic generating resources, supplemented by thermal and wind generation as well as imports (the latter source when required) allow for projected annual exports of energy ranging from about 4,000 GW.h to 15,000 GW.h per year, actual volumes to be affected by water flows and domestic load.

Typically, MH has forecast exports (total supply minus domestic load) in each current year on the basis of known water supply conditions. For the second year of a multi-year forecast, MH utilizes known end of Year 1 conditions plus an

3.0 Forecast Revenues

assumption of median water flow for the second year. The third year forecast, and each year thereafter, uses the long-term mean flow conditions (basically the average experience of the past).

In IFF 07-1 export sales are forecast at:

MH Forecasted Export Sales

Fiscal Year	GW.h	\$ million
2008	11,152*	\$582 *
2009	7,549	\$468
2010	6,608	\$416

Note*

MH has indicated that exports for fiscal 2007/08 will be significantly higher than its forecast due to higher than forecast water flow.

Also, exports assume that in addition to hydraulic generation, MH will have other resources, as follows:

MH Forecasted Power Resources (GW.h)

Fiscal Year	Thermal Generation GW.h	Imports GW.h	Wind Purchase GW.h	Total GW.h
2008	351	880	320	1,551
2009	203	1,194	320	1,717
2010	928	1,948	320	3,194

The export forecast for fiscal 2008/09 of 7,549 GW.h compares to total exports and average export prices in 2005, 2006, and 2007, as shown below:

MH Average Export Prices (2005 to 2007)

Year	2005	2006	2007
Export Revenue (\$ millions)	\$554	\$827	\$592
Export Power (GW.h)	10,780	16,034	11,717
Average Price (¢ per kW.h)	5.13 ¢	5.16 ¢	5.05 ¢

3.0 Forecast Revenues

When river flows are above average, MH's hydraulic generation resources supply the export of energy surplus to domestic needs. MH provides "clean" energy at competitive prices into American, Ontario and Saskatchewan energy markets.

The following table illustrates the historical average annual export prices achieved by MH, in comparison to natural gas supply prices:

Average Annual Export Prices/Natural Gas Supply Prices

Fiscal Year	U.S. and Canadian Exports (Canadian ¢/kW.h)	Natural Gas Supply (USD/MMBtu)
1993	1.58	1.91
1994	2.54	2.25
1995	2.69	1.75
1996	2.54	1.95
1997	2.33	2.61
1998	2.16	2.41
1999	2.82	2.00
2000	3.43	2.46
2001	3.91	5.03
2002	4.90	3.08
2003	4.89	4.29
2004	4.99	5.16
2005	5.53	6.28
2006	5.19	9.29
2007	5.08	6.67
2008	5.00 (est.)	8.00 (est.)

Until 2004/05, the Corporation's average electricity export prices tended to track and move in tandem with changes in natural gas prices. However, from 2006 average export prices appear to have plateaued at just above 5.0¢/kW.h. This has occurred despite currently-high natural gas prices.

3.0 Forecast Revenues

In 2007/08, a dramatic shift in the Canadian/U.S. exchange rate contributed to average export prices moving below 4¢/kW.h for opportunity energy sales, and below 5.5¢/kW.h for firm (dependable) energy contract sales. As illustrated in the following table, the recent price drop appears to be largely related to changes in the exchange rate. However, and as well, the Board notes no indication that prices for dependable energy in USD terms have escalated with inflation.

NEB Average Export Price Data* (converted to U.S. ¢/kW.h)

Date	Exchange Rate (CDN \$)	Opportunity Export		Dependable Export		Imports	
		¢/kW.h (CDN)	¢/kW.h (US)	¢/kW.h (CDN)	¢/kW.h (US)	¢/kW.h (CDN)	¢/kW.h (US)
2006							
November	1.14	6.3	5.55	6.1	5.35	5.6	4.95
December	1.16	6.5	5.6	6.4	5.5	5.9	5.1
2007							
January	1.18	6.0	5.1	6.0	5.1	5.6	4.8
February	1.18	8.7	7.4	6.2	5.3	6.0	5.1
March	1.18	6.6	5.6	6.1	5.2	4.0	3.4
April	1.14	6.8	6.0	6.0	5.3	4.0	3.5
May	1.10	5.0	4.55	6.0	5.45	2.0	1.8
June	1.06	4.5	4.25	5.5	5.2	6.0	5.65
July	1.05	4.0	3.8	5.2	4.95	9.5	9.0
August	1.05	4.0	3.8	4.8	4.55	7.8	7.4
September	1.05	3.8	3.7	5.0	4.9	8.2	7.8
October	0.98	3.6	3.7	4.8	4.9	9.8	9.6
November	0.97	4.0	3.9	5.8	6.0	10.0	9.7
December	1.00	6.2	6.2	5.4	5.4	2.5	2.5
2008							
January	1.05	5.2	5.2	5.3	5.3	6.1	6.1
February	1.00						
March	0.98						

3.0 Forecast Revenues

Firm dependable export contracts reflect the '5 x 16 peak period' (five days/week and 16 hours/day), with most of MH's exported energy being sold being on-peak and displacing natural gas electricity generation. As previously indicated, export prices in USD terms have, at least until recently, tended to reflect natural gas supply costs.

Current long term export contracts assure MH of export sales of about 2,500 GW.h/year at prices above 5¢/kW.h (5.5¢/kW.h on average for fiscal 2007/08). Other active contracts are shorter-term market based arrangements, and, for them, prices are now running below 4¢/kW.h for sales volumes of 1,500 GW.h/year.

Overall, the above contracts engaged about 50% of tie-line capacity during the '5 x 16 peak period' in 2007/08.

Interruptible opportunity export sales are broad-time spectrum sales that attempt to capture the remainder of on-peak tie-line availability, and relying on shoulder and off-peak periods to maximize total electrical energy sales. These off-peak sales in fiscal 2007/08 accounted for an additional 8,000 GW.h in 2007/08, and brought an average price somewhat below 5.0¢/kW.h.

3.0 Forecast Revenues

Contract and other energy sales are as follows:

Export Revenue in CDN (\$000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Date	EPE-33	EPE-34	EPE-35	EPE-144	EPE-155	EPE-207	EPE-224	EPE-268	EPE-269
April/07	0	0	0	1,468	1,109	2,303	9,376	1,152	24,811
May/07	0	0	3,857	1,461	1,177	2,451	9,867	0	31,331
June/07	0	1,246	4,101	1,263	1,097	0	9,195	0	33,861
July/07	2,439	1,829	4,930	1,400	1,136	0	9,576	0	33,768
August/07	2,648	1,986	4,836	1,445	1,155	0	9,745	0	34,890
September/07	549	412	2,807	1,206	994	0	8,435	0	22, 852
CDN \$MWh									
Date	EPE-33	EPE-34	EPE-35	EPE-144	EPE-155	EPE-207	EPE-224	EPE-268	EPE-269
April/07				87.65	55.03	68.64	56.07	68.57	73.20
May/07			60.86	79.81	53.29	67.31	54.10		48.55
June/07		36.22	53.19	80.34	54.43		55.73		43.35
July/07	36.30	36.30	54.38	79.84	53.78		54.65		39.45
August/07	35.98	35.98	50.08	78.81	52.74		53.41		38.31
September/07	33.93	33.93	37.44	75.39	51.80		52.87		32.94

The above table illustrates MH's current firm export sales contracts (the first eight columns) and MH's current opportunity sales (EPE-269). As the Canadian dollar strengthened, export prices in Canadian currency declined: 35% of the export

3.0 Forecast Revenues

prices realized by MH were in the 3.5 to 5.0¢/kW.h range; 60% of export sales were at prices between 5.0 and 5.5¢/kW.h; and export prices above 7.0¢/kW.h were realized in only approximately 5% of the sales.

The above low pricing situation may not prevail as new export agreements come into play, with potentially-higher environmental premiums. Opportunity sales outside the agreements currently being negotiated are averaging about 5¢/kW.h, as opposed to the 6-7¢/kW.h that MH had previously anticipated.

MH's forecasts of average export prices employed for the second year of each IFF compare favourably with actual prices in fiscal 2004 and fiscal 2005, though at that time, natural gas prices had soared following hurricanes Katrina and Rita and the connection between natural gas prices and MH's export sales were stronger. However, in the last three years MH has over estimated the average CDN \$ export price.

Fiscal Year	IFF-2nd Year Price Forecast	Actual Results
2006	6.2¢/kW.h	5.2¢/kW.h
2007	7.5¢/kW.h	5.1¢/kW.h
2008	7.1¢/kW.h ¹	5.0¢/kW.h (est.)

¹ From PCOSS 07/08

MH contends that the current situation of a high Canadian dollar and flatter U.S. electricity prices is temporary. Accordingly, the Corporation's forecasts of future energy prices reflect the assumption of higher prices aided by a substantial environmental premium.

MH's IFF 07-1 appears to reflect export market conditions as experienced in fiscal 2007/08 to the end of September 2007, but also assumes that the

3.0 Forecast Revenues

Canadian dollar will return to \$1.16 USD/CDN exchange rate by the end of the forecast period (fiscal 2017/18).

The following table illustrates export values employed in IFF 07-1, and shows the difference in export market prices that could be expected should the Canadian dollar remain at or close to unity:

Year	IFF 07-1 (CDN \$) ¢ Per kW.h	¹ USD/CDN\$ EXCHANGE RATE	² IFF 07-1 (Unity) ¢ Per kW.h	³ Forecast Range PUB/MH II-38 ¢ Per kW.h
2007/08	5.2¢	1.07	4.9¢	5.3-6.2¢
2008/09	6.2¢	1.08	5.7¢	5.3-6.3¢
2009/10	6.3¢	1.11	5.7¢	5.3-6.4¢
2010/11	6.4¢	1.11	5.8¢	5.5-6.4¢
2011/12	6.7¢	1.11	6.0¢	5.9-7.0¢
2012/13	7.1¢	1.13	6.3¢	5.9-7.2¢
2013/14	7.4¢	1.14	6.5¢	6.0-7.5¢
2014/15	7.8¢	1.16	6.7¢	6.3-8.5¢
2015/16	8.9¢	1.16	7.7¢	6.5-10.0¢
2016/17	9.3¢	1.16	8.0¢	6.6-10.5¢
2017/18	10.0±¢	1.16	8.6¢	6.7-11.0¢

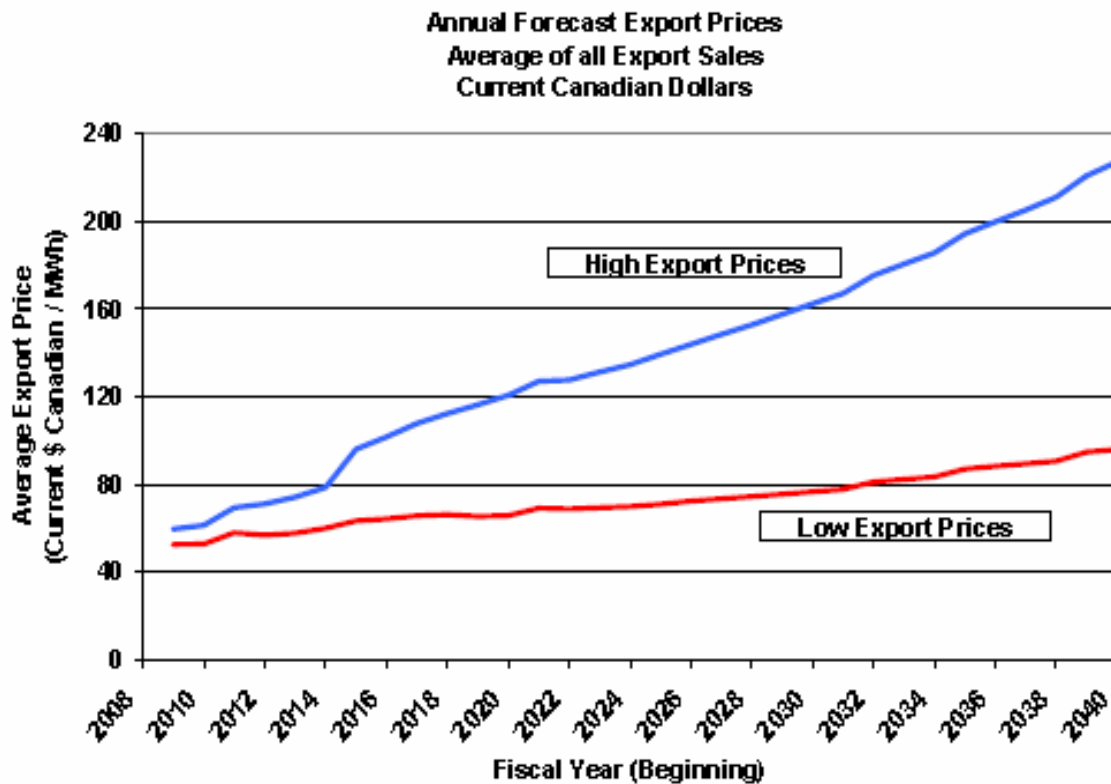
Notes:

¹ MH's forecast of CDN \$ values reflect the average forecast of four independent consultants (all employing a starting exchange rate upward of 1.05).

² IFF-01 export prices recalculated on a unity exchange rate basis for the entire forecast period.

³ In an exhibit provided at the hearing (PUB/MH II-38, below), MH's export energy price market forecast was updated from that of the 2003 Clean Environment Commission application, and suggests a significant upward movement in Midwest Independent System Operator (MISO) region prices will occur in about seven years, assuming past historical exchange rates return.

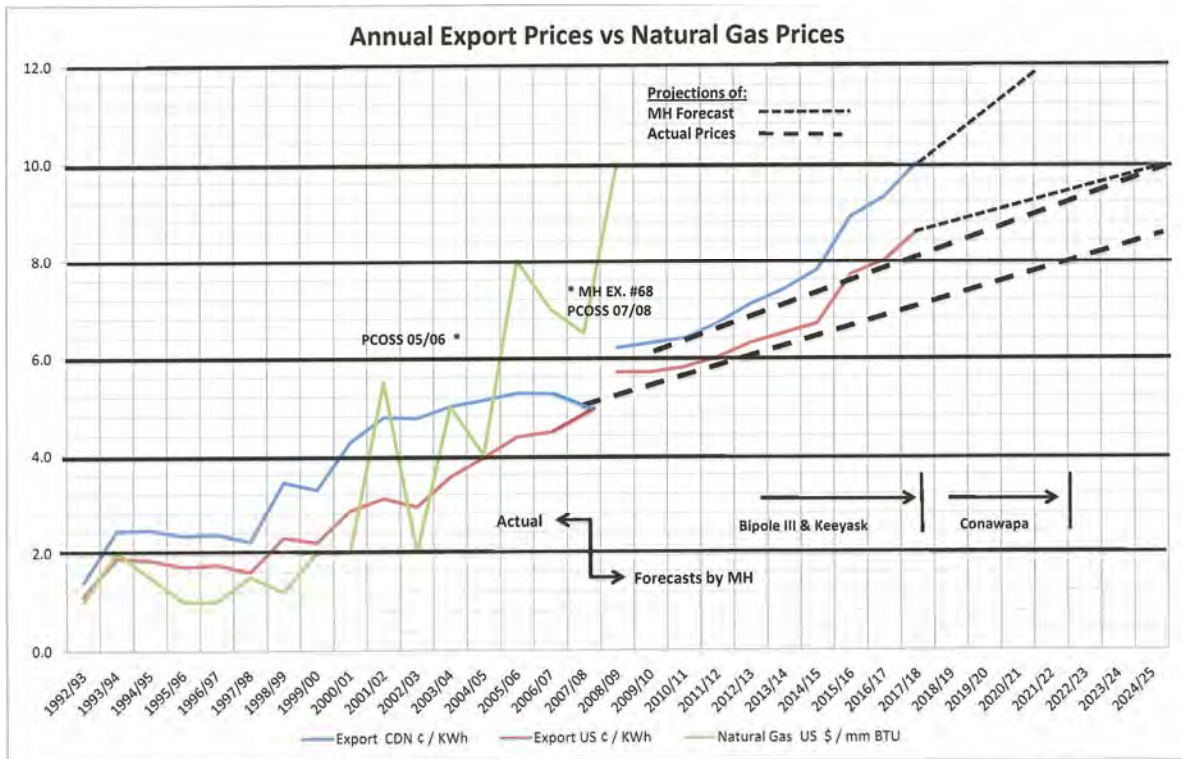
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Comparing IFF 07-1 to the forecast range depicted in PUB/MH II-38 shows that MH anticipates prices in the medium to high range. This would require the exchange rate to return to 1.16 USD/CDN and significant progress on the CO₂ emissions front (recognition of environmental costs reflected in pricing). The 1.5 to 2.0¢/kW.h increase in the high export price curve forecast circa 2015 appears to coincide with MH's anticipation of legislated action on the CO₂ front.

The following chart illustrates that from the early 1990s to about 2004/05, U.S. Export electricity prices achieved by MH (USD) moved in tandem with annual average natural Gas Supply prices. Subsequently, natural gas prices have risen dramatically while electricity export prices (USD) have grown only modestly. In terms of Canadian dollars, the prices have in fact plateaued at about 5¢ per kW.h.

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The export energy prices employed by MH in PCOSS–06 and PCOSS-08 were 6.2¢ and 7.2¢ CDN/ per kW.h respectively. In IFF07-1, MH has forecast export prices (USD) to continue a gradual upward movement until 2014/15 when they are expected to step upward in response to carbon tax legislation and continue to rise more steeply to about 8.5¢ per kW.h in 2018. If a steep rise continued to 2022, export prices would be about 10¢ per kW.h.

MH has suggested that USD/CDN exchange rates will return to about 1.16 by 2015; this would yield forecast average export prices of 10¢ per CDN per kW.h in 2018, and 12¢ CDN per kW.h in 2022, and might be sufficient to support new generation and transmission development [Bipole III, Keeyask and Conawapa] if

3.0 Forecast Revenues

interest rates do not increase. However, if the movement to carbon taxation does not happen, lower prices may well prevail. It can be speculated the prices of 7¢ U.S. per kW.h in 2018 and 8¢ U.S. per kW.h in 2022 would result from projections of recent [2005 to 2008] actual average export prices. If the exchange rate moves to 1.16 USD/CDN as anticipated by MH, the export price forecast would be 8¢ CDN per kW.h in 2018 and about 9.5¢ CDN per kW.h in 2022.

It can be realistically speculated if the costs of Bipole III, Keeyask G.S., and Conawapa G.S. were fully allocated against export revenues, average export sales prices would have to be 11¢ CDN per kW.h to break even.

In the 1990s, natural gas prices were relatively constant \$1.50 to \$2.00 (USD) per BTU. Natural gas-fired electricity generation (with its low Capital Investment requirements) became very attractive as an alternative to building new coal plants. There were predictions as recently as 2001 that all new generation would be natural gas-fired, and numerous new natural gas generation plants did come into service in Western Canada and the U.S. Midwest.

In 2001/02 natural gas prices almost tripled but fell back the following year, only to renew the upward climb in 2003/04. This led to reduced natural gas generation, and consequently greater exports by MH at then favourable average prices of 3¢ to 5¢ U.S. per kW.h

The advent of Hurricane Katrina in 2005/06 led to a further doubling of natural gas prices. However, MISO average market prices for electricity only increased by about 25% and now appear to be almost static at about 5¢ U.S. per kW.h, even though natural gas prices have been above \$11.00 U.S. per MBTU in June 2008 (falling back since). It appears obvious that current MISO market prices for electricity are not being driven by natural gas prices.

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The Mid-Continent Area Power Pool (MAPP) merger into MISO after 2000 reduced the relative significance of natural gas generation in determining MH's export pricing. Access to more coal generation could be responsible for the low off-peak prices. Other possible explanations for this disconnect between market electricity pricing and natural gas prices are that:

- Mandated wind generation, when available, could also be used in conjunction with MH's exports during the off-peak period and create base load energy at prices only marginally above coal generated energy.
- Natural gas generated electricity provides a very limited fraction of the total energy consumed within the MISO region; in the 2005 summer, natural gas generation might have been in play about 25% of the time but only supplied about 5% of the total market energy.

Coal-fired Electricity Generation greatly influences MH export markets in the MISO region and, to a somewhat lesser extent, in Ontario and Saskatchewan. Coal based generation is inherently base load in nature (MISO utilities rely on coal and natural gas, hydro is a minor source) and the replacement of coal-fired generation by MH's hydroelectric power currently brings an average market export price significantly below 5¢/kW.h.

Consequently, at the prices MH seeks for its power (prices well above 5 cents), the Utility is not competitive for base load and can achieve export market access at better prices primarily at the time of MISO system peak loads. For MH to compete for base load, a substantial environmental premium would have to exist for clean energy; that is coal generation would have to be "penalized".

In MH's 2003 Clean Environment Commission (CEC) Application to construct the Wuskwatim G.S., the Corporation's energy price forecasts reflected environmental price premiums for its export sales. At the recent GRA, MH

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suggested that these scenarios are still valid and will come into play within the forecast period. Within its 2003 CEC submission, MH categorized three levels of environmental premiums in 2000 U.S. dollar terms:

- Low (long-term CO₂ valued at \$10 U.S./ton)
- Medium (long-term CO₂ valued at \$20 U.S./ton)
- High (long-term CO₂ valued at \$25 U.S./ton).

For MH's future exports of hydraulic generation to realize prices of 7 cents or more per kW.h, it appears that coal generation by MISO market utilities would have to be assessed substantial CO₂ emission premiums.

Natural Gas Electricity Generation at current natural gas prices can readily be displaced economically by MH exports in the MISO region, even during peak load periods. During off-peak hours, there is little (if any) natural gas generation to displace, resulting in low export prices for the Corporation.

MH's own natural gas generation of electricity is not economical at today's natural gas supply prices. Incrementally, these generation costs range from 5¢/kW.h with natural gas at \$3.00 CDN/GJ, to 15¢/kW.h with natural gas at \$9.00 CDN/GJ.

MH has suggested that pending U.S. legislation on Green House Gas emissions will make new natural gas generation plants more economically attractive to U.S. utilities, as coal should bring much higher environmental cost premiums than natural gas. Such a development would favour MH and its price forecasts over the longer term.

Wind Generation has essentially been mandated in some U.S. states which now specify minimum levels of required renewable energy (not including large hydro)

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that must be incorporated within the supply system. As MISO market wind may be displacing MH exports (on an energy supply basis), about one third of the time, MH exports may also be called upon to serve to back up this generating source for the Americans.

3.2.2 Foreign Exchange

As suggested above, MH's export revenue is significantly influenced by the foreign exchange rate.

MH's present forecast of the exchange rate was updated in July 2007, and the exchange rate utilized in IFF MH-07-1 ranges from 1.07 USD/CDN to 1.16 USD/CDN. The exchange rate used for fiscal 2007/08 was 1.07 USD/CDN, and 1.08 USD/CDN was used for fiscal 2008/09, yet the CDN dollar remains close to parity with the U.S. dollar.

MH's exchange rate forecast fails to fully recognize the significant appreciation of the CDN dollar versus the U.S. dollar, and the underlying reasons for the appreciation that suggest the change may persist. This has had the effect of MH overstating both the value of U.S. export sales and finance expense.

MH indicated that if the CDN dollar was to remain at par with the U.S. dollar throughout the IFF forecast period, this would result in a decrease of \$170 million in its forecast retained earnings. MH indicated that due to its Exposure Management Program, the exchange impact will be limited to the portion of dollar flows that are not perfectly hedged.

MH remained of the view that over the long term the CDN dollar will weaken against the U.S. dollar, consistent with its long-term 1.16 USD/CDN foreign exchange forecast.

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3.2.3 Long-Term Export Contracts

MH has typically entered into long-term export contracts for the sale of dependable energy surplus to forecast domestic customer base loads. By and large, these contracts are for peak (5 x 16) energy sales and reflect a commitment by MH to provide a defined amount of capacity (MW) and energy (GW.h) during the 5 x 16 period throughout a year at an agreed price. MH has also entered into diversity agreements that involve the seasonal exchange of firm energy between the Corporation and a MISO counter-party, at prevailing market rates.

MH currently has executed agreements and/or term sheets for about 3,500 GW.h (900 MW) per year of firm energy for both 2008/09 and 2009/10. These volumes essentially utilize all of MH's dependable energy resources available for export.

The 500 MW commitment to Wisconsin Public Service (WPS), to commence in 2019, will increase MH's firm export requirements to 3,600 GW.h, and this is substantially above forecast dependable energy resources in place at that time. MH will require the Keeyask Generating Station to be in place or, alternatively, will have to employ natural gas turbines to provide the energy. MH will need to proceed with its new generation and transmission plans in a very timely fashion to avoid the high costs that would accompany being obliged to generate power through natural gas, import the power or buy the commitments out.

When the 250 MW contract with Minnesota Power takes effect in 2020, MH will then be committed to supplying 5,000 GW.h of firm energy into the U.S. If Conawapa is not in-service by then, natural gas turbine generation and more wind generation (or imports) will be required to offset a shortfall that could approximate 2,000 GW.h in 2020.

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3.2.4 Inter-Tie Limitations

Extra-provincial sales or purchases of electricity are achieved at Manitoba's borders through a number of two-way transmission connections to the U.S., Ontario, and Saskatchewan. Theoretically, MH should be able to export a maximum of about a) 25,500 GW.h/year into the U.S., b) 2,600 GW.h/year to Ontario, and c) 3,900 GW.h/year to Saskatchewan.

To date, MH's maximum annual exports have been 16,000 GW.h, and those primarily went into the U.S. market. This means that about 7,000 GW.h/year can be exported during the 5 x 16 peak period and a further 9,000 GW.h/year during the off-peak periods. Consequently, during median flow years, MH can provide 3,500 GW.h to its existing firm export contracts and another 3,500 GW.h into the U.S. or other markets at peak period pricing. Other available energy can only be exported during off-peak periods, and at significantly lower prices.

During high flow years, MH can be faced with selling about as much as 9,000 GW.h at off-peak prices. This depresses the average export price achieved, but increases overall revenue.

3.2.5 Potential Hydraulic Generation

Reservoirs within the Nelson-Churchill drainage basins allow MH to store water for later generation of electricity. This 'energy-in-storage', held at virtually no economic cost to MH, permits the Corporation to shift energy generation into other seasons of the year to meet variable domestic demand for electricity and to optimize export sales.

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At the time of the hearing, MH's energy-in-storage was near the historic high level achieved in 1977 when Lake Winnipeg Regulation and Churchill River Diversion came into service. Lake Winnipeg water levels were at the high end of its operating range; flows on the Winnipeg River and the Churchill River were above normal; Saskatchewan River flows were near normal; and only Red River flows were below normal. This situation augurs well for fiscal 2008/09.

In IFF 07-1, MH predicted hydraulic generation of 31,000 GW.h for 2008/09 (representative of about 1,000 GW.h above the median flow scenario), reflecting the-then (at the time of the forecast being prepared) high level of energy-in-storage and median river flows. Current indications suggest hydraulic generation will remain above median for 2008/09.

3.2.6 Fuel and Purchase Power

In defining "dependable energy" available for export contracts, MH counts on about 4,300 GW.h of thermal energy, available to utilize in a worst-case situation. In reality, MH has typically employed about 800 GW.h of coal-fired thermal generation, but, due to the high cost associated with natural gas, rarely has MH fired up its natural gas-fired thermal generation for delivery of energy to the market.

In IFF 07-1, MH expects to employ thermal generation of 350 GW.h and 200 GW.h respectively in fiscal 2008 and 2009. In subsequent mean (average) flow years, coal generation would be fully utilized to support export sales.

IFF 07-1 anticipated that imports of 1,200 GW.h at a cost of about 5¢/kW.h would be required for purchase in fiscal 2009, with a further 100 MW of wind energy purchases. In mean flow years (that is, average flow conditions), about 2,000

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GW.h of imports are expected to be required, in addition to increased wind energy purchases to meet domestic and export commitments.

Power purchase unit costs beyond 2008/09 are forecast to be about 0.5¢/kW.h below average export prices. Presumably, this expectation reflects anticipation of a degree of off-peak purchases for on-peak sales.

MH is also involved in short-term 'energy trading' in the MISO market. MISO transmission rights allow for energy to be purchased from MISO utilities for resale, either to another MISO utility or to Ontario, all within very narrow windows of time. No internal MH generation of energy is employed in short-term energy trading. Usually these trades produce a profit; and both the purchases and sales are recorded in MH's records as revenue and expense.

3.2.7 Costs of Export

As reflected in MIPUG's evidence presented at the hearing, PCOSS-08 results indicate generation and transmission 'bulk power' unit costs for metered energy, as follows:

- Residential 3.72¢/kW.h
- GSS-ND 4.12¢/kW.h
- GSM 3.84¢/kW.h
- GSL>100 3.29¢/kW.h
- Exports 4.83¢/kW.h

These costs neither include existing DSM nor the uniform rate adjustment, nor reflect net export revenue allocations. The class variations in generation and transmission pricing are largely attributable to the impact of distribution system losses and class variable load factors.

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If the above values were recalculated at generation, each domestic class would be reported as incurring 3.0 to 3.2¢/kW.h of generation and transmission costs, and exports would be indicated to incur about 4.4¢/kW.h of generation and transmission costs. The latter indicated export cost compares to MH's forecast export price of 7.0¢/kW.h (and the actual export price of 5.0¢/kW.h for 2007/08).

In the absence of exports, MH's total costs would be lower by:

Share of generation and transmission costs	\$167 M (including water rentals)
Imports	\$134 M
Thermal fuel cost	\$ 23 M
MISO, etc./trading distribution costs	<u>\$ 20 M</u>
	\$344 M

Even without an export operation, MH's costs would still reflect:

Uniform rate adjustment	\$ 17 M
DSM	<u>\$ 25 M</u>
	\$ 42 M

Without an export operation (also without a corresponding import capability), MH's costs would be expected to be higher because of a requirement for the additional usage of natural gas turbine generators, the costs of which are estimated to be between \$50 million and \$100 million/year.

3.3 Interveners' Position

None of the interveners actively questioned the reasonableness of MH's domestic and export revenue and price forecasts. While RCM/TREE expressed concern about the growth of domestic load and the potential for that to result in

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reduced exports, the pricing of such exports was not subject to Intervener comment.

3.4 Board Findings

Overall, in the three-year period 2005 to 2008 MH has exceeded forecasted export revenues despite significantly lower than forecast export prices. Substantially above-average water flows and hydraulic generation has allowed for the higher export volumes, which have more than offset the lower prices.

Export prices in the last three years have averaged about 5.0 CDN¢/kW.h for dependable (firm) and interruptible energy sales. These pricing levels, when adjusted for the exchange rate, suggest a 4.6 U.S.¢/kW.h average MISO market rate. This is substantially below MH's IFF projections for the last three years.

MH's dependable sales into the MISO region in 2007/08 earned about 5.3 U.S.¢/kW.h for 5 x 16 energy. This price was similar to that experienced in 2005/06 and 2006/07, for the period of time that followed by a major escalation of natural gas prices after the damages of hurricanes Katrina and Rita were largely repaired and demand fell with weather deviations. It does not appear that export contracts that came into force about 2005 have provided any market price escalation beyond the consumer price inflation.

MH's opportunity sales into the MISO region in 2007/08 earned about 4.6 U.S.¢/kW.h. This price was also very similar to prices in 2005/06 and 2006/07. It also continued to track below the firm energy price - contrary to MH's forecasts of 2005.

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MH's export market prospects in Ontario and the MISO region have not improved since the CEC market analysis. Rather, it appears that competition from other energy sources - coal, wind, nuclear and purchased co-generation - are reducing the potential.

Accordingly, MH's projected export prices in IFF 07-1 may be overly optimistic, in that they require additional demand for MH exports and significant environmental premiums in future contracts. American electricity prices are also contingent on achieving decisive U.S. actions with respect to GHG emission controls in the near future.

Overall, there are logical bases for the Board questioning MH's forecast of export pricing in IFF 07-1. Lower export revenues will result if:

- Exchange rates remain closer to unity;
- CO₂ pricing does not progress to a \$30 CDN/tonne level in MH's market area within the forecast period;
- New coal generation plant in MISO region does not include substantial CO₂ emission reductions; and/or
- Inter-tie transmission capabilities into MISO are not significantly increased.

Export Sales

For reasons of confidentiality (commercial sensitivity), MH did not provide specific contract energy prices to the Board; the Board was not willing to accept the information in confidence. However, from public information it can be inferred that MH currently has contracts providing 5.5¢/kW.h and may be considering future contract prices that would result in average export revenues of about 7¢/kW.h or less (for firm and opportunity sales) in the absence of legislated carbon pricing in the U.S.

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As such, the Board is unable to assert that MH will not be hard pressed to achieve the forecast export energy prices implied in IFF 07-1. Off-peak pricing is usually several cents/kW.h lower than on-peak prices and tends to lower the average export revenue price. It is possible, perhaps probable, that pending contract negotiations will achieve some indexing relative to natural gas prices and inflation. Indexing to coal generation prices (if employed) would rely heavily on possible future carbon pricing, which, as yet, does not have a definitive timeline.

MH export contracts are priced at 5.3¢/kWh, well below forecast average prices of 6-7¢/kWh. Consequently, opportunity sales prices would have to be upwards of 7¢/kWh, levels not evidenced by the information that is available. MH opportunity export sales are expected to return 4.6¢/kW.h in 2007/08 under a high water flow scenario, and these prices did not exceed firm contract prices. In short, MH's export market pricing has not lived up to the potential anticipated in the 2003 CEC market analysis.

MH's IFF 07-1 forecast export prices are based on a low CDN dollar and the presence of environmental premiums (GHG emissions) for both dependable and interruptible export sales. Existing contract and recently-announced term sheet prices do not appear to provide significant market price escalations beyond general consumer price inflation. In fact, MH's IFF 07-1 forecast export prices appear to require substantial carbon emission premiums, likely to be well in excess of recently suggested cap and trade CO₂ prices.

MH's IFF 07-1 forecast prices may only be achieved by a combination of:

- Exchange rate returning to 1.16 USD/CDN;
- New coal plants in MISO being required to show substantial CO₂ reduction; and

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- Additional inter-tie transmission capability being added in very near future.

MH's most recent commitment to continue supplying peak energy into the MISO region for the 2010 to 2020 period is expected to backstop substantial new wind energy projects in the region. By taking hydraulic energy from MH when wind is not blowing, the receiving utility will be able to blend the costs and achieve possible GHG savings of wind energy with peak energy contract prices from MH and off-peak energy purchases at typically low spot market prices. The resulting average cost of electricity for the U.S. utility could be below MH's forecast export prices.

This suggests that MH's practice of selling all of its available energy capable of being transmitted during off-peak hours supports MISO's energy blending process. It ensures that, in general, substantial surplus energy is available at low prices during the off-peak.

In the Board's view, it might be in MH's best interest to withhold this energy from the market. At minimum, the Board suggests that MH consider this option and the Board will require that MH file a report on this option, providing the option's pros and cons.

Inter-tie Capabilities

Even in the absence of major new generation, additional inter-tie capability would enhance the value of MH's exports in above median flow years. As yet, MH has not gained formal commitments from cross-border counter-parties to expand inter-tie capacity.

Existing transmission inter-tie capacities are a serious impediment to higher prices; current limits are restricting peak energy sales and resulting in frequent off-peak sales at very low prices.

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Recent term sheets signed by MH with Minnesota Power and Wisconsin Public Service offer hope for additional transmission capacity from the Manitoba border into and from the MISO market. This, coupled with new transmission from Riel Station to the U.S. border, could add appreciably to MH's export market potential.

While the concept of an East–West transmission grid has received some political support, there currently seems to be only limited prospects for enhanced export capabilities for MH into Ontario and Saskatchewan. As such, MH does not have an alternative market at the MISO scale.

Hydraulic Generation

MH has enjoyed favourable water supplies in 12 of the last 16 years. On a long-term basis, a reversal of this situation is a virtual certainty. Below median flow years and droughts are in the Corporation's history and can be expected on a regular basis; MH has had a beneficial "run" of better-than-normal water flow conditions now for the better part of two decades, a period of time that has seen MH's highest and lowest net income years (the lowest being the drought year of 2003/04).

Because energy-in-storage normally cannot be substantially carried from year to year, lower hydraulic generation during the forecast period through 2017/18 is an issue of realistic possibility. Export sales are likely to be reduced significantly in below-average flow years, and increased imports at higher cost per unit than the unit value of sales can also be expected in such years.

In the absence of higher export sale prices, MH should expect lower export revenues as hydraulic generation reverts to median, near-normal and below-median levels in the upcoming years. The favourable water supplies

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experienced in 12 of the last 16 years cannot be expected to continue without interruption.

While MH does not provide specific contract information for reasons of commercial sensitivity, access to this information is essential in order to confirm existing and projected contract prices of between 5.5¢/kW.h and 7.0¢/kW.h, and to ascertain what environmental escalation assumptions are being “banked” on. Given the crucial nature of these contracts and assumptions and potential impact on domestic rates, the prior review of upcoming export contracts by this Board would seem wise and appropriate.

Fuel and Purchased Power

A number of questions require responses in assessing MH's forecasts, these include:

- Does IFF 07-1 adequately represent MH's prospects for domestic and export revenues?
- Has MH adequately defined potential energy for export sales, export sale prices, and energy purchase costs (thermal fuel, wind, and imports)?
- MH's coal generation, on a fully costed basis (approximately 6.5¢/kW.h), probably can compete in the MISO market during the peak load periods as it would displace gas generation. On an incremental fuel and variable Operating and Maintenance cost basis (approximately 3.5¢/kW.h) MH's coal generation is an attractive export product.
- If the Brandon Coal Plant is either 'moth-balled' or limited to emergency operations after 2011/12, in accordance with the announced intention of government, MH will have to expect to import, in a median flow year, an additional 800 GW.h at a cost of between \$10 - 20 million/year.

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- The allocation of MH's system costs in PCOSS-08 suggests that exports incur up to about 5.0¢/kW.h in costs for generation and transmission. Recent average export prices have been only slightly above this cost level.
- With the large investments required to meet domestic load and committed and/or contemplated export levels, there may be a need for export revenue prices even higher than the average 9¢/kW.h projected for 2017/18 under IFF 07-1. An updated IFF that extends out to at least fiscal 2027/28 should be provided to the Board by MH, this to project export revenue requirements and domestic rate levels required to support the current assumptions as to the economics supporting export commitments and capital expenditure plans.

In light of the many complex issues and questions related to MH's export program, the Board will direct MH to file a report by January 15, 2009 addressing the following:

- a) An Overview of strategy, options, and historical costs and revenues;
- b) Historical prices (monthly for the last five years) for exports including both on peak and off-peak;
- c) Existing and pending contract commitments with forecast revenues, both aggregated and also disaggregated (in confidence if necessary);
- d) Forecast export revenues – until 2028 identifying opportunity sales distinct from firm contract sales- broken down by on/off-peak;
- e) Detailed assumptions used in market price forecasts (filed in confidence if necessary);

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- f) A testing of MH's assumptions through detailed sensitivity analysis for upper/lower quartile water flows, foreign exchange, domestic load growth and natural gas prices; and
- g) Given the crucial nature of these export contracts and assumptions and the potential impact on domestic rates, MH file for Board review all upcoming export contracts.

4.0 Finance Expense

4.0 Finance Expense

4.1 Changes in Finance Expense

The Corporation's finance expenses were \$454 million in 2003/04, then-representing over 26% of total operating expenses. Finance expenses increased to \$472 million in fiscal 2006/07, yet for the fiscal years 2003/04 through 2006/07 actual finance expenses were \$172 million lower than forecast in IFF 03-1 (2004 GRA), as a result of declining long-term interest rates and the strengthening of the Canadian dollar.

MH forecast finance expenses of \$404 million for fiscal 2007/08, and to increase by \$22 million to \$426 million in fiscal 2008/09 (the latter then to represent 29% of forecast annual operating expenses). The increase is attributable to higher debt levels and to a lesser degree, an increase in the debt guarantee fee paid to the Province, in aggregate offset by foreign exchange gains on the sinking fund related to changes in accounting standards for financial instruments (discussed below).

MH capitalizes interest on all capital projects during the construction phase, and does not amortize these costs and reflect them in rates until the project is in service. MH's finance expense for its electric operation before capitalized interest was forecast at \$515 million for fiscal 2008/09 and \$426 million on a net basis, after deducting capitalized interest of \$89 million.

MH's gross finance expense is forecasted to grow to \$906 million by 2017/18, and to \$616 million on a net basis (again, after adjusting for capitalized interest of \$290 million).

4.0 Finance Expense

Finance expense and capitalized interest for the years 2009 through 2018 are as follows:

Finance Expense (\$ millions) For the years ended March 28/29	IFF MH07-1									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Gross Finance Expense	\$ 515	\$ 572	\$ 609	\$ 640	\$ 657	\$ 695	\$ 756	\$ 803	\$ 864	\$ 906
(Less) Capitalized Interest	(89)	(126)	(158)	(141)	(104)	(152)	(209)	(247)	(285)	(290)
Total Finance Expense	\$ 426	\$ 446	\$ 451	\$ 499	\$ 553	\$ 543	\$ 547	\$ 556	\$ 579	\$ 616
% Capitalized	17%	22%	26%	22%	16%	22%	28%	31%	33%	32%

MH forecast that its debt would grow from \$8.0 billion in 2008/09 to \$13.6 billion in 2017/18, a projected increase of \$5.6 billion. The major increase in finance expense (before and after the deduction for capitalized interest) relates to the planned new major generation and transmission projects.

Over the planning period to 2017/18, capitalized interest is expected to aggregate to \$1.8 billion. And, once the projects are in-service, the interest costs that have been previously capitalized will begin to be amortized/expensed, to be recovered in MH customers' rates.

In addition to the major capital expenditures included in the capital expenditure forecast provided at the hearing, MH also indicated that due to potential new export contracts, it may incur at least \$6 billion more in capital costs and debt for additional required major generation and transmission facilities.

If these plans are implemented, MH's long-term debt may approach \$20 billion by 2022, a large number, particularly in comparison with current provincial debt of approximately \$11 billion.

4.0 Finance Expense

4.2 Exposure Management Program and Foreign Exchange

MH has an Exposure Management Program (EMP) to manage the Utility's exposure to USD-foreign exchange fluctuations. The EMP operates by establishing a natural hedge between USD cash inflows from export revenues and USD cash outflows (long term debt coupon and principal payments, thermal fuel purchases).

The Overall Exposure Strategy concerns itself with a horizon of up to 30 years, and attempts to limit overall US foreign exchange fluctuations to within a range of + or – 20% of total debt. Only the portion of the USD inflows and outflows that are not matched under MH's EMP may affect annual net income. Fluctuations outside the 20% parameter are valued at the market exchange rate, and affect the annual financial result. The exchange rate at year-end is used for the balance sheet presentation of USD-denominated debt and investment instruments.

Commencing with 2007/08, the new standard of the Canadian Institute of Chartered Accountants (CICA) for the recognition and measurement of financial instruments and for hedges will apply to MH, and the forecast result was included in the IFF MH07-1.

The new standard requires significant changes in MH's accounting for financial instruments and hedging relationships, as well with respect to the recognition and presentation of foreign exchange gains and losses in annual financial statements. The change is expected to result in positive impacts to net income in the first two years of the new standard, benefiting 2007/08 by a forecast \$37 million and 2008/09 by \$9 million.

4.0 Finance Expense

As a result of the implementation of the accounting change, the Board notes that MH has forecast amending opening retained earnings for 2007/08 by a one-time increase of \$65 million.

4.3 Debt Management

4.3.1 Long Term Debt

MH's debt was \$7.3 billion as at March 31, 2007, and forecast to increase to \$8 billion by March 31, 2009. MH must rely on debt as its primary source of capital to finance new major generation and transmission projects, as government does not inject capital into the organization but relies on retained earnings from operations to provide capital.

To hold borrowing to a minimum required level, MH funds all routine capital construction from internally generated funds (i.e. from net income). Non-routine and major capital expenditures under way or planned include major new (other than the Pointe du Bois revitalization) generation and transmission projects and the new downtown Head Office building.

MH is in an expansion mode with planned capital spending of \$11.3 billion over the eleven year period between fiscal 2007/08 and March 31, 2018. Over that period MH plans on spending \$3.8 billion on its regular capital program and \$7.5 billion on New Generation and Major Transmission and the Head Office project, as previously reported. As the result of recent export undertakings, yet to be formally confirmed, MH also expects to expend and borrow a further \$6 billion by 2022, in addition to the \$11.3 billion noted above.

Generally, and on average, debt financing is expected to fund approximately 62% of capital expenditures, with the remaining 38% to come from increased

4.0 Finance Expense

retained earnings, the latter from domestic rates and net export profits – the percentages reported excluding the additional \$6 billion of debt related to above.

All in, including the additional \$6 billion, MH forecasts an increase in its debt, from 2008's \$7.3 billion to almost \$20.0 billion by 2022.

4.3.2 Fixed vs. Floating Rate Debt

Pursuant to *The Manitoba Hydro Act*, MH's short-term debt limit has been set at \$500 million; MH uses short-term debt to fund seasonal working capital requirements and bridge the timing before new long-term debt issues.

Historically, and in a typically upward sloping yield curve environment, the borrowing costs of fixed rate long-term debt tends to be higher than for short-term debt, though long-term debt fixes the interest rate for the full and longer period of the term, therefore reducing the risk of having to refinance at higher rates. In contrast, the borrowing costs of short-term or floating rate debt tend to be lower on average than for long-term debt, but are fixed for shorter periods, increasing the risk of having to refinance the debt at higher interest rates.

MH's reported policy is to limit the level of its floating rate debt to no more than 30% of total debt outstanding, and to manage the level of floating rate debt within a target range of 15% to 25% of total debt.

MH utilizes these target guidelines in an effort to provide rate payers with the economic benefits associated with the typically lower interest rates of short-term debt while protecting their customers against the risk of higher refinancing charges by reliance on the majority of borrowing being through long-term bonds.

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MH's percentage of floating rate debt at each quarter end over the past three fiscal years has been:

Period Ended	Floating Rate Portion
Mar-2004	21.85%
Jun-2004	19.33%
Sep-2004	18.58%
Dec-2004	19.34%
Mar-2005	18.76%
Jun-2005	17.88%
Sep-2005	18.18%
Dec-2005	18.00%
Mar-2006	16.61%
Jun-2006	17.52%
Sep-2006	17.71%
Dec-2006	18.20%
Mar-2007	18.98%

Over the past four years, long-term interest rates have been at recent historic lows, and MH's general preference during this period has been to fix the majority of its new financing at the relatively attractive and low long-term interest rates. The strategy of favouring long-term fixed rate financing during periods when long-term interest rates are low relative to historic norms, and when the premium associated with long-term fixed rate debt is low and the yield curve is relatively flat, may produce costs over the long-term similar to that of a strategy of adding more floating rate debt, but with the added benefit of reducing the volatility of interest expense.

4.0 Finance Expense

4.3.3 Sinking Fund Management

MH's bonds obligate the Corporation to establish and maintain a sinking fund, that are segregated investments held towards ensuring repayment of the debt. This obligation is currently legislated.

The legislated minimum contribution requirement is 1% of the long-term debt outstanding at the end of the previous year, plus 4% of the balance of the sinking fund at that date. Contributions for fiscal 2007/08 and 2008/09 will be equal to the legislated minimum, and total approximately \$100.6 million and \$109 million, respectively. MH has \$246.5 million of USD denominated debt maturing during fiscal 2008/09, which is forecast to be fully retired through the sale of the related sinking fund investments.

MH reported that changes to CICA accounting standards with respect to Financial Instruments have made sinking funds less valuable, and, as matters were currently understood, the Corporation did not foresee any negative impacts from either borrowing at current interest rate levels, or to access capital from an elimination of the sinking fund requirement from its Act.

MH alluded to a possible transitional phase that could be considered that would, over a few years, substantially reduce or eliminate the Sinking Fund. MH has further suggested that such an elimination might be associated with a forecast cost saving of \$93 million over the 11 forecast years of IFF07-1.

4.0 Finance Expense

4.4 Interveners' Positions

The Coalition

The Coalition observed that MH has kept floating rate debt at about 20% of the Corporation's overall debt portfolio, which now exceeds \$7 billion. The Coalition noted that MH's longstanding policy is to have no more than 30% of its debt in the short-term floating category, and that it has held to a target guideline of between 15% and 25% of total debt for the category. The Coalition noted that the policy is over 20 years old and cited studies indicating that employing a higher proportion of short-term floating debt than has been and is the current practice may lower interest costs and reduce finance cost volatility.

The Coalition submitted that while floating debt appears to offer economic benefits, high levels of such debt doesn't necessarily lead to the lowest level of risk. Coalition stated that with MH's overall debt in excess of \$7 billion and with the current level of short-term debt in the range of 15 to 25% of that total, there appears to be a potential to move approximately \$700 million of currently long-term debt to short-term, and that if by so doing MH was able to reduce its interest cost by a mere five basis points, annual savings of \$3.5 million would result.

The Coalition expressed concern that MH has been managing its floating debt policy at the bottom end of the 15 to 25% range, and noted that in the 13 quarters between March 2004 and March 2007, MH's proportion of floating debt was below 20% for 12 of the quarters. While not suggesting mismanagement of the debt portfolio, the Coalition suggested the potential for savings and the level of risk related to decisions to be made warranted a re-examination of the current policy.

4.0 Finance Expense

The Coalition recommended that the Board request MH to engage an independent review of its floating vs. fixed target range maximum, with consideration of options to be in terms of economic benefit and stability.

MIPUG

MIPUG requested that the Board direct MH to seek relief from the province with respect to all sinking fund requirements as soon as possible, and that the sinking fund requirement for MH's debt should be eliminated. MIPUG noted the projections of savings to come with such elimination, that being \$93 million over the IFF07-1 forecast period. MIPUG noted that MH had indicated that the Corporation does not expect that the elimination of the sinking fund requirements would have any adverse affect on its borrowing rates, its ability to access capital markets, its available range of borrowing instruments, or the debt rating for the Province of Manitoba.

MIPUG suggested this was an urgent matter, given the scale of borrowings anticipated over the next 15 years, and in light of the forecasted reduced cost of longer-term borrowing.

4.5 Board Findings

Finance Expense

The Board is concerned that the projected growth of finance expense through to 2017/18 and beyond is being obscured by the increasing amount and percentage of interest being capitalized i.e. \$89 million or 17% of gross finance expense in 2008/09, to increase to \$290 million or 32% in 2017/18. Given MH's expansion plans are consummated, MH's debt is expected to increase to about \$20 billion by 2022, and gross finance expense is expected to almost double from 2008/09

4.0 Finance Expense

levels to over \$900 million in 2017/18, while the annual amount of capitalization of interest is expected to more than triple, masking the cash cost of financing major new generation and transmission projects, costs that will ultimately have to be recovered in rates.

The Board notes that MH's policy and practice of capitalizing interest raises a question of the risk of inter-generational inequity, and requires close examination. That said, the Board realizes that if less capitalization occurred, then more of MH's current years' interest costs would be expensed and reflected in rates. In short, without capitalization, the ratepayers of today through to those of the era when the new generation and transmission assets would be in-service would face increased rates to finance capital projects, projects intended (other than through the economic benefits associated with construction) to benefit future ratepayers.

Thus, the Board accepts there is an argument for MH's current approach. To expense costs in the current period and reflect them in current rates when the costs related to the projects are not expected to provide "rate related" benefits until the future would mean charging the current generation of MH's customers for costs that, arguably, should be met by future generations.

The major question relates to risk and conservatism with respect to financial planning. Probably the best approach is a balanced one, an approach that would have current ratepayers pay for some of the costs of proceeding with new projects – which will generate current economic benefits for the Province – while holding future generations responsible for the majority of these costs, as it is those future generations that are intended to reap "rate-related" benefits from the new construction.

4.0 Finance Expense

The potential for the approach to change lies in part with the upcoming adoption of IFRS. The new standards may not allow MH to capitalize costs for future amortization to the same degree as is now occurring. And, as indicated above, expensing costs that are now being capitalized in the period incurred will result in future ratepayers' rates being reflective not only of "current" costs, including currently amortized costs, but also cost burdens that would otherwise have been reflected in future rates for future ratepayers.

For the welfare of succeeding generations, this generation will likely have to shoulder more responsibility for the costs and risks being assumed by the capital expenditure plans of MH. This was the experience with the prior development of generating stations in the lower Nelson River – i.e. there is precedent for less capitalization of current debt costs.

Fixed versus Floating Debt

As to what represents the optimal mix of fixed vs. floating debt, the Board agrees that increasing the exposure to short-term floating rates would likely benefit current ratepayers in lower finance costs in the near term, but it might also expose future ratepayers to greater volatility and risk over the long-term (as and if interest rates increase).

Given that the debt, by its very nature, has been incurred to fund capital assets with expected lengthy service lives, MH's approach of funding the majority of its debt requirements with fixed term debt appears reasonable.

However, with the anticipated unprecedented growth in debt levels, the Board sees merit in the concerns raised by the Coalition and agrees that MH's longstanding policy related to floating debt would benefit from an independent

4.0 Finance Expense

review. Such a review may suggest a different mix between fixed and floating debt, which may reduce finance expense.

Because of the potential for MH's overall debt level reaching \$20 billion, possibly over twice the debt taken on by the province on its own account (with all debt guaranteed by the province) the Board will direct MH to engage an external assessment of the Corporation's relative weighting of fixed vs. floating debt, and file a report with the Board on or before June 30, 2009.

Sinking Fund

The Board notes that elimination of the sinking fund requirement has been forecast to result in savings of \$93 million over an eleven year forecast period. While the potential savings are alluring and demand a consideration of the positions of interveners and the views of the Utility, the Board believes that MH has been served well in the past by the obligation to have sinking funds. Yet, the Board accepts that its future benefit may be diminished due to changes in accounting standards and improvements in the capital markets.

The Board understands MH's perspective that elimination of the sinking fund requirement will have no impact on the credit rating of MH or the Province, nor would it limit MH's access to the capital that it clearly needs to proceed with its expansion plans.

Out of an abundance of caution, and in light of the major capital expansion and related anticipated growth in debt levels now planned, the Board will recommend that MH seek independent advice, as well as advice from government and its credit rating agencies, as to the merits of a possible elimination of the sinking fund requirements.

5.0 Operating, Maintenance, and Administrative Expenses

5.0 Operating, Maintenance, and Administrative Expenses (OM&A)

5.1 General

Over 74% of OM&A costs relate to labour costs, which include employee benefits extending to pension obligations. Actual and forecast OM&A expenses for fiscal years 2004 to 2009 are:

Operating and Administrative Costs (\$000's) Fiscal Year	Actual				IFF07-1	
	2004	2005	2006	2007	2008	2009
Labour						
Wages, Salaries & Overtime	343,424	354,661	370,289	383,597	411,091	425,514
Employee Benefits	59,154	68,442	70,184	73,636	78,335	79,902
	<u>402,578</u>	<u>423,103</u>	<u>440,473</u>	<u>457,233</u>	<u>489,426</u>	<u>505,416</u>
Other Expenditures						
Employee Safety & Training	-	5,275	3,686	3,487	5,267	5,367
Travel	23,062	23,534	26,212	27,729	29,679	30,399
Motor Vehicle	16,687	17,726	19,380	19,735	20,017	21,036
Materials & Tools	23,325	23,891	26,040	25,420	24,663	25,249
Consulting & Professional Fees	8,024	7,269	7,229	8,498	10,071	10,137
Construction & Maintenance Services	11,373	13,345	13,700	13,711	15,481	15,669
Building & Property Services	21,799	21,031	22,973	24,697	24,522	24,700
Equipment Maintenance	9,571	9,546	10,720	11,606	12,235	12,475
Consumer Services	5,081	4,203	4,301	4,316	4,881	4,980
Computer Services	4,547	3,959	4,293	2,622	1,077	1,102
Collections	5,035	5,161	6,790	7,218	5,359	5,466
Customer & Public Relations	4,956	5,223	5,585	6,493	4,581	4,698
Sponsored Memberships	1,163	1,149	1,012	1,187	1,172	1,197
Office & Administration	14,996	15,448	15,904	14,939	15,532	15,882
Communication Systems	2,027	1,844	1,447	1,866	1,834	1,870
Research & Development Costs	3,742	3,685	3,542	3,251	3,414	3,483
Miscellaneous Expense	1,957	2,461	2,143	2,423	2,757	2,812
Contingency Planning	-	-	-	-	4,941	7,254
Operating Expense Recovery	<u>(17,263)</u>	<u>(18,104)</u>	<u>(19,199)</u>	<u>(20,579)</u>	<u>(19,806)</u>	<u>(20,192)</u>
Total Costs	<u>542,660</u>	<u>569,749</u>	<u>596,231</u>	<u>615,852</u>	<u>657,103</u>	<u>679,000</u>
Less: O&A Charged to Centra	<u>(52,786)</u>	<u>(55,232)</u>	<u>(53,085)</u>	<u>(53,505)</u>	<u>(56,600)</u>	<u>(58,000)</u>
	<u>489,874</u>	<u>514,517</u>	<u>543,146</u>	<u>562,347</u>	<u>600,503</u>	<u>621,000</u>
Capital Order Activities	(147,693)	(157,730)	(170,459)	(176,994)	(196,853)	(207,500)
Capitalized Overhead	<u>(58,824)</u>	<u>(58,174)</u>	<u>(62,028)</u>	<u>(61,887)</u>	<u>(63,450)</u>	<u>(64,500)</u>
O&A Costs Attributable to Electric Operations	<u>283,357</u>	<u>298,613</u>	<u>310,659</u>	<u>323,466</u>	<u>340,200</u>	<u>349,000</u>
Number of Customers	<u>501,650</u>	<u>505,660</u>	<u>509,791</u>	<u>516,861</u>	<u>520,259</u>	<u>524,220</u>
OM&A Cost Per Customer (\$)	<u>565</u>	<u>591</u>	<u>609</u>	<u>626</u>	<u>653</u>	<u>665</u>

5.0 Operating, Maintenance, and Administrative Expenses

Total OM&A expenses attributed to electric operations and after allocations to Centra Gas and the deferral and capitalization of such expenses to be amortized in future periods have increased from \$283.4 million in 2003/04 to \$349 million in 2008/09, a compounded annual growth rate of over 4%.

MH indicated that over the last few years, the Corporation has experienced cost and operating program pressures relating to: increased maintenance requirements (due to aging infrastructure); wage and benefit settlements that exceed inflation; additional overtime and increased staffing levels (to meet extra-provincial requirements); the expansion of programs (to meet higher customer numbers) and needs; and the meeting of environmental and other stakeholder expectations. These pressures were reported to be continuing and being compounded by a looming shortage of skilled labour, manifesting itself in higher training and labour costs.

MH stated that the annual compound growth in labour and benefit cost per Equivalent Full Time (EFT) position has averaged 3.8% over the period 2002 to 2007. The increases are due to a combination of general wage increases, merit and/or pay schedule increments, and other adjustments. MH reported that wage and benefit settlements that have been above the general inflation rate reflect higher compensation requirements for attracting and retaining skilled trades and professional staff and, as well, higher compensation requirements for northern staff.

Unfortunately, MH was unable to provide a segregation of OM&A expense associated with maintaining/sustaining existing assets versus expenses associated with changed processes and plans and actions related to construction of new plant.

5.0 Operating, Maintenance, and Administrative Expenses

5.2 Staffing Levels

MH indicated that between 2005 through 2009, its staffing levels were projected to increase further, by 455 EFT employees (from 5,866 to 6,321), with related labour costs to increase by \$102.8 million. These increases were reported to be largely due to increased work requirements, with the largest additions expected for staffing levels in Power Supply (234 EFT) and Transmission & Distribution (142 EFT). MH attributed the growth of 180 EFT's between fiscal 2004/05 and 2008/09 as being related to meeting the Corporation's operating and maintenance needs, particularly given the plans for major expansion.

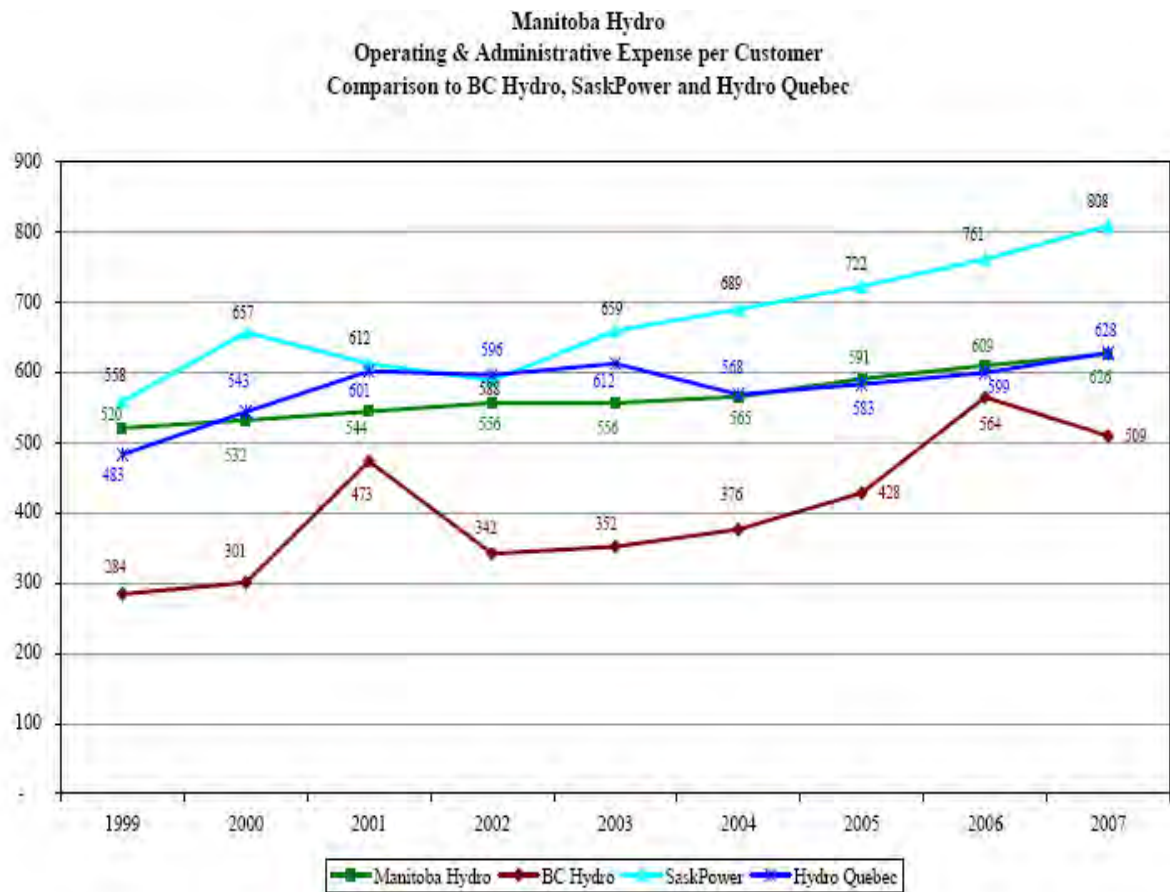
MH indicated that currently there were 200 unfilled EFT positions from the staff level forecast for fiscal 2007/08, and that between 125 and 150 of the EFT vacancies were due to difficulties in recruiting. The remaining unfilled positions were reported to be the result of awaiting the completion of the new head office and expected staff synergies to arise as a result of the consolidation of staff in one location. MH further noted that the hiring difficulty associated with the skill shortage had resulted in forecasted fiscal 2007/08 OM&A costs being \$16 million less than forecast for the ten months ended January 31, 2008.

5.3 OM&A Costs per Customer

MH OM&A costs per customer have increased from \$565 in 2004 to \$626 in 2007. While MH indicated that it was not appropriate to directly compare its OM&A cost per employee to the ratios of other utilities, it noted that based on annual report information, Hydro Quebec's OM&A cost per customer was \$628, BC Hydro's cost per customer was \$509 and SaskPower's was \$808, in 2007, as noted in the following graph.

5.0 Operating, Maintenance, and Administrative Expenses

MH compared its OM&A cost per customer with the other utilities for the years 1999 to 2007:



MH reported that its OM&A expense per customer experience, relative to its established targets in the Corporate Strategic Plan, is as follows:

Fiscal year	CSP Target	Actual
2004	\$600	\$565
2005	\$584	\$591
2006	\$600	\$609
2007	\$612	\$626
2008	\$640	\$653 (est)
2009	N/A	\$665 (est)

5.0 Operating, Maintenance, and Administrative Expenses

The Board notes that MH's OM&A costs and OM&A expense per customer levels were and are materially reduced by the capitalization of significant amounts of OM&A, making the comparisons with the other utilities of questionable value.

5.4 Capitalization of Operating and Administrative Expenditures

5.4.1 Current Capitalization Practices

MH segregates costs between operating activities, which are charged against the operating income for the year, and capital activities, which are charged to future periods and amortized over the future life of the capital project. MH capitalizes certain of its OM&A expenditures.

Many of the expenditures are capitalized as deferred charges, and are amortized over a period of years; others allocated to construction in progress and amortized once the asset is in service over its expected service life.

MH indicated that employee's timecard their activities to specific capital projects. This amount, combined with other related costs, is charged to a capital order. In addition, MH also capitalizes 'overhead' by applying predetermined overhead rates to all capital projects.

OM&A expenses were \$615.8 million in 2006/07, that is before capitalized activities and overheads. MH indicated that approximately 29%, or \$177 million of the \$615.8 million, was charged to capital order activities with an additional 10% (\$61.9 million) charged as capitalized overhead. Overall approximately 39% of OM&A was capitalized.

MH forecast OM&A expenses of \$679 million for fiscal 2008/09, of which \$207.5 million (30%) is to be charged to capital order activities and \$64.5 million (9%) as capitalized overhead.

5.0 Operating, Maintenance, and Administrative Expenses

MH capitalizes annually in excess of \$60 million of overhead costs to its capital projects, to be amortized when the capital asset goes into service. In addition to the capitalized overhead, MH also includes some overhead costs to determine its activity rates, which are used for allocating direct costs of labour to operations or to capital projects.

MH also capitalizes Demand Side Management (DSM) expenditures arising from its Power Smart program. DSM program costs are deferred and amortized on a straight-line basis over 15 years, regardless of the expected present value of the benefits to be realized.

The carrying value of deferred DSM was \$123 million at March 31 2007, and forecast to reach \$180.9 million as at March 31, 2009.

Planning Studies involve costs related to uncommitted major generation or transmission facilities. These costs are recorded as deferred charges and are amortized to operations (expensed) on a straight-line basis over 15 years. If there is reasonable assurance that a project will proceed to construction, any unamortized balance related to that project is then transferred from deferred charges to construction in progress. The carrying value of the Unamortized Planning Studies balance was \$28 million as at March 31, 2007 and forecast to be \$22.5 million as at March 31, 2009.

Construction in Progress consists of contracted services, direct labour, material and expense, a proportionate share of overhead costs and interest applied at the weighted average cost of capital related to projects in development. Once the projects become operational, the costs are recovered in rates through depreciation and finance expense.

5.0 Operating, Maintenance, and Administrative Expenses

Establishment of the Affordable Energy Fund (AEF) by the provincial legislature, was funded by an allocation of electricity export revenues, and is to be used to fund low-income energy efficiency initiatives throughout the Province.

The AEF resulted in the creation of a \$35 million deferred charge (asset) and a corresponding \$35 million deferred credit (liability) in MH's financial accounts (balance sheet). Annual program expenditures from the fund are to be expensed against income in the year incurred, with the corresponding asset and liability reduced by the equivalent amount.

The balance of the AEF at March 31, 2007 was \$34 million, after deductions for low-income related DSM project expenses, including overhead allocations, and the balance of the AEF as of March 31, 2009 was forecast to be \$28 million. No interest accrues on the balance.

Goodwill of \$62 million related to the 1999 acquisition of Centra Gas Manitoba Inc. and \$46 million of additional goodwill associated with the acquisition of Winnipeg Hydro (WH) remains on MH's balance sheet. Goodwill represents the difference between the purchase prices paid for these enterprises and the values assigned to specific assets obtained. Goodwill is not amortized unless judged to be impaired, and impairment tests are performed annually in accordance with GAAP requirements – to-date, these tests have not indicated any impairment of the recorded goodwill.

MH also capitalizes experience gains and losses on its Employee Pension Plan, and amortizes the net result over the expected "life" of the employee group. The unamortized balance was reported to currently be in the \$30 million range.

5.0 Operating, Maintenance, and Administrative Expenses

As of March 31, 2007, MH had \$457 million of deferred charges recorded as an asset, including rate-regulated assets which, if MH were not subject to rate regulation would be charged to operations in the period that they were incurred.

The balance of the rate-regulated assets at March 31, 2007 were as follows:

Regulated Assets (\$ millions)	March 31, 2007
Deferred taxes (Centra Gas)	\$ 40
Site restoration costs	\$ 38
Acquisition costs	\$ 26
Power smart programs – gas	\$ 11
Total	\$115

Income Taxes paid by Centra Gas (July 1999) as a result of its change to non-taxable status upon its acquisition by MH were deferred and are being amortized on a straight-line basis over 30 years. Acquisition costs related to MH's purchase of both Centra and Winnipeg Hydro are also being amortized on a straight-line basis over 30 years.

Site restoration costs are deferred and amortized on a straight-line basis over 15 years.

5.4.2 Mitigation Costs

MH is party to a December 16, 1977 agreement also involving Canada, the Province of Manitoba and the Northern Flood Committee Inc., the latter representing the five First Nations in the communities of Cross Lake, Nelson House, Norway House, Split Lake and York Landing.

5.0 Operating, Maintenance, and Administrative Expenses

This agreement provides, in part, for compensation and remedial measures to ameliorate the impacts of the Churchill River Diversion (CRD) and Lake Winnipeg Regulation (LWR projects). Comprehensive settlements have been reached with all communities except Cross Lake. Expenditures incurred to mitigate the impacts of the CRD and LWR projects were \$17.3 million during fiscal 2006/07 and, to March 31, 2007, \$616 million had been spent in the effort. MH forecast to spend an additional \$30.5 million in fiscal 2007/08 and a further \$29.9 million in fiscal 2008/09.

In recognition of the anticipated future additional mitigation payments, the Corporation recorded a liability of \$132 million as at March 31, 2007. Mitigation related expenditures are amortized over the remaining life of the Generation and Transmission assets to which they pertain.

MH has also entered into agreements with the Province of Manitoba whereby MH has assumed certain obligations of the province with respect to certain northern development projects.

To-date, MH has assumed obligations totalling \$143 million and in return, Water Power Rental charges were fixed until March 31, 2001. The remaining liability outstanding as at March 31, 2007 was \$13 million.

5.5 Future Changes in Accounting Standards

5.5.1 Adoption of International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board (AcSB) has established that 'publicly accountable enterprises' (MH, including its subsidiaries, is such a body) are to prepare their audited accounts in accordance with International Financial

5.0 Operating, Maintenance, and Administrative Expenses

Reporting Standards (IFRS). In short, IFRS is to replace current Canadian Generally Accepted Accounting Principles (GAAP) and it is to be implemented effective January 1, 2011. As annual accounts are provided with comparative information for the previous year, MH will be required to also develop IFRS-based accounts as of fiscal 2010 – 2011, to be disclosed as comparative information when it files its 2011/12 accounts.

In advance of the adoption of IFRS, Canadian GAAP standards have changed for rate-regulated operations. Specifically, section 1100 General Accounting of the CICA Handbook will apply to the “recognition and measurement of assets and liabilities subject to rate-regulation” for fiscal years beginning on or after January 1, 2009.

MH stated that the interim changes to GAAP are not expected to have an impact on its fiscal 2008/09 or 2009/10 financial results and statements. MH has taken the position that it will continue to be allowed its current accounting practices for rate regulated assets through its adoption of a secondary source of GAAP found in US accounting standards, also related to accounting for regulated operations. The assets and liabilities subject to rate regulation pursuant to US accounting standards amounted to \$115 million at March 31, 2007.

Yet, early adoption of IFRS is provided for by GAAP and, depending on the actions of the Board, may result in a change in accounting for rate-regulated assets ahead of the required adoption date for IFRS.

5.5.2 Future Financial Implications of Adoption of IFRS

MH indicated that the major implications expected from the adoption of IFRS are reduced annual and forecast net income and retained earnings as of the date of

5.0 Operating, Maintenance, and Administrative Expenses

adoption. These impacts are due to “stricter” standards than now exist with Canadian GAAP as to what must be capitalized as opposed to what should be charged to operations in a given year.

Although the implications for MH are not fully known, there is a likelihood that IFRS will require MH to recognize a higher level of expense each year, and a corresponding lower level of costs will be deferred and capitalized.

The current version of the International Accounting Standard (IAS) 38 - Intangible Assets, on which IFRS is based, is much more comprehensive than current Canadian GAAP. In order for an intangible asset to qualify, it must be separable from the entity, such that it can be sold, transferred, licensed or otherwise disposed of to another entity. Also, in order to record an intangible asset, it must be probable that future economic benefits are attributable to the asset and will flow to the entity.

If regulatory assets and deferred pension costs are not allowed under IFRS, the deferred balances at the date of implementation will no longer be allowed to be presented on the balance sheet and will be deducted from Retained Earnings, restating retained earnings to a lower balance.

MH stated that the full impact that IFRS will have on MH financial statements is not known at this time, as IFRS accounting standards are still in the discussion stage, with some of the discussion centred specifically on the capitalization policies of rate-regulated enterprises.

A major matter of considerable potential importance to the issue of rates to be resolved is whether IFRS will allow capitalization and deferral of certain costs for recovery through rates over future periods, providing that the utility's regulator assures that future rates will reflect the deferred or capitalized costs.

5.0 Operating, Maintenance, and Administrative Expenses

MH indicated that it would be engaging a consultant to guide the Corporation through the transition to IFRS, and expects to have a better idea by the fall of 2008 on what impacts IFRS will have.

As of yet, there had been no preparation of pro forma IFF modeling the potential impact of the new accounting standards. MH further indicated that while the Corporation has no present plan to make an earlier adoption of IFRS, this decision may be revised once the impact that IFRS will have on its financial reporting is known.

In particular, MH testified that certain of its current capitalization policies may be affected by IFRS, and that several types of currently-deferred charges may have to be expensed for accounting purposes in the year they are incurred, unless it can be demonstrated that the charges have a future benefit to MH, thereby satisfying the requirements of IFRS. Included in deferred charges are \$115 million of charges related to rate-regulated assets, which may or may not have a basis for capitalization and deferral under IFRS standards. MH further indicated that deferred charges related to Planning Studies (current balance, \$28 million) and the Affordable Energy Fund (current balance, \$34 million) may also not meet the IFRS capitalization criteria.

Another specifically cited major impact of IFRS adoption will be on MH's practices related to capitalized overheads, which are now in excess of \$60 million annually. MH's understanding is that overheads will have to be a direct charge to specific projects, and to continue MH's current approach may involve undue administrative complexity. Potentially, the full \$60 million of annual capitalized overhead could be charged against operations in the year incurred, under IFRS.

MH further indicated that the allocation of direct labour to capital projects also includes an element of overhead, which also could be in contravention of IFRS

5.0 Operating, Maintenance, and Administrative Expenses

and require revision. MH indicated that such a change in this matter could result in an additional \$20 million to \$30 million of annual costs to be expensed rather than capitalized. (MH testified that its understanding is that overhead capitalized in the years prior to IFRS will not have to be written off, and that IFRS would be prospective rather than retrospective in this regard.)

MH also stated that its current accounting policy that amortizes experience gains and losses on the Employee Pension Plan may also be affected by IFRS, and will likely result in a one-time write-off of the then-current unamortized balance, now being approximately \$30 million. The future impact on operating results and retained earnings with respect to this particular matter will depend on the experience of the pension fund to fiscal 2010 – 2011, and thereafter.

MH also stated that its capitalization of mitigation costs may also be affected by IFRS, in that although costs may still meet the standards for capitalization, the tests used to treat them as an asset may require a more direct correlation to a specific capital project than is currently used.

MH opined that its current deferral of Power Smart Programs (\$123 million) can be demonstrated to have a future benefit (that being the intended and expected creation of increased export revenue) and thus, continued deferral may be allowed under IFRS. Natural Gas Power Smart Programs (Centra) were specifically identified as possibly not meeting IFRS capitalization criteria, and thus may require expensing in the year incurred.

Overall, MH advised that the changes expected to be brought on by IFRS may result in annual increases in operating expenses in the order of \$100 million (now, the equivalent of a 10% rate increase for domestic customers). In addition, MH has reported a potential \$100 million write-off of disallowed assets against

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retained earnings on implementation of IFRS (and this may prove a low estimate).

MH understands that the application of IFRS will generally be prospective but noted that there are certain electives for first time adopters of IFRS that allow a deemed approach to be used to value items such as property, plant and equipment. This, too, could involve adjustments to MH's accounts, including retained earnings.

MH advised it expected to have its consultant's advice by the fall of 2008, at which time a more definitive assessment of the impact of IFRS will be available.

5.6 OM&A Cost Control Process

MH utilizes a comprehensive budgeting process to establish and monitor its OM&A expenses. An IFF target is established through a top-down process whereby submissions are made to MH's Executive Committee for review and assessment of the amount of operating costs required to operate the utility.

The Executive Committee reviews requests and makes submission to MH's Board of Directors for approval of a final budget. Once approved, target levels are allocated to the business units, and business units prepare detailed operating plans. Business units are expected to review opportunities for both cost increases and decreases in their detailed budgeting process, and are required to submit that information to the Executive Committee to assist with the next year's target-setting process. Variance analyses are performed monthly to evaluate the performances of the business units.

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MH advised that its forecast for annual OM&A incorporates a 1% productivity factor to its otherwise expected labour costs in each of the years. Labour costs represent approximately 75% of MH's OM&A costs.

In Order 07/03, the Board stated:

“Corporate performance measures, such as the operating and administration costs per customer or per kW.h targets, are of great assistance in assessing the performance of MH's cost control initiatives compared to other utilities. The Board recommends MH aggressively pursue meeting its operating and administration costs-per-customer target while finding ways to increase productivity. The Board also encourages MH to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements in its operations as compared to other utilities.”

In its last three Corporate Strategic Plans (CSP), MH has outlined various strategies for improving productivity, including process benchmarking and the development of corporate and business unit performance targets. In the 2005/06 CSP, MH outlined two strategies for improving corporate financial strength: “leverage technology to reduce costs and the benchmarking of key corporate processes.”

In the 2006/07 CSP, MH again outlined strategies for improving corporate financial strength, citing intentions to “leverage technology to reduce costs” and “benchmark against recognized service leaders”. Yet, MH indicated at this GRA that it had not recently participated in any benchmarking exercises comparing its costs with those of comparable utilities.

In updating the Board on the status of these initiatives, MH stated that terms of reference and/or work plans have yet to be developed. MH conceded that work needed to be done in the area but stated that staffing resource limitations affect projects to be prioritized, and that benchmarking of processes was not of the highest priority level.

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5.7 Intervener's Positions

The Coalition

The Coalition questioned whether MH had done what it said it would do to improve corporate financial strength. Mr. William Harper, a Coalition witness, expressed concern as to whether MH is undertaking everything it can do to identify and pursue productivity and efficiency improvements. Mr. Harper noted MH is forecasting an average annual increase in OM&A expense of 3.9% for the two year period fiscal 2007- 2009. Mr. Harper observed that the OM&A forecast of growth for this period was higher than reported in previous financial forecasts for the same period.

Mr. Harper further noted that the historical growth in OM&A over the last four years was 4% per annum. Looking forward, he noted that MH is forecasting annual customer growth of 0.6% per year, down from 0.9% historically, while wage and salary increases per FTE are also forecast to move down from 3.8% to 2.6%. Mr. Harper stated these two factors alone would suggest that OM&A spending over the two year period should be increasing significantly less than the 4% experienced historically, and less than the 3.9% increase proposed in the application.

Mr. Harper indicated that the potential annual savings related to a change in the expense growth factors would be \$7 million in fiscal 2007/08 (the year finished before the hearing concluded) and \$14 million in fiscal 2008/09, representing approximately a potential 1% reduction in rates.

Harper opined that overall projected OM&A cost for the periods through fiscal 2008/09 are too high and that a growth rate of 3% per annum (as opposed to the 3.9% forecast) would be more in line with the underlying cost drivers. Mr. Harper

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recommended the Board direct a reduction from the proposed rate increase of 2.9% (to 1.9%) to reflect this factor.

During the 2003-2007 period, MH's annual productivity improvement was reported to have been in the order of 1% per annum. However, during this period actual OM&A costs (when normalized on a per-customer basis) were generally higher than earlier forecasts and also higher than the annual CSP targets. Mr. Harper suggested that the evidence called for more discipline in the management of costs. Mr. Harper further stated that MH has consistently missed its CSP performance targets related to electric operations OM&A cost-per-customer. The OM&A cost-per-customer target for fiscal 2007/08 was \$640 per customer; he suggested setting rates to match this target would reinforce the message that OM&A must be managed within expectations.

Mr. Harper suggested that productivity improvements cannot occur without action, and that what was required is an environment where opportunities for such improvements can be identified and staff encouraged to aggressively pursue them.

Mr. Harper noted that while appropriate strategies have been articulated in the CSP (such as leveraging technology to reduce costs and benchmarking key corporate processes against recognized service leaders), these steps have not been undertaken, and with respect to benchmarking, Mr. Harper noted that MH has indicated not having participated in any formal benchmarking exercises comparing its costs to those of comparable utilities. And similarly, that there has been no formal benchmarking process undertaken, even though the strategy has been articulated in prior corporate strategic plans over the last few years.

In the area of corporate and business unit performance measures, the Corporation has yet to develop a term of reference of work planned for this

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initiative, and Mr. Harper stated that MH should be encouraged to follow through on the strategies with a view of ensuring that the 1% per annum productivity improvement is actually achieved, if not exceeded.

The Coalition stated that given the large number of pending major new projects, it would be difficult for MH to balance priorities. The Coalition stated it was important for MH to get the “fundamentals” right, and that benchmarking has not been seen as a high enough priority for the Corporation.

The Coalition also cited the concerns raised by Mr. Bowman, a witness for MIPUG, about the divergence between forecast and actual OM&A results, a divergence that undermines the achievement of financial targets. The Coalition noted Mr. Bowman’s observation that systematic increases in OM&A spending have been a consistent and compounding reason underlying MH’s failure to achieve the debt:equity target of 75:25.

The Coalition noted an example from its review of IFF05-1, where the forecast cost per customer in fiscal 2009 was \$338 and that by IFF-07-1 the forecast costs per customer for the same year had increased to \$360. The Coalition seconded Mr. Bowman’s observation that this negative trend threatens to undermine the achievement of MH’s financial targets.

With respect to the upcoming adoption of IFRS, the Coalition supported MH’s position that it was premature to reach any conclusions on the impact at this time.

In supporting Mr. Harper’s recommendation for the Board to reduce MH’s requested revenue increase by 1%, the Coalition observed that while, at least in the short term, granting less than the requested rate increase might appear to be

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counter-productive to the goal of achieving financial targets, for the Coalition the short-term “pain” would likely prove beneficial in the longer term.

Reducing the requested rate increase would still leave the option for MH to put forward an application in 2009 or 2010 demonstrating improvements in cost control, and seeking increases in the revenue requirement once new capital expenses are projected and the Corporation has more certainty about the financial impact of the adoption of IFRS.

Mr. Harper suggested OM&A expenditures be evaluated on four criteria.

1. A review of cost elements, focusing on those that have changed significantly from one year to the next, to test the reasonableness of the underlying changes.
2. Evaluation of key cost drivers; with variations to be explained on the basis of unique or one-off requirements.
3. Benchmarking of the specific activity costs of the Utility against other utilities of similar characteristics.
4. Review of utility spending plans and priorities, incorporating an evaluation of an Asset Condition Assessment, to support any proposed increased spending. An Asset Condition Assessment (ACA) would, according to Mr. Harper, provide a “snapshot of the utility’s assets, noting the degree of degradation and need for rehabilitation and replacement”. For Mr. Harper and the Coalition, MH should be required to demonstrate that the condition of the assets has changed such that additional spending is required.

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MIPUG

MIPUG also noted that MH's OM&A forecasts have progressively increased since the 2002 Status Update review, and that the Corporation's actual spending also routinely exceeds forecasts.

MIPUG noted that the growth in the level of OM&A spending has occurred despite prior Board directives for MH to consider cost control initiatives, citing that recently the Board noted in its decision with respect to MH's interim 2007 rate increase that it "...relies on MH's Board of Directors and senior management to continuously strive to operate the utility efficiently and incur no material costs that are not warranted from the perspective of sound business practices".

MIPUG submitted that MH's evidence in the proceeding did not support the conclusion that MH's OM&A spending is at levels consistent with an efficient operation. For MIPUG, this is particularly true when viewed in the context of forecasts prepared in recent years, as noted in some detail in the evidence of the Coalition's witness Mr. Harper which indicates increasing levels of spending.

MIPUG's witnesses Mr. Bowman and Mr. McLaren demonstrated that MH's OM&A forecasts generally trend higher, and have been doing so in each successive forecast since IFFO2-1, with IFFO7-01 being the latest of the series. Mr. Bowman and Mr. McLaren further observed that actual OM&A expenses have consistently been above the rising forecasts. In comparing the forecast period fiscal 2003 through 2013 with the forecasts in IFF 02-1 and IFF 07-1, Bowman and McLaren indicated a cumulative increase in OM&A of 10% as a consequence. MIPUG submitted that the Board should develop instructions and measures to better ensure MH applies effective cost control in the future.

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MIPUG further suggested that the Board direct MH to provide full benchmarking information comparing its operations with other utilities, for review in a future GRA. MIPUG also suggested the Board direct MH to provide OM&A actual and forecast expenses by major function (Generation and Transmission, distinct from Distribution, Customer Service, and Administration). This request focused on the rationale that Generation and Transmission costs are not driven by the number of customers and, as such, a "cost/customer" ratio is of "no meaning".

For MIPUG, OM&A cost-per-customer ratios should be restricted to the distribution, customer service and administration functions.

In discussing the implications of the approaching adoption of IFRS, MIPUG stated there was insufficient information to make meaningful determinations on potential impacts on MH at this time. MIPUG urged the Board to direct MH to include with its next GRA filing an IFRS transition plan, including copies of reports produced for MH's consultants, and a summary of potential financial impacts.

With respect to adopting regulatory accounting to counter any negative implications of IFRS (in short, the construction of a set of financial statements prepared on a different basis than IFRS GAAP), MIPUG stated it was premature to consider whether such a step should be undertaken. MIPUG noted that regulatory accounting is an acceptable process currently being utilized by the Ontario Energy Board (OEB). MIPUG opined that there are an increasing number of issues that may lead to such an approach becoming justified in future, and in that event, the Board should not be averse to adopting the approach if needed.

As to MH making charitable donations, MIPUG opined that charitable donations, sponsorships and general economic development expenditures should not be reflected in rates, if material. However, MIPUG stated that there is no reason to

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exclude such costs in determining rates when such costs are not of material consequence to MH's financial results and forecasts. MIPUG opined that the current level of donations, as disclosed by MH in the GRA, should not be disallowed for reflection in rates, because the amounts involved are not material.

MKO

MKO agreed with the other interveners that MH should do more to restrain OM&A expenses, and also opined that MH's capital cost forecasts do not appear to be reasonable in light of the experience of actual costs. MKO also noted that MH's OM&A forecasts have generally trended higher in each successive forecast since IFF 02-1, with IFF 07-01 being the highest to date. MKO also demonstrated that MH's OM&A expenses have, in most cases, exceeded targets, and questioned MH's achievement of productivity gains.

MKO supported MH benchmarking costs against other utilities, and requested MH report to the Board why MH's costs deviate from the statistical average of benchmarked utilities.

MKO supported the suggestion of other Interveners that the implications of IFRS be considered in a future proceeding, at which time additional evidence would be required of MH and be tested by the Board and interested parties.

MKO recommended that MH revenues should ordinarily not be used for charitable purposes without specific direction from government. MKO suggested that MH had paid the Province \$198 million in fees and capital taxes in 2007, and suggested that with provincial earmarking of such contributions for charitable purposes, the donations should be made directly by government, as that would be, in MKO's view, more appropriate.

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MKO also recommended that MH and the Board clearly distinguish MH's necessary and appropriate costs (expenditures and investments related to operations, mitigation and agreement obligations) from "charitable donations". MKO suggested that endowments funded by MH's net export revenues (intended to benefit "MH Affected Communities", such as for regional economic development, community infrastructure and the enhancement of fish and wildlife) should not be "charitable donations".

5.8 Board Findings

The Board remains concerned with the growth of OM&A expenses, particularly the level and growth of these expenditures prior to deferrals, capitalization and allocations to subsidiaries.

As stated in Order 101/04:

"The Board will expect MH to maintain vigilance over its costs, so that the additional revenues [from PUB approved rate increases] contribute as they are intended to move towards achieving the debt to equity target more quickly than suggested in MH's 2003 Integrated Financial Forecast."

Expectations from past recommendations related to OM&A expenses have not been met. The Board expects MH to control OM&A expense levels to assist in meeting its financial targets. Further control of OM&A costs is vital given the planned major capital expansion, and in light of the fact that MH will not meet its debt to equity target over the current forecast period.

And, in this Order, the Board continues to be concerned with MH's "aggressive" capitalization and deferral policies with respect to OM&A expenses. While there is an argument for the practice, the net result is that costs now being incurred are not reflected in rates until years, in fact decades, later, meaning the current

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generation of ratepayers leave the results for the generations that will follow to meet.

The following concern, from Order 143/04, echoes past concerns raised by the Board with respect to the capitalization policies followed by MH. The Board then stated:

“The Board is concerned with the range and level of costs being capitalized by MH. While the Board understands that many of the projects undertaken by MH are long-term in nature, both from a benefit and cost perspective, aggressively capitalizing costs and selecting long amortization periods increases the rate risks to future generations of electric customers. If the Board questions whether aggressive capitalization policies are prudent..... The Board does not dispute that MH's accounting is based on GAAP, only that GAAP also provides for a more conservative capitalization approach.”

In Order 117/06 the Board further stated:

“The Board is concerned with MH's present capitalization and notes MH's comment that net export revenue represents a form of “windfall” which cannot be guaranteed to continue at recent levels. Even though net export revenues have been significant over the past decade, progress towards the debt:equity target of 75:25 is slow.”

The Board notes MH defends its level of OM&A expenditures on the basis of 'need' and has argued that it has successfully 'controlled OM&A cost per customer account'. The Board is of the view that this premise will remain not fully substantiated, given the enormous amount and percentage of total OM&A costs that have been and are forecast to be capitalized, at least until adequate peer benchmarking has been performed and the results reviewed.

As expressed in past Orders, for two decades MH's annual net income result has been assisted/increased by its deferral and capitalization process. If non – direct construction costs (an allocation of the salary of staff in contracts not involved in actual construction but more in planning in supporting roles) had been expensed

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in the period incurred, rather than capitalized or deferred, annual net income would have been considerably lower, and possibly negative in many years; OM&A cost per customer account would have been much higher; rate pressure would have been considerably greater than has been demonstrated to date; and retained earnings would be much lower.

As indicated, while there is an argument for MH's current approach (to expense costs in the current period and reflect them in current rates, when the costs relate to projects not expected to provide benefits until the future, would mean charging the current generation of MH's customers for costs that could arguably be met by future generations), MH's rate structure and rates, even including the increases directed and indicated in Order 90/08, is premised on past and future OM&A cost deferrals and capitalization. If the approach was to change (a distinct possibility with the upcoming adoption of IFRS), costs now capitalized in the current period would be expensed. This would, again as previously noted, result in current and future ratepayers being billed for costs reflective not only of current costs but also cost burdens avoided by past ratepayers as a result of the current process of deferral and capitalization.

The Board does not believe OM&A should be adjusted based on the corporate strategic plan target of \$640 per customer as suggested by the Coalition. The Board is not convinced the benchmark is completely relevant, given the level of expense deferrals and capitalization impacting the current result. Once more stringent capitalization requirements are put in place with IFRS such a metric may have more value and use in the establishment of rate requirements.

To arbitrarily direct, as some interveners have suggested, that a significant amount of expense not be reflected in rates, as a way of sending a message to

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MH that it is spending too much on OM&A, would be irresponsible given what the Board and the recent process has revealed.

This Board must rely on the public GRA process to provide opportunities to assess OM&A, and while the Board continues to express concern, there is nothing on the record sufficiently concrete to justify not accepting the costs in rates.

IFRS

The Board notes the coming adoption of IFRS is likely to have a material impact on MH's financial reporting and results. The Board further notes that AcSB has, in advance of IFRS, established a new reporting standard with respect to accounting for intangible assets [including goodwill, deferred charges and capitalized expenditures].

These new requirements are effective for fiscal years beginning on or after October 1, 2008 and could have an impact on MH's fiscal 2009 - 2010 accounts. However, the Board is aware that MH is looking to U.S. Federal Accounting Standards Board (FASB) accounting standards in support of its continuing its present accounting practices in the short term.

The Board's primary concern is not accounting for the short-term, but the long term, particularly with MH's massive capital expenditure plans.

The Board notes in The FASB Handbook section 71.34 (in part), Accounting for the Effects of Certain Types of Regulation, reads as follows:

"The regulator's action provides reasonable assurance of the existence of an asset (paragraph 9). Accordingly, the regulated enterprise would capitalize the cost and amortize it over the period during which it will be allowed for rate-making purposes."

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The Board notes that interpretation of the above standard, which suggests continuing the current accounting practices of MH until IFRS is in place, will require the continued support of this Board.

Given MH's reliance on a U.S. accounting standard, the question is - if the Board were to develop its own regulated retained earnings, net income and debt:equity ratio approach (ahead of mandatory IFRS adoption), one that is more "conservative" and has the effect reflecting in expenses and rates, more current period expenses, would regulatory accounting, in effect "two sets of books", be in the public interest?

At the hearing, MH's witness Mr. Derksen dismissed changes to rate regulated accounting at this time, noting that the CICA had deferred the matter awaiting a future conversion of Canadian GAAP to IFRS. Under US GAAP, exemptions from normal GAAP for rate regulated utilities depend upon the regulator directing the accounting treatment and are premised on the regulator effectively guaranteeing the utility future cost recovery of expenses then to be deferred through higher rates later on.

If the Board took the position that current capitalization and deferrals should not occur, perhaps reflecting its assessment of IFRS guidelines, MH would lose the ability to defer such items in its accounts, and this would affect total current expenditures, net income and, likely, rates.

The Board remains concerned with the Corporation's ongoing aggressive deferral and capitalization accounting practices, and recommends that MH consider early adoption of IFRS standards. The Board further recommends that the Board's prior concerns as well as its current views as expressed in this Order be brought to the attention of both MH's external auditors and also, its independent consultant to assist the Corporation with its IFRS transition strategy.

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In any case, with the reflection of IFRS in its accounts, intangible assets now on MH's books may have to be expensed. .

The Board further notes that MH has not adjusted its current forecast (IFF 07-1, which, as previously reported extends to fiscal 2017/18) to reflect the implications and impact of the new accounting standards. The Board accepts that such an adjustment, at least in a formal final sense, may be premature as the true impact and implications have not yet been resolved. Nonetheless, the Board is concerned with the impact on MH's financial statement of the transition to IFRS. The Board needs to be made aware of the implications to arise from the adoption of IFRS so as to be in a position to consider its regulatory options relative to the Board's jurisdiction.

Accordingly, the Board will direct MH to provide it a report by February 1, 2009, to be prepared by an independent professional accounting firm.

The Board will require MH to file, by January 15, 2009:

- a) A report explaining and quantifying the proposed transition to IFRS.
- b) A copy of MH's consultant's report indicating the projected impact of the adoption of IFRS on the Utility, specifically with respect to MH's current deferral and capitalization approaches, and as to the likely status of goodwill now recorded in its accounts.
- c) An articulation of the new proposed MH accounting policies detailing how they comply with IFRS
- d) An explanation of any changes to the internal operations of MH which may be planned or contemplated to offset any increased annual expenses expected as a result of the adoption of IFRS; MH's and its consultant's views of the Board's regulatory options, including a review of the pros and

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cons of special purpose financial reporting for utilities for rate-setting purposes.

- e) Updated IFF and CEF forecasts, covering the years 2008 to 2028, reflecting the expected impact of the new standards and assumptions of related operational changes as may be planned or contemplated by MH.

MIPUG recommended that regulatory accounting be considered as an acceptable deviation from GAAP for rate-setting purposes, following IFRS being implemented and assuming the implementation will have major implications for annual expenses, net income, retained earnings and, quite possibly, future rates.

MIPUG noted that regulatory accounting is prevalent in Ontario, and is a practice followed by OEB. However, the Board further notes that the OEB regulates natural gas utilities and 80 electric distribution companies, with varied ownership structures. In the Board's view, the use of regulated accounting by the OEB may be due more to the fact of the number of electric utilities it regulates and a perceived need to account for results on a consistent basis, rather than a desire by the OEB to depart from GAAP for rate-setting purposes. There is only one electric utility in Manitoba, MH, and it is regulated by this Board.

The Board notes the importance that MH and its financial position, plans and results has in the considerations of debt-rating agencies regularly assessing the financial strength and debt rating of the Province. The financial statements of MH are currently prepared in accordance with GAAP. IFRS will be the new GAAP required by all utilities, including MH. Any deviation from GAAP for rate-setting purposes may not be viewed in a positive light by debt-rating agencies, and a negative view could have negative implications on the credit rating of the Province, potentially limiting the source of capital and increasing the cost of borrowing for both MH and the Province.

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Accordingly, the Board currently does not believe that separate regulatory accounting should be considered at this time, an approach that would involve deviating from GAAP and, in a sense, establishing a second set of books for MH rate-setting purposes. The Board further believes that a change to regulatory accounting, even if a case for it is established and found valid by the Board, is premature at this time.

The potential for adopting separate regulatory accounting standards that deviate from GAAP (after the adoption of IFRS) will be considered by the Board only once the Board has more information on the potential impact of the accounting changes on MH arising from IFRS, the implications of adopting regulatory accounting, and the potential implications of staying with GAAP or moving to regulatory accounting for rate-setting for the Utility's customers.

Staffing Levels

MH's personnel complement (measured in EFTs - equivalent full-time positions - and based on hours worked as recorded by MH) has soared since 1999, the first large increase accounted for by the additional staff added to the complement following the purchase of Centra Gas, followed up in 2002 by another major influx of personnel upon the purchase of Winnipeg Hydro (WH).

Even taking into account the additional personnel associated with those purchases, and after acknowledging MH's claims of synergistic savings resulting from one employer of all staff, it remains evident that considerable additional personnel growth also occurred, and this is ahead of the actual start up of construction (other than site preparation and roads at Wuskwatim) of Wuskwatim, Pointe du Bois, etc. (an increase of a few hundred additional personnel relates to new trainee positions associated with the Wuskwatim project).

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Staffing levels are projected to further increase as the capital expenditure plan develops and is implemented. That said, and some growth explained, the Board remains of the view that MH should develop enhanced analytical tools to allow for a better understanding of the reasons for staff increases over the years. It is important to understand that staff costs represent the vast majority of OM&A expenses. Such staffing analytical tools should be developed and incorporated in the benchmarking analysis which the Board will direct be undertaken in this Order.

Cost Control Measures

The Board notes that staffing levels (EFT) is an important metric, though only one among others that should be further developed. The Board further notes that while the development of performance benchmarks and metrics has long been established as a performance goal of the Corporation, due to prioritization it, regrettably, is yet to be acted on.

The Board agrees with the Coalition that MH should develop performance benchmarks just as the Corporation has indicated it has planned to do for several years in a succession of corporate strategic plans. Given OM&A expense growth in prior years and forecast for the future, MH should assist GRA proceedings by providing the Board better tools to assess the appropriate level of OM&A for rate-setting.

Accordingly, the Board will direct MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most currently-available data and including:

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- a) Primary key drivers of OM&A in each operational division [Board preference is to allow for a comparison with a greater number of other utilities].
- b) Comparable other Canadian Utility data for each of the drivers.
- c) Key comparison indicators including staffing levels.
- d) A comparison with and discussion of industry best practices.
- e) Potential improvement areas.

The Board expects to be apprised of the scope of the study in advance of it being undertaken, and will anticipate being provided the opportunity to provide direction.

The Board is convinced that both the Province and ratepayers will benefit from the developments of appropriate metrics to assess the reasonableness of the level of current and future OM&A expenses, in advance and particularly because of, the proposed major capital expansion program.

MH's justification for the level and growth of OM&A expenditures includes an indicated need for increased maintenance and/or replacement of aging capital assets to maintain the safety and integrity of its electrical system. Recently this assertion is difficult for the Board to evaluate, as the Board lacks jurisdiction over MH's capital expenditures, yet capital expenditures are the major driver of rates.

One item that is lacking is sufficient support for the level of maintenance and upgrades to the existing capital assets of the Corporation. The Board notes Mr. Harper's suggestion that as a best practice, MH should undertake an Asset Condition Assessment, and his view that such a study will provide information on the degree of degradation of existing assets and the need for rehabilitation and/or replacement of capital assets.

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Despite prior cautions from the Board, MH intends to spend, on average, \$385 million a year on capital construction through to and including 2017/18, capital expenditures that are not related to major generation and transmission projects, which are accounted for separately. In an effort to better justify and demonstrate the necessity of such normal capital expenditures, the Board agrees with interveners on the need for a periodic Asset Condition Assessment Study.

The Board agrees that a study of this nature, done at reasonable intervals, will assist in evaluating MH's progress in maintaining the electrical system, and should also provide additional support for the level of OM&A being incurred and forecast. The Board believes it's appropriate that MH undertake such a study, and will so direct MH to undertake and file with the Board an Asset Condition Assessment by June 30, 2009, that defines:

- a) major assets and categories of assets;
- b) the estimated remaining economic life of each major asset and category of asset;
- c) an indication of the implications for OM&A costs related to maintaining required and scheduled maintenance;
- d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;
- e) forecast expenditures for planned renovations and/or replacements with respect to now-available energy supply and transmission; and
- f) Dam Safety Condition Assessment and Maintenance requirements.

In advance of the commencement of the Asset Condition Assessment Study, MH is to file with the Board detailed Terms of Reference containing the scope for

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undertaking such a study and a definition of the resources to be employed, on or before January 15, 2009.

New Head Office

With respect to MH's head office project, which is currently expected to involve capital expenditures in the range of \$280 million (approximately 1/5th of the Corporation's retained earnings), the Board remains concerned that MH's savings from operating synergies and abandoned current leases may not develop sufficient overall savings to avoid a rate impact arising from the project.

MH suggested that there would be no increase in rates to pay for the new corporate head office, and that the Corporation expects the financial benefits of productivity improvements, and lapsed lease payment requirements, to offset the approximate \$20 million of annual additional costs associated with its new building.

The Board has heard MH suggest it will target headcount (EFT) reductions and lease lapses to help offset the increased costs expected to arise with the new head office (depreciation, property and capital taxes, interest, operating costs, etc.), but also heard doubts expressed as to whether such savings would fully materialize.

The Board will direct MH to file a report with the Board by June 30, 2009, detailing the final all-inclusive capital cost of the corporate head office project including such things as construction cost, furniture and equipment, telecommunications, equipment leases and the contemplated or planned operating actions to recover incremental costs related to the new head office. The Board reaffirms that no additional incremental costs are to accrue or be allocated to Centra as a result of the new MH head office.

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The Board reminds MH that the Corporation has already been directed by the Board, through an Order arising out of a Centra GRA proceeding, that no additional costs are to accrue or be allocated to Centra as a result of the new head office. The head office came about as a condition of MH's purchase of WH; it had nothing to do with Centra.

6.0 Depreciation & Amortization

6.0 Depreciation & Amortization

6.1 General

Depreciation and amortization expense was \$276 million in fiscal 2003/04, rose to \$314 million in fiscal 2006/07, and is forecast to further increase to \$332 million for fiscal 2007/08 and \$347 million for fiscal 2008/09.

MH attributed \$6.5 million of the \$18 million increase expected in fiscal 2007/08 (from fiscal 2006/07) to new depreciation rates, while the balance was attributed to normal amortization on increased capital assets.

MH instituted new depreciation/amortization tables as of April 1, 2007, flowing from a study that resulted in a forecast annual overall 2.2% increase in depreciation/amortization expense. The new study replaces the previous study that was undertaken in 2002; MH updates its depreciation/amortization studies every five years.

At the GRA, MH advised that it had revised the annual depreciation rate for the Pointe du Bois Generating Station from 1.94% to 11.65% to allow for the full amortization of the unamortized capital cost of the existing and old generating station over its estimated remaining life of nine years (a new generating station is planned to be constructed on the site, one with a higher capacity). As a result, the annual depreciation expense related to the existing facility increased by \$1.9 million annually. MH plans on decommissioning the existing generating station effective March 31, 2015.

Depreciation and amortization is forecast to grow to \$453 million by 2017/18, due to planned major increases in capital assets.

6.0 Depreciation & Amortization

6.2 Board Findings

The Board agrees with the new depreciation rates, including the acceleration of the depreciation of Pointe du Bois to recognize that the existing asset is to be decommissioned and replaced. However, the Pointe du Bois upgrade and forecast work on the Slave Falls G.S., coming relatively shortly after the purchase of WH, raises a question as to the adequacy of present depreciation and amortization rates in use for the other generating, transmission and distribution assets acquired when WH was purchased, notwithstanding the five year review of such rates.

The Board further notes the provincial plan for curtailing Brandon Coal Plant generation [MH has estimated reducing the use of the plant to emergencies only will reduce its annual net income forecasts by \$10 to \$20 million dollars]. When the IFF is updated to reflect IFRS and other changes and issues raised in this Order, the decision to reduce the output of the Brandon Coal Plant should be reflected. And, if there is a decision to close the plant, this asset should be subject to an accelerated depreciation similar to that now in place for Pointe du Bois.

Accordingly, the Board will require MH to file a report by January 15, 2009 with the Board, indicating whether the current depreciation rates for the Generation, Transmission, Distribution and other assets purchased from Winnipeg Hydro, including Slave Falls, and the Brandon Coal Plant remain appropriate and the related proposed capital replacement, expansion and decommissioning costs.

The accelerated write-off of the existing Pointe du Bois facility also brings into question the price paid for Winnipeg Hydro, a price that also included a requirement to build the new head office, the cost of which is now roughly four times the original “placemaker” for the project reported by MH at the 2004 GRA.

6.0 Depreciation & Amortization

The Board has concerns with the planned growth in capital expenditures and the related forecast increases in depreciation and finance expense, and comments further on this topic in other sections of this Order.

7.0 Payments to the Province

7.0 Payments to the Province

As a Crown Corporation, MH is not subject to corporate income tax, and it is neutral as to the federal Goods and Services Tax (GST), since GST paid for its purchases are refunded. While these exceptions are of considerable value to the Corporation, and, by extension, to its customers, MH does pay the Provincial Retail Sales Tax on its purchases, and, as well the Corporation Capital Tax, a tax that is to be deleted for private companies. The Province of Manitoba also levies a number of other fees on MH.

At the 2004 GRA, reported annual payments made to the Province from MH for fiscal 2003/04 were \$175 million. The aggregate payment increased to \$219 million in fiscal 2006/07 and was forecast to increase further to \$230 million in 2007/08 and \$223 million in 2008/09.

Total payments to the Province either made or forecast to be made from 2002/03 through 2008/09 are summarized as follows:

Payments to the Province (\$millions)

Fiscal Year	Actual					IFF 07-1	
	2003	2004	2005	2006	2007	2008	2009
Corporation Capital Tax	33	35	35	36	37	38	40
Payroll Tax	6	6	7	7	8	8	8
Water Rentals	95	62	104	124	106	114	103
Debt Guarantee Fee	70	67	68	66	68	70	71
Sinking Fund Admin Fee	1	1	1	1	-	-	1
Special Payment	200	4	-	-	-	-	-
Total Payments	405	175	215	234	219	230	223
Retained Earnings	1135	707	845	1,265	1,386	1,650	1,774
Retained Earnings including Payments to the Province ¹	1,540	882	1,060	1,499	1,605	1,880	1,997
Total Payments as a % of Retained Earnings - Return to Shareholder ²	28.8%	14.5%	22.1%	18.3%	14.1%	12.2%	11.2%
Total Payments as a Percentage of Gross Revenue	30.3%	13.6%	14.3%	12.8%	13.4%	13.8%	13.9%

Note 1. Approximates what retained earnings would have been at the end of the year if no payments to the Province were made.

Note 2. The Return to Shareholder is based on the payments to the Province over average Retained Earnings in each year (including the 2003 and 2004 special payments to the Province)

7.0 Payments to the Province

Overall, MH's payments to the Province have represented, excepting for 2003, a return on overall electricity sales to the shareholder in the range of 14%. While the concept of summary budgets results in the net income of MH also being recognized as income for the Province, that income is not available to the Province for its departmental spending unless paid in the form of a fee or dividend. Previously, this Board has recommended that no dividends be paid by MH to the Province until such time as MH has achieved and is expected to hold to its 75:25 debt:equity ratio target.

While MH pays Corporation Capital Tax to the Province based on its invested capital, which is a function of the level of capital employed, both debt and equity, Corporation Capital Tax is being phased out for all private corporations at the end of 2010. MH will remain subject to Capital Tax beyond 2010.

Water rentals relate to the use of provincial water resources, and the fees are paid to the Province on a monthly basis based on hydraulic generation. When, about a decade ago, MH was transferred certain northern liabilities of the Province, water rental rates were frozen to 2001.

The Provincial Debt Guarantee Fee is 1.0 % of the sum of MH bonds, provincial advances to MH and provincial short-term debt outstanding related to MH at MH's year-end. The fee was increased from 0.95% to 1.0% effective for fiscal 2006/07, and the level remains unchanged in MH's forecast for the full forecast period of IFF07-1. The Sinking Fund Service Charge is 0.075% of the amount of the sinking fund balance, and is paid to the Province for its managing of MH's sinking fund investments. MH's sinking fund is a covenant related to its bond issues.

A now expired legislative amendment to the MH Act provided for a special payment to the Province (dividend), which was made through a first instalment of

7.0 Payments to the Province

\$200 million in 2002/03, followed by a remaining instalment of \$4 million in 2003/04. For the purpose of comparison, dividends are regularly paid, and on an annual basis, by Hydro Quebec and B.C. Hydro to their respective provincial government owners.

The Province recently announced an intention to introduce new carbon legislation towards reducing Green House Gas emissions (GHG) in the province. MH stated that if it continued to operate the Brandon coal generating station at current production levels, the cost of the expected emissions tax on coal would be in the order of \$5 to \$6.5 million per year, commencing in 2011. However, it is expected that the generating station will, in the near future, be operated under very restricted conditions (for emergencies), which would reduce the emissions tax considerably. Nonetheless, the loss of the current level of average annual coal generation is forecast by MH to be \$10 to \$20 million annually – the operation of the plant has been profitable for the Corporation.

In addition to the payments to the Province, MH makes Grants in Lieu of Taxes (GILT) to municipalities with respect to MH buildings and structures that are located throughout the Province. In 2006/07, MH made \$10 million in GILT payments, and the payments were forecast to increase to \$15 million in 2008/09, the increase primarily the result of the new Corporate Head Office being added to Winnipeg's tax rolls. MH is currently negotiating with the City of Winnipeg and has estimated the annual property and business tax bill for its new head office will be in the range of \$5 to \$7 million dollars, the full effect to occur from 2009/10.

7.0 Payments to the Province

7.1 Interveners' Position

The Coalition noted that the special payment to the province of \$204 million then-increased the debt to equity ratio by 3% and the debt component to 85% vs. 82%. By MIPUG's calculation, for 2008/09, the impact of the earlier payment remains at three percentage points.

The Coalition noted that payments to the province represent a significant benefit to the province.

7.2 Board Findings

The Board accepts that the projected payments to the Province represent a return to the Province of approximately 14% per annum of MH's overall electricity revenues. The Board understands that the Province employs these receipts to support health, education, social and other programs, for the benefit of all Manitobans.

MH is a prominent contributor to the overall economic well being of the Province, assisting in a variety of ways:

- Annual payments in excess of \$200 million for water rentals debt guarantee fees, payroll taxes, capital taxes and other miscellaneous fees;
- Sales taxes, personal and corporate tax revenues with respect to staff and contractor complements and activities;
- MH's Annual net income, (projected to average \$161 million per annum through 2017-18), which is included in the overall accounts of the Province;

7.0 Payments to the Province

- Mitigation payments to First Nations and Northern Communities related to the northern flood agreement and related pacts, amounting to in excess of \$600 million on a cumulative basis, which has greatly assisted northern First Nations communities;
- Partnership agreement with NCN with respect to the Wuskwatim G.S. development, and potential pending relationships with other First Nations with respect to Conawapa and Keeyask;
- Targeted training and employment of northern and first nations residents;
- Grants in lieu of taxes payments to Manitoba's municipalities ;
- DSM expenditures towards the environmental objectives of the Province;
- Investment in wind generation, furthering provincial environmental objectives and rural community development;
- DSM low-income programs, to assist in sustaining low-income households;
- Planning for Bipole III to be constructed on the west side of the Province rather on the east side of Lake Winnipeg, to support the Province: object of protecting the boreal forest;
- Uniform rate design, (all communities and customers on the provincial electricity grid are subject to the same rate schedule, assisting with the economic and social development of rural and northern communities); and
- Export/import arrangements with American utilities within the MISO market and the provincial utilities of Ontario and Saskatchewan, which assist in increasing electrical reliability and the overall reduction of GHG emissions.

7.0 Payments to the Province

A further benefit to the City of Winnipeg has been the building of a new Corporate Head Office in downtown Winnipeg, a component of MH's agreement to purchase Winnipeg Hydro. The new head office will result in approximately 2,000 MH employees relocating to the new head office and contributing economically to local businesses and the further revitalization of the Winnipeg downtown.

The acquisition of Winnipeg Hydro has also provided the City of Winnipeg with an ongoing stream of revenue as a component of the sale agreement and saved the City and its ratepayers from the otherwise required massive expenditures to upgrade and maintain aging WH assets, such as Pointe du Bois G.S. Finally, with respect to the benefits provided to the City of Winnipeg, MH has expended over \$13 million to upgrade the energy efficiency of the City's operations, the result to have an ongoing and substantial benefit to the City.

8.0 Financial Targets

8.0 Financial Targets

8.1 Background

In September 1995, MH adopted the following financial targets, which were subsequently reviewed by this Board at the 2002 Status Update Hearing and, most recently, at the 2004 General Rate Application.

MH's current financial targets are as follows:

1. To achieve and maintain a minimum debt to equity ratio target of 75:25;
2. To achieve and maintain an annual gross interest coverage ratio of 1.20 annually; and
3. To fund all new capital construction requirements, except major new generation and/or major new transmission facilities (which include the new head office), from internal sources.

MH's financial targets have varied over the years, due to changing circumstances and priorities. Financial targets have been as follows:

Year	Financial Target
1995	75:25 debt equity ratio by 2005/06, interest coverage ratio of 1.20 to 1.35 and fund all capital expenditures, except major new generation and transmission facilities, from internally-generated funds
2001	75:25 debt equity ratio by 2005/06, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new generation and transmission facilities, from internally-generated funds
2002	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.10 and fund all capital expenditures, except major new generation and transmission facilities, from internally-generated funds
2007	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new generation and transmission facilities and new head office building and DSM, from internally-generated funds

8.0 Financial Targets

In 1995, MH moved to more aggressive financial targets to achieve a balance between fiscal responsibility, competitive positioning and customer bill affordability. MH expected that attaining the updated targets would result in lower debt, thereby reducing interest costs and ultimately assisting in rate restraint and competitiveness.

As at March 31, 2002, MH had a debt:equity ratio of 77:23, and appeared well on its way to meeting the 75:25 target. While the dividend to the Province represented an addition of 3 points to the debt element, the target was largely missed as a result of the 2003/04 drought.

The drought resulted in an approximate \$600 million reduction to net export revenues relative to a normal flow period, and this, coupled with the \$204 million special payment to the Province (planned and implemented before the drought), increased the debt ratio 10 percentage points in two years, severely impeding MH's progress toward its financial target.

Subsequently, the target year to reach a 75:25 debt equity ratio was changed from 2005/06 to 2011/12 to allow for a more gradual rate impact on customers. Since then, with major new capital construction in process and planned, requiring extensive new borrowings, there is no current expectation for the target to be met.

8.2 Debt to Equity

The debt to equity ratio measures the relationship of long and short-term debt (less short-term investments and sinking fund investments) to equity. The ratio is

8.0 Financial Targets

used by bond rating agencies and the Board, among others, to assess the financial risk MH represents.

Subsequent to reviewing the level of debt issued by the Corporation in relation to the amount of equity held in the form of retained earnings, there is no expectation that the Province will make equity injections into the Corporation; it is to manage its affairs such as to avoid such a requirement. MH established a debt to equity ratio target of 75:25.

MH's actual and forecast debt to equity ratios for fiscal 2003/4 to 2008/09, as compared to the forecasts of IFF03-1 presented at the last GRA, were and are as follows:

Debt to Equity Ratio Comparison Actual/IFF07-1 to IFF03-1

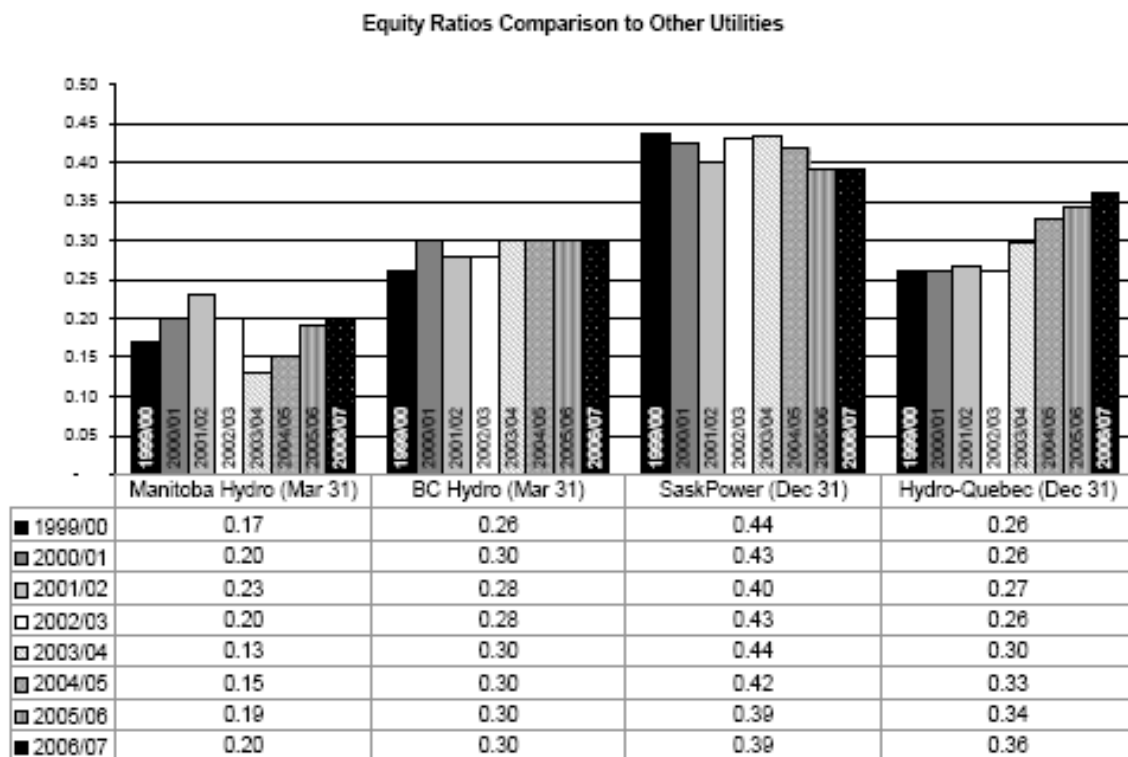
	Actual				Forecast	
Fiscal Year	2004	2005	2006	2007	2008	2009
Actual/IFF07-1	87:13	85:15	81:19	80:20	77:23	77:23
IFF03-1	85:15	85:15	86:14	86:14	87:13	87:13

MH has made a marked improvement in its movement towards the 75:25 debt to equity ratio target since the 2003/04 drought. The Corporation's improved financial position relates to higher than expected extra-provincial revenue in fiscal 2005/06 and 2007/08, and rate increases granted by the Board in 2004 (5%), 2005 (2.25%), 2.25% (granted on an interim basis April 1, 2007 and finalized by Order 90/08), and 5% as of July 1, 2008 (Order 90/08). The 5% increase granted July 1, 2008 (Order 90/08) should assist.

8.0 Financial Targets

At the recent hearing, MH stated that its proposed 2.9% rate increase would assist MH in pursuing its debt:equity target, while being sensitive to the impact that electricity rate increases have on customers. The Corporation advised that it did not expect to reach the target debt to equity ratio within its latest long-term forecast period, that is, through 2017/18.

Compared to other Canadian utilities, MH has a higher debt to equity ratio:



MH's current forecast IFF07-1 does not foresee MH meeting its 75:25 debt to equity target, neither by 2011/12 nor over the remainder of the IFF07-1 forecast period to March 31, 2018. MH forecasts a debt to equity ratio of 77:23 in fiscal 2017/18, the same as forecasted for fiscal 2007/08, even with cumulative rate increases of 33% assumed over the forecast period.

8.0 Financial Targets

MH indicated in addition to the 2.9% rate increase it was seeking at the recent GRA, that (hypothetically) consecutive increases of 6.60% in fiscal years 2010, 2011 and 2012 would be required to reach the debt to equity ratio target of 75:25 by fiscal 2011/12.

Achievement of the 75:25 debt to equity target without larger rate increases appears to be virtually impossible due to the planned major increases for capital spending initiatives on New Generation, Major Transmission and the new office building, because of the corresponding increased debt levels to fund such construction.

As well, there is an increasing statistical probability that a new drought will set the Corporation back, and the losses from a serious drought could more than eliminate the current retained earnings balance. Other risks, including currency, interest rates, accounting standards changes, increased domestic loads and higher than now-projected capital expenditures also increase MH's risk status.

As suggested, changes in GAAP to come with the move to IFRS in fiscal 2011 can be expected to further hinder MH's progress to its debt to equity target, if not place even more pressure on rates going forward. A discussion of the IFRS changes is provided in other sections of this Order. As in previous Orders, the Board questions MH's cost deferral and capitalization practices which now have the effect of increasing annual net income and retained earnings and assisting in progress towards the stated debt:equity ratio.

8.0 Financial Targets

8.3 Interest Coverage Ratio

The Interest Coverage Ratio is calculated to measure the degree to which net income before interest exceeds finance expense. MH's interest coverage ratios, actual or projected, for 2003/04 to 2008/09 are as follows:

Interest Coverage Ratio Comparison Actual/IFF07-1 to IFF03-1

	Actual				Forecast	
Fiscal Year	2004	2005	2006	2007	2008	2009
Actual/IFF07-1	0.12	1.27	1.83	1.24	1.56	1.30
IFF03-1	0.29	1.08	1.05	1.05	1.03	1.04

The improved interest coverage ratio, relative to IFF03-1's actual and forecast, is due to higher than forecast net income and lower interest costs than forecast in IFF03-1. The actual ratio for fiscal 2003/04 was due to the drought and the loss incurred in that year. In the current IFF07-1, the interest coverage ratio target is achieved in all years of the forecast except for minor shortfalls from fiscal 2010 to 2014.

Again, achievement of the target in recent years has been assisted by MH's cost deferral and capitalization practices, which will change with IFRS. And, of course, there are the myriad of other risks that could lower annual net income and put the achievement of this target at risk.

8.0 Financial Targets

8.4 Capital Coverage

The Capital Coverage, as formally stated, measures MH's ability to make "normal" non-major capital purchases without taking on additional borrowings. MH's actual or projected capital coverage ratios for 2003/04 to 2008/09 are:

	Actual				Forecast	
Fiscal Year	2004	2005	2006	2007	2008	2009
Actual/IFF07-1	(0.42)	1.20	2.52	1.12	1.74	1.07
IFF03-1	(0.21)	0.54	0.50	0.41	0.48	0.56

Again, the actual results for fiscal 2003/04 were due to the drought, and the improved results since to improved water flow conditions and resultant higher exports, and with the continued exception of capital spending on major projects from inclusion in calculating the ratio.

MH's current practice is to exclude major capital expenditures when determining the capital coverage ratio. When major capital expenditures are included, the resultant capital coverage ratio indicates that MH must finance its major capital expenditures with debt, as opposed to the intended internally-generated cash flows.

8.0 Financial Targets

Comparison of MH Capital Coverage Including Major Capital:

	Actual				Forecast	
Fiscal Year	2004	2005	2006	2007	2008	2009
Actual/IFF07-1	(0.42)	1.20	2.52	1.12	1.74	1.07
Including Major Capital and Head Office	(0.35)	0.86	1.64	0.70	0.58	0.34

Comparison of MH Capital Coverage Including Major Capital IFF07-1:

Fiscal Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual/1FF07-1	1.74	1.07	0.69	0.76	0.84	1.13	1.03	1.1	1.22	1.21	1.40
Including Major Capital and Head Office	0.58	0.34	0.3	0.34	0.41	0.46	0.29	0.31	0.31	0.28	0.36

As previously indicated, the deterioration in the capital coverage ratio in 2003/04 was due to the drought; it led to MH's largest and a very major loss. The improvement since 2003/04, relative to the forecast in IFF03-1, is related to higher than forecast income due to excellent water conditions, providing for higher than expected export revenue, and a succession of Board-approved rate increases.

MH's capital coverage is forecast to decline in 2008/09 from that forecast for 2007/08 due to increases in capital spending. In the current IFF07-1, the target is met in all years except fiscal 2010 to 2012, those missed target years being due

8.0 Financial Targets

to increases in capital spending on new generation and major transmission projects.

Again, IFRS and the myriad of other risks faced operationally and financially by MH could reduce the net income now forecast for future years and further worsen the capital coverage ratios.

8.5 Reserves

The concept of MH establishing specifically defined reserves to meet risks associated with a drought or another calamity was suggested by MIPUG's witnesses.

The suggestion was that a reserve fund would be established out of retained earnings and future net income and, when deemed adequate, would be utilized to avoid what otherwise might be judged "excessive" rate increases, which, in the absence of adequate reserves, could be required.

With an adequate reserve in place, annual rate changes would be decided based on a judgment as to the sufficiency of the reserve funds in place to meet the risks of the Corporation, utilizing net income to build the fund during normal years and providing for a gradual recovery of a depleted reserve following a calamity that had resulted in the use of the reserve to prevent an "excessive" rate increase.

If MIPUG witnesses' advice and the intervener's recommendation was taken and such a reserve or reserves established, this approach would supplant the current reliance on retained earnings and the now-required or goal of meeting the 75:25 debt to equity target (as the means to avoid "excessive" rate increases driven by a calamity).

8.0 Financial Targets

MH did not agree that a specific rate-protection reserve or reserves should be established, and considered the idea of segmented or restricted reserves to represent an outdated concept, and one abandoned by MH in 1992. Specific purpose reserves would, for Hydro, be inconsistent with contemporary principles of Enterprise Risk Management, in which the interdependence of risks is to be managed in a coordinated way across the Corporation.

In short, MH prefers to keep the 75:25 debt to equity ratio as its target “buffer” against all financial risks, and to forego the development of specific reserves to meet specific risks.

8.6 Interveners’ Positions

Coalition

Mr. Harper opined that MH established a target debt to equity ratio for two primary reasons: first, to demonstrate to the financial community that MH is a financially sound Corporation (important because the perception of MH’s financial integrity in the financial community affects the borrowing rate not only for MH but also for the Province of Manitoba, which guarantees the Corporation’s debt), and the second, that maintaining a satisfactory level of equity provides a means of stabilizing rates under particularly adverse events such as a drought.

In meeting the financial impact of a drought (which brings losses and increased debt to equity ratios) what is important for Mr. Harper is the overall level of retained earnings and how it compares with the level of losses that might occur under various types of adverse events.

8.0 Financial Targets

Establishing an appropriate level of reserves within this context involves more than estimating the cost of a five-year drought. Mr. Harper stated that more work needs to be done to assess MH's risks if the Board wants to establish an appropriate target reserve, even if the reserve is to continue to be expressed as retained earnings.

Mr. Harper stated that a proper determination of an appropriate level of reserves for MH would entail:

- Identification and quantification of the risks faced by MH;
- Identification of ways to manage these risks and, in particular, identification of those risks that would be managed through maintaining financial reserves as opposed to other approaches such as insurance, financial hedges and rate increases;
- A determination of the likelihood of occurrence of the various risks that are to be managed through reserves, and the extent to which individual risks are either independent or interdependent;
- A determination of the degree of a risk MH is willing to accept; and
- A quantification of the resulting reserves required.

Mr. Harper noted that the development of an appropriate reserve target should be an iterative process, as the degree of risk MH is willing to accept is dependent upon the level of reserves required and the cost of achieving such reserves, the cost being measured in the magnitude of possible rate increases.

Mr. Harper stated that forecast capital spending in 2007/08 and 2008/09 is considerably higher than historic averages, mainly due to expected higher spending on New Generation and Transmission, and noted that this spending is

8.0 Financial Targets

putting noticeable pressure on MH's debt to equity ratio. As of March 31, 2007, spending on major new generation and transmission projects was estimated to have increased the debt ratio by 2%, and by March 31, 2009, 5%.

MIPUG

MH's total capital – debt plus equity - is the denominator in the debt: equity ratio, and is expected to increase massively as the planned major new projects proceed. With domestic load expected to continue to increase, average export sales volumes can be expected to decline until new generation comes on stream. And, when new generation does come on stream, MIPUG noted that the experience has been that each new plant experiences a few years of marginal or loss years, placing pressure on annual net income levels and the debt to equity ratio during those years.

Thus, and for MIPUG, in the absence of annual and material domestic rate increases the current debt to equity target of 75:25 should not be expected to be reached in the foreseeable future, that is for more than a decade. Hence the problem, assuming the debt:equity target ratio of 75:25 is important and required to be met. If the target ratio is to be met, for MIPUG, ratepayers should expect annual rate increases, the only question being the magnitude of the increases.

To a large degree, the magnitude of the needed increases is, as MIPUG stated, necessarily related to major new capital projects and the new debt taken on to allow those plans to be realized. MIPUG thus linked future rate increases with projects to be advanced earlier than needed for domestic purposes, i.e. for export reasons, and claims that such rate increases would be contrary to "clear policy objectives" for these projects.

8.0 Financial Targets

As such, for MIPUG, the debt:equity target (even if accepted as a valid target for assuring the Corporation's Board of Directors) is much too coarse to use as an analytical tool for the purposes of setting rate levels.

With the potential for further billions of dollars for additional capital projects in the years following the current IFF horizon, bringing debt up to, say, \$20 billion by 2022, for MIPUG it is apparent that a 75:25 debt to equity ratio could only be achieved with unprecedented additions to net income by way of rate increases on top of the forecasts contained in IFF 07-1.

As to how much additional net income would be required to allow retained earnings to increase sufficiently to attain and hold to a 75:25 debt:equity ratio, MIPUG asserted up to an additional \$2.5 billion in additional net income would be required, depending on the level of capital expenditures, above and beyond the net income forecast to come from annual 2.9% rate increases and net export revenues as currently forecast.

Reserves are required for the goal of protecting ratepayers from the risk of large rate increases driven by the actuality of a major risk. MIPUG's witnesses opined that MH's projected levels of retained earnings will be ineffective for this purpose, as the level of retained earnings is not directly overseen by this Board and does not provide the Board with a sufficient level of control.

MIPUG recommended that the Board should establish a reserve to cushion ratepayers from rate increases due to the risks faced by the Corporation, and discard further reliance on the debt:equity target ratio. And, per MIPUG, ahead of establishing the reserve to be required, the Board should direct that a major review of alternatives to the establishing of appropriate reserves be undertaken, as may be permitted within the appropriate legislation.

8.0 Financial Targets

MIPUG urged the Board to consider the need for a focused debate on issues and options regarding establishing secure reserves. In such a review, consideration should, for MIPUG, extend to the determination of the appropriate levels of these reserves, alternatives for maintaining the reserves fully under the Board's jurisdiction and oversight, and, as well, measures for calculating, in any given year, the necessary level of appropriation to or withdrawal from, the reserve accounts – to affect the rate increase to follow.

8.7 Board Findings

Notwithstanding MIPUG's concerns and the hypothetical value the intervenor claims for leaving the current method of determining the adequacy of MH's reserves, i.e. reliance on a debt to equity target, for specific reserves, the Board remains concerned that MH is not making sufficient progress in meeting and assuring holding to maintaining its current debt to equity target once met.

The Board is further concerned that during particular fiscal periods of the current forecast to and including fiscal 2017/18, MH does not expect to maintain either or both of its other financial stability targets, that being its interest and capital coverage ratio targets. The three measures of financial health and stability (debt to equity, interest coverage and capital coverage) are taken seriously by debt rating agencies and others, and while the ratios may not be expected to be maintained throughout the whole forecast period due to the effects of the expanded capital program, they still remain important.

Financial targets are set to be met, and to secure the future financial integrity of the Corporation MH also must, logically, take into account the upcoming adoption of IFRS, the possible future effects of continuing if not increased Canadian dollar

8.0 Financial Targets

appreciation and rising interest rates, and the rising cost of constructing new assets. The Board suggests MH consult with bond-rating agencies and government over what would represent an acceptable deviation from the existing financial stability targets during periods of considerable capital expansion, all to be financed by debt and rates.

The Board further notes that, cumulatively to March 31, 2009, and including the 5% established by Order 90/08 from July 1, 2008, approximately \$400 million of additional revenue will have been generated from recent (since 2004) rate increases, following a decade of no domestic rate increases. However, despite these revenues and the on-going effect of these rate increases, with its current capital program plan and with ongoing increases in OM&A expenses, MH still does not expect to meet its debt to equity target within the current forecast period ending March 31, 2018.

The Board understands an argument can be made that current rate increases are due to capital expenses advanced for export purposes ahead of domestic load need, and that this may be considered to involve a degree of inter-generational inequity. However, the Board finds it unreasonable to expect current ratepayers to avoid any rate implications of plans now being made and implemented that contain not only opportunity but also increased risk for future generations.

The Board observes that this current generation of ratepayers may reasonably expect to gain from the economic activity associated with the Corporation's current capital plans, even ahead of those plans yielding any new export or domestic generation sales, and seeks a balance of interests.

That said, MH needs to provide the Board more assurance, through more detailed analyses and external assessments, that the risks now being taken on

8.0 Financial Targets

are reasonable and that the intended new projects will benefit not only current generations but future ones as well.

The Board notes that MH has a growing and significant level of non-revenue producing assets (intangible assets, such as deferred charges, goodwill and capitalized OM&A expenditures, the new head office building; and construction in progress, which includes large accumulations of capitalized OM&A). MH's current and forecast Retained Earnings through to 2017/18 is fully accounted for by these non-revenue producing assets, bringing into question the adequacy of a 75:25 debt:equity target with the current accounting approach - and this does not include reflection of IFRS.

The Board notes recent major export contracts being entered into since the filing of the GRA, though briefly reported on during the proceeding, are expected to require additional generation and transmission not yet included in the Corporation's capital expenditure forecast, projects that will push MH's debt closer to \$20 billion by 2022 (assuming the forecast of the cost of these projects does not further increase materially).

It is the Board's view that, given the ambitious capital program and related increasing growth in debt, it is unrealistic to anticipate that MH will meet its debt to equity ratio of 75:25 even by the end of the current forecast period, 2017/18. Such a target has become seemingly impossible to attain given that the major capital expenditures contemplated are to be financed by debt, without truly significant rate increases.

The Board notes the Coalition's inference that Hydro's debt:equity ratio could be 80:20, and that such a change would be without risk as such a ratio is comparable to B.C. Hydro's new government-set target. However, BC Hydro does not have the same approach for deferral of expenditures as MH, and may

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not have the same OM&A capitalization policy as well. Furthermore, while BC Hydro's total long-term debt may be similar to MH's, BC Hydro has an annual revenue stream that is almost three times that of MH, providing a greater ability to service debt.

Furthermore, the degree to which B.C. government's debt ratings are dependent on B.C. Hydro is considerably less than the case with MH and Manitoba. It is the Board's understanding that rating agencies look prominently at MH's financial strength in assessing the credit rating of the Province. A weakening of the financial strength of MH would not be viewed favourably by those credit rating agencies and may have implications impacting the credit rating of the Province, making provincial borrowing more expensive. Such a development would not be in the public interest.

It is the Board's understanding that private utilities would have difficulty raising debt with a debt:equity ratio greater than 60:40, and that new projects would proceed only with the assumption of injections of additional capital. In MH's case, the assumption is that retained earnings represent the Utility's capital and that capital increases only by means of net income, derived from domestic rates and export profits.

If the Board were to implement, at least for rate regulation purposes, the Rate Stabilization Reserve model (RSR) proposed by MIPUG, it would be expected to deem certain earnings to contribute to the RSR while "unapproved" costs would "fall back" to MH and its sole shareholder, the Province. Under MIPUG's suggested approach, if the Province did not reimburse MH directly for such "unapproved costs", the Utility would be further at risk of missing vital financial targets.

8.0 Financial Targets

As to MH's opposition to the RSR proposed by MIPUG, it is only partially valid. Put in the proper context, the RSR could be restricted only in the sense that it could only be used for identified operating "disaster" conditions. Under such an approach, deemed excess spending would not be reflected in rates by the Board, and would fall to the shareholder through the unrestricted retained earnings balance. However, if the Board were to adopt such an approach, a process would need to be developed to determine an appropriate level of the RSR.

What would represent an adequate RSR? Previously, the Board has requested that MH file a quantified analysis of its major risks and analysis that would put numbers to the major risks that have been identified. Not only would the risks associated with a five-year drought be quantified (MH has suggested that such a drought could result in losses of over \$3 billion), but also the risks associated with the failure of major infrastructure, interest rate increases, further currency changes and, for any reason, the loss, even if temporary and for whatever reason, of the export market. In the absence of much more rigorous analysis, the Board is uncertain whether such an analysis would arrive at a RSR lower or higher than the current level of retained earnings required under a 75: 25 debt to equity target. The Board is concerned that there may be a case for establishing a higher reserve requirement, one that would further push rates.

On balance, the Board is of the view that a regulated RSR, i.e. the adoption of MIPUG's specific reserve proposal, is currently premature, at least ahead of MH identifying and properly quantifying its risks, as has been requested in past orders. Such quantification is vitally important given the increased risks that will accompany a debt level that may reach \$20 billion by 2022.

Given the increase in capital spending, and recognizing MH no longer forecasts achievement (by 2012 or even 2018 for that matter); a 75:25 debt:equity ratio, it

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is time for MH to re-evaluate the equity target and set a new date for achievement.

Accordingly, the Board will require of MH a detailed, comprehensive and quantified Risk Review. The Board will withhold its final judgment on the development of reserves designed to meet the risks faced by MH until such a review has been placed before it and reviewed at a subsequent GRA. At least until then, the current financial targets stand.

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9.0 Capital Expenditures

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9.1 General

MH's CEF 07-1 is a projection of MH's capital expenditures for new and replacement facilities to meet the electricity requirements in Manitoba, as well as expenditures to meet firm sales commitments outside the Province.

CEF 07-1 summarizes an eleven-year program of capital expenditures totalling \$11.3 Billion to fiscal 2018, ranging from \$831 Million in fiscal 2008 and increasing to \$1.1 billion in fiscal 2018. Spending for New Generation, Transmission (and the New Head Office) total \$7.5 billion, with the balance of \$3.8 billion representing an ongoing capital program of, on average, \$345 million per year. This represents a ten-year increase of \$930 million in anticipated new capital costs, from that previously forecast in CEF 06-1.

New Generation and Major Transmission forecast in CEF07-1 was:

New Generation & Major Transmission Capital Expenditures CEF07-1 (\$ millions)

Fiscal year	Project Cost	2008	2009	2010	Culmulative to 2018
Wuskwatim Generating Station	1,274.6	147.1	287.4	293.9	1,080.4
Wuskwatim Tansmission	319.8	79.2	107.9	47.1	280.0
Keeyask Generating Station Licencii	325.3	50.5	63.4	-	113.9
Conawapa Generating Station	4,978.4	32.6	57.8	54.7	2,162.1
Kelsey Improvements/Upgrades	183.9	36.1	30.6	28.4	123.0
Point du Bois Rebuild	900.5	13.5	23.3	35.0	896.0
Bipole III Western Route	2,447.8	1.9	2.9	9.3	2,237.0
Other	305.0	7.3	13.6	46.2	253.5
Demand Side Management		40.4	43.1	34.2	338.4
Total		408.6	630.0	548.8	7,484.3

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9.2 Comparison of CEF03-1 to CEF07-1

At the 2004 GRA, MH filed CEF 03-1, which reflected capital spending of \$5.8 billion over the eleven-year period from 2003/04 to 2013/14. Over the same eleven-year period, MH's actual capital expenditures for 2003/04 to 2006/07 and projected expenditures for 2007/08 through 2013/14 is now forecast at \$8.5 billion, \$2.7 billion greater than that forecast in CEF 03-1, as illustrated in the following table:

Capital Expenditures (\$millions)									
Fiscal Year	Actual				Forecast				11-Year Total
	2004	2005	2006	2007	2008	2009	2010	2011-14	
Actual/CEF07-1	455	485	504	634	801	1,016	958	3,648	8,502
CEF03-1	481	583	622	748	748	641	598	1,405	5,826
Difference	(26)	(98)	(118)	(115)	53	375	360	2,244	2,676

The major increase since 2004 is attributable to additional new Major Generation and Transmission, the new head office and cost escalations above the rate of general inflation on capital projects, expanded DSM programs, and increased maintenance on existing infrastructure.

9.3 New Generation and Major Transmission

There has been a significant increase in the costs of new generation and Major Transmission projects since 2004. MH cited the increase is due to inflationary pressures on labour, contract services and materials, the latter representing a condition of hyper-inflation, as well as other considerations. A comparison of significant projects cost changes between CEF 04-1 and CEF07-1 follows:

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New generation and Major Transmission CEF04-1 to CEF07-1

(\$ millions)	CEF 04	CEF 05	CEF 06	CEF 07	\$Increase 04-07
Wuskwatim G.S.	846	935	1094	1,275	429
Wuskwatim Transmission	199	200	257	320	121
Wuskwatim Total Project	1,045	1,135	1,351	1,595	550
Herblet Lake Transmission	55	54	54	95	40
Bipole III(1)	388	1,879	1,879	2,248	1,860
Pointe du Bois	288	692	834	900	612
Conawapa G.S. & licensing	4,050	4,516	4,978	4,978	928

Note 1: CEF-05 assumed Bipole III would be build east of Lake Winnipeg, the current intention is a western route.

MH indicated a significant escalation in capital costs for its projects that relate to many market factors beyond its control. Utility industry construction costs have risen and are expected to remain elevated for some time, reflecting underlying trends for cost increases for steel, copper and concrete due to high global demand and, as well, increased production and transportation costs due to much higher fuel costs. Another factor is a shortage of skilled workers that has driven costs higher for utility construction services.

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9.4 Wuskwatim Generating Station (Wuskwatim)

9.4.1 General

The Wuskwatim Generating Station represents Manitoba's first new hydroelectric development since the late 1980s, and the first in Manitoba structured as a partnership (MH and the First Nations Nisichawayasihk Cree Nation (NCN). In approving the project the CEC recommended that:

"The Government of Manitoba grant The Public Utilities Board jurisdiction to review, on an ongoing basis, as part of Manitoba Hydro's future General Rate Applications, the actual revenues and costs of the projects relative to forecast, along with the impact of the Projects on Manitoba Hydro's financial stability and its domestic rates."

This application represents the Board's first review of the Wuskwatim project as it now stands.

At the CEC hearing, MH justified Wuskwatim on the basis that the new generating station would be built to serve export markets, and stated that the power from the station would not be required for domestic consumption until 2019. Now, given current firm export contracts and an increase in forecast domestic load, MH indicates the power generated from Wuskwatim will be required by 2012 to meet domestic needs and firm export contracts.

9.4.2 Capital Cost of Project

At the outset, the capital cost of the Wuskwatim project, as presented to the CEC, was estimated at \$900 million. The updated cost estimate now indicates a project cost of approximately \$1.6 billion, an increase of \$700 million since the CEC hearing in 2004, and an increase of \$550 million since CEF04-1.

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MH attributed the increase to inflationary pressures on labour, contract services and materials. The estimate also increased to account for both the deferral of the in-service date, from 2010 to 2012 and to account for increases in licensing costs.

MH also reported that the Wuskwatim Project Development Agreement allocates MH's overhead costs at a rate of 21% as opposed to the "normal" 29%, this reduction allowing for the exclusion of a share of costs related to Winnipeg facilities and computer systems not expected to be utilized by the project.

9.4.3 Wuskwatim Power Limited Partnership (WPLP)

The project is to be developed by the Wuskwatim Power Limited Partnership (WPLP), an equity partnership between NCN and MH. The project is unique, and represents the first time MH has entered into an equity partnership on a generating station project. MH suggested that the experience gained through the WPLP may be used in structuring agreements for future northern Generation projects, including the now-expected development of Keeyask and Conawapa.

The two Limited Partners are to invest equity in the project by subscribing for ownership units to represent 25% of the total capital cost of the project. The WPLP agreement allows for NCN, through its wholly owned Taskinigahp Power Corporation (TPC), to subscribe for up to a 33% stake in the Equity Partnership Units. MH, through a holding company (General Partner), would have a 0.01% interest, with MH, as a Limited Partner, holding the balance of 65.99%.

The assets of the Partnership are to consist of the Wuskwatim G.S. and required working capital. MH is to lend WPLP the funds required to build the generating station. Based on the Corporation's current estimated cost of constructing

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Wuskwatim, excluding the transmission component, MH projects lending the partnership \$927 million to build the generating station, representing approximately 75% of the cost of the project (the remaining funding to be through the Equity Partnership Units).

MH assumes TPC will subscribe for 33% of the ownership interest, i.e. 33% of the 25% equity component. Based on the current construction cost estimate for the generating station, TPC's cost for the partnership units would be \$102 million. According to the agreements, TPC will invest up to \$34 million of its own capital and borrow up to \$68 million from MH to fund the balance.

Revenues generated from the project are to be allocated to the partnership from MH's overall revenues, based on an agreed-to (between NCN and Hydro) formula utilizing average export prices for peak and off-peak sales. Revenues are to be adjusted as changes in export prices are experienced and realized, and are to be based on the actual output of Wuskwatim G.S., reduced by the average system line loss rate for the MH system (currently 10%). WPLP is to pay MH 3% of the partnership's gross revenues, to contribute towards the marketing and transmission costs and risks borne by the Corporation.

MH will be fully responsible for the operations of the generating station and related transmission facilities, and will charge WPLP for its incremental operating costs. MH will make no cost allocation to WPLP for system generation and transmission. Control Center costs will not be directly charged to the project but be included in the overhead charge to the project. Finance costs incurred by the Corporation, related to the loans it will take on to allow it make loans to the partnership to build the generating stations, are to be recovered, at cost, from WPLP. The financing cost related to loans to WPLP has been estimated at 7%

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interest, based on MH's expected long term-cost of borrowing of 6% plus a 1% Provincial debt guarantee fee.

The proposed Development Agreement requires that WPLP maintain a 75:25 debt to equity ratio, except for the first 10 years of operations where an 85:15 debt to equity ratio will be allowed (to account for anticipated initial losses in the operation of the facilities, losses are expected for the six-year period from fiscal 2011/12 to 2016/17).

If the partnership's debt to equity ratio falls below the above parameters, there is a requirement for further cash contributions from WPLP partners based on their ownership interest in the partnership.

The agreement between Hydro and NCN also allows for advances on dividends to NCN, even during loss years and/or when the equity threshold test has not been met. MH indicated that dividend advances are to be limited to 5% of the actual cash invested by NCN, and are to be repaid by NCN out of forecast future distributions.

9.4.4 Wuskwatim Transmission

In addition to the generating station, Wuskwatim requires incremental transmission facilities. MH is to build the required transmission facilities at an estimated cost of \$320 million. The cost of incremental Wuskwatim transmission is to be recovered from WPLP by way of repayment over 50 years, the payments to include principal and interest.

Repayment of the loan is to commence upon Wuskwatim's in-service date, and MH stated that the blended principal and interest payment required will be the equivalent to having the transmission asset and offsetting debt on the books of

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the partnership and expensing depreciation and interest. In addition, the operating costs of the transmission facilities will be charged to WPLP.

9.4.5 Project Economics

In justifying the Wuskwatim project to the CEC, MH advanced many assumptions. Based on the then-projected construction costs of the project the levelized cost of the energy was to be 6.6¢ per kW.h (costs forecasted before the CEC). Given the escalated cost of the project, the Corporation's revised estimated cost of energy has increased to 7.2¢ per kW.h.

Before the CEC, and in forecasting export prices to be realized by Wuskwatim, MH utilized a USD/CDN exchange rate of 1.35. Based on its most current forecast in 2007, the exchange rate utilized in the Corporation's forecasts as for when Wuskwatim comes in-service in 2012 was 1.14, and this appreciation of the Canadian dollar from the original projection was forecast to result in a 5% reduction in forecast export revenues.

However, if the Canadian dollar remains near par with the U.S. dollar, MH projects export prices will be 17% lower than now forecast, a result that would further negatively impact the economics of Wuskwatim.

At the CEC Hearing, and in the Corporation's justification of the project, MH calculated that the Internal Rate of Return (IRR) would be 10.3%, based on generation being sold as exports. As a result of the escalation in the cost of the project and employing the same type of financial analysis as was presented to the CEC, the IRR has reduced to 7.8 %, excluding sunk costs, and to 6.5% including sunk costs. And, even this revised IRR would be further materially reduced if the Canadian dollar remains at par.

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MH cautioned that recalculating the IRR on a similar basis to that presented at the CEC hearing, as reported on above, neither reflects the decision now required nor is consistent with engineering economics. MH's rationale for this view is based on Wuskwatim being built for domestic load purposes, and a comparison of the projected cost of energy to arise from Wuskwatim with the cost expected if that amount of generation arose from with operation of a MH combined cycle natural gas turbine. On that basis, for MH, Wuskwatim is expected to result in \$14 million in annual savings over the next 30 years (providing \$153 million of net present value).

9.5 Bipole III

Bipole III is to be a 2,000 MW, high voltage direct current (HVDC) transmission line from Gilliam, Manitoba to The Pas, and then down the west side of the Province to Winnipeg, Manitoba. In CEF 07-1 MH budgeted for a West Side Bipole III to be in-service in 2017 with a total cost, including escalation and interest during construction, of \$2.247 billion.

The new HVDC line and associated converters (at Henday and Riel) is being advanced for domestic and export transmission capacity and reliability reasons. The recently-announced power sales to Minnesota Power and Wisconsin Public Service, (again not reflected in MH's forecasts as filed at the proceeding) if finalized, will also advance the need for Keeyask and Conawapa generation. On this basis, the new Bipole III line, with its converters, will be required to meet firm export load, as well as strengthen the domestic transmission system.

Due to provincial environmental and societal considerations, MH is proceeding with a West Side of Province routing for Bipole III, rather than the originally planned shorter routing on the East Side of Lake Winnipeg. MH provided a cost-

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benefit comparison of a West Side Bipole III as opposed to an East Side Bipole III, and identified a \$400 million capital cost differential and a line loss differential of up to a further \$181 million (in favour of an East Side Bipole III).

MH identified the potential for further significant price increases for construction as a whole, and power generation and transmission in particular. And, if this concern is realized, a further significant increase in forecast Bipole III costs could result.

Evidence presented at the recent hearing suggested that a repeat of the September 1996 failure of Bipole I and II, once Bipole III is in operation, built on the west side of the Province, would have more serious consequences if the interruption occurred during peak load. While an East Side Bipole III could function in parallel with existing Bipoles I and II, and in the event of the outage of both, make use of Bipoles I and II converters as well as the new Bipole III converters to provide 3,000 MW to the south, a West Side Bipole III would be limited to using only its own converters and thus could only provide the South with 2,000 MW in such a situation. MH advised that an outage of Bipoles I and II during the summer season could result in an additional cost to the Corporation of \$160 million over the cost that would be incurred if Bipole III were built down the east side, the extra costs due to a requirement for additional imports to make up for the 1,000 MW differential.

In short, during a major outage of both Bipole I and II, an East Side Bipole III could serve both domestic and firm exports, while a West Side Bipole III would require significant additional needs and presumed expensive imports to meet domestic needs and firm exports.

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9.6 Other Generation

Pointe du Bois Generating Station

MH is moving forward with its approval process for construction of a new generating station to replace an aged Pointe du Bois G.S. This \$900 million replacement project is viewed to be an economically superior option to upgrading the existing plant.

In the 2005/06 Power Resource Plan, MH compared the capital costs of various scenarios as follows:

Capital cost scenarios (\$ millions)

Capital Expenditure	Cost Estimate	Timeframe
Decommissioning	\$125	By 2014
Rehabilitation	\$358	By 2021
Repowering	\$562	By 2017
Redevelopment	\$615	By 2013

On the basis of subsequent economic, technical, environmental and socio-economic evaluations, MH concluded that the redevelopment of the Pointe du Bois G.S. was the more attractive alternative, with an in-service date of 2015/16. The capital cost estimates based on further analysis were refined and updated to reflect current conditions.

It is not clear whether this new capital requirement was taken into account during negotiations for the acquisition of WH.

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Kelsey Generating Station

MH is upgrading the Kelsey G.S., at a forecasted cost of \$123 million, by re-running the turbines. The intent is to increase plant capacity and gain additional energy output under average flow conditions. MH advises there was no expected gain in dependable flow generation from the enhancement.

Keeyask & Conawapa Generating Stations

In January 2008 after the GRA had been filed with the Board, MH announced it had signed a term sheet for a 250 MW power sale to Minnesota Power. And, at the hearing, MH stated that it had just signed a term sheet (an intent to sell) with Wisconsin Public Service (WPS) for 500 MW, the sale to start in the year 2018 for a 15-year term, with an expected value of approximately \$2 billion over the term.

Occurring after MH had filed its GRA, the WPS sale was not considered in MH's filed Power Resource Plan. The sales, Minnesota and Wisconsin, are contingent on MH developing new hydro generation. New transmission inter-tie capabilities will be required by both MH and the counter-parties to the agreements, again to meet a condition of sale.

MH will require new transmission from Riel Station, on the East Side of Winnipeg, to the U.S. border, and estimated the cost of the Manitoba portion of the new transmission inter-tie to be approximately \$30 million. Costs related to the new transmission line were not included in CEF07-1, and MH also suggested that additional Alternating Current (AC) transmission could also be required to optimize the new generation projects.

MH indicated it could have to develop Keeyask (620 MW) and Conawapa (1,420 MW) generating stations in close succession, (2018 and 2021, respectively) to

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meet the new export sales requirements. MH forecast that the cost of Keeyask, at approximately \$4 billion, also not included in CEF07-1, and Conawapa, estimated to cost approximately \$5 billion, of which \$2.8 billion in capital cost are forecasted to be incurred after the current CEF07-1 forecast period of 2018, were not fully included in the latest IFF or CEF. (Recently, public statements have suggested that the cost of the Conawapa capital project could reach \$6 billion.)

MH further stated that it may be required to build a combined cycle natural gas fired plant, at a cost of approximately \$600 million, to meet projected energy deficits that could arise as early as 2017, ahead of Keeyask and Conawapa coming on stream. The cost of a new combined cycle natural gas fired plant was not incorporated in the current capital forecast, or in the latest IFF.

In short, the impacts expected to arise from the two new power sales are not fully incorporated in MH's forecasts; and IFF07-1 and CEF07-1 are to be revised by MH, with a copy to be filed with the Board.

9.7 New Head Office

As a condition of the purchase agreement entered into when WH was acquired, MH agreed to build a new Corporate head office in downtown Winnipeg. The building was originally forecast in CEF 03-1 at a cost estimate of \$75 million, the amount then cited as a 'place marker' subject to design changes and cost revisions.

The new building is to accommodate approximately 2,100 employees and to be ready for occupation by 2009, and come at a projected revised cost of \$278 million. Issues related to MH's new head office were also reviewed by the Board in Order 99/07, wherein the Board noted:

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“Centra estimated that overall cost impacts of the new head office would be \$21 million per annum, to be offset by lease payment savings of \$5 million and annual productivity savings projected to be in the range of \$20 million annually. Centra assured ratepayers there would be no increase in rates”.

The Board directed in Order 99/07, that:

“Centra confirm to the Board that no incremental costs are to accrue to Centra's customers for MH's new head office;”

MH, on behalf of Centra, provided that confirmation in this GRA.

The incremental annual cost related to the new building was estimated at \$22.8 million in the first year of occupancy, with an annual cost of \$18.75 million thereafter. MH expects that productivity savings will be realized by bringing staff together at one location, allowing staff to work in closer proximity and in a more efficient environment, and that this will be sufficient to result in synergy savings of between 10% and 20% of otherwise head office payroll, to offset in part the incremental costs of the new building.

MH further stated that \$20 million in productivity savings, to also include lapsed leases for currently-rented facilities, will be realized and offset the increased costs from the new building.

That said, MH indicated it would be difficult to focus on the details of savings associated with the new head office at future hearings. MH recommended the Board focus on the review of costs and savings from an overall basis to ensure that costs are fair and reasonable, rather than focusing on the head office.

While the new head office is being constructed as an obligation made upon the acquisition of WH, moving to common facilities may benefit both MH and Centra in terms of more efficient operations and better customer service, to be achieved through enhanced collaboration opportunities. Given that the costs allocated to MH's electricity and Centra Gas natural gas operations are based upon the costs

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incurred, any productivity savings that are attributable to providing service to gas customers would flow to Centra through the normal cost allocation process.

MH opined that substantial benefits were flowing to Centra as a result of the acquisition of WH and the related move to common facilities, and recommended that continuing to allocate the actual costs of the work performed on behalf of each utility to each utility would be the best course of action. As such, for MH there should be no special allocation process implemented to ensure that the costs of the new head office flow only to electric customers.

9.8 Interveners' Positions

The Coalition

The Coalition commented that the interaction of MH and the Province has led to tremendous benefits for Manitobans, citing benefits that included rural interconnection, connection of remote communities in the north, the northwest transmission developments, and cooperation between MH and the province that has realized significant economic development and provided contributions to provincial finances. The Coalition also stated it was important to also recognize costs to the Province in terms of these developments, including mitigation expenditures related to the Churchill River diversion.

The Coalition also observed ongoing impacts on MH's revenue requirements and financial indicators that are a product of the interaction between MH and the Province. The Coalition mentioned the new head office and the west side vs. east side debate concerning Bipole III as issues with important cost consequences.

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In terms of Wuskwatim, the Coalition noted that the development is placing pressure on MH's debt to equity ratio and on its revenue requirement. In addition, the Coalition noted that the intended closure of the Brandon Coal plant (that is except, for emergency use) is another important impact arising from provincial involvement in MH decision-making. The Coalition stated that MH is experiencing significant pressures on its financial results from a variety of government policy and other initiatives, though many of them have, in the past, been beneficial to Manitobans.

Mr. Harper noted that MH's capital spending for the two closest forecast years, 2007/08 and 2008/09, is to be considerably higher than historic levels, mainly due to higher spending on new generation and transmission. Mr. Harper stated the spending is in part to protect in-service dates and is being done to meet export commitments and goals, and that this spending is putting noticeable pressure on MH's debt to equity ratio.

As of fiscal 2006/07, Mr. Harper opined the impact of spending on major new generation and transmission projects has increased the debt ratio by 2 percentage points. And, by fiscal 2008/09, increased capital spending will drive up the debt ratio by 5 percentage points.

Mr. Harper submitted that in the near term, Wuskwatim will have the most impact on the change in outlook for capital spending, due both to cost increases and as a result of the advancement of the in-service date. The Coalition observed that MH's capital spending plans influence decisions about the level of net income and the level of rate increases.

As previously mentioned, Mr. Harper argued for a direction to Hydro to develop an ACA and described an ACA as a snapshot of the condition of a utility's assets, noting that it would include degree of degradation and need for rehabilitation and

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replacement. He suggested that ACA are usually undertaken at intervals of two to three years.

Mr. Harper claimed that an ACA helps a utility pull together, on a systematic and organized basis, an overall comprehensive assessment (for planning purposes) of work to be prioritized across its entire asset base. And, through a process of prioritizing assets by way of an ACA, MH can further prioritize work in areas of the company where there is a deficiency of a critical nature. Mr Harper stated an ACA provides a logical foundation to support OM&A and capital spending

Mr. Harper further recommended that MH undertake regular ACAs every 2 to 3 years, and that the preparation of such assessments over time will allow MH to determine whether its assets are improving or deteriorating, helping to substantiate where there is a need for increased spending.

Mr. Harper noted that MH's capital spending requirements for both base capital and new generation and transmission projects are growing, when compared with past spending levels. He indicated that while increased export revenues should benefit future customers, the capital expenditures to prepare for those exports are putting pressure on current rates and are one of the drivers for MH's requested rate increases (that now exceed inflation). For Mr. Harper, MH needs to be mindful of these pressures when developing its overall capital expenditure plans.

Mr. Harper opined that the advancement of Wuskwatim was a contributing factor to current rate pressures. In reaching this conclusion, Mr. Harper noted that a significant portion of the increases in capital spending to be experienced in the next few years relate to the development of Wuskwatim.

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The Coalition stated that there were lessons to be learned from the Wuskwatim development, lessons best learned before entering the anticipated decade or more of major capital expansion. The Coalition cited submissions made by MH to the Wuskwatim CEC proceeding, that:

“Temporary increases in MH’s debt to equity ratio and decreases to the level of interest coverage which may occur in the early years of the project are judged to be manageable without impacting the Corporation’s financial stability or requiring off-setting increases to domestic rates.”

The Coalition further cited the CEC report which stated:

“The Commission’s support for the project is contingent on Manitoba Hydro being able to maintain its commitment that domestic ratepayers will not experience rate increases as a result of the project.”

The Coalition noted that the project is now forecast to cost \$ 1.6 billion, including transmission. Taking into account both inflation and the effects of the delay in-service date, the Coalition noted an increase of \$418 million (in 2002 dollars) in the expected cost of construction, and that as a result, the IRR, based on the methodology employed in the submission to the CEC, has been reduced to 7.8% when sunk costs are excluded, and to 6.5% when sunk costs are included.

The Coalition submitted that the revised IRR of 6.5% is roughly equivalent to the Corporation’s cost of debt, and suggested that the lesson to be learned from the deterioration of expected return is that the CEC hearing did not examine closely enough the capital expenditure forecasts of MH.

As to the new head office, the Coalition questioned whether synergies forecast by MH will be realized to offset the approximate \$20 million increase in annual costs.

As MH enters into a decade of expansion, the Coalition recommended that MH employ an independent review of both its capital expenditure procedures for

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major projects and also for its OM&A expenditures, considering both in terms of forecasting and management best practices.

The Coalition also recommended that the Province provide the Board the legal jurisdiction to review MH's major capital expenditures.

MIPUG

MIPUG also expressed concern with the growth in MH's capital spending. Mr. Bowman and Mr. McLaren suggested that the increase in capital spending has contributed to a deterioration in MH's financial position and is one reason that MH's debt: equity targets have not been achieved. Mr. Bowman and Mr. McLaren mostly attributed the failure to meet the accepted targets to major new generation and transmission plans, including Wuskwatim.

Given that these new projects were to be pursued on MIPUG's understanding that they would not drive rates higher for domestic customers but would, over the long term, benefit domestic customers, the witnesses opined that the use of these capital projects as an implicit justification for rate increases should be of concern to the Board.

MIPUG stated that although MH had not indicated it was seeking rate increases to address the costs of bringing Wuskwatim into service, the net effect of retaining the 75:25 debt to equity ratio target requires rate increases from domestic ratepayers.

In assessing the level of MH's capital spending and its impact on the province, MIPUG suggested the Board should set rates that both reflect the cost of

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operating the Utility plus provide provisions or reserves for the maintenance, operation and eventual replacement of existing assets.

For MIPUG, there is no basis or regulatory convention allowing the Board to focus on the credit condition of the shareholder (the Province) in determining rate levels. For MIPUG, the Board's role is to focus on the financial condition of the Utility, solely for the benefit of its customers.

MIPUG also opined there was no basis to argue that rates should be increased for "balance sheet" reasons, i.e. to "pre-fund" the equity required for the coming phase of capital expansion (Conawapa, Bipole III, Keeyask, new cross-border transmission, Wuskwatim and Pointe du Bois).

MIPUG strongly opposed the Board taking into account concern for the Province's credit rating, and suggested that to do so would be roughly equivalent to raising rates in the 1950s to advance Grand Rapids, which came into service in the 1960s. MIPUG contended that such an approach would not have been necessary, as the Grand Rapids project, as a long-lived MH asset, has been able to cover its interest costs, repay all debt borrowed for the purposes of its construction, and provide cost-effective power for generations of ratepayers..

MIPUG cited prior Board Orders which expressed concern as to the implications of increased capital spending by the Corporation, noting from Order 143/04:

"The Board continues to be concerned with the progress of substantial growth in capital expenditures and accompanying debt. The Board accepts that many of the capital expenditures are related to reliability and safety, and therefore are may [sic] be prudent to incur. The Board also recognizes that many of the forecast capital expenditures are related to or the equivalent of generation expansion, such as supply side enhancements, Wuskwatim, Keeyask, Conawapa, and may be justified individually when considering the each project purpose and forecast results over the long term. However, collectively these projects negatively impact MH's debt to equity ratio of and

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net income in the initial years, placing increase strain on the financial stability of the MH and adding additional risk for existing ratepayers. The Board is concerned that MH has not developed a threshold for capital expenditures and associated debt growth that considers all projects, together with the health and financial stability of the company.”

MIPUG noted that MH’s normal capital program has not been reduced, despite the Board’s “strong” directives of Orders 7/03 and 143/04. MIPUG argued for greater regulatory scrutiny of capital spending, and urged the Board to continue to seek the necessary legislative amendments, as sought in past Orders to provide for Board oversight of MH’s capital expenditures, an oversight that, for MIPUG, would be consistent with the objectives of *the Public Utilities Board Act*.

Mr. Bowman and Mr. McLaren cited CEF 07-1 as indicating that MH will be spending approximately \$4.1 billion on normal capital programs to 2017/18, an average of \$375 million per year. When compared to CEFO2-1, where normal capital spending was forecast to be \$3.1 billion, an average of \$285 million per year, the witnesses expressed concern over an increase of 30%, or 6% per year.

Mr. Bowman and Mr. McLaren noted that this level of growth, only half being consistent with expected general inflation over the period, was excessive. They opined that with capital project cost escalation occurring, it is possible that while a 6% sustained annual growth may be justifiable as reflective of premium “construction project” inflation over the period, MH has not reflected any notable cost control measures consistent with the Board’s past directives.

MIPUG again recommended the Board should pursue oversight of MH’s major capital projects, perhaps via a recommendation to the government for a legislative provision similar to the Certificate of Public Convenience and Necessity process that occurs in other jurisdictions.

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MIPUG further stated that in the event additional Board oversight is not provided by government, nonetheless the Board clearly retained the ability to set the Utility's rates, and could employ that ability to ensure MH is not provided upward rate adjustments to compensate the Corporation for investments the Board may not view as prudent. MIPUG stated that the Board is not bound to "adequately fund" all operating and capital decisions made by the Utility, and that the Board should reach a conclusion on the prudence of the expenditures to be reflected in rates.

MIPUG further suggested that the Board request renewal of the mandate provided the Board in 1990 (via OIC 1990-177), a mandate that provided for a detailed and comprehensive integrated review of MH's Major Capital Projects (covering the period 1990 to 2009). Among the other benefits MIPUG suggested would arise from such a review, MIPUG suggested that the Board's resulting report to the Lieutenant Governor-in-Council, which would arise from the review, could include a discussion of compelling policy considerations for the Government of Manitoba to address. Given the current expansion plans of MH, MIPUG held such a review would be timely.

MKO

MKO noted that MH has an aggressive capital plan that may be the most extensive in the Corporation's history, with the possible exception of the previous nearly back-to-back projects at Grand Rapids and Kettle.

MKO agreed with the position put forward by MIPUG, and suggested the Board should take on the responsibility to review major capital expenditures expected to have an impact on rates.

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MKO further recommended that the Board acknowledge that MH-affected First Nations are, in essence, the original capital investors in the MH system. MKO asserted that Article 18.4 of the 1977 Northern Flood Agreement acknowledges its assertion.

Accordingly, MKO recommended the Board acknowledge that MH-affected First Nations are, at minimum, co-investors in MH's hydroelectric generating facilities, and are, in effect, "perpetual holders of Class "A" shares (in MH)", for which a return on investment should be identified and "paid" to First Nations.

RCM/TREE

RCM/TREE also noted that MH is facing significant capital costs with the major construction projects now expected and suggested that the capital costs to be incurred will take place at a time when MH has a high debt:equity ratio.

RCM/TREE suggested that even with the new construction programs, MH is forecasting energy shortages in the years 2009 to 2011, shortages to arise from accelerated domestic load growth. RCM/TREE indicated that load growth continues to exceed past projections with negative impacts on MH's finances, customers and the environment

RCM/TREE suggested that the consequence of 'suppressed electricity rates' is increases in domestic load growth that go beyond previous predictions, and that the increasing load growth threatens the export surplus, hastens the requirement to construct more costly new plants for domestic use, escalates the level of greenhouse gas emissions in North America, and has the potential for an adverse impact on Centra Gas' results and situation "if the flight from gas to electricity for water and space heating continues".

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9.9 Board Findings

The Board recognizes its statutory jurisdiction does not extend to the approval of capital expenditures. Yet, it is clear MH's anticipated capital spending and associated increased debt levels is and will place upward pressure on rates. The Board has, as interveners have noted, expressed concern with MH's debt growth in previous orders. In Order 143/04, the Board noted:

"The Board continues to be concerned with the progressive substantial growth in capital expenditures and accompanying debt. The Board accepts that many of the capital expenditures are related to reliability and safety, and therefore are may [sic] be prudent to incur. The Board also recognizes that many of the forecast capital expenditures are related to or the equivalent of generation expansion, such as supply side enhancements, Wuskwatim, Gull, Conawapa, and may be justified individually when considering each project's purposes and forecast results over the long term.

However, collectively these projects negatively impact MH's debt to equity ratio and net income in the initial years, placing increased strain on the financial stability of MH and adding additional risk for existing ratepayers. The Board is concerned that MH has not developed a threshold for capital expenditures and associated debt growth that considers all projects, together with the health and financial stability of the Company."

The Board reiterates the prior concerns, and notes that with planned major capital expansion, such concerns are now graver.

In this GRA, interveners requested that the Board revisit its prior recommendations and recommend to government that the Board be provided with the statutory authority typically vested in the public utility regulators – that is, the authority to review MH's capital expenditures before such investments are committed.

In prior Orders, the Board has recommended to Government, that *The Public Utilities Board Act* be amended to make the regulation of MH equivalent to the

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regulation of Centra Gas by removing the exemption now provided under Section 2(5) of the Act.

In Order 143/04 the Board noted:

"Given the risks related to the very significant additional plant investments and associated borrowings contemplated, the Board is of the view that the Province of Manitoba should re-evaluate the existing legislation."

The Board reiterates its past recommendation.

The Board's concern with MH's capital spending has previously been described, (Orders 07/03 and 143/04). With this new GRA, and with the update provided during the hearing, MH has set out planned capital expenditures that are unprecedented in the Utility's history. The Capital Expenditure Forecast projects that from 2008/09 to 2017/18, the Corporation plans to spend \$11.3 billion (of which \$7.5 billion is for new major generation and transmission assets and \$3.8 billion for other power supply requirements) – with further capital expenditures likely to also occur given recent export sales (i.e. Keeyask and Conawapa).

In its application, MH projected that its in-service undepreciated plant will increase by \$8.6 billion to reach over \$20 billion by the end of 2018, and that its debt would correspondingly increase from \$7.2 billion to almost \$12.7 billion by the same end date. In addition, due to recently-reported potential new long-term export contracts to Wisconsin and Minnesota, capital expenditures are expected to further increase. Assuming they are finalized, the new export contracts will require additional generation and transmission expenditures of a currently estimated cost of another \$7 billion (for the planned construction of Keeyask by 2018, and Conawapa by 2022).

The additional capital expenditures are not reflected in the current capital forecast, and accordingly, the Board will, require MH to update and extend its

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forecasts to include the new projects. The overall level of capital spending now anticipated will result in a large increase in debt that will result in higher finance (interest), depreciation and OM&A expenses. The Corporation's debt:equity ratio, already not at the target range, will also be negatively affected.

And, based on historical experience, and consistent with MH's forecast with respect to Wuskwatim, new generating stations can be expected to operate at a loss during a large part of their first decade of operation, and this too will add pressure on the financial targets, debt levels and rates.

Limestone G.S., which came on line in 1992 at a favourable capital cost, did not achieve any positive cash flows from export sales during the first eight years of operations. However, the project recovered the initial shortfalls and now continues to contribute substantially to the Corporation's bottom line. In the absence of Limestone G.S., MH could not anticipate any significant export revenues in the IFF 07-1 forecast period.

With unexpectedly high capital costs and a somewhat flat export market, Wuskwatim G.S. may not achieve a positive cash flow for a period exceeding the projected loss estimates of the Corporation. By the time Wuskwatim can be expected to "break into the black" its output will serve domestic load only and the advancement of the project for export purposes, as originally planned, will not have proven out.

It could be reasonably expected that the advancement of Bipole III, Keeyask and Conawapa projects will face at least a decade of negative cash flow, even if transmission inter-tie capabilities are doubled. Thereafter these projects are projected to contribute to the bottom line as long as there is substantive action in the MISO region toward achieving CO₂ emission reductions.

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To allow the Board to gain a further understanding of the implications of the capital expenditures now contemplated, MH is to file with the Board by January 15, 2009 an updated Capital Expenditure Forecast, and an Integrated Financial Forecast and Power Resource Plan and Load Forecast, all to extend from 2008 to 2028.

The updated Power Resource Plan should provide alternative scenarios with and without implementation of the pending new export contracts and related capital spending. It should also provide an indication of what hydro generation opportunities remain, such to be feasible opportunities, after Wuskwatim, Keeyask and Conawapa, and where the additional projects would occur and what possible quantity of energy would be expected, along with the assumed development timeline. The Load Forecast should also reconcile projected and actual DSM savings.

While MH anticipates that interest rates and inflation will continue to be low, history suggests that both factors fluctuate. Increases in either interest rates or inflation would be problematic to the costs of the proposed capital expansion program. Construction cost inflation over the past five years has been dramatic, in some years 10 times or more the rate of general inflation for some construction cost elements, particularly commodities. As to currency fluctuations, this factor is also subject to widely different possible scenarios, again outside the control of the Corporation (excepting, and to a limited degree, for longer-term “natural” hedges, and, for the short-term, financial instrument hedges).

While the Board agrees interest rates, currency fluctuations and commodity costs are affected by events outside MH’s control, the Corporation should still consider the risks of undue developments in these factors as it plans.

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In the Board's view, the capital expenditure forecasts for future construction may prove to be low, thus it would be prudent to model worst case scenarios as well as those considered more likely and reasonable by the Corporation.

MH's export commitments appear to be the recent driver of the need for new major generating stations and transmission facilities. With the exception of Wuskwatim, which was reviewed by an expanded CEC hearing on the basis of export (not domestic) need, the new major capital project and export commitments have not been subject to regulatory review.

Such major capital projects and export agreements can either help or negatively affect MH's financial position, and one of the possible negative outcomes is the potential for rate increases. This was the case in 2004, when MH experienced a drought and the honouring of its export commitments came at a great cost and had a role to play in the rate decisions then made.

The consumers of MH electricity, as represented at the GRA by MIPUG, Coalition, MKO and RCM/TREE, advocate that the Board pursue oversight of MH major capital projects. MIPUG suggested a further recommendation to the Government of Manitoba, to establish legislation similar to the 'Certificate of Public Convenience and Necessity' employed by other regulators. Alternatively, Interveners want a review of MH's major capital projects through a renewal of the mandate provided to the Board in 1990 (via Order-In-Council 1990-177), when the Board was requested and did review MH's major capital plan, then covering 1990 to 2009 (a plan much modified since).

And, given the emphasis placed on exports (the source of rate subsidies for domestic customers and capital for early construction), and the risks for domestic customers if export commitments and water conditions collide, it could lead to significant financial losses.

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The Board agrees with Interveners that regulatory review of the impact on consumer rates that MH's planned capital program may have is warranted, and that such a review should consider the risks faced by the Corporation and its ratepayers.

In light of the unprecedented capital expansion now under consideration, the Board will direct MH to propose to the Board on or before January 15, 2009 the terms of reference for a regulatory review of MH's planned Capital Program and its possible implications for consumer rates. The Board will also direct MH to prepare a study, for filing with the Board by January 15, 2009, a thorough and quantified Risk Analysis, including probabilities of all identified operational and business risks. This report should consider the implications of planned capital spending, taking into account revenue growth, variable interest rates, inflation experience and risk, and potential further currency fluctuation.

To provide the maximum benefit of such a risk analysis, MH will be directed to file by September 30, 2008, for Board approval, a conceptual outline for an in-depth and independent study of all the operational and business risks facing the corporation. And, as a follow-up to the risk analysis study, MH will be directed to file, by June 30, 2009, recommended risk mitigation measures and a review of possible suitable capital structures, given the capital expansion now planned or contemplated, and risks quantified.

As for Wuskwatim, it is now clear that the economic justification presented to the CEC in 2004 has changed. At the CEC hearing, MH calculated the projects IRR (Internal Rate of Return) would be 10.3%. Before this Board and incorporating changed assumptions in that original forecast, a recalculation of the IRR yielded 6.5%, a yield that approximates MH's current annual cost of debt.

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With higher than expected domestic load growth, Wuskwatim is now required to meet both domestic load and firm export commitments. However, the project is now of debateable economic value, given the ongoing escalation of construction costs and the potential for under-achievement of forecast export prices.

Wuskwatim's original cost estimates, as provided to the CEC, have risen by a factor approaching 2 – with the overall cost now expected to be not \$900 million but \$1.6 billion. The cost increase is troubling enough, but there is also no assurance that export sale prices have increased correspondingly (if at all). The dramatic rise of the Canadian dollar has lowered revenue expectations, and there is no certainty that either a cap or trade on carbon tax is on the immediate horizon, to benefit MH's planned newest generating station.

MH does not forecast that WPLP will be profitable for the first 6 years of operations, and these forecasts may be optimistic. While MH's cost allocation approach favours the Wuskwatim project, with the Wuskwatim partnership not being allocated all costs, particularly indirect overheads, yet being assigned full export prices for all of its energy output, it is possible the project in a full economic sense may not achieve a positive cash flow.

On an overall economic basis, with construction cost estimates up 60% more and the forecast price per kW.h basically unchanged, Wuskwatim's net present value may not meet the original floor threshold assumed at the CEC hearing. MH now bases its requirement for Wuskwatim on domestic rather than export requirements. Accordingly, MH states it no longer requires Wuskwatim to meet or exceed its threshold economic return, as MH now classifies the construction as being necessary to meet future Manitoba load requirements.

That said, the Board does not agree that Wuskwatim is required for domestic purposes, particularly with its current expected in-service date. Yet, this view is of

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little consequence, as the Board is not required to give approval to MH's capital plans and projects. As well, Wuskwatim's plans are well past the "point of no return". Yet, it is neither the fault of MH or the government that high inflation and a much higher Canadian dollar has developed massive construction cost overruns and problems with export receipts in Canadian dollars.

As to the arrangement with NCN, the First Nation is to receive up to 33% of ownership of the limited partnership that will construct the generating station. Yet, and until the project is finished, NCN is required to invest only \$1 million, with MH borrowing what is required to complete the project. Following completion, NCN will have to make its decision whether to come in as a partner or not. Overall, and assuming NCN does take up the full ownership position it has the option to take, NCN is only required to put up \$34 million of its own capital, the balance to be borrowed from MH.

The First Nation carries no direct risk with respect to the \$1.6 billion project. It has an option to take up to a 33% ownership position, but it need not do so; it can evaluate the situation upon the project's completion. And, an NCN holding company will hold NCN's partnership interest in the project. With the holding company inserted between it and the partnership, and with almost all of its investment funded through a loan from MH, without any mark-up, its risks are negligible. As well, NCN will be able to receive payments from the partnership once the new generating station is in-service, even during partnership loss years. Such advance dividends will also be funded by loans from MH, as advances on future dividends.

With respect to the capital structure of the partnership, the standard formula for determining MH's debt to equity ratio has been amended, and for the Wuskwatim partnership the debt to equity ratio will exclude the expected \$320 million in debt

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related to the necessary transmission line loan. This arrangement, having the transmission asset held “off-balance sheet”, and by MH directly, will allow for profit-sharing to occur much earlier than would be the case if the standard 75:25 ratio test was applied employing the standard debt and equity components.

MH concurred with the hypothesis that the Wuskwatim/NCN arrangement was driven by factors other than “strict economics”, and that the driving factor for the arrangement is MH's operative assumption that without an agreement with NCN Wuskwatim could not proceed. The Board notes that as the generating station and related transmission lines will be located in NCN's traditional trading area, it is not surprising that the First Nation would insist on compensation for its support of the project, and that a lack of support from NCN would have made proceeding unlikely.

From the Board's review of the WPLP Agreements, it has arrived at significant concerns with the financing arrangements, cost sharing and revenue allocation, and while there may be reasons that go beyond strict “economics” that lie behind the terms of the arrangement, the Board's concern with the overall structure of the arrangement is such that the Board cannot, at least without being in receipt of further rationale, recommend that the agreements serve as a template for any future joint ownership opportunity.

While the WPLP is not recommended for use as an “automatic” template for further First Nations participation in Generation and Transmission projects, the experience of Wuskwatim, todate, should be used to model possible outcomes of possible future arrangements with respect to Keeyask and Conawapa.

For any future projects where joint ownership is contemplated because of the potential impact on consumer rates, the Board recommends MH seek the Board's prior review and approval.

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With respect to Bipole III, MH reported that its construction cost estimates had increased dramatically, from IFF-03's forecast of under \$400 million (that estimate excluded the cost of converter stations) to \$2.2 billion (which now includes the advancement by several years of the construction of converter stations, required for future generating facilities now contemplated).

The increase in forecasted spending is primarily driven by a government policy decision, supported by MH's Board of Directors, to place the line on the west side of the Province and materially increased construction costs.

The Board notes that the new \$2.2 billion forecast neither includes the present value of line losses associated with the longer distances required to go down the west side of the Province, nor any value that could be associated with the additional risks pertaining to the possible future loss of Bipole I and II transmission, which, if it occurred, would require northern transmission from the north to the south to come only from Bipole III, at a potential capacity loss of 1,000 MW.

Including the present value of the additional line losses associated with increased distance, the revised routing of Bipole III has added over a half a billion dollars of additional costs. The Board notes that export prices are set in the marketplace and are not based on MH's generation and transmission cost. Thus, it is not the Board's assumption or expectation that the additional costs for a 'west side' routing of Bipole III can be passed on to MH's export customers. It appears that the increased cost of Bipole III, brought about by a west side route will be a cost to MH that will reduce otherwise expected future export profits.

Again, it is critical to understand that this Board is not empowered to approve MH's capital expenditures. To similar effect, the Board is required to honour

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explicit government policy. Given these conditions, the Board's options are limited when it comes to the rate regulation of MH.

To "starve" MH by suppressing rates in an effort to stymie a project would be to counter government policy, a measure that the Board cannot undertake, first lacking the legislative authority and secondly, the public mandate – unlike government, this Board is not elected. In short, government and the Board of MH has, as they should, taken responsibility for the major capital expenditures and policy actions of MH. The Board has no mandate to contradict such policies. Therefore, while the Board does not find all of MH's actions justifiable on a strictly MH-centric economic rationale, it considers itself obliged to ensure MH has sufficient revenue to allow it to achieve objectives transparently established or approved by government.

Before moving to a general discussion of MH's other capital expenditure plans, the Board has some further comments to make with respect to the projected routing of Bipole III.

Currently, Manitoba Hydro's primary electricity production, from the north, is transmitted through two transmission lines from Gillam to Winnipeg through the Interlake. For a considerable period of time, it has been assumed that a third line was required, for reliability purposes, and with the continuing growth of domestic load and committed or intended export contracts, the third line has become a necessity. Upon its completion, now scheduled for 2017, Bipole III will provide backup to the existing two lines and transmit increased volumes of electricity from the planned new generating stations to southern Manitoba and further south, the primary export market.

Bipole III, to be MH's third high-voltage, direct-current transmission line, is to be constructed down the west side of Lake Manitoba, rather than taking a much

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shorter route through boreal forest on the east side of Lake Winnipeg. The east side of Lake Winnipeg is marked by pristine boreal forest, which the government has indicated it wants to preserve by building Bipole III down the province's west side, rather than the east.

The government, in partnership with some “east-side” First Nations, seeks what is considered to be the second-largest intact boreal forest in the world to be designated by the United Nations Educational, Scientific and Cultural Organization (UNESCO – through UNESCO’s Word Heritage Committee) as a World Heritage Site.

World Heritage sites are important, having significant positive impacts for decades to come, draw considerable world attention, and can attract significant eco-tourism. The government has indicated that an attempt to construct a major transmission line through a potential World Heritage Site would be strongly resisted by First Nations and be so opposed by environmentalists that it could result in MH’s export potential being severely damaged. In short, the Board understands that the government’s claim is not based on “economics”, particularly “relatively” short-term economics, but broader concerns extending beyond the environmental to include the cultural and the political.

There is little doubt that the proposed route down the western side of the province is both longer and will cost hundreds of millions more than if the new transmission line were to be built on the east side of Lake Winnipeg. As the precise route for the line cannot be determined until a process of environmental, design and public consultation has taken place, the certainty of the government’s final direction cannot be assured.

While opponents and/or critics of a “west-side” Bipole III include interveners at this most recent GRA proceeding, with their criticism based largely on

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“economics” (the undisputed understanding is that a west-side line will cost more than an east-side approach, result in increased line losses due to the longer distances involved, and, as discovered through this recent proceeding, pose an increased reliability risk in the low-probability occasion of Bipoles I and II being out of service), neither the interveners nor MH set out in detail the argument for the west-side siting of Bipole III directed by government.

The Board’s mandate is to determine what is in the public interest, and has previously defined this Board’s definition of what represents the public interest with respect to a public monopoly utility incorporated and operated to provide required services to Manitoba. So, while this Board does not have the statutory authority to approve or reject MH’s capital expenditure plans, it certainly does have a considerable interest in what those plans are and as to what the basis for those plans are. Capital expenditures represent a major driver of rates, and this Board does have oversight and responsibility for rates.

Accordingly, the Board, in this Order, sets out herein its conclusions to date on the rationale and implications associated with building Bipole III. In setting out its perspective on the matter as it now stands, the Board concludes that it is also in the public interest to set out, as it has above, the Board’s understanding of the government’s, and MH’s, rationale for the decision to take Bipole III down the west-side.

The gist of MH and the government’s position on the matter is that taking Bipole III down the west side of the Province will better ensure the Utility’s reputation and relationship with its major American export customers, and provide an opportunity to achieve, develop and enjoy a potential World Heritage Site.

In short, it is the Board’s understanding that MH and the government have concluded that constructing Bipole III on the West side of Lake Manitoba is, on

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balance, and despite it being considerably more costly and carrying additional risks, the only truly available option at this time (assuming domestic load growth and export commitments are to be met and reliability better assured).

Finally, the Board notes a third potential option, one involving underwater cables that would carry the power through at least a portion of the distance required. The Board senses that discussion and review is likely to continue, and, until that is concluded, is content with setting out its understanding of the costs and implications of the concepts and plans provided to-date.

10.0 Load Forecasts and Power Resources

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10.1 Load Forecast

MH's 2005/06 metered domestic load was 20,800 GW.h., comprised by:

Residential	6,578 GW.h	32%
GSS-ND	1,329 GW.h	6%
GOSS-D	2,038 GW.h	10%
GSM	2,949 GW.h	14%
GSL<30	1,612 GW.h	8%
GSL 30/100	988 GW.h	5%
GSL >100	5,202 GW.h	25%
ARL	96 GW.h	<1%

The segmented metered load corresponds to a load at generation of 22,899 GW.h, after taking into account distribution and transmission losses as well as weather adjustments.

MH forecasts base domestic loads at generation of:

23,318 GW.h in 2006-07	actual	
23,769 GW.h in 2007-08	451 GW.h increase	2%
24,577 GW.h in 2008-09	808 GW.h increase	3%
25,509 GW.h in 2009-10	932 GW.h increase	4%
26,069 GW.h in 2010-11	560 GW.h increase	2%
26,503 GW.h in 2011-12	434 GW.h increase	1.5%

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The forecast indicates a 3,200 GW.h increase (14%) in domestic load over the five-year period, which compares to a forecast 2,350 GW.h increase forecast for the same period in the 2005/06 load forecast. (Peak load grew by 10% during that period of 750 GW.h increased usage.)

MH's 2006 Electric Load Forecast indicated that residential and commercial load growth of 1% is expected from 2006/07, and onward that industrial load growth (GSL customers) of about 2.3% annual growth should be expected from 2006/07 to 2011/12, and a further 1% per annum or less thereafter.

The chemical and petroleum transport sectors of MH's industrial customer class are expected to provide about 75% (1,300 GW.h/year) of the 1,700 GW.h total anticipated industrial load growth between 2006/07 and 2011/12. These industry sectors are energy intensive and are usually associated with relatively low levels of employment per GW.h of energy consumption. Projected load growth in the sector has not been expected to produce high levels of additional Manitoba employment. As such, the sector represents the primary target for MH's interest in a new industrial rate class that would be assessed marginal rates.

The projection of load growth does not provide for the potential arrival of new industries in Manitoba with similarly low levels of employment per GW.h. Such firms, which may be attracted by low energy rates, would reduce MH's export sales and affect general consumer rates, and, as well, possibly affect the now planned in-service dates for new generation and transmission.

This situation has led to a concern that MH may have to increasingly forego export sales (at prices from 5¢ to 7¢/kW.h) in order to service domestic industrial loads assessed at 3.5¢/kW.h or less.

10.0 Load Forecasts and Power Resources

Again, to counter the impact of reduced exports caused by low-employment energy intensive industry, MH sought approval for a new energy intensive rate, one more reflective of export market pricing. However, the rate proposal has been deferred to a subsequent hearing, now expected to occur later this year or early in 2009.

MH's domestic load forecast contemplates:

- Only nominal increased demand from electric space heating;
- Significant increase in demand from electric water heaters;
- Significant increase in demand from computer and internet usage;
- No increased demand relative to climate change (global warming);
- Little change in seasonal load variation due to climate change;
- A significant increase in electric load due to customer movement from natural gas to geothermal heating but no identified decrease for customer movement from electric to geothermal heating;
- No customer movement from natural gas to electric heating; and
- No change in loads due to self-generation.

Given the lengthy planning process required for new generation and transmission, the accuracy of domestic load forecasts, including the categories of customers associated with specific forecasts, are critical to assessing MH's domestic load and opportunities for exports. A major risk to the present load forecast lies with the nexus of natural gas and electricity, with natural gas potentially to be a more expensive heating source than electricity.

Over half of MH's space-heating customers rely on natural gas, while the rest primarily depend on electricity. Until the May 1, 2008 Centra rate changes,

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electricity was the higher cost option where natural gas service was available for space heat. However, natural gas commodity prices are linked to oil prices, and oil prices have increased from the range of \$15 U.S./barrel in 1999 to over \$140 U.S. in recent months; while some observers suggest oil prices could reach \$200 U.S./barrel within five years prices have recently moved to below \$130, still basically twice last year's level.

As to natural gas, it is becoming a world-traded commodity, priced by the markets on a supply and demand basis, as is oil. The advent of LNG, liquid natural gas, and the coincident ability to transport natural gas between continents, has further increased the risk that natural gas will follow the oil price curve and out-price itself relative to electricity in Manitoba. In jurisdictions where market prices prevail, the prices for electricity produced by natural gas, coal and nuclear are rising. This increases the demand (and price of) for natural gas as a direct heating source. Consequently natural gas heating in Manitoba becomes less attractive relative to electric heating.

Assuming that full conversion of heating from natural gas to electricity may be expected to cost in the order of \$3,500 (assuming the customer has 200 amp service), the payback period for conversion to electric heat would be fairly lengthy at current price differentials. However, once the change is made a customer is unlikely to reverse that decision; fuel switches are essentially permanent.

A larger risk rests with the initial selection of a space-heating source with new construction. And, as to existing customers, they need not switch entirely from natural gas to electricity to affect the domestic electricity load. At a lesser level, customers may increasingly supplement their natural gas heating by electrical

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sources (electric base board heating and small electric space heating units) as natural gas prices outpace electricity prices.

Recently a surge and continued volatility in and with natural gas prices has brought about suggestions of subsidies or monetary transfers from MH to Centra in order to limit the rate impact on residential natural gas heating costs. The support for such action is based on:

- Limiting the degree of fuel switching from natural gas to electricity for heating and thus avoiding the loss of favourably priced export sales which may also provide a net reduction in GHG emissions;
- Cushioning the majority of Manitoban from the full impact of soaring natural gas prices on their winter heating bills; and
- Limiting the extent of fuel switching in older residential areas that lack of adequate distribution networks to service broad scale electric heating loads.

The counterargument on cross-subsidizing natural gas vs. electric heating is as follows:

- Paying subsidies to natural gas heating in order to limit electric heating does not necessarily result in economic gains for MH from exports. Residential electricity rates are typically higher than average export prices. The net GHG reductions for displacing natural gas generation in the U.S. are only nominal; displacement of coal generation is not assured;
- Having domestic customers pay more for electricity in order to maintain current levels of natural gas consumption by Centra may keep MH whole, but implies that the electricity customer should subsidize Centra's natural gas imports as well as MH's electricity exports;

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- Moving costs from natural gas customers to electricity customers distorts the market economics. In the absence of cost causation, the issue becomes how to limit the subsidy if natural gas prices rise to \$15 U.S. /GJ or \$20 U.S. /GJ the need for a subsidy becomes greater and at some point the subsidy from power becomes unmanageable.

10.2 Energy Supply

10.2.1 Hydraulic Generation

MH's hydraulic generation resources consist of:

- Lower Nelson hydraulic stations - 3,670 MW (HVDC transmission) with dependable output of 13,780 GW.h and a high flow output of 26,690 GW.h.
- Upper Nelson hydraulic station - 350 MW (AC transmission) with dependable output of 2,260 GW.h and a high flow output of 3,000 GW.h.
- Saskatchewan River hydraulic station - 479 MW (AC transmission) with dependable output of 1,320 GW.h and a high flow output of 2,520 GW.h.
- Winnipeg River hydraulic station - 582 MW (AC transmission) with dependable output of 2,300 GW.h and a high flow output of 4,410 GW.h.

Overall, MH's hydraulic generation output is 19,750 GW.h under dependable flow conditions, and 36,690 GW.h under high flow conditions. Although these generation forecasts assume normal water flows are not augmented by drawing water from reservoir storage, MH does use energy-in-storage to arrive at a dependable flow output of about 21,000 GW.h (representative of 85% of base domestic load).

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In median flow years (i.e., approximately 50% of the time), MH's hydraulic output is expected to be 29,500 GW.h, while in mean flow years (i.e., on the average based on 94 years of experience), hydraulic output is 29,100 GW.h. These outputs cover about 115% of base domestic load, providing the opportunity for entering into firm export commitments.

10.2.2 Augmented Flow Programs

MH employs augmented flow programs to optimize hydraulic generation output at the various plants. These programs typically involve compensation through direct payments and/or energy offsets with other jurisdictions (Saskatchewan and Ontario), or to First Nations and other to Manitoba communities.

Examples of an augmented flow program include:

- The augmented flow program on the Churchill River Diversion system allow increased additional flows by up to 5,000 cfs, annually by the approval of the Provincial Minister responsible. Deviations from the original license were offset by mitigation projects and compensation payments with respect to the communities of South Indian Lake, Nelson House, City of Thompson and town of Churchill.
- The Lake St. Joseph project, in conjunction with the Lac Seul project in northwestern Ontario, utilizes flow storage and releases that augment Winnipeg River flows by up to 9%. Under the agreement with the Lake of the Woods Control Board, MH compensates Ontario Hydro for the additional energy values.

In response to MKO interrogations, MH has provided information on a proposed water regime modification, not yet implemented, where Saskatchewan Power

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would be compensated for seasonally adjusted outflows from Reindeer Lake and Churchill River, controlled by the Island Falls G.S. to the benefit of MH. According to MH, Saskatchewan manages Reindeer Lake's water level to meet Saskatchewan Power's needs at its Island Falls G.S., and that potentially extra flow in the summer could be made available to MH.

MH's review to-date has not determined whether there would be any economic benefits to arise from such a flow modification. Nor has MH explored the level of compensation or mitigation that would be required from upstream or downstream affected parties.

10.2.3 Thermal Generation

To support and back-up MH's hydraulic generation, and to meet domestic load and firm exports commitments, MH relies on thermal generation:

- a) Brandon Unit #5 (coal-fired), 105 MW with a maximum output of 837 GW.h.;
- b) Selkirk Units #1 and #2 (natural gas), 126 MW with a maximum output of 1,060 GW.h.; and
- c) Brandon SCCT, two units (natural gas), 298 MW with a maximum output of 2,400 GW.h.

The plants can provide about 4,300 GW.h/year, if fully utilized. When the Brandon coal generation is removed from full service and related to "emergency use", pursuant to a government directive related to mitigating climate change, maximum thermal output will decline to about 3,500 GW.h/year. At the present time, combining thermal and hydraulic generation provides for 100% of base domestic load.

10.0 Load Forecasts and Power Resources

MH rarely uses its natural gas generation plants, as such generation is uneconomic when natural gas prices are above \$5 CDN/GJ. With natural gas prices currently in the range of \$8-11/GJ, imports of power from the MISO market may be used instead. It is assumed that these imports come from natural gas rather than coal generation.

MH currently relies on its coal generation to provide support to hydraulic and wind generation in meeting export sale commitments. On an incremental fuel cost basis, coal generation is economically viable and contributes \$10-20 million a year to MH's annual net income, in a median flow year.

The availability of the Brandon coal generation during the 2002 – 2003 drought saved MH approximately \$50 million; the government has indicated that the Brandon coal plant will still be available for use in emergency conditions in the future.

The energy deficit in the MISO market caused by the Brandon coal plant closure may well be filled by additional coal generation; Sask Power or Ontario Hydro in summer and MISO region coal plants in winter. These sources if available are likely to be lower priced than natural gas generation.

10.3 Wind Generation

MH currently purchases 100 MW of wind energy from a private energy firm. The power is generated at St. Leon, Manitoba and has had a capacity factor of approximately 39%, as expected wind speed and direction are neither constant nor consistent. With forecast annual output of 320 GW.h, to be drawn on in conjunction with hydraulic generation, wind is deemed to be dependable energy.

10.0 Load Forecasts and Power Resources

The St. Leon wind farm has now been operational for almost three years; providing a reasonable but still limited track record for defining on-line availability of dependable energy. Though MH has cited commercial confidentiality reasons for not disclosing the operation's specific operational profile, apparently there have been some wind downtimes due to cold temperature conditions that have fallen outside the design operating range.

Another 300 MW (900 GW.h) of wind generation is to be added by 2013/14, assuming reported ongoing contract negotiations with non-utility generators lead to acceptable terms, including pricing. And, a further 600 MW is to be considered at some time in the future, although MH has expressed concern about a declining energy value of wind as related to the energy integration process of moving wind generation into the Manitoba grid.

The recent movement of MH toward new major export commitments raises the possibility that more wind generation could have positive market values. In the long-term, MH may achieve greater transmission inter-tie capabilities allowing the export of more wind and hydraulic blended energy.

As MH's anticipated 2,000 MW of new generation projects come online to meet domestic load growth and export opportunities, the limited level of then-remaining untapped hydraulic generation may have to be supplemented. More wind may well be the choice.

As the pending restriction of the Brandon coal generation plant operation by 2012 will remove 800 GW.h from MH's power resources, wind energy may now be worthy for consideration as a cost effective replacement.

10.0 Load Forecasts and Power Resources

10.4 New Generation and Transmission

MH is proceeding with the Wuskwatim Generating Station with a targeted in-service date of 2012/13. An Agreement has been reached with WPLP for purchase of all output, estimated to be 1,515 GW.h on average. This arrangement is expected to provide a 1,220 GW.h increase in MH's dependable power (4%).

The replacement of the Pointe du Bois G.S. on the Winnipeg River with a new plant is expected to achieve a 150 GW.h/yr increase in the dependable flow output upon the expected 2016/17 in-service date for the new plant, and would add 300 GW.h/yr to average flow plant generation. The planned Kelsey rerunning will not increase dependable flow output but will increase the average energy output of the plant by 350 GW.h/yr.

Bipole III is slated to be in-service in 2017/18, and is expected to add 442 GW.h/yr to MH's dependable generation, this by reducing transmission losses on the HVDC system. The loss reduction could be 1,000 GW.h under average flow conditions, based on the existing Upper Nelson generation plant.

MH's 2007/08 Power Resource Plan indicates that by 2017/18 total generation plant output under a dependable flow scenario will be 28,845 GW.h, equal to base domestic load. At that point, and until Conawapa and Keeyask G.S. are constructed, exports would have to be supplied from domestic load reductions, through DSM and by imports or MH natural gas generation.

The Power Resource Plan calls for Conawapa G.S. to come on-stream in 2021/22, but Keeyask G.S. had then not been scheduled. And, a number of new pending export contracts were not included in the Power Resource Plan, those being:

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- a) 375/500 MW sale to NSP (estimated 1,600/2,000 GW.h);
- b) 250 MW sale to Minnesota Power (estimated 1,000 GW.h); and
- c) 500 MW sale to Wisconsin Public Service (estimated 2,000 GW.h).

Essentially, these additional export sales, if consummated, commit MH to export 5,000 GW.h/yr firm on-peak (5 x 16) power and require the development of both Keeyask and Conawapa, in close succession, and to be in place by about 2020. In the absence of Keeyask, MH's dependable domestically generated energy of, then forecast to be, about 30,000 GW.h would just cover forecast 2022/23 base domestic load. In such a case meeting the new export commitments would require further domestic load reductions through DSM savings and additional imports or MH natural gas generation.

If either space heating conversions from natural gas to electricity occurred or new large industry or large industry expansion drew power, the situation would be more problematic.

The addition of Keeyask Generating Station and Conawapa would have the following impact on the generation available from the Lower Nelson and the loads to be:

Forecast Future Lower Nelson Power Supply in 2020 GW.h				
Flow Condition	MW	Dependable	Average	High
Conawapa (2020)	1,300	4,550	7,050	9,000
Keeyask (2018)	600	2,880	4,400	5,000
Total New Plants	1,900	7,430	11,450	14,000
Total Existing Plant	3,560	13,770	21,350	26,130
Total Low Nelson	5,460	21,200	32,800	40,130

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MH has identified a transmission loss reduction of 442 GWH for a west-side Bipole III at current dependable energy levels. On a relative basis, the loss reduction at current average flows would be about 1,000 GWH. This level of reduction would, if moved to the export market, contribute significantly towards the annual carrying charges of the \$2.2 billion investment in Bipole III and with Keeyask G.S. online the revenue contribution would be considerably larger.

Hypothetically on a relative basis for an East Bipole III that average flow scenario loss reductions would have been an additional 300 GWH. In 2022 after Keeyask and Conawapa G.S. come into service, the loss differential would be about double that amount.

With Bipole III in place and both Keeyask and Conawapa on line, MH has suggested that additional transmission may be required presumably to lower transmission losses. This could further affect capital spending plans.

10.5 Alternative Fuels and Energy Supply

Notwithstanding the recent pursuit of DSM (to reduce domestic load growth) and additional wind resources, MH has not been aggressive in pursuing other energy sources. This, in large part, relates to the relatively high cost associated with alternative sources of generation in comparison to MH's current costs and rates.

In justifying alternative energy sources, MH has to look beyond the current demand-supply economics to additional considerations, including environmental and social issues, when considering:

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- Residential and general service DSM initiatives, with the average domestic rate higher than the average export price and with residential rates higher than general service rates;
- Wind costs (prices now similar to peak export prices, (i.e. in the range of 9 cents per kW.h);
- Bio-mass costs (above peak export price);
- Solar costs (currently estimated to be well above peak export prices);
- Geothermal (lost revenues and embedded costs may exceed export revenues, particularly during off-peak);
- Non-utility Generators (lost revenues and embedded costs may exceed export revenues);
- Brandon coal generation restrictions (higher prices for replacement energy) could approach \$20 million a year; and
- Bipole III - West Side (no offsetting revenue for higher capital cost, reduced savings on transmission losses) and higher risk in the expected rare case of an outage of Bipole I and II.

10.6 Greenhouse Gas Emissions

MH's GHG 2005 emissions from electricity operation were reported to be about 650 kilotonnes of CO₂ equivalent. The Brandon Coal Thermal Generation station, on average, accounted for 550 kilotonnes of the total, while generating about 500-600 GW.h/year of electricity. Closure of the plant would result in net reductions of about 300 kilotonnes of CO₂ if the replacement energy source is natural gas based.

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Converting from coal to natural gas generation would reduce CO₂ emissions by about 60%, but the costs involved would equate to about \$120/tonne of CO₂. Theoretically that leads to a strictly economic conclusion that continues to favour operation of the coal plant, though buying carbon credits could reduce its economic profitability.

Electricity exports into the MISO market in 2005/06 were 9,800 GW.h and required 2,000 GW.h of imports, to arrive at a net export of 7,800 GW.h. If this level of net exports displaced American natural gas generation, the indirect GHG savings would have been about 2,500 kilotonnes; if the exports displaced some coal generation as well as natural gas, the CO₂ reduction would have been up to 50% higher.

In 2005/06, MH reported indirect GHG reductions of 738 kilotonnes arising out of deemed DSM energy savings of 1,030 GW.h/yr. MH's estimate is consistent with an assumed 50% natural gas/50% coal generation displacement.

Because 2005/06 involved record hydraulic generation of 36,200 GW.h from exceptionally high water flows, GHG reductions in that year actually resulted from surplus hydraulic generation and not from the DSM initiatives, as there was no additional energy export from DSM possible as tie-line and other transmission constraints limited both exports and total hydraulic generation in 2005/06.

10.7 Interveners' Positions

None of the interveners challenged MH's load growth assumptions, its portrayal of the existing supply situation, or MH's identification of the consequences of increasing domestic load.

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RCM/TREE is concerned about the negative consequences of continued low electricity prices, which, it holds, encourage greater domestic consumption and leads to lower exports, and hence lower GHG reductions in the U.S.

MIPUG would promote DSM activities encouraging the use of natural gas rather than electric heating, questioned the pending restrictions on the Brandon coal plant and questioned the rationale for MH's proposed new generation and transmission facilities, being built primarily to serve exports.

MKO suggested a need for what it would consider a more accurate reflection of the risk of fuel switching in MH's load forecast.

MKO recommended that, as one test to be applied to determine whether or not MH's costs are just and reasonable, the Board should require MH to ensure that wherever it is able to identify value from a change in its operation, for example the Augmented Flow Program, that MH be required to associate any adverse effects with justified mitigation and ensure that the projected adverse effects are fully identified, reported, accounted for and addressed. MKO suggested MH be required to provide full disclosure of augmented flow programs, and any related extra-provincial arrangements on water supply.

The basic issue of there being a financial risk associated with energy intensive industry expansion, as identified by MH, was not been challenged by the interveners. And, both the Coalition and RCM/TREE indicated strong support for MH's intentions to implement marginal cost pricing for new industrial loads not associated with strong Manitoba economic benefits.

MIPUG didn't dispute the premise of charging higher rates for some industrial loads, but disagreed with MH's proposed approach and placed a higher value on large industry's contribution to the Manitoba economy.

10.0 Load Forecasts and Power Resources

10.8 Board Findings

Load Forecast

Based on past experience and recent price increases and volatility related to natural gas, MH's future domestic load forecasts may prove to be low, with space heating by natural gas potentially now more expensive (leaving aside the cost of conversion) than by electricity.

With natural gas prices continuing to rise faster than electricity prices (2008-09 natural gas space heating costs may be considerably higher than was the case in 2007-08), and far more costly than was the case in 1999 when MH purchased Centra Gas Manitoba Inc., more new customers may opt for electric heat and existing natural gas customers may either convert to electric heat in greater numbers or supplement gas heating with electric baseboard or small electrical heaters.

The result would be greater domestic load and reduced opportunity for the export of electricity unless and until new generation is available.

While MH has acknowledged that there is a growing potential for customers switching from natural gas to electric space and water heating, it has not reflected the risk in its current load forecasts. MH should include an analysis of the issue and the risks with its next Load Forecast.

MH has not been attempting to influence customer fuel choice, taking the view that it is the customer's responsibility to assess the relative merits of the options. The approach taken represents an attempt by MH to remain neutral on the relative merits of electric and natural gas space heating.

10.0 Load Forecasts and Power Resources

However, given the financial and environmental issues at stake, MH should carry out a study to define the implications of fuel choice and take a more active role in assisting consumers in making choices, given seemingly ever-increasing energy costs, both in an absolute and as a percentage of disposable household income sense.

As MH enters into more export contracts with fewer remaining hydraulic sites apparently available, it is more likely that wind generation could have a greater prominence, and potentially-an increased market value. In light of the current wind generation project(s) developed and contemplated for development in the future, the Board requires additional information on the implication of MH's wind strategy on future consumer rates.

Accordingly the Board will direct MH to submit a report to the Board on January 15, 2009 on the 300 MW additional wind energy project(s) and a discussion of the business case, wind strategy, prospects and timelines for this project, as well as the further 600 MW moving toward the government's target of 1,000 MW of wind energy. The Board will also require access to the agreements for the existing 100 MW St. Leon wind project, and an opportunity to review the pending agreements for the 300 MW project(s).

MH's recent announcements of new power sales into the U.S. have possibly precluded further firm energy contracts, as the Utility's dependable hydraulic energy has been largely committed. This suggests that, at least in the relatively immediate future material energy sales to Ontario, Saskatchewan and even Alberta may have to be non-firm and primarily off-peak. What this says with respect to the merits and prospects for an east-west national electricity grid is a subject for conjecture.

10.0 Load Forecasts and Power Resources

If GHG emission reductions are seriously targeted for achievement in Canada and the U.S., MH's available energy should gain value. It is important for MH to negotiate prices providing for escalation in certain circumstances, such as further increases in oil, natural gas and coal prices, and increased attention to emission reductions (by way of cap and trade or carbon taxes).

The decision to place Bipole III on the west side of the province involves major additional costs, when construction costs, transmission losses, and reliability considerations are included. A west side of the province location for Bipole III is favoured by government, giving consideration to a hoped-for and possibly pending designation of a large sector of boreal forest East of Lake Winnipeg as a World Heritage Site. The avoidance of major development in what is deemed one of the last undeveloped large areas of boreal forest in the world has, at minimum, intrinsic value, and is consistent with recognition of the overall climate change issue and the responsibility of governments to mitigate known and expected effects.

The westerly route, while traversing similar terrain over a greater distance than the rejected eastern route, is not expected to face the same constraints that an eastern route would encounter in seeking environmental and community approval. The west side of the Province is already developed to a significant degree, and may face less opposition to the construction of a new transmission line.

As sole shareholder of MH, the Province has the right to direct the west side routing. Yet, it should be acknowledged that the additional costs will be borne by Manitoba ratepayers, either in the form of higher rates in the longer-term or a reduced export "subsidy" reflected in rates. Export contracts are price

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competitive and, in the absence of CO₂ taxes, coal generation costs will largely dictate future energy prices negotiated in the MISO market.

As such, the added costs for Bipole III is unlikely to be reflected in the energy sales price, although, and this is an important consideration, "clean hydro" power may eventually command a premium price and MH's future sales may be made "easier" by its environmentally-friendly route choice.

For MH, the development of alternative energy in its export markets may tend to reduce energy demand from MH. As well, alternative energy sources that may come into use in the future in Manitoba may well affect domestic consumption and revenues, without a corresponding reduction in the need for infrastructure and services. While MH is a significant revenue generator, its margins are low (particularly if the cost of new construction is considered), and rates are likely to be under continued upward pressure going forward.

Given that MH is incurring costs for environmental and social purposes (i.e., West Side Bipole III; Brandon Coal Plant, etc.), such costs should be separately defined and tracked to allow for subsidies and for the cost of choices made for environmental objectives to be transparent.

As noted in the findings for MH's capital expenditures, new export agreements are driving MH's construction of new hydraulic generating stations. The underlying economics have not been publicly disclosed or tested. Because of the potentially negative impact on domestic consumer rates, at least in the initial years, the economic justification of expansion presented on export agreements should be reviewed and approved before such export agreements are finalized.

The Board is of the view that it would be in the public interest that MH's export contracts be filed with the Board for review, and possible approval.

10.0 Load Forecasts and Power Resources

There does not appear to be any clearly-defined process that MH follows in achieving augmented flow projects. Parties potentially affected by such a program might be better served if a publicly-known approval process were in place. The Board will direct MH to provide a summary of existing programs and potential future programs defining the arrangements for increased or modified (augmented) water flows within and external to Manitoba. They should include the specifics of the program and mitigation and compensation related thereto.

11.0 Demand Side Management

11.0 Demand Side Management

11.1 General

MH's Demand Side Management (DSM) initiative, "Power Smart" consists of energy conservation and load management activities designed to lower the demand for both electricity and natural gas in Manitoba. The most current plan is the 2006 Power Smart Plan.

For the electric business, the initiative is one element of the resource options available for meeting the Province's electrical needs and the initiative plays an important role in the Corporation's overall integrated resource plan. DSM initiatives are to assist customers in meeting their energy needs through energy efficient measures. For the electric business, such initiatives enable MH to serve more domestic customers with less energy. Reduced domestic load requirements allow for reduced capital expenditures and increased energy available for export. Electric DSM initiatives are evaluated utilizing the same underlying criteria and economic evaluation approach as used with alternative resource options.

11.2 Program Evaluation

To evaluate new programs a high level assessment Marginal Resource Cost Screen compares the expected benefits to the incremental capital costs. If programs pass the initial screening, a more detailed assessment is undertaken involving developing program concepts and designs and projecting costs and benefits.

MH determines the cost effectiveness of DSM programs using the Total Resource Cost and Rate Impact Measure Tests. The primary economic indicator

11.0 Demand Side Management

for evaluating the effectiveness of both electricity and natural gas incentive-based programs is the Total Resource Cost (TRC) test. TRC measures the cost effectiveness of a product or program, and a TRC benefit/cost ratio greater than one (>1.0) indicates that a program is cost effective.

The secondary economic indicator for evaluating the effectiveness of programs is the Rate Impact Measure (RIM) test. RIM indicates the cost effectiveness of a program from the utility's perspective. All DSM related savings and costs incurred by the utility, including revenue loss and incentive payments, affect the RIM benefit/cost ratio. The results provide an indication of a program's expected long term impact on rates.

As a guideline, MH attempts to design electricity based DSM programs that have a RIM of 1.0 or greater. However a program with a RIM of less than 1.0 may trigger a program redesign, and may still proceed if the program design is judged to provide overall benefits.

Once Power Smart programs are in place, they are evaluated to determine the net program load savings and costs as well as the cost-effectiveness of the savings. Net savings take into consideration factors such as free riders (benefits derived that carry no specific cost), heating and cooling interactive effects, and system peak coincidence and persistence effects. Customer data and market information are used to assess the impacts of these factors on the overall savings attributable to incentive-based Power Smart programs.

In evaluating DSM programs, MH attributes no value to delayed generation in its TRC test, nor does it consider the full benefit of displacing carbon in export markets.

11.0 Demand Side Management

11.3 Program Costs and Amortization

MH plans to spend \$401 million over the next 11 years on DSM expenditures. Of that amount, MH budgeted to spend \$38.3 million in fiscal 2008-09, a figure later revised at the hearing to \$43.1 million.

MH plans to spend a cumulative amount of \$571 million on DSM expenditures through to the end of the 2017/18 fiscal year. While one purpose for spending on DSM is to delay new generation, new generation has, to date not been delayed due to DSM.

MH has defined “levelized” costs for various DSM initiatives. The following table provides insight as to the cost effectiveness of various activities and programs.

Exhibit 4.3.2.5
Electric Levelized Utility Costs
¢/KWh Saved by Incentive-Based Power Smart Program

Program	Results 2005/06
Efficiency Programs:	
1. Residential	
New Homes	7.2¢
Home Insulation	2.8¢
Compact Fluorescent Lighting	0.8¢
LED Lighting	6.6¢
2. Commercial	
Commercial Construction and Renovation	1.1¢
Internal Retrofit	1.8¢
Commercial Lighting	1.7¢
Agricultural Heat Pads	0.4¢
City of Winnipeg Agreement*	7.7¢
3. Industrial	
Performance Optimization	0.3¢
4. Discontinued/Completed Program Costs	N/A
Efficiency Programs Costs Subtotal	1.0¢
Rate/Load Management Programs:	
Curtailable Rates**	N/A
Overall: Program Costs	1.0¢
Overall: Program + Support Costs***	1.1¢

* The levelized cost of the electricity savings estimate is being associated with the City of Winnipeg's Power Smart Agreement is 7.7¢/kW.h.

** Levelized cost analysis is not provided for rate/load management programs.

*** Support costs only include incremental support costs, no customer service initiatives or standard costs are included.

11.0 Demand Side Management

MH identified that its calculation of cents per kilowatt hour saved was based upon current program kilowatt hour savings, and assumed generation over a thirty (30) year planning period.

MH amortizes its DSM costs over an average 15 year period, which is longer than other comparable utilities. BC- Hydro and Quebec Hydro amortize DSM cost over a maximum 10 year period. While MH states that their policy is fully supportable. The Board has expressed reservations in past Orders and has suggested that MH could express such costs over a shorter time frame.

The unamortized balance of DSM expenditures was \$17 million as of March 31, 1994, and is forecast to grow to \$180 million by the end of the 2008/09 fiscal year. The amortization of DSM expenditures was \$978,000 in fiscal 1993/94, to increase to \$13.7 million in the fiscal year ending March 31, 2009.

MH has not yet determined the effect IFRS will have on its accounting treatment of DSM expenditures.

11.4 DSM Program Savings

By the end of 2005/06, MH opined that its Power Smart Programs would achieve an annual load reduction of 1,030 GW.h in energy, and 434 MW in winter peak demand (at generation), and that this level of “saved power” translated to a cumulative reduction of over \$214 million in customer bills, and indirect greenhouse gas emission reductions of approximately 738,000 tonnes of carbon dioxide equivalent emission (the latter in 2005/06 alone).

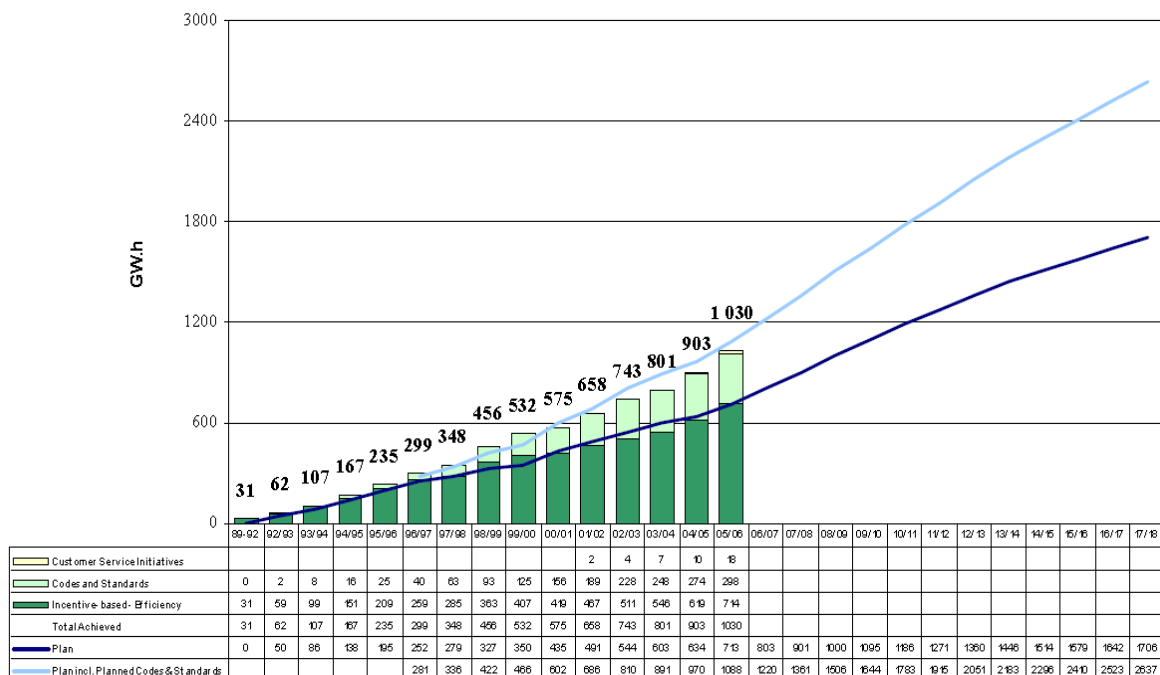
11.0 Demand Side Management

Domestic energy reductions contribute to surplus generation capacity, which contributes to energy sales in the export market. The cumulative energy and demand reduction achieved (including savings to date) through the Corporation's DSM efforts is on target to achieve 2,695 GW.h/year of energy savings and 848 MW by 2017/18. MH also has a plan to achieve natural gas savings of 101 million cubic meters.

In total, the programs are expected to result in greenhouse gas emission reductions of 2 million tonnes by 2017/18.

The following table depicts energy and demand savings realized to fiscal 2006, and that forecast through fiscal 2018:

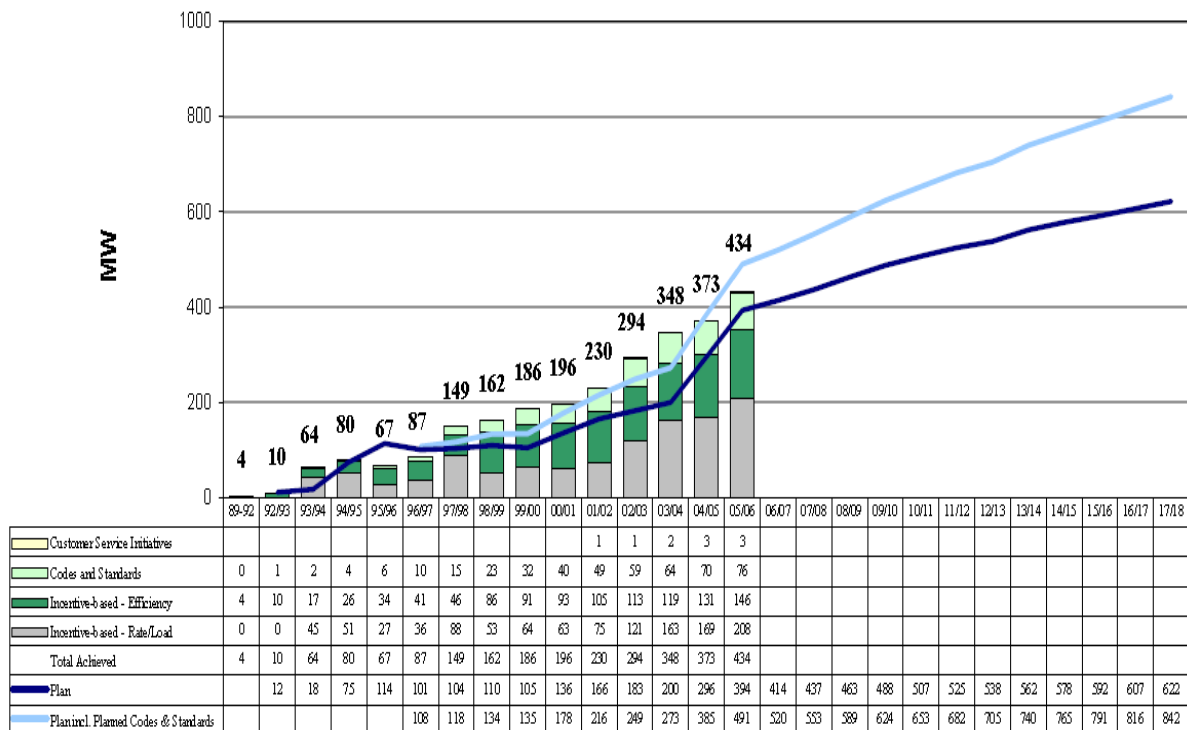
Electric Energy Savings - POWER SMART Portfolio
GW.h Savings Achieved to Date vs. Plan
(at Generation)



11.0 Demand Side Management

Electric Demand Savings- POWER SMART Portfolio

MW Savings Achieved to Date vs. Plan
(at Generation)



The tables suggest that MH's DSM initiatives are running at about 90% of target. Incentive-based programs, which are individually tracked, run above 95% of target, but Codes and Standards programs, which have not been specifically defined, are running at about 80% of target.

DSM has managed to offset about 20% of otherwise domestic load growth and freed-up additional energy for export. However, it does not appear to have delayed the Wuskwatim G.S. in-service date.

11.0 Demand Side Management

MH claims to have reduced GHG indirectly by 730 kilotonnes on a cumulative basis, due to reduced emissions resulting from their export of electricity.

MH acknowledged that the estimated GHG benefits have no tangible financial benefit for MH.

11.5 City of Winnipeg DSM Program

As a condition of MH's acquisition of WH, MH and the City of Winnipeg entered into a Power Smart Agreement on September 3, 2002. The objective was to capture energy efficient opportunities within the City's facilities, with a minimum target of reducing the City's energy bill by \$800,000 annually. MH guaranteed the City an annual savings of \$800,000 from the measures or the equivalent in the form of deemed savings plus a monetary payment by MH. MH's commitment over the ten year term this condition applied had a total value of \$8 million.

A variety of energy efficient measures have been implemented for new construction and renovations in a large number of City owned or operated facilities towards meeting the objective of the program.. The energy savings forecasted to be achieved is 12.3 GW.h, a goal to be limited to a 20 year time horizon.

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The estimated annual saving achieved by the City of Winnipeg related to the agreement is as follows:

Contract Year, ending August 31	Savings (\$)
2003	607
2004	65,175
2005	144,426
2006	654,239
2007	771,905
2008 (forecast)	850,000
2009 (forecast)	900,000

To the end of 2007/08, MH has paid \$2.4 million to the City, this because it could not deliver the \$800,000 of annual DSM savings each year as prescribed in the agreement with the City.

So far, including the \$2.4 million paid, MH has spent over \$10.3 million under the agreement, exceeding the ten-year commitment of \$8 million of savings and/or payments. MH states that the levelized cost of the program has been the equivalent of 7.7¢ per kW.h.

MH stated that due to the energy savings realized from the initiatives undertaken, MH is economically better off, as the energy saved has been and may be exported to the United States.

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11.6 Carbon Trading

In 2002, MH became a founding member of the Chicago Climate Exchange (CCX). CCX requires participants to reduce emissions relative to historic baselines. Each participant is provided an annual allowance (of CCX units), an allowance that decreases each year from the historic baseline. If a participant's emissions exceed their allowance, the participant is required to buy additional units through the exchange. Conversely, if their emissions are below their allowance, they are able to sell the surplus units.

Through participation in this CCX, MH gains experience with the measurement, reporting and trading of admissions. Export sales, for which MH negotiates ownership of the associated emission reductions, make up a significant component of the offsets earned. While having these reductions delivers real value in complying with the voluntary commitment, surplus reductions may not yield additional value.

MH reported its intention to continue to monitor emerging market rules for opportunities to extract value from its emission reductions achieved in either Manitoba or in the Corporation's export market.

11.7 Low Income DSM Program

In its 2006 Power Smart Plan, MH included a new residential program, the "hard to reach" (HTR) program. The HTR program targets low-income residential households on an integrated basis (i.e. for both natural gas and electric consumption). The program has since been modified and now integrates funding made available by the federal government's ecoEnergy program. The current design of the low-income program was implemented December 14, 2007.

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MH's Lower Income Energy Efficiency Program is designed to bring Power Smart and energy efficient measures to an estimated 4,600 lower income households over the next three and a half years ending 2010/11. The program targets lower income Manitoban homeowners and tenants.

In the case of lower income tenants, an agreement must be reached between MH and the landlord/building owner in order that a substantial portion of the benefits associated with retrofit measures funded by MH's program will be passed on to tenants. Private landlords and non-profit social housing organizations, including Manitoba Housing Authority (MHA) public housing and other non-profit subsidized housing organizations, are eligible to participate in the program.

Eligibility for households pursuant to the program was established by the Corporation at 125% of the Low Income Cut-off (LICO) established by Statistics Canada. Targeted measures to be addressed by the program include:

- low or no-cost basic energy efficiency measures, such as compact fluorescent lights;
- faucet aerators, low-flow showerhead, pipe wrap, hot water tank set back, and caulking/air-sealing;
- insulation for basement, attic and crawlspace installation; and
- High-efficiency natural gas furnaces.

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Energy Efficiency Measures	Assumptions		
	Ave. electric Savings Per Home* (kw.h.)	Net to Gross Adjustments (Persistence Factor)	Participation
Insulation: including attic, basement and crawlspace	2,797	100%	Attic: 84% Basement: 58% Crawlspace: 8%
Compact Fluorescent Lighting (6 CFLs per home)	138	90%	100%
Drainger	162	100%	18%
Water Measures: including tank set back, 1-Low-Flow Showerhead and 2-Faucet Aerators, pipewrap	404	Tank set back: 50% Showerheads: 90% Aerator: 90% Pipewrap: 95%	50% 100% 100% 100%
Weatherization: including air sealing and gasket covers	640	100%	100%

*- includes single detached homes, town houses, multiplexes and mobile homes

The anticipated duration of MH's Lower Income Program is tied to the Federal government's ecoEnergy program, which is currently approved to operate until March 31 2011. Contemplation of changes to the existing program will be undertaken closer to the date of the end of the Federal funding commitment.

MH intends to deliver the program through both Community Based Organizations (CBO) and individual household participation. Both approaches require pre- and post-audits, to identify energy efficiency opportunities and verify work completion.

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The cumulative budget through fiscal 2017/18 for MH's Lower Income Program is \$12.6 million, including rate-based, federal and Affordable Energy Fund (AEF) funding; the program's budget for 2008 was reported to be:

Program	Budget (millions in 2008\$)
AEF Low Income - Electric Component	\$3.5
AEF Low Income – Natural Gas Component	\$6.1
AEF Total	\$9.6
Power Smart Low Income – Electric	\$1.1
Power Smart Low Income – Natural Gas	\$1.9
Total Low Income DSM	\$12.6

In assessing the economic benefits associated with the Lower Income Program, MH determined that the TRC for the program is 0.9, the RIM, 0.7, and the levelized cost of the program, 11.2¢ per kW.h. The results of testing indicate that the program results in some degree of cross-subsidization (of lower income customers by other residential customers).

11.8 The Affordable Energy Fund (AEF)

Following a spike in oil and natural gas prices in the summer and fall of 2005 on the heels of hurricanes Katrina and Rita, which damaged energy availability from south-east American production and distribution sites, and the Board's subsequent action as of November 1, 2005 when it deferred costs and restrained natural gas rates for Centra Gas' residential customers to recognize what the Board then-deemed to be a price bubble, the Provincial Government introduced

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The Winter Heating Cost Control Act (which was subsequently passed, proclaimed and implemented in 2006).

Among other provisions, the Act established the Affordable Energy Fund [AEF], requiring MH to contribute 5.5 % of its fiscal 2006/07 gross export revenues to the AEF. This resulted in a fund of \$35 million to be utilized for various energy efficiency initiatives, including if not primarily, assisting low-income electricity and natural gas customers.

MH indicated that \$19 million of the AEF's \$35 million was earmarked for province-wide low-income initiatives, with \$8 million for community energy development, \$0.25 million to expand the eligibility of Power Smart programs in Manitoba to include residential homes heated with energy other than natural gas or electricity, \$0.75 million for rural and northern support and outreach, and \$1 million for special projects then-yet to be defined.

MH indicated its intention that the \$19 million reserved for low-income programs would mostly benefit electricity and natural gas space-heated homes, and would provide for programs that would not otherwise be funded from MH/Centra's rate-based DSM programs, including the Corporation's HTR Program.

In commenting on the establishment of the AEF at the most recent Centra GRA, in Order 99/07 the Board stated:

"The Board notes Centra has indicated that the AEF is not slated to be credited interest on unused balances. Centra should impute interest income on AEF funds transferred to it, the proceeds to be utilized to underwrite additional or expanded low-income programs. Such an approach would also allow the funds available within the AEF to represent some measure of an endowment (the problem with the AEF is that it has been funded with a "one-time" transfer, while the work of upgrading heating efficiency and retention is likely to require more than a decade and cost more than the initial allotment of

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\$19 million – which must address both electricity and natural gas low-income households).”

In Order 99/07 the Board directed:

“Centra segregate funds transferred to it from the Affordable Energy Fund (AEF) and funds accumulated for the new Furnace Replacement Program, with such funds to earn interest at Centra’s short-term borrowing rate.”

MH has yet to act on the direction, responding that the AEF should not attract interest as it would result in an accumulation, before deductions for expenditures made, of more funds than were contemplated in the Act. MH stated having the fund attract no interest to be consistent with the legislation.

Recently, MH, in partnership with the Spence Neighbourhood Association initiated a pilot project. The next steps for the Corporation’s province wide low-income program were reported to include continuing with the execution of private and community programs, and marketing and promoting in communities, rural areas, and other relevant venues.

11.9 Interveners’ Positions

The Coalition

DSM Program Evaluation

The Coalition suggested that MH should think of DSM in a different way. Mr. Dunsky, who appeared on behalf of the Coalition, opined that the RIM Test should not be utilized to screen for justification of DSM programs, and that while the TRC should remain the primary test for DSM programs, under MH’s current approach there will be proposed measures that will fail the TRC test that should still be pursued if they pass the “utility cost” test. The Utility cost test compares money invested in a program with the value of expected energy savings for the

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utility. For Mr. Dunsky, if MH can generate cost effective kW.hr savings, the program initiative should proceed.

Mr. Dunsky further stated that in evaluating low income programs it was extremely important to account for non-energy benefits (NEBs), noting that a growing body of evidence points to very significant NEBs arising from low-income programs. Mr. Dunsky suggested that NEBs include fewer shut-offs, reduced emissions and health and safety benefits. Mr. Dunsky recommended that the Corporation take into account NEBs in its future cost-benefit analyses of low-income programs.

The Coalition recommended NEBs be included in the screening of potential DSM programs. The Coalition further recommended that either an independent or an internal review of MH's current DSM portfolio be undertaken, and that the review consider the screening tests, portfolio of programs and NEBs.

Low-Income Programs

Mr. Dunsky observed that consumers face an array of market barriers to the adoption of cost effective energy efficiency products and practices, and suggested that the barriers are most acute for low-income customers. Mr. Dunsky cited that barriers such as information and search costs and below average language and computational skills (literacy, poor math skills, English as a second language) represent significant hurdles to both participation in DSM programs and adoption of efficiency measures.

Mr. Dunsky also cited performance uncertainty and higher than average housing mobility for low-income consumers (multiple moves within a short period of time) adds to the uncertainty regarding the economic value of long-term energy

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savings measures for low-income households. He also cited transaction costs: and greater difficulty experienced by low-income households in dealing with complex transactions can also lead to lower measure uptake and higher dropout rates. And, of equal importance as operating barriers to the participation of low-income households in energy efficiency measures, Mr. Dunsky noted:

- a) financing difficulties – a general lack of access (or access at unreasonable cost) to capital;
- b) an aversion to debt due to the payments associated with debt;
- c) a diminished ability to meet upfront costs;
- d) the organizational practices of many contractors, unwilling to work for low-income customers or charging a premium for the perceived risk of non-payment; and
- e) the daunting issue of split incentives in rental markets, whereby landlords are unwilling to pass on savings to tenants or invest in measures that would assist in lowering utility bills but not benefit the landlord financially.

Mr. Dunsky reiterated a concern previously expressed by the Board that generally low-income customers will lack access to the capital required to make improvements to the energy efficiency of their homes. He further noted that low-income individuals are often caught in a “vicious cycle of debt”, such that even if they could have access to capital, they will have an aversion for incurring debt requiring increased demands for their disposable income, and, therefore are unlikely to invest in their home (even if the investment would be in their long-term interests).

Mr. Dunsky suggested four key principles for success in administering a low-income program:

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1. Keep it simple. Participation drops precipitously as complexity increases. Program implementers need to take “A-Z” ownership of the complexity involved in conducting audits, hiring contractors and overseeing work. Complexity should occur on the implementer’s side, not the participant’s. Similarly, proof of income and other eligibility requirements need to be flexible.
2. Keep it free. While it may be tempting and intuitive to request even symbolic participant contributions, Mr. Dunsky suggested that attempts to do so in other jurisdictions have generally met with failure.
3. Incent “sales” (outreach). For Mr. Dunsky, the difference between a good theoretical design and good performance is sales. Ideally, the utility, the contractor and other low-income stakeholders (supporters) will contribute to an active outreach effort, with only the utility and the supporting community having the capacity, tools and incentives to find potential customers and “close the sale”.
4. Be comprehensive. As with any sale, the hard part is getting in the door. Mr. Dunsky suggested that once a participant is in the program, it is critical to capture all possible opportunities, recognizing that any measures not installed will likely be lost for years and/or their savings will cost significantly more to achieve at a later date. Comprehensive programs typically include education, a suite of “light” measures (CFLs, caulking/weather-stripping, low-flow aerators and showerheads, etc.), envelope measures (insulation and weatherization) and appliance and equipment replacements (especially old fridges and furnaces).

Mr. Dunsky opined there were a number of major weaknesses in MH’s low-income energy efficiency program, beginning with the fact that the current

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program design is too complex, consisting of a number of hurdles that the low-income customer must overcome to participate. Mr. Dunsky noted that MH has not taken ownership of the delivery of its programs, passing the responsibility to low-income customers, an approach that he opined represents a serious barrier for low-income customers.

To assist in reducing low-income household resistance to implementing energy efficiency measures, Mr. Dunsky proposed that MH take full ownership of its DSM programs, including taking on all the necessary administration. He noted that in other jurisdictions where programs have been successfully implemented, full utility ownership of all approaches taken had been followed, with the benefits including the elimination of needless hurdles, the ability to negotiate better prices with contractors than can be achieved by individual low-income homeowners, and assurance of quality control.

Mr. Dunsky criticized MH's reliance on others, suggesting that relying on CBO's to identify and involve low-income customers is unlikely to secure success. Mr. Dunsky opined that another weakness in MH's program relates to the involvement of CBO's in program delivery. He recommended that MH be selective and choose only organizations with the institutional ability, reputation and capacity to deliver low-income programs effectively. He also suggested that MH invest significantly in helping CBO's develop the necessary capacities and abilities to deliver programs effectively.

Mr. Dunsky recommended that when such organizations are involved they be closely monitored and regularly assessed, particularly as to their ability to meet targets. For Mr. Dunsky, MH should measure and evaluate the time from "first contact to work completion", and both undertake quality control spot checks and utilize client satisfaction surveys.

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To avoid the problems he expected to arise with involving CBOs in MH program delivery, Mr. Dunsky recommended that MH lead the projects and underwrite the costs of the measures required, dealing with the Federal government directly to recover any federal incentives that may be available.

The Coalition suggested that approximately 30% of MH's residential accounts pertain to rented homes, excluding duplex apartments, and that there are almost 98,000 apartment units. The Coalition noted renters' average household income is significantly lower than the Manitoba average, and that apartment units, where renters predominate, are currently excluded as a target group for the low-income energy efficiency program.

Mr. Dunsky stated that a major barrier faced by low-income customers is the lack of access to capital and a concurrent aversion to new debt. Mr. Dunsky also noted that the majority of low-income households are renters, and that a renter would not be willing to invest in improving the energy efficiency of a building if they were not to receive the benefit. Conversely, a renter responsible for the utility bill may find the owner of the building not willing to invest in improving the energy efficiency of the building envelope, because the landlord will not retain the benefits.

Mr. Dunsky stated that programs requiring landlord support should be made attractive for both the low-income tenant and the landlord, and that otherwise a low-income tenant will not benefit because of a lack of landlord participation. Mr. Dunsky proposed that MH offer a turnkey approaches, whereby MH would pay for all the measures undertaken and collect any external incentives. Mr. Dunsky indicated such an approach would best facilitate landlord participation.

With specific respect to natural gas furnace replacement, Mr. Dunsky indicated that MH's current program is inadequate. Mr. Dunsky suggested MH offer a

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zero-interest loan or, preferably, a lease. The loan/lease would involve owner payments over a maximum of 10 years.

He suggested that a leasing approach would allow repayment to remain tied to the furnace, the newer more efficient furnace to provide the energy savings benefits allowing the lease payment to be made. Mr. Dunskey also suggested that a more aggressive financing offer may overcome low-income customers' reluctance to participate, and provide an opportunity to replace inefficient furnaces (which result in high levels of emissions and bills).

Mr. Dunskey also suggested MH expand its current DSM program to include a fridge replacement program, which would target the early retirement of inefficient refrigerators. Mr. Dunskey estimated that replacing inefficient refrigerators could be expected to result in an average saving of over 900 kW.h annually for each fridge replaced.

Based primarily on its witness' testimony, the Coalition recommended, for Low-Income and Tenancy DSM:

1. MH provide turnkey service;
2. CBO capacities be evaluated prior to involvement;
3. A fridge replacement program be implemented;
4. A more aggressive approach to furnace replacement be undertaken; and
5. Expedite the rollout and implementation of low-income DSM programming, addressing costs, benefits, and sources of funding.

The Coalition did not endorse RCM/TREE's recommendation for a bill assistance program, stating that while the intervenor was open to a further study of the issues involved, it had concerns with problems found in US jurisdictions, those

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reported to be related to low participation levels, and suggesting the potential to divide low-income customers from other customers and, as well, a concern with the income means testing that would be required.

MIPUG

DSM Programs

MIPUG suggested MH pursue all DSM opportunities where the projected costs to secure energy savings are at or below the marginal cost of new generation.

MIPUG advised MH not to screen out DSM opportunities on the basis of customer economics, but instead focus on ensuring customers have sufficient information to conduct their own evaluation of the costs and benefits of the DSM opportunity. MIPUG suggested MH's current approach may be screening out beneficial DSM measures.

DSM Program Evaluation

MIPUG expressed concern that MH's present approach is screening out economically justifiable opportunities, and opined that the TRC test excessively focuses on participant economics, and that it is possible that DSM activities that would be economically beneficial to MH and its customers are being screened out under the TRC test because the economics were not sufficiently advantageous to the participant.

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Low-income programs

MIPUG opined that affordability programs to benefit low-income customers represent social policy considerations that more properly lie within the mandate of the provincial government. To base rates on a customer's ability to pay is, for MIPUG, discriminatory. Similarly, operation of a DSM program targeted solely at low-income customers is considered by MIPUG to be discriminatory, with MIPUG focused on MH's obligation to provide power to all its customers.

MIPUG opined that precedent suggests that decisions undertaken that exceed or define the bounds of discrimination should be made by explicit direction by the legislature and should not be undertaken in the absence of such direction. MIPUG's cited past legislation related to uniform rates and the establishment of the AEF, both created through government initiated legislative changes.

MIPUG further stated that if any approaches are to be undertaken to benefit low-income customers, they should be revenue neutral to non- low income customers

MKO

DSM Program Evaluation

MKO submitted that DSM programs should not be required to be revenue neutral for any particular customer class, or group of customers.

For MKO, to the extent that a provincial government elects to use MH rates as a social policy implementation tool, and provides clear direction to MH to do so, then the variance from standard rate design principles is justified.

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MKO further stated for DSM programs targeted to benefit certain customers, that in the absence of a clear provincial government direction on “who should pay”, MKO submits that all MH customers should bear the costs.

Diesel Community DSM Programming

MKO submitted that energy efficiency measures are very important, especially for high-cost diesel served communities. In measuring energy savings in the diesel zone, 1 kW.h saved also reduces the cost of diesel fuel to generate the kW.h. However, since a kW.h saved in the diesel zone does not provide an extra kW.h for export sale, the more traditional approach of valuing a kW.h saved with respect to delaying new generation capacity or adding to export sales should not be used with respect to the diesel zone.

MKO noted that MH has suggested that through population growth the electricity required to serve the diesel communities may double over the next 20 years. MKO noted its understanding that INAC will pay for new generation capacity only for the diesel communities, whereas all MH customers pay for new generation capacity for the rest of the province. MKO is concerned that since MH does not have to pay for new generation capacity in the diesel communities (with the costs largely being met by INAC and rates), the Corporation has not pursued energy efficiency programs in the remote communities to the extent that it should.

MKO indicated concern with MH's statement that its home audit program would not apply to homes in MKO communities, where, for MKO, MH perceives the benefits flow to INAC. Accordingly, MKO recommended that the Board immediately direct MH implement DSM programs for all customers in all MKO First Nation communities, whether or not MH perceives that benefits may accrue to INAC. MKO further recommended that MH personnel working with MKO First Nations customers be directed to meet with MKO First Nations to resolve

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misconceptions regarding the beneficiaries of DSM programs in the MKO First Nations communities.

MKO submitted that MH has been operating in violation of the spirit of Board Order 17/04, where MH was directed to implement DSM and energy efficiency programs in the diesel communities as part of the effort to reduce the financial burden on MKO customers. MKO further submitted that MH should re-evaluate its energy efficiency programs and incorporate Mr. Dunsky's recommendations to revise qualification criteria and set more realistic targets for the amounts MH will invest in energy efficiency measures in the diesel communities.

RCM/TREE

DSM Programs

RCM/TREE stated the principles of sustainability and justice should guide the Board in its determination of the public interest.

RCM/TREE noted that despite MH's internal assessment of success in its DSM program efforts, MH's standard electric residential customers continue to increase their energy consumption while Saskatchewan Power customers reduce their consumption.

While RCM/TREE supported MH in its bid to be both financially secure and socially responsible, the intervener suggested MH should further develop DSM and bill affordability programs for low-income customers.

Mr. Paul Chernick, a witness engaged by RCM/TREE, suggested that MH should double or triple its energy-efficiency spending, and energy savings, from current levels. Mr. Chernick stated that increased energy savings over the next few years

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would help to offset the expected and/or risk of energy shortages that may lie ahead, and that while MH asserts that “the only option available for 2009 is imported power” (to meet a possible energy shortage), accelerated DSM is clearly a lower-cost option.

For Mr. Chernick, increased energy savings over the next decade would increase MH’s flexibility, allowing it to avoid the anticipated 2020/21 energy deficit (before both Conawapa and Keeyask are expected to be on stream), without having to extend the operation of the thermal plants, while allowing the Utility to commit to larger and longer-term firm export sales.

Mr. Chernick advised that if the Board were to increase MH’s funding for DSM, low-income programs, economic development, or to strengthen MH’s balance sheet, the additional charges should come in the form of higher energy rates rather than increased demand charges, and by way of inverted higher tail-block energy charges.

DSM Program Evaluation

Mr. Chernick recommended the RIM test be discarded as a guide to the selection of DSM programs, and suggested that there are better ways to evaluate DSM programs. As to the evaluation of DSM programs, Mr. Chernick suggested the Board embed a value for carbon even though a carbon tax is currently not being received through current export prices.

Mr. Chernick recommended the Board direct MH to incorporate in its planning environmental costs for which it is not now being paid by export customers, and report back to the Board on the feasibility of including the additional benefits to Manitoba and the global environment from the reduction of carbon emissions,

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and how these benefits might best be incorporated in rate design and DSM evaluation.

Low-Income Programs

RCM/TREE submitted that MH should institute an affordability program, as recommended by Mr. Steven Weiss, a witness engaged by the intervener. For RCM/TREE, in addition to the social benefits that would come from a bill affordability program for the least well-off in society, such programs are also beneficial to non-participating customers because of reductions in utility collection and administration costs and reduced bad debts of low-income customers.

Mr. Weiss stated to make energy affordable, it is important for the Corporation to focus on customer energy burdens and target for benefits the most vulnerable, the benefits to be DSM and direct bill assistance. He defined energy burden as the percentage of income that non-transportation energy costs represent of household income. Mr. Weiss described a high-energy burden to represent 11% or more of household income, with a severe energy burden defined as being 15% or more of a household's income paid for energy.

Mr. Weiss recommended MH measure energy affordability, gather information on the energy burden of Manitobans, and track the effectiveness of its programs in reducing the number of customers with high and severe energy burdens. Mr. Weiss recommended MH should aim to reduce low-income residential consumers' energy burden to, at minimum, levels below the severe burden level of 15% of household income. He also suggested that over time MH should amend its goal, and seek to reduce the maximum energy burden to 11% of household income.

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Mr. Weiss stated specific plans should be set to target the Low income households with the highest usage, and these residences should be provided conservation measures and bill assistance. Mr. Weiss also suggested MH should set goals and outreach targets for seniors, minorities, the disabled and families with young children.

Mr. Weiss noted that the bill assistance programs of other jurisdictions take many forms, including one-time crisis assistance payments (in the \$200 - 300/year range), arranging forgiveness, rate discounts, monthly credits and assistance based on maximum percentage of household income..

Mr. Weiss indicated that programs considering the percentage of income required to be devoted to energy bills work best, when assistance levels can be set according to income level. He provided an example, whereby a customer would be charged no more than 9-10% of his/her income, being deemed a level that is "affordable." In Mr. Weiss' example, any bill amount over that level would be met through the bill assistance program.

Mr. Weiss stated that the customers of utilities offering such programs are often required to make timely payments in order to remain with the program; the goal being to provide an incentive for customers to stay current within a budget they can afford. Mr. Weiss further stated that these programs have proven to be extremely successful in reducing disconnection, arrearages and write-offs. He also recommended that such measures work best with equal payment plans.

Mr. Weiss' final recommendation was that a bill affordability program could begin as an experiment, and involve the use of a control group of low-income customers not enrolled in the program. He suggested that frequent evaluations of bill assistance programs and pilots are very useful, and that an advisory group consisting of social service agencies, low-income customers, conservation and

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social justice advocates, as well as utility personnel involved with the program would prove useful.

In addition, RCM/TREE expressed support for the proposals put forward by Mr. Dunskey, the witness for the Coalition who proposed recommendations to remove barriers to low- income program access.

In addressing the question of whether the Board has the jurisdiction to implement low-income programs, RCM/TREE referred to a recent decision of the Ontario Supreme Court of Justice Divisional Court (dated May 16, 2008) involving the *Advocacy Centre for Tenants and others versus the Ontario Energy Board* (OEB). In the Court's decision, Justices Kiteley and Cumming dealt with the issue of whether low-income programs could be viewed as being within the OEB Board's jurisdiction.

In that decision, the Court held:

"However, in our view, the Board need not stop there. Rather, the Board, in the consideration of its statutory objectives, might consider it appropriate to use a specific method or technique in the implementation of its basic cost of service calculation to arrive at a final fixing of rates that are considered just and reasonable rates."

RCM/TREE interpreted the finding to mean the Board's jurisdiction could extend, to include the objective of energy conservation, and, as well, to the use of incentive rates or differential pricing, to further the objective of protecting the interests of consumers. RCM/TREE further interpreted the decision to suggest the Board may take into account income levels in setting utility rates, to achieve the delivery of affordable energy to low-income consumers (on the basis that this would meet the objective of protecting the interests of consumers with respect to prices).

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RCM/TREE submitted the Board is engaged in rate setting within the context of the interpretation of its statute (*The Public Utilities Board Act*) in a fair, large, and liberal manner and that is not engaged in setting broad social policy; accordingly RCM/TREE urged the Board consider the approaches it recommended.

11.10 Board Findings

DSM Programs

The Board recognizes that MH has been making an increasingly significant investment in DSM programs, and has gone beyond the efforts made by the vast majority of other utilities, with spending increasing in recent years from \$11.9 million in 2003/04 to a forecast in the order of \$43.1 million for fiscal 2008/09.

MH's program now has a low-income component and it is a segment of MH's integrated resource plan, as energy savings allow for additional energy to either be sold on the export market or allow for the deferral of expensive new generation. Both outcomes can have the effect of improving MH's financial position and dampening the need for sizeable future rate increases.

The Board encourages MH to continue to pursue environmental objectives on an integrated natural gas-electricity basis, and in particular, to consider the position of low-income customers increasingly faced with higher energy costs and too often lacking the funds and know-how to achieve needed upgrades that would reduce their energy bills and GHG emissions.

For the Board, the Utility's DSM focus should be four-fold:

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- a) environmental – the reduction of wasted energy through reduced GHG emissions (here and in MH's export markets – climate change is a global challenge, the wind blows north as well as east, south and west);
- b) economic – energy not consumed by Manitobans should be available for sale on the export markets, and as much of that as possible during on-peak hours at peak prices – exports are taken into account in determining domestic rates without exports current rates would be, on average, 15% higher;
- c) economic – energy not consumed by Manitobans and not sold on the export market, either due to transmission capacity or price issues, can assist in the deferral of new generation and transmission, saving capital dollars and attendant interest and depreciation (construction and commodity costs have recently soared, driven in part by extraordinary expansions – of oil sands production in Alberta and the energy demand of China and India; sometimes delays can allow for projects to take place in times of more stable prices); and
- d) social – increasing the energy efficiency of low-income households will allow more families to remain in their homes and to have more disposable income available for necessities other than energy (the total cost of energy – gasoline, natural gas, electricity, propane, etc., has soared for all households, but the cost increases have been particularly devastating for households in the bottom four deciles of household income levels).

With respect to the approach the Utility now takes to accounting for DSM costs, as it has in past orders the Board continues to question the appropriateness of deferring DSM costs, an approach that is now challenged not only by the Board's concern but also by the upcoming IFRS. The Board has had and remains of the

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view that DSM costs should either be expensed in the period incurred or amortized consistent with the much shorter periods of amortization followed by other jurisdictions.

MH defers DSM expenditures for subsequent amortization over 15 years, whereas Hydro Quebec and BC Hydro, (sister crown utilities) defer less DSM and amortize deferred DSM expenditures over a much shorter time frame. In the case of BC Hydro, DSM costs are amortized over the short term of the useful life of the program or a maximum of 10 years. Hydro Quebec also amortizes DSM expenditures over a 10-year period. With the coming introduction of IFRS, the current amortization policy will be reviewed and a more conservative approach may be an option for early adoption.

Amortization of DSM spending is forecast to grow from \$9 million in fiscal 2007 to over \$13.7 million in fiscal 2009, while actual spending on DSM initiatives is forecast in 2007 at \$36.1 million, and to grow to over \$43 million in fiscal 2009. Thus, MH now plans for deferred DSM to grow to over \$180.9 million by March 31, 2009, a balance expected to continue to grow significantly through to 2018, due to increasing annual DSM spending which will eventually have to be recovered in rates – now to be achieved over a period too long for the Board.

The Board recommends MH consider changing its accounting approach to one that provides for the amortization of DSM costs over a period no longer than five years.

DSM Program Evaluation

The Board notes that MH projects that by fiscal 2017/18 (and speaking now as to electricity operations) it will have achieved 2,637 GW.h of DSM savings (1,706 GW.h through incentive-based programs and 931 GW.h of savings through

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changes to Codes and Standards, etc.). If achieved, this would represent a 240% increase in DSM savings over 12 years, a growth rate of almost 20% per year. (Demand savings are expected to reach 842 MW, an increase by 170% over 12 years, or almost 15% per year.).

While the projections are impressive, the Board suspects the opportunity for further reductions is great. As well, the projections are also highly subjective. MH relies on forecasts which can only be partially verified.

Despite major increases in DSM expenditures over the last four years, DSM has not had a marked effect on the deferral of planned generation and transmission projects. Since inception, DSM has, at best, offset 20% of domestic load growth. The Board notes that MH is forecasting the risk of energy shortfalls (demand, domestic and committed exports, as compared to local hydro-electric supply) through to the in-service dates of future generating stations Keeyask and Conawapa. If shortfalls do occur, and past experience and probabilities suggest a high risk of drought or below median water conditions occurring within the next five to ten years, then, as matters now stand, MH will have to rely on imported power from the MISO market. MH's MISO-market partner utilities generally use natural gas for peak demands, so the cost of imports can be a multiple of the average price of MH's exports.

In such a condition, and if a drought were to be sustained for five years (which has occurred in the past), MH has advised the Board that it could "run" a loss of over \$3 billion, an amount that dwarfs the Corporation's current retained earnings balance and which would have implications for rates and the general view of the Corporation's fiscal stability going into a period of expected significant expansion.

For the Board, the risks inherent to a Corporation depending in the end on the weather suggest that there should be an even more increased focus on

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conservation and DSM, so as to further reduce demand to provide an increased buffer between Manitoba hydro-electric supply and likely demand in the future. Such increased DSM initiatives may also address the currently-forecast future expected shortfalls.

Energy conservation has never been of such importance to MH as it is now, as it contemplates a massive capital expenditure program, to produce power that now is expected to be required to meet rising domestic load and continuing committed export markets.

Now, as previously indicated, MH does not expect the conversion of current natural gas space heating load to electricity, nor does it expect an abandonment of natural gas as the space heating choice for new residential construction. Given the Board's understanding of current and forecast natural gas prices, and its expectation for even higher domestic load growth due to such new phenomena as "electric" and "hybrid" cars, relying on electricity rather than gasoline, the Board urges MH to focus on conservation and upgrade and develop new DSM programs, to free up hydro-electric generation to meet the risk of much higher domestic load growth than the Corporation now forecasts.

This will likely require an expansion of existing as well as additional DSM programs, along with taking more into consideration societal impacts in the evaluation of DSM programming. In short, the Board recommends that MH "step-up" its DSM plans and targets.

Indirect GHG Reductions

Intervenors have suggested that increased export sales achieved by diverting price restrained domestic load growth to MISO will achieve global GHG reductions comparable to displacing coal-fired generation.

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MH's evidence was that the GHG reductions are, to a greater degree, reflective of natural gas generation displacement, since the carbon footprint for natural gas generation is less than 50% of that for coal generation.

The Board sees a need for more clearly defining the relative environmental benefits of exports, and will direct MH to provide a detailed analysis and report to the Board before June 30, 2009 as to whether there are greater global environmental (GHG) and economic benefits by exporting hydraulically-generated electricity than would be achieved by fuel switching (from natural gas to electricity) and/or geothermal within Manitoba. The report should address and clearly define the relative environmental and economic benefits of exports. The assumptions should also be included in the report. Currently, Manitoba consumers and businesses transfer \$1 billion to the gas producing provinces and states that supply Manitoba's natural gas, and these costs and transfers of funds to outside the province may soar even higher in the future.

Low-Income Energy Efficiency Programs

With respect to low-income programs, the Board commends MH for recently beginning to address the energy conservation needs of low-income households.

The Board is also encouraged that MH plans to enhance its low-income programs and target rental premises as well as owner-occupied residences, with MH's commitment to extend the low-income program to tenants of apartments. The Board further understands that there may be resistance for landlords to take part in the program due to split incentives and low-cost business models that some landlords may choose to operate under.

The Board also urges MH to make efforts to incent landlords to participate in the program to improve the energy efficiency of their properties, to the benefit of their

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tenants and the environment. The Board will expect MH to consult with stakeholders on its enhancements to its low-income programs to ensure it adequately addresses low-income needs, and to report to the Board by September 30, 2008 on the results of the consultation and subsequent development and implementation of this program.

Although MH is beginning to address the issue of energy poverty, more is required. The Board is very concerned with the slow pace of the overall effort. The Board notes that MH's current program is anticipated to address only 4,600 lower-income households over the next three and a half years, while the current low-income population is likely at least in the order of 100,000 households – and that is before taking into account recent major inflationary increases in general energy costs and risks of a slowing economy and higher unemployment.

Based on the current pace of MH's low-income DSM programs, the Corporation's spending over the next three years on low-income programs will not put a dent in the problem, and, at best, address only a very small fraction of low-income households. At the proposed pace of the program, it would take decades to obtain a significant level of participation of low-income households in MH's energy efficiency programs.

Low participation acts as a barrier to the lowering of excess energy bills and GHG emissions, and the putting in place of meaningful inverted rate program designs for residential customers. The Board agrees with the views expressed by the Coalition and RCM/TREE that more should be done in this area, to accelerate its efforts with respect to reducing the energy burden of low-income households.

The Board will direct MH to file with the Board on or before June 30, 2009 a draft plan, with projected implications, to increase the Corporation's integrated (natural

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gas and electricity) energy efficiency initiatives with respect to low-income households, so as to allow for reduced energy consumption for all such households within a decade.

The Board notes the evidence of Mr. Dunsky who critiqued MH's design of its low-income programs. Mr. Dunsky's suggested changes to MH's program were designed to overcome the barriers of program participation, barriers that clearly remain a significant concern of the Board. The suggested changes put forward by Mr. Dunsky have merit and should be considered by MH in its design of current and new low-income programs. The Board notes a willingness by MH to consider many of Mr. Dunsky's recommendations, and urges MH to not only consider the recommendations, but to internalize many of them, and take full ownership as to the delivery of the programs.

The Board was intrigued by the refrigerator replacement program proposed by Mr. Dunsky, and will direct MH to report back to the Board on a low-income and a general refrigerator replacement program, and provide the merits of such programs, on or before June 30, 2009. And, with respect to MH's new natural gas furnace replacement program (launched following Board direction that arose out of a Centra GRA), the Board appreciates the evaluation provided by Mr. Dunsky, and takes note of Mr. Dunsky's suggested changes to the program, including his suggestion for a lease program, with the lease payment linked to the energy benefit.

The Board notes Mr. Dunsky's critique that, as designed, the furnace replacement program will not prove an adequate incentive for the early replacement of inefficient natural gas furnaces and, at best, will likely only marginally assist the natural replacement market. The Board urges MH to seriously consider program changes to increase participation in early

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replacement of inefficient furnaces. Changes to the program that will better provide this opportunity are well worth the effort, and should provide energy savings for low-income customers and significant non-energy benefits to society, the Utility and the participants in the program.

The Board is aware that MH only recently launched its furnace replacement program, and suggests that design changes may be fairly easy to introduce at this time. MH has an opportunity to put this program on the “right footing” in advance of the upcoming heating season – when natural gas bills for all customers, not only low-income, may be considerably higher than they were in the previous winter.

The Board is interested in the take up of the program, and understands that it has been very low to-date, and will require MH to provide an update on the status of the current natural gas furnace replacement program (including actual and forecast take-up rates), as well as reports of possible changes to the program relative to the suggestions put forward by Mr. Dunskey, on or before September 30, 2008.

While not as aggressive, perhaps, as the Board’s recommendation that low-income customers be allowed subsidized Power Smart Loans and payment schedules involving an option requiring payment only upon the sale of the residence, Mr. Dunskey’s lease concept has merit as an option. Whether MH proceeds to adopt the Board’s recommendation for a subsidized loan program secured by the residence, or follows up and introduces a furnace lease program as suggested by Mr. Dunskey, either approach appears to be more likely of achieving success than the current approach being followed by the Corporation.

Installing high-efficiency furnaces in residences now relying on furnaces that may have efficiency ratings as low as 40% or below should assist in restraining the

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conversion from space heating by natural gas to electricity, that would, if it occurred, only intensify MH's supply/demand situation in the years to come.

With respect to the AEF, MH has taken the position that interest should not accrue on AEF balance, this contrary to that directed by the Board in Order 99/07. If interest was accrued on outstanding AEF balances, the AEF would have additional revenues available to fund further low-income programs. The Board recognizes that capacity issues may exist in program delivery; however, the Board believes that if more funds were made available, such programs could be expanded to meet more of the needs. If interest is not allowed to accrue to the AEF, its purchasing power will decline by at least the rate of CPI inflation; accruing interest will remove any disincentive to move quickly to put the AEF to work.

The Board does not agree with MH's perspective of the intent of the legislation that gave rise to the AEF. The Board will require MH to accrue interest on the AEF balance to ensure additional funds are available to fund expanded low-income energy efficiency programs.

The Board is also particularly concerned with the delivery of low-income programs on First Nations diesel communities. The Board notes MKO's concern that energy audits and low-income programs may not be available to diesel community households, with the perception that the benefits will be realized by INAC. The Board expects MH to meet with MKO and representatives from the diesel communities to discuss the issue of the access of those communities to MH's low-income programs, and to report to the Board on the outcome of these discussions on or before September 30, 2008.

The Board is very concerned with the burden low-income households face with higher energy costs, even more so given the rapid increases in both oil costs and

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natural gas pricing. The Board believes that MH has a duty to ensure a safe and reliable service to its customers. The question is whether that duty should extend to ensuring electricity is made available on an affordable basis.

Bill Assistance

The Board notes that the low-income high energy burden problem is extensive in Manitoba and that MH now relies on a voluntary program, Neighbours Helping Neighbours (Salvation Army), which allows MH customers to donate to a fund, a fund the Board finds sorely inadequate. Families and seniors who are unable to pay their natural gas or electricity bill due to personal hardship or crisis can receive support from the program, but only if sufficient funds are available.

While a voluntary program is beneficial, it cannot meet the need in the Province as it is now established. A low-income bill assistance program would assist in reducing the energy burden faced by low-income households. Significant non-energy benefits would arise, including increased comfort, reduced health costs, lower bad debt write-offs etc. .

Manitoba is a cold environment from the fall through to the spring; in this Province, adequate heat is a necessity of life. In light of this reality, the Board recommends government seek from the Federal government an exemption from GST for residential customers, as heat in Manitoba is a necessity like food; and to fund low-income and DSM programs, the Province should set aside all or a portion of provincially and or municipally sanctioned sales taxes charged to residential customers on energy used for heating purposes.

The Board notes that MH's commercial customers may recover GST paid on input costs and that health and educational institutions also receive favourable treatment with respect to the GST.

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In a 2007 proceeding before the Ontario Energy Board (OEB) the Low-income Energy Network (LIEN) sought approval of a rate affordability assistance program to make natural gas distribution rates affordable to poor people. The underlying premise of LIEN's position was that low-income consumers [estimated at approximately 18% of Ontario households] should pay less for gas distribution service than other customers. The issue LIEN sought to advance were:

- Should the utility's rates include a rate affordability assistance program for low income consumers?
- If so, how should such a program be funded?
- How should eligibility criteria be determined?
- How should levels of assistance be determined?

In a split decision, the majority of the OEB panel concluded it did not have jurisdiction, pursuant to its existing legislation, to order the implementation of a low-income affordability program. The majority of the OEB concluded LIEN'S proposal amounted to an income redistribution scheme requiring one consumer rate class based on income characteristics as well as implicitly require subsidization of this new class by other rate classes.

LIEN appealed the OEB decision to the courts. Also by a split decision, the Ontario Superior Court of Justice, Divisional Court recently allowed the LIEN appeal and declared that the OEB has the jurisdiction to establish a rate affordability program for low-income consumers of the utility.

Because both the Manitoba and Ontario rate setting jurisdictions are similarly broad, this Board has previously indicated its concurrence with a dissenting position of the OEB on its ability to establish a rate affordability program for low-income utility customers, a position since upheld by the Court.

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Energy affordability for low-income families is very much an issue that requires more or less immediate attention in Manitoba. The Board suspects that low-income individuals, families and seniors, unable to pay their natural gas or electricity bills due to personal hardship or crisis, could receive support from a rate reduction program without causing a major rate increase for MH's other customers.

The Board believes that in light of the recent Ontario court ruling, it (the Board) would be acting within its mandate and in the public interest if it were to direct MH to implement a bill assistance program. Accordingly, the Board sees merit in the proposition put forward by Mr. Weiss. And, therefore, the Board will direct MH to propose for Board consideration (as soon as possible for the coming heating season, but no later than September 30, 2008) a low-income bill assistance program, where such a program would occur in conjunction to and compliment an expanded low-income DSM program.

MH should address the issues of: how such a rate affordability assistance program should be funded, how eligibility criteria should be determined and how levels of assistance should be determined. Consultation with the Coalition and RCM/TREE may be of assistance to MH.

The Board understands the issues and problems raised by the Coalition relative to similar programs available in the US, where access to funds is "real", thanks to U.S. federal government funding. The Board further believes a bill assistance program (as proposed by Mr. Wiess) should be extended along with a program to improve the heat retention and the efficiency of low-income homes, and the sooner the better.

12.0 Risk Analysis

12.0 Risk Analysis

The Board has, in past Orders, requested that MH to file a quantified Risk Analysis. To date, MH has submitted limited scope and/or generic discussions of issues that would better be incorporated in a fully integrated and quantified risk analysis that provides a detailed quantification of all substantial risks and a probability analysis to assist in the testing of the appropriate level of debt:equity ratio.

Over the years and at various GRA proceedings, MH has flagged numerous business risks to its financial well being, and stressed the need for adequate retained earnings in order to make progress towards its debt/equity target of 75:25. And, consistent with these views and in response to past Board Orders, MH submitted the following reports at this year's GRA:

- a) Risk Advisory Report (January 18, 2005) (2004-04 Drought Risk Management Review);
- b) MH's report on Risk Strategy and Quantification (January 31, 2005); and
- c) MH's analysis of Financial Loss Due to Extended Periods (July 26, 2007).

The first of these reports was narrowly focussed on MH's response to the 2003/04 drought, particularly as related to hedging and energy buy-backs. The report did not deal with MH's operational strategies going into the drought, an issue the Board has a considerable interest in (now, as an indication of possible future risks). MH's second report addressed generic issues of risk management and how the Corporation defines overall business risks. Again, it neither provided detailed assessments nor quantifications of those risks.

In the third document filed, MH quantified the financial implications associated with a repeat of the three extreme drought events in recorded history. The

12.0 Risk Analysis

events were presented as individual risks and not integrated in an overall quantified business risk assessment. Also, MH, in response to interrogation, provided forecast financial impacts for a variety of business risks. However, it remained MH's position that these risks should not be aggregated and that appropriate methodology does not exist to allow the incorporation of risk probabilities to produce an overall risk quantification.

The Board observes that Manitoba Public Insurance also faces a diverse list of risks for which an aggregation would not provide a fair impression of even likely worst case scenarios yet, its actuarial advisor has assigned probability, allocated provisions for adverse deviations, and produced an overall assessment.

12.1 Drought

The following tables identify the reduction in retained earnings as of March 31, 2018 that MH projects as being associated with various unfavourable events (as identified during the hearing).

12.0 Risk Analysis

Drought Risks (\$ millions)

Event in Forecast Period	Frequency	Retained Earnings Reduction	Retained Earnings, March 31, 2018
IFF 07-1	0	0	\$3,349
One Year Drought (50% of 2003/04 Loss)	1 in 10	\$ 490	\$2,859
2003/04 Drought	1 in 15	\$ 891	\$2,458
Five-Year Drought (as per 1987-91)	1 in 50	\$2,800	\$ 549
Seven-Year Drought (as per 1936-42)	1 in 100	\$3,500	(\$ 151)

A review of 94 years of river flow history revealed that MH has faced drought situations in 23 of the 94 years (1 year of each 4). Consecutive years of drought occurred in the periods 1929 to 1932, 1936 to 1942, 1976 to 1977, 1980 to 1981, and 1987 to 1991. MH has recognized the compounding effect on retained earnings of a multi-year drought and defined the financial consequence of a five-year drought modelled on the 1987 to 1991 experience, and, as well, the consequence of a seven-year drought modelled on the experience of 1936 to 1942.

These forecasts are presented as if these events had happened during the forecast period, to 2017/18. (The 2003-04 drought may well have been the most severe single-year drought in MH's flow history.)

The modeled multi-year droughts were projected to have retained earnings impacts of \$2.8 billion for a five-year drought, and \$3.5 billion for a seven-year

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drought. MH has never identified a “dollar based” retained earnings target, but relies on a 75:25 debt:equity target.

For a seven-year drought projected as above, and given an initial retained earning of \$1.7 billion, MH forecast that an additional 4.0% annual rate increase, on top of the currently projected annual increase of 2.9%, applied over a 10-year period would not only restore the \$1.7 billion projected to be lost as a result of the drought but would provide for a doubling of retained earnings to \$3.5 billion by March 31, 2018.

This may suggest that \$1.7 billion could be considered an adequate reserve for a seven-year drought, and that a 2% to 2.5% additional and annual rate increase for the ten years following such a drought would restore the initial reserve. However, assuming MH’s current capital expenditure forecast is realized, restoring the \$1.7 billion of retained earnings through annual 4.9-5.4% rate increases would not achieve a 75:25 debt:equity ratio; in fact, the retained earnings deficiency in such a situation would be quite significant.

The 2003-04 drought demonstrated that MH’s generally “aggressive” approach to export energy marketing, while conducive to higher profits in median or above flow scenarios, carries the risk of increased losses during drought or low flow years. MH has acknowledged this risk, but believes its present strategy (that is, depending on median water flows) provides greater longer-term financial returns. The Board is not so certain and would prefer an independent assessment be conducted and filed.

Some of MH’s exports involve three to four month advance sales of firm energy, without the certainty that the firm energy sold will be available (i.e., precipitation may not replenish water resources). Such practices lead to reasonable results in the absence of poor water conditions, but significant cost consequences when

12.0 Risk Analysis

water flows fall and imports have to be purchased to fulfill contract obligations. This situation occurred in the summer of 2006/07 and, in the Board's view, contributed to MH's request for a 2.25% interim rate increase (granted initially as an interim increase and finalized by Order 90/08).

The drought scenarios represent events that could all occur over a 100-year period. However, the Board considers it reasonable that there is a very low probability that more than one multi-year drought would occur in a 50-year time period, let alone more than one during a 10-year forecast period. As such, the forecasts of multiple drought situations are not reasonably additive.

MH cannot prevent droughts from occurring, but, arguably, could do more than was done in 2003/04 to mitigate the consequences of a multi-year drought. In 2003/04, energy from water held in reserves was sold at low prices (off-peak pricing) to boost that year's annual income, only for the energy to be required to be "bought back" from the MISO market to meet MH's export commitments, and then at much higher prices than what the energy was sold for.

12.2 Other Risks

The "other risks" displayed in the following table are also circumstances that MH cannot control. However, as with droughts, the cost consequences of each can be mitigated to some degree by MH actions:

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Impact of other Risks (\$ millions)

Event in Forecast Period	Frequency	Forecast Retained Earnings Reduction	Forecast Retained Earnings, March 31, 2018
Lower Average Hydraulic Generation for 10 Years (1,000 GW.h Less)	(1)	\$500	\$2,849
Lower Export Revenue Prices (6¢/kW.h for 10 Years)	(1)	\$800	\$2,549
Exchange Rate Remains @ Unity for 10 Years	(1)	\$170	\$3,179
7.5% Capital Cost Price Escalation Per Year	(1)	\$872	\$2,477
Loss of Bipole I & II (for 4 months in 2011/12)	(1)	\$200 ⁽²⁾	\$3,149
Higher Interest Rate (up 2% on Average)	(1)	\$234	\$3,115

(1) Each of the above “other risks” have potentially high probabilities, ranging from 1 year in 5, to 1 year in 50

(2) Does not include costs for infrastructure repair or replacement.

The risks shown in the above table are “all inclusive”, and reflect scenarios that were raised in Board proceedings. As such, each is indicative of levels of risks that MH may be subject to at various times in the near future. From the Board’s perspective, given the importance of MH to the Province and the capital expenditure plans that are now “on the table”, a more exhaustive listing is still required, again with probabilities quantified.

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The financial implications of these “other” risks may be considerably increased when MH's recent export sales commitment announcements are confirmed in contract form. The nature of these sales and the additional capital costs associated with Conawapa and Keeyask generation and such additional transmission as may be required to meet the new commitments could substantially increase the magnitude of forecast reductions in retained earnings upon the occasion of an adverse event.

Not included in the above table are variations in domestic energy demand, medium-high domestic load scenarios as a result of extremely cold winters that can lead to energy shortages which would have to be offset by high priced imports, or conversions of energy sources to electricity from natural gas and propane. On the other hand, low-medium domestic load scenarios that arise with very mild winters can lead to energy surpluses, which in high flow years may have very limited market value.

Domestic residential and small commercial load growth comes with average revenue rates that have been above those achieved by average export rates. Domestic load growth in the large industry sector obtains the lowest rates offered by MH, other than those obtained from export sales during off-peak hours.

Overall, adverse events have variable probabilities. Two or three of these additional risks could occur in the same time period and, as such, their impacts on retained earnings could be additive. However, it appears that the total impact of the “other risks” might be of a lesser magnitude than what would be occasioned under severe drought situations.

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12.3 Interveners' Positions

MIPUG, Coalition, and RCM/TREE all questioned the need for a retained earnings level based on a ratio of debt to equity, but, excepting for MIPUG's concept of specific reserves, have not made specific recommendations. A specific Board initiated review and quantification of risks has been recommended and the Coalition continues to support improved equity levels and suggests that further testing of retained earnings and reserves targets are required.

MIPUG proposes that the Board convene a special hearing to deal with risk and reserve issues, and that the Board should provide MH with prescriptive requirements and scope to define what would represent an acceptable comprehensive risk analysis and adopt an appropriate reserve mechanism for testing at future proceedings.

MKO also supports a broader role for the Board in defining business risks, including those associated with major capital programs.

12.4 Board Findings

Drought

Over the past decade or so, extra-provincial revenues have represented a significant portion of MH's actual and forecast revenues. And, as demonstrated by the \$428 million loss in 2004, MH honours its obligation to meet firm export commitments by purchasing high price power in the event of a drought. The drought made clear the significant dependence that MH has on water flows; reasonable water conditions are clearly a requirement for MH to obtain favourable net export revenues and sustain domestic rates at below-cost levels.

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As such, MH's energy supply resources and export commitments require constant monitoring, particularly as its assets and debts are to increase with planned massive capital expenditures.

MH has suggested that the drought of 2003/04 can be expected to re-occur once every 15 years, on average. Yet, longer droughts of greater consequence have occurred at least three times in MH's relatively short history. While MH has defined the potential impacts of various drought events, it has not provided a frequency-based in-depth analysis that is required to demonstrate the full range of economic consequence of the risk. MH will be directed to provide such an analysis.

In low water years, when MH experiences an energy shortfall, the available sources of "make-up" energy in the MISO market tend to be less efficient and very high cost natural gas generation (like the Brandon SCCT units, which recently had output costs of about 15¢/kW.h – compared to 6 cent rates for residential customers and 3.2 cents for large industry). Consequently, when MH operates gas generation to meet its export commitments, it is fulfilling export contract commitments at a substantial loss.

Unfortunately, in high flow years, MH's surplus (can be up to 7,000 GW.h greater than average) may only attract off-peak prices (and these have been under 2¢/kW.h during the summer months), as peak and shoulder-hours generation sales are limited due to transmission capacity and MISO needs. The difference between the price of a sale during peak hours and one during off-peak hours can be very significant, the former sometimes 10 times the latter, and with the latter usually being so low as to give rise to the question as to whether the sale was of strategic value.

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This indicates a fairly large market risk related to MH's marketing strategies. To monitor these, the Board will be requiring MH to provide the Board with specific quarterly reports on energy supplies (including imports), domestic demand, and export sales (e.g., similar to NEB volume and price data). Alternatively, the Board could rely on annual reports, but they would enable only a form of post-mortem analyses and provide no opportunity for the Board to offer comment on more current strategies and their possible implications for consumer rates.

Infrastructure

Given the risks that abound with massive operations of high importance to not only utility customers but the Province overall, the Board will direct MH to provide regular due-diligence reports on its infrastructure, focusing on the risk aspects of the operation (e.g., Dam Safety Reports, Maintenance, and Rehabilitation Schedules, etc.), as part of expected regular updates to an Asset Evaluation Study.

Load Growth

The Board acknowledges MH's concerns about domestic load growth, particularly in the industrial sector. MH should provide a more detailed tracking of industrial load growth, along with a range of reasonable projections for the future when it re-files its application for a new industrial rate category in the fall..

The Board understands that MH's increasing DSM program is expected to offset a significant portion of domestic load growth. As such, it is essential that MH reconcile forecast DSM savings with its load forecasts and actual domestic loads. This type of analysis should be incorporated in Future Load Forecasts.

MH has yet to take a position on what might be likely climate change impacts on hydraulic generation, yet it assumes the global warming scenario in defining its

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export price forecasts and DSM benefits. The Board wants to explore the risks and opportunities that may lie with climate change at the next GRA, and trusts that MH is involved presently with such studies and is considering various possible scenarios, given recent new export commitments and plans for additional investments in generation and transmission facilities.

Capital Cost Escalation

The ambitious major capital program which has been undertaken to meet future export commitments and domestic load growth is expected to result in the spending of approximately \$18 billion on major projects, including Bipole III, Keeyask and Conawapa. The Board notes that hyper-inflation and labour shortages was cited by MH as major reasons for the escalation in the costs to construct Wuskwatim, which is currently under development. In its evidence, MH did not indicate that the price increases experienced to date represented a short-term trend.

The Board is concerned that this higher-cost trend may continue. The Board questions and is concerned whether current forecasts of major capital programs are fully reflected in the forecast before the Board, and is concerned with the risk that an updated capital forecast more reflective of recent inflationary experience related to capital projects may show substantially-higher capital requirements, putting upward pressure on future rates.

The Board needs to examine a variety of cost and price scenarios to better assure it that the planned new capital projects will not require significant domestic rate increases over the longer term. The Board has directed MH to file an updated Power Resource Plan and provide an analysis of the rate impacts of the new planned capital projects.

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Export Commitments

While the Board has not been provided with MH's specific export contract prices and terms, it is concerned because of recent average export price history. MH's forecasts assume an USD/CDN exchange rate of 1.16 and CO₂ legislation to achieve average export prices of 10¢/kW.h by 2018. If that expected price in Canadian currency does not materialize, MH could be faced with an extended period of time where average export prices will not cover incremental costs associated with Bipole III, Keeyask G.S., and Conawapa G.S, just as happened after the Limestone G.S. in-service of 1992, and as expected for several years following Wuskwatim coming into service.

With construction costs in a higher inflation mode and with interest rates at recent historic lows, it is impossible to be certain prices that have been secured on the export market will prove adequate. A relatively modest worst-case scenario could involve a 1-2¢/kW.h shortfall on export sales extending well beyond 2025. And, with Bipole III routed on the West Side of the Province, costs to be allocated under the COSS model may be 0.5¢/kW.h more than if Bipole III was to be on the East Side of the Province. A shortfall from required export pricing could have the effect of reducing future annual net income significantly after 2018, placing further pressure on domestic rates.

Other Risks

With inflation increasing and transportation costs soaring, it is difficult to imagine interest rates being sustained at current historically low levels. And, with oil at \$140 a barrel and some industry observers predicting the price reaching \$200, it would appear less than conservative to assume that the Canadian dollar is going to depreciate significantly from its current "near parity" level. Both an increase in interest rates and, perhaps, even a further appreciation of the Canadian dollar

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would have significant implications on the operations and results of MH, implications not yet quantified.

In light of the many risks discussed, the Board has directed MH to prepare a Risk Analysis to fully quantify the financial impact of the risks faced by MH.

13.0 Cost of Service

13.0 Cost of Service

13.1 Background

Currently, MH's Cost of Service Study is a prospective study of average (embedded) historically-based costs classified, functionalized, and allocated to each customer class and sub-class on the basis of system usage. The costs reflect invested funds in Generation, Transmission, and Distribution, updated to use in forecasting costs for the next upcoming fiscal year.

Costs related to finance (interest, etc.), depreciation, and OM&A are shared by domestic customer classes and one export class on the basis of energy consumption, peak load demand, and customer numbers. Currently, surplus export revenues (above assigned and allocated costs, i.e. notional profit) are credited to the various domestic classes proportional to their share of total allocated costs.

COSS is a tool to assess the extent to which each customer class' revenues recover/compare to allocated and historic costs. The revenue to cost coverages derived from PCOSS-08 illustrate a degree of disparity in embedded cost sharing by the various classes. Yet, the results should not be viewed as being representative of a degree of unfairness, but rather as an indication of possible rate increase differentiations, if only historic costs are to be taken into account and the current method of allocating costs and revenue (including net export results) is maintained.

MH employs a Zone of Reasonableness (ZOR) from 95% to 105% to assess the need for differentiated rate increases. In this GRA, MH chose to seek an across-the-Board rate increase for all classes other than Area and Roadway Lighting (a

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class composed of municipal and other governments providing area roadway lighting to their communities).

MH opined that an across-the-board increase was justified, as no rate class is “paying” its full cost of service as long as MH has a retained earnings deficiency.

13.2 Amended PCOSS-06

In response to Order 117/06, which followed a comprehensive review of MH’s cost of service methodology, MH submitted a 16-page document that reflected most of the changes directed to be made by the Board in PCOSS-06 by Board Order 117/06.

Notably, the amended COS employed the following energy inputs:

Domestic Load at Generation	22,830 GW.h
Export Load at Generation	9,786 GW.h
Total Load at Generation	32,616 GW.h

For hydraulic generation cost sharing purposes, export load at generation was reduced by 9,786 GW.h, comprised of:

2,010 GW.h	(derived by imports)
587 GW.h	(derived by thermal)
1,117 GW.h	(DSM savings)
6,072 GW.h	(exports served hydraulic generation pool)

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Revenues reported in the COS were:

Domestic:	\$1,018.2 M (19,900 GW.h @ 5.12¢/kW.h at meter)
Export:	\$547.4 M (8,800 GW.h @ 6.22¢/kW.h point of sale) - actual average export prices in 2005/06 were 5.2¢/kW.h.

MH carried out a 12-period weighting process of all hydraulic generation using the average Surplus Energy Program (SEP) pricing over an eight-year period. This approach was applied to actual domestic energy consumption and 2003/04 net export sales at generation. The use of a drought year for defining the 12-period export sales would have overstated the share of generation costs allocated to the export class (and accordingly, was not employed).

13.3 Export Costs

The COS directly assigned \$123.8 million of costs and allocated a further \$248.7 million of costs to the export class. These costs reflected:

	(\$ Millions)
Uniform Rate Adjustment	\$16.7
DSM	\$17.8
Trading Desk Costs	\$9.1
MAPP/MISO/NEB costs; Purchased Power; and Thermal Costs	\$80.2
Allocated Generation and Transmission (including Water Rentals)	\$248.7

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Revenue to Costs Coverage Ratios (RCC)

The revenue cost coverages for the amended COS were reported at:

Residential	94.1
GSS-ND	107.6
GSS-D	107.0
GSM	101.4
GSL<30	91.4
GSL 30/100	91.4
GSL>100	104.8
ARL	106.1

The Board did not formally respond to MH's filing of the Amended PCOSS-06, and requested the Corporation to employ the COS approach directed by Order 117/06 for the next GRA, the subject of this Order.

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13.4 Embedded Cost Revenue Cost Coverages (RCCs)

In PCOSS-08, MH calculated the RCCs for the various customer classes as follows:

	After Net Export Credit	Prior to Net Export Credit	MIPUG/MH I-25(b)
Residential	96.4%	83.0%	95.9%
GSS-ND	104.3%	90.8%	103.9%
GSS-D	107.2%	93.8%	107.5%
GSM	101.1%	87.7%	101.3%
GSL <30	90.4%	76.9%	90.3%
GSL 30-100	103.7%	90.1%	104.6%
GSL >100	108.7%	94.8%	110.4%
AWR	105.8%	96.7%	105.6%

The foregoing PCOSS-08 RCC's (pre-2008 rate increase, 5% as per Order 90/08) continue to suggest a need for differentiated rate increases in the future. The results are relatively consistent with historical embedded cost RCC's, as shown in the following table:

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Table: Historical RCC

	RCC PCOSS- 08	RCC PCOSS- 06¹	RCC PCOSS- 04	RCC PCOSS- 03	RCC PCOSS- 02	RCC PCOSS- 01	RCC PCOSS- 99	RCC PCOSS- 97
Residential	96%	97%	91%	92%	97%	91%	92%	91%
GSS-ND	104%	107%	105%	107%	109%	104%	107%	107%
GSS-D	107%	105%	110%	108%	105%	105%	108%	105%
GSM	101%	101%	105%	103%	104%	109%	106%	102%
GSL 0-30 KV	90%	90%	100%	93%	97%	103%	101%	101%
GSL 30-100 KV	104%	102%	110%	109%	109%	119%	110%	108%
GSL >100 KV	109%	103%	114%	114%	100%	116%	109%	111%
A&R Lighting	106%	107%	109%	110%	102%	92%	93%	109%

1. MH's Recommended Version

The methodology used for the Cost of Service Study was changed for each of the following studies (suggesting, as was stated by the Board in Order 117/06, that COS is 'in a state of flux'):

- PCOSS-99
- PCOSS-01
- PCOSS-02
- PCOSS-04
- PCOSS-06
- PCOSS-08

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13.4.1 Compliance with Board Order 117/06

Board Order 117/06 directed MH to re-file COS as presented in “PCOSS 06 - Recommended Method” on the basis of directives provided by the Board. The following identifies the Board’s directives and the extent of MH’s compliance.

One Export Class

MH defined a single export class encompassing both firm (dependable) energy exports and interruptible (opportunity) energy exports. Costs were either to be assigned directly or allocated on the basis of total export energy sales.

However, MH has not specifically defined the export operation as a class for regulation purposes.

Uniform Rate Adjustment

As per Order 117/06, MH credited the residential, general service small, and the area and roadway lighting classes with appropriately calculated energy-based shares of foregone revenue incurred as a result of the Uniform Rate Adjustment (URA). URA, established by provincial legislation, provides for all grid-served customers to receive the same rate, pursuant to the Board’s class rate schedule.

The URA provides significant savings to rural and grid-served northern communities, compared to the previous approach which established grid rates by customer zone, with rural and northern zones being allocated higher proportional costs to serve that urban areas. Grid-rates have also been provided to residential customers served by diesel-generated power in the four northern communities still not on the grid.

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The full amount of the adjustment has been deducted from the total export revenues, the assumption being that the URA has been “paid for” by export profits.

Imports and Power Purchases

As per Order 117/06, MH directly assigned all energy import and wind energy purchase costs as costs to be allocated against export revenues. Import energy costs include energy actually transmitted into the MH system and energy purchased for immediate resale (arbitrage) in the external export market. These latter energy amounts have been deducted from exports in determining the export class’ share of overall costs.

Thermal Generation

MH’s interpretation of Order 117/06 resulted in the Utility directly assigning only thermal fuel (coal and natural gas) costs at \$19.3 million/year to the export class. Other generation costs, totalling \$69.3 million/year for finance, depreciation, and OM&A, were not directly assigned, but placed in the generation pool for overall system cost-sharing customer classes.

However, MH elected to deduct the full amount of thermal generation (587 GW.h) from exports in determining the percentage of generation costs to be shared by exports. This interpretation by MH results in no embedded costs being allocated to the export class for the 587 GW.h thermally-generated electricity. The net effect was to reduce costs otherwise allocated to the export class by approximately \$10 million.

Overall, MH’s approach reduced the unit cost assigned to exports by nearly 1¢/kW.h. MH rationalized the deviation from the Board’s instruction of Order 117/06 on the basis that while fuel costs fluctuate with export levels, the other

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costs do not. And, these other costs relate to fixed plant, and that the thermal plants were constructed to provide added security of reliability to domestic load demand requirements.

DSM Energy Deduction

In keeping with Order 117/06, MH charged all DSM costs directly to the export class. However, MH also deducted the DSM energy savings from exports in defining the export class share of hydraulic generation costs.

If DSM costs were allocated to exports (as per the Uniform Rate Adjustment), but energy savings were not, about \$28 million of generation costs would be shifted from domestic classes to export class.

The longer-term result of MH's approach to the DSM energy savings, if accepted by the Board, would have very little (if any) generation costs being allocated to the export class; this, because DSM-derived energy savings could outstrip actual exports by 2017/18.

Energy Weighting (12 periods)

As per Order 117/06, in the cost allocation process for Generation energy supply, MH employed a 12-period price weighting rather than the four periods at initially proposed in PCOSS-06. The weighting was based on energy values during both the four seasons and the peak/shoulder/off-peak periods. The weightings in the following table reflect the average from January 1999 to December 2006, relative to a summer off-peak base value of 1.000.

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The relative value of energy supply resulting were:

	Peak	Shoulder (¢ per kW.h)	Off-peak
Spring (2 months)	2.513	2.144	1.246
Summer (4 months)	3.258	2.388	1.000
Fall (2 months)	2.624	2.155	1.396
Winter (4 months)	3.406	2.262	1.796

The energy consumption values employed in the generation cost allocation process by MH reflected the domestic and export energy consumption profiles for 2003/04 in PCOSS 06 (a drought year) and for 2005/06 in PCOSS 08 (a high flow year). Consequently, the generation cost allocation to exports are quite different in the two PCOSS'.

13.5 PCOSS-08

13.5.1 Treatment of Exports Class Cost Allocations

In Board Order 117/06, MH was directed to establish a single export class, to be fully allocated costs for generation and transmission. MH opposed this direction opining that opportunity sales should only attract variable costs and not fixed costs. This view was reflected in MH's treatment of thermal costs, where MH assigned only fuel costs to the export class in contravention of the Board's directive.

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13.5.2 Review of PCOSS-08

PCOSS-08 employed the following energy inputs:

Domestic Load at Generation	23,740 GW.h
Export Load at Generation	<u>8,460 GW.h</u>
Total Load at Generation	32,200 GW.h

Forecast Revenues in PCOSS-08

Forecast Domestic	- \$1,066 M (20,800 GW.h @ 5.13¢/kW.h at meter) (actual average export prices in 07/08 were 5.0¢/kW.h)
Forecast Export	- \$551.5 M (7,700 GW.h @ 7.16¢/kW.h at point of sale)
	(While the above were forecast, the actual average export prices in 07/08 appear to be 5.0¢/kW.h)

For hydraulic generation cost sharing purposes, export load would be reduced as follows:

	GW.h
Export Load at Generation	8,462
Less	
Served from imports and power purchase	(2,028)
Served by thermal generation	(560)
DSM savings	<u>(1,350)</u>
Net exports served from hydraulic generation pool	4,524

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13.5.3 Treatment of Exports Class Cost Allocations

Out of a total generation and transmission cost of \$1,165 million , PCOSS-08 defined export costs as follows:

Directly Assigned Costs

Uniform Rate Adjustment	\$17 M
DSM Costs	\$25 M
Trading Disk Costs	\$13 M
MAPP/MISO/NEB Costs	\$7 M
Imports and other purchased power	\$134 M
Thermal Fuel Costs	<u>\$23 M</u>
Sub-total	<u>\$219 M</u>

Allocated Costs

Generation (including water rentals)	\$116 M
Transmission	<u>\$51 M</u>
Sub-total	<u>\$167 M</u>

Total export costs	<u>\$386 M</u>

Export sales accounted for 27% of system energy sales, about 20% of winter CP demand and 33% of summer CP demand.

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The \$386 million of defined export costs equates to approximately 5¢/kW.h at the point of sale – and were derived by MH without assigning “fixed” thermal costs to the export class as directed by the Board. While MH’s forecast export sales prices in PCOSS-08 were 7.2¢/kW.h, it now appears that the actual average export price will be closer to 5¢/kW.h

MH Position

MH contends that its current COSS model, as depicted in PCOSS-08, does not provide the most suitable basis for evaluating either class revenue requirements or establishing a rate design. MH’s fundamental issue with PCOSS-08 relates to the magnitude of assignment (allocation) of costs to Exports.

The ultimate impact of the Board’s directives with respect to these matters was depicted in the pre-filed evidence of Patrick Bowman and Andrew McLaren, witnesses for MIPUG. In their Table 4-1, Bulk Power costs are depicted for each of the major classes, as follows:

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	Residential		GSS-ND		GSM		GSL>100kV		Exports	
	(\$ M)	(¢/kWh)	(\$ M)	(¢/kWh)	(\$ M)	(¢/kWh)	(\$ M)	(¢/kWh)	(\$ M)	(¢/kWh)
Costs										
1 Bulk Power Costs	\$248.8	3.78	\$54.8	4.12	\$113.2	3.84	\$171.1	3.29	\$372.2	4.83
2 DSM adjustments	(\$4.2)	(0.06)	(\$3.2)	(0.24)	(\$4.2)	(0.14)	(\$6.6)	(0.13)	\$24.6	0.32
3 Net Bulk Power Costs	\$244.6	3.72	\$51.6	3.88	\$109.0	3.70	\$164.5	3.16	\$396.8	5.15
4 plus: Subtransmission-related	\$38.5	0.59	\$6.8	0.51	\$11.7	0.40	\$0.0	0.00	\$0.0	0.00
5 plus: Distrib. and Cust. Serv.	\$229.7	3.49	\$42.1	3.16	\$39.7	1.35	\$2.0	0.04	\$0.0	0.00
6 Total Costs	\$512.9	7.80	\$100.4	7.56	\$160.5	5.44	\$166.4	3.20	\$396.8	5.15
Rates										
7 Total Sales Revenue	\$417.8	6.35	\$91.7	6.90	\$144.2	4.89	\$164.0	3.15	\$490.3	6.36
8 Uniform Rate Credit	\$15.4	0.23	\$1.2	0.09	\$0.0	0.00	\$0.0	0.00	(\$17.2)	
9 System Merchant Sales									\$61.2	
10 Total PCOSS Revenue (7 + 8 + 9)	\$433.1	6.59	\$92.9	6.99	\$144.2	4.89	\$164.0	3.15	\$534.3	6.93
Surplus/Shortfall before Net Export Credits										
11 Rates compared to costs (10 - 6)	(\$79.8)	(1.21)	(\$7.5)	(0.57)	(\$16.3)	(0.55)	(\$2.4)	(0.05)	\$137.5	1.78
Net Export Credits										
12 Net Export Revenues Allocation	\$58.6	0.89	\$11.5	0.86	\$18.3	0.62	\$19.7	0.38	(\$137.5)	(1.78)
13 Surplus/(Shortfall) after net export revenue credits (11 + 12)	(\$21.1)	(0.32)	\$3.9	0.30	\$2.0	0.07	\$17.3	0.33		
Total Class Metered Energy (GW.h)	6,578		1,329		2,949		5,202		7,707	

The table illustrates that for transmission voltage domestic customers (General Service Large > 100kV), MH's embedded historic cost per kW.h is 3.29¢ compared to 4.83¢ for the Export Class. In fact, bulk power costs for Generation and Transmission (G&T) for all domestic classes are lower than the costs allocated to exports. MH opined that the view was counterintuitive, and that the embedded bulk power (G&T) cost of export sales should not be higher, on a unit basis, than the embedded cost to Transmission voltage domestic customers, and probably should be lower than the embedded cost of similar voltage domestic sales.

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Board Order 117/06 also directed that certain other costs be specifically assigned to the Export Class, including the revenue impacts of Uniform Rates and the costs of DSM for domestic customers.

MH contends that the directed methodology of Order 117/06 assigns a much larger portion of Generation and Transmission costs against exports, and thus reduces the amount of residual export revenue available for allocation to domestic customer classes. This approach would appear to have the same effect on class RCC ratios as previous methodologies, in which the allocation of export revenues to the domestic rate classes was limited to only the Generation and Transmission functions.

With respect to DSM costs, MH interpreted Order 117/06 to mean that all DSM energy savings should be assumed to serve the export market. Accordingly, the \$24.6 million in forecast DSM costs and the associated 1,350 GW.h of annual energy savings associated with all DSM carried out to-date were applied to the Export Class.

If the Board continues to direct DSM and thermal costs be assigned to exports, MH recommends that the Board confirm the treatment proposed by the Corporation for PCOSS08. However, MH reiterated that the Corporation has serious overall concern about what it perceives as an over-allocation of costs to Exports, with resulting deleterious impact on the outputs of the embedded cost study.

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13.6 Marginal Cost Considerations

In Board Order 117/06, MH was directed to provide a strategy to allow for the consideration of marginal costs and environmental costs, in addition to the current embedded costs, within the COS. In the current Application, MH provided a single page marginal cost analysis without explanation or suggestion as to how the analysis would best be applied in the context of rate design.

Briefly, MH's marginal cost calculations assumed that for:

- **Generation:** All domestic customer classes should be allocated costs on the basis of annual consumption applied to forecast peak (5 x 16) export prices. (No costs were to be assigned to the export class.)
- **Transmission:** All domestic customer classes should be allocated costs on the basis of two coincidental peak (2 CP) peak load cost sharing of future additions to in-service assets, plus OM&A costs. (No costs were to be assigned to the export class.)
- **Distribution:** All domestic customer classes should be allocated costs on the basis of (NCP) peak load cost sharing of future additions to the assets in-service plus OM&A costs.

The proposed methodology was subsequently amended during the hearing; the revisions dealt with numbers employed but did not address how the RCCs calculated should be applied to rate design.

In the absence of disclosure of key assumptions (deemed commercially sensitive by MH), it is unclear to the Board as to how MH determined key inputs to the marginal cost calculations. For example, it appears that no generation or transmission investments were allocated to exports. And that no costs for water

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rental, imports, fuel, transmission losses, etc. were deducted from forecast export prices, employed in assigning marginal costs for generation to domestic customers. High levels of distribution investments in the distribution plant over the last ten years were not reflected in marginal cost going forward.

MH's filing on marginal cost was subsequently amended by MH, and presented marginal cost values for:

- Generation - \$1.315 billion (equivalent to 20,800 GW.h @ 6.32¢/kW.h) allocated to various classes on SEP weighting basis and is essentially based on export market values;
- Transmission - \$280 million (equivalent to 20,800 GW.h @ 1.35¢/kW.h) is allocated to various classes on a 2 CP basis and reflects the cost of all new transmission plant; and
- Distribution - \$294 million (\$133 million for distribution plant and \$161 million for OM&A costs) allocated to various classes, as applicable, on a NCP basis.

There is no readily apparent definition of marginal cost, although MH's approach could be taken to represent the cost of providing each additional increment of energy, demand, or service (as these requirements grow). It could also be taken to mean the value of the last increment already supplied.

MH's approach suggests that marginal cost could be a stand-alone COSS, rather than being incremental to the existing embedded cost of service study.

Marginal cost of service methodology is complex and, to the Board's understanding, has only been employed for rate setting by a limited number of electric utilities. It could be argued that it is not readily applicable to MH's

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circumstances that being a vertically integrated utility with surplus energy going into a competitive export market.

13.7 Interveners' Positions

The Coalition

The Coalition cited a changing face of consumption among the various customer classes, noting that annual consumption from General Service top customers are projected to exceed residential customers by 2009/10 and are projected to be significantly higher than residential sales by 2017/18.

The Coalition further noted that average gross export rate prices for fiscal 2007/08 and fiscal 2008/09 were forecast at 5.4¢ per kW.h and 5.6¢ per kW.h respectively. This compares with an average residential rate above 6¢ per kW.h, while the average GSL greater than 100 KV rate is less than 3.5¢ per kW.h. The Coalition observed that residential rates are closer to marginal rates than those of large industrial customers. Current residential rates are 6¢ per kW.h while the long run marginal cost is 7.6¢ per kW.h, as compared to GSL greater than 30 KV with a current rate of 3.2¢ per kW.h while the long run marginal cost is approximately 6.8¢ per kW.h.

The Coalition suggested that the Board's objective is to look at the results of a marginal cost based cost allocation and use it to help inform decisions with respect to revenue allocation to customer classes. The Coalition prefers MH's approach, while considering MIPUG's approach to be better suited to a situation where one wants to incorporate marginal cost principles in an embedded COSS (as opposed to doing a marginal cost based COSS).

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The Coalition noted the allocation of generation costs using the SEP prices is an example of where MH is utilizing an approach very similar to MIPUG's (i.e., determine the marginal cost for a function and use them to allocate the cost of that function). The Coalition further noted if the Board wanted to review the implications of using a marginal cost based COSS it should not look at the end results proposed by MIPUG, as MIPUG's approach distorts the results by forcing a reconciliation to the embedded cost approach on an individual function basis.

With respect to whether the differential rate increases should be based on the new cost of service study, Mr. Harper noted that the Board has directed that the zone of reasonableness (ZOR), a range of between 95% to 105%, be considered, and that some minor rebalancing might be appropriate given that three out of the eight classes are outside the range, though some only marginally.

However, Mr. Harper further stated this represents the first time that the revised cost of service study has been reviewed and that there remain some methodology issues that require resolution. Therefore, given that the RCCs are relatively close to the ZOR boundary, for Mr. Harper it would be appropriate to resolve the outstanding issues before entering into rate rebalancing.

In addition to cost of service study results, the Board has indicated that it may consider a number of other factors in assessing the revenue allocation between the classes, including the pre-export allocation as well as an allocation based on marginal environmental costs.

Mr. Harper noted that given various exhibits filed by MH and others these varying perspectives yield significantly different results, and depending upon how much

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weight one puts on one perspective as opposed to another can result in totally different view as to what differentiated rate increases would result to the customer classes. In addition, Mr. Harper noted that MH is seeking an increase that is higher than inflation and that differentiated rate increases would compound a negative impact for some customer classes.

The Coalition concluded that, except for Area and Roadway Lighting, there should be no differential rate increases at this time.

MIPUG

MIPUG stated the current COSS fairly reflects the embedded cost of service with the exception of the treatment of DSM. For MIPUG, MH has correctly assigned the DSM costs to the export class as directed by Board Order 117/06, however MH has also deducted 1,350 GW.h in DSM savings from the export energy used to allocate common generation pool costs.

MIPUG stated that as these same DSM Energy savings are accounted for in the domestic sales forecast, MH's treatment has erroneously double-counted the DSM Energy savings, and created an energy imbalance in PCOSS-08.

MIPUG stated MH's approach also effectively "claws back" from the common generation pool a priority allocation of generation to exports. The result being that for all intents and purposes the benefits secured from the domestic classes' participation in DSM is lost. MIPUG suggested that the Board's directive in Order 117/06 did not specify a specific treatment of DSM energy. As MH's treatment results in an energy imbalance in the PCOSS-08, MIPUG recommended the issue must be addressed.

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MIPUG recommended that the Board direct MH to address the error by removing the 1,350 GW.h DSM Energy credit from the export class. MIPUG submitted the DSM costs should continue to be directly assigned to the export class but that the energy savings should remain with the domestic customer classes that undertook the measures leading to the savings.

MIPUG further stated that PCOSS-08 also failed to strictly reflect the Board's directive from Order 117/06 as to the assignment of all thermal plant costs to exports. (MH assigned only fuel to the export class, with the remainder of thermal plant costs allocated to the overall generation pool.) Yet, although the approach did not strictly conform to the Board's directive, Mr. Bowman stated MH's treatment does not appear unreasonable as thermal assets are a necessary complement to the hydraulic assets and, as a result, merit treatment as common pool generation assets. MIPUG recommended the Board approve MH's treatment of thermal costs in the COSS.

MKO

MKO concurs with the MIPUG recommendations on the 2008/09 COSS. MKO did not provide recommendations on whether embedded versus marginal costing should be utilized or whether rate increases, if granted, should be set on a differential basis.

MKO noted that it was reasonable to identify how additional environmental costs were included in PCOSS-08. In general, MKO supports greater consideration of environmental costs being given and advised it would continue to argue for a fair share of environmental benefits to accrue to MKO communities. MKO recommended that future PCOSS should quantify both environmental benefits and costs.

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RCM/TREE

RCM/TREE observed that this GRA was the first to employ the new cost of service methodology, which treats export customers as a separate class and defines a revenue surplus arising from that class.

RCM/TREE noted that all domestic customer classes have a revenue shortfall relative to allocated costs, and are subsidized by export surpluses. RCM/TREE stated that this reality raises a policy question, that being how best to distribute export surplus (to the elements, activities, and classes of the utility).

RCM/TREE stated that general service large customers should be charged the embedded energy rate for usage up to a baseline, and assessed marginal cost, including environmental costs, for consumption above that level. RCM/TREE also recommended that new general service large customers should be charged the marginal energy rate. For the intervener, additional revenue raised through the implementation of the recommendations would best be used to fund economic development grants, increase DSM efforts, and to decrease demand charges.

RCM/TREE recommended that the Board direct MH to participate in a public review of marginal costs, and that those costs include environmental costs. RCM/TREE further submitted that if MH's forecast data is to be considered commercially sensitive, then publicly available information should be used to satisfy the Board's directives of Order 117/06. RCM/TREE stated that MH had not satisfied the Board's directive, by including only environmental costs internalized in the market, and that those costs are only part of the full costs of full cost accounting, which should inform decision-making as prescribed by guideline one of *The Sustainable Development Act*.

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Mr. Chernick stated that reducing domestic consumption would either lead to increased exports, reduced imports, or reduced MH's thermal generation, and that all of these possible outcomes would result in reduced GHG emissions. According to Mr. Chernick, currently the "costs" of greenhouse gases are not internalized in the prices charged by U.S. utilities.

Mr. Chernick submitted that the total social cost of domestic consumption of electricity is thus higher than the direct costs as calculated by MH. Mr. Chernick recommended that such additional environmental costs should be incorporated in marginal costs and reflected in the COSS, although the benefits flow to the U.S. and reduce environmental costs incurred in the U.S.

Mr. Chernick recommended that MH's rate design should be based on marginal costs, not embedded cost. and that the current COSS is based on a faulty model of cost causality, as it ignores the effects of energy use on transmission and distribution (T&D) costs.

Mr. Chernick stated that the transmission and distribution system is impacted by energy in at least three respects:

First, a large portion of MH's transmission is required to move power from remote hydro stations in the north to the load centers located in the south, and for export. Second, MH's transmission system is more expensive because it is designed to allow for large transfers of energy between neighbouring utilities. Third, MH's transmission system is designed to minimize energy losses over extended hours of high loads. Mr. Chernick submitted that were the system designed only to meet peak demand, a less costly system would suffice and, in some cases, lines or circuits now in place would not be required, voltage levels could be lower, and fewer or smaller transformers would be needed.

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Mr. Chernick stated that MH's distribution costs are impacted by energy requirements, and that the sizing of transformers and underground lines are driven by the energy use on the equipment in high-load periods, in addition to maximum hourly loads. Mr. Chernick also stated that similar high load energy usage affects the service life of transformers as well as impacts the cost of other components of the transmission and distribution system.

For Mr. Chernick, high-load factors impact the sizing of underground transmission, primary, and secondary lines, and he stated that since heat builds up around hydro lines, the length of peak loads and the amount of load relief in the off-peak period affect the sizing of the underground lines.

Mr. Chernick further stated that since the number and sizing of underground lines is a function of load factor, a portion of the cost of the lines should be recovered through energy charges, even if demand charges could reasonably measure the contribution of customer loads to peak demands on distribution equipment.

Mr. Chernick concluded that there is a cost causation relationship between energy, transmission and distribution costs. Reflecting these effects by incorporating transmission and distribution costs in energy charges rather than demand charges, would, for Mr. Chernick, encourage energy efficiency. Accordingly, he recommended that a portion of the cost of transmission and distribution facilities should be allocated to customer classes based on energy.

RCM/TREE suggested that MH's reluctance to release marginal cost information goes beyond the restrictions placed by most other utilities in North America. And, while **MIPUG** supported MH's need for non-disclosure of commercially sensitive price data, RCM/TREE cautioned against excessive restrictions on the release of information, as without the information, rigorous testing cannot be achieved.

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In short, **Coalition and MKO** alluded to the need for transparency and did not support the Board accepting information in confidence from the utility.

13.8 Board Findings

Embedded Cost of Service

- (i) The Board will require future COSS regulatory filings to incorporate the export and diesel zone classes in the same fashion as other customer classes (i.e., separately disclosed, and including all exports in all COSS calculations and charts).
- ii) The Board considers MH's interpretation of the Board's direction as to what thermal costs to assign to exports to essentially constitute a "Motion to Review and Vary Order 117/06". While MIPUG agreed with MH's interpretation, the Board reiterates its requirement that MH is to assign fixed costs as stated in Order 117/06 and allocate them to the export class, (including the \$69.3 million/year for finance, depreciation and OM&A of thermal plants).

The Board understands that this will result in more costs being allocated to the export class, and that as a result unit export costs will rise above 5¢/kW.h.

The Board also accepts the risk that the stricter interpretation of the directions of Order 117/06 may result in zero or negative net export revenues in some future years. For example, in 2006 MH assigned \$386 million of costs to the export class, representing a unit cost basis of approximately 5¢/ kW.h. By assigning \$69.3 million of additional costs to

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the export class, the total cost will increase to \$455 million, or approximately 6¢/kW.h.

When Brandon Coal Generation is restricted to emergency use only (in accordance with the government's direction), the allocation of costs to the export class will decrease, assuming MH doesn't replace coal with natural gas generation (e.g., combined cycle combustion turbine).

In reaching this conclusion, the Board also discards the option of directing MH not to deduct the 587 GW.h of energy from the total export energy costs and only assign fuel costs to exports. To take this route would have increased total allocated costs to the export class for generation by \$10 million (\$396 million as compared to \$386 million). And, restriction of the Brandon plant would essentially eliminate the fuel cost and energy deductions for average year scenarios (and, the estimated \$10 – 20 million of annual net income attributed to current coal-fired generation).

The Board understands that the rationale to support MH's rejected option (i.e. not charging thermal finance and depreciation charges against the export class) is that the thermal plants provide dispatchable energy, increase dependable energy for export, and enhance the reliability of domestic energy and, as such, all non-variable costs should be shared by both domestic and export classes.

However, for the Board to allow the approach favoured by MH and MIPUG would mean the Board would reject the principles of cost causation and would be avoiding a proper allocation of costs (of the thermally generated component of exports).

The Board observes that with the pending restriction on the Brandon plant, the Board's direction will have less of an effect on the average cost of

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export class generation; that is, unless MH moves to increased natural gas generation. At this time the Board will amend its Order 117/06 directive and assign all fuel costs and 50% of the fixed costs to the Export class. Upon the coal plant going into emergency service status, the allocation will be further reviewed.

- (iii) Re: DSM: MH's approach to charging DSM costs to exports and deducting DSM energy saving from the export class results in an arithmetic imbalance in the energy generation calculation, and could ultimately result in zero generation cost allocations being made to the export class.

Because DSM-originated energy savings reduce domestic consumption, prior to determining available energy for export, DSM energy savings should be added back to the domestic loss component, to determine the percentages for generation cost-sharing.

- (iv) The energy consumption values employed in the generation cost allocation process by MH reflected two distinct consumption profiles for both domestic and export energy - one for 2003/04, which was a period of drought, and the other, 2005/06, a year of high water flows.

Consequently, the generation cost allocations to the export class were quite different in the two studies. Compared to the 8-year price period, the drought year costs would be overstated, and in the high flow years, those costs would be understated. Accordingly, it would be preferable to utilize the same 8-year time period for weighting both prices and consumption.

- (v) In making its closing submission, MH remained critical of Order 117/06's "considerable" cost allocations to the export class, particularly with respect to:

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- a) Imports (no reduction for domestic load support);
- b) Thermal generation costs (fuel costs not shared by domestic load);
- c) Degree of embedded costs going to both firm and opportunity exports (with MH contending that no fixed costs should be directed at opportunity sales in the export class). That argument by MH was heard and rejected by the Board at the earlier Cost of Service Review proceeding;
- d) DSM (costs should only be directed to export class if energy savings are credited to export);
- e) Uniform Rates Adjustment (a legislated provision); and;
- f) Trading Desk/MAPP/MISO costs (no reduction for domestic load support).

The Board previously found that MH is designing and building greater generation and transmission plant capacity to achieve additional opportunity sales. Therefore, those extra costs incurred in that effort should be allocated to the export class; with the emphasis being placed on total exports, exports can no longer be viewed as “by-products” of MH’s system.

In reality, exports tend to employ the last units of generation and could arguably, and fairly, be costed (if not priced) on a marginal cost basis.

The Board decision in 117/06 appears consistent with MH’s Power Resource Plan, in which hydraulic generation capacity in excess of dependable flow is not used to supply either domestic load or firm export contracts. Typically, dependable flow from MH’s hydraulic stations represents less than 60% of installed capacity. Therefore, the balance of plant capacity can be utilized in most years to produce energy for additional opportunity export sales.

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MH's position that export cost allocation should be no greater than $GSL > 100$ cost allocations has only limited merit. Intuitively, one could argue that generation and transmission (G & T) costs relate to common energy sources, which should be shared on an equal access basis. This suggests export load has equal status to domestic load.

Alternatively, the counter argument is that domestic load has covered the past investments in G & T, and is entitled to "Heritage rates". Hence, exports should use and carry the cost of newer assets on an incremental cost basis. Examples are:

- Imports (not usually required for domestic load);
- Thermal (not usually required for domestic load);
- Transmission (losses increase exponentially with added export loads); and
- New Generation (built to serve export contracts)

The current COSS falls between these two positions, and assigns imports and thermal fuel costs directly to exports while allowing exports to share in the overall blended costs of generation and transmission (without regard for vintage pricing). The approach does not make exports solely responsible for incremental embedded costs or marginal costs for energy.

Government and Board directives have assigned the costs of the uniform rate adjustment and the evolving DSM programs to exports. These must be considered as societal benefits, the charges for which do not vary with MH's actual energy sales on either the export or domestic fronts.

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Use of Marginal Costs in COSS

MH argued that there is sufficient data on the public record to support the marginal cost values it advanced. While there may be sufficient data, the key assumptions are lacking, and are required to confirm MH's marginal cost forecasts.

MH's marginal cost for generation appears to assume an unlimited market for MH's entire energy output at 5 x 16 peak prices. Because of inter-tie transmission capacity constraints, MH can only achieve that pricing for about 7,700 GW.h of energy. In addition, firm export commitments and deliveries now fully utilize the entire tie-line capability during median flow scenarios. Consequently, new energy coming from load reduction or new plant can only earn off-peak prices.

Accordingly, the value of export energy for marginal cost purposes should be estimated to be substantially lower than the \$1.315 billion suggested by MH. And the reduced amount should be further reduced by deducting appropriate costs; the Board is of the view that current export prices and market conditions do not support marginal costs of 6.3¢/kW.h for generation.

Greater inter-tie capability during the 5 x 16 period could become available when the newest export contracts go on-line, but these would likely be fully utilized by Conawapa and Keeyask. Output reductions in domestic load through DSM activities would still not be able to earn on-peak prices if that energy were exported, given transmission capacity and MISO demand limitations.

MH's marginal cost for transmission appears to reflect significant new plant requirements during the next two decades (\$240 million/year of financing and depreciation costs would equate to about \$3 billion of plant upgrades or

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expansions). The most obvious new facility, Bipole III, is being built for domestic reliability and new export loads and not for domestic load growth. The expected cost of the project was also largely allocated to the generation function in PCOSS-08. As such, most of its costs should not accrue to the domestic transmission marginal cost.

MH's marginal cost for distribution appears to be derived from a forecast of plant investment level that is considerably lower than actual capital expenditures on distribution plant over the past decade. The resulting substantially-lower marginal cost of distribution (compared to embedded costs in PCOSS-08) raises a question as to how the embedded (sunk) costs for distribution should be recovered.

The projected overall marginal cost for generation and transmission provides a perspective of what additional revenues could be extracted from domestic customers if they were to be treated as an export customer by an externally-owned utility providing only generation and transmission services. With respect to MH's current mandate, the generation and transmission marginal cost values are seriously flawed and, in the current form, should not be considered as a basis for rate adjustments.

MH has not presented any compelling arguments to support its marginal cost calculation, and reference to multi-year analysis in the SPLASH model, using undisclosed (confidential) inputs and assumptions, does not allow for any critical review or instill confidence in what would best be a transparent process.

Furthermore, MH has implied marginal cost is a separate (free standing) cost coverage process that can be compared to embedded costs. In reality, marginal cost should be treated as being only incremental to embedded costs. Historical costs still need to be recovered.

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MH has suggested that available public information on actual export sales and prices is sufficient for the Board and Interveners to test the validity of the Corporation's projected marginal cost value(s). Reference was made to MH's SEP and NEB's cross-border trading data, and MISO clearing prices, etc., as useful and valid sources of information for defining marginal cost.

MH's position is only partially correct. The marginal cost identification process involves critical key assumptions (i.e., quantity of energy that has marginal cost value, transmission assets being acquired for export versus domestic load expansion, and the distribution assets which are due to load expansion). For better transparency, the Board will direct MH to file all appropriate data (e.g. SEP/ NEB/ MISO clearinghouse information and avoided cost information etc.) required for input to the marginal cost determinations for generation, transmission and distribution and to further define the key assumptions employed by MH in support of this process with the Board (on a confidential basis if necessary) on or before December 1, 2008.

Forecast Export Price Input

In MH Exhibit #68, it appears that a forecast export energy price of 7.48¢/kW.h (6.32¢/kW.h for generation and 1.16¢/kW.h for transmission) at the meter has been employed in the marginal cost calculation. This rate is difficult to rationalize given that average export prices have been about 5.0¢/kW.h for generation and transmission over the last three or four years. The Board may be compelled to direct the release and use of actual prices rather than forecast unless more transparency is displayed.

MH has suggested that historical price data has been corrected upward to reflect market conditions for electrical energy under median flow scenarios. And, this would seem reasonable given that recent years have seen above average to

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high flow situations which result in a greater proportion of off-peak sales, effectively driving the average export price down. However, that scenario is flawed because, in the Board's considered opinion, MH has not and cannot support its forecast of achieving an energy price of 7.5¢/kW.h based on known existing export circumstances:

Median flow scenario reflects 7,700 GW.h of export energy in 07/08, which theoretically could all be 5 x 16 peak energy, but about half would be covered by contract prices at about 5.5¢/kW.h. While the remaining peak energy might achieve 7.0¢/kW.h, it would appear that the overall average cannot reach 7.5¢/kW.h.

Dependable flow scenario reflects 4,000 GW.h of export energy, all of which could be 5 x 16 peak energy and covered by existing contracts at 5.5¢/kW.h, this well below the 7.5¢/kW.h forecast; and the high flow scenario reflects 11,700 GW.h of export energy, of which about 7,700 GW.h could be 5 x 16 peak energy including existing contracts at 5.5¢/kW.h, and 4,000 GW.h would be off-peak energy in a surplus market pricing at below 3¢/kW.h, which brings down the overall average to about 5¢/kW.h.

MH suggests export pricing will escalate in tandem with rising natural gas prices. However, this assumption is contrary to the experience over the past 4 or 5 years.

In the determination of generation marginal cost, MH applied a marginal cost, derived primarily from forecast export prices, to the entire domestic energy consumption (20,800 GW.h as metered), and arrived at a marginal cost of domestic generation of \$1,315 million (or 6.3¢/kW.h at sales).

Unfortunately, MH's scenario appears unrealistic and unattainable, because:

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- a) the calculation suggests MH expects to export 20,800 GW.h over and above the existing export level of 7,700 GW.h, when maximum tie-line capabilities are only about 16,000 GW.h;
- b) the forecast suggests it is possible to achieve peak (5 x 16) export prices above 6¢/kW.h for an additional 20,800 GW.h, although the peak period tie-line capabilities are limited to about 7,500 GW.h and are already fully committed;
- c) with existing export sales contracts of 4,000 GW.h for 5 x 16 energy at current average prices of 5.5¢/kW.h, and assuming the sale of the entire remaining 3,500 GW.h of peak energy and 8,500 GW.h of off-peak at average prices of 9¢/kW.h, when MH's average price for exports has been about 5¢/kW.h for both generation and transmission, this suggests the projection is not realistic;
- d) to transmit 16,000 GW.h/year of energy into the MISO market and not see average prices decline below 5¢/kW.h seems unlikely; and.
- e) shifting domestic load of 8,300 GW.h (16,000 GW.h minus 7,700 GW.h median flow exports) to export would appear to yield additional revenue of about \$415 million at today's average export prices. Given this could not be at 5 X 16 peak pricing, this appears to suggest a marginal cost of about 2¢/kW.h when applied to the entire 20,800 GW.h of domestic load. (This compares to the \$615 million (or 3¢/kW.h) of embedded costs allocated to domestic load for generation in PCOSS-08.)

The foregoing review suggests that the marginal cost scenario for generation presented by MH is flawed and in need of revision. It also suggests that the RCCs that arise are being driven by an overstatement of generation marginal costs.

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Only MIPUG, of the Intervener groups, provided comment on MH's marginal cost calculations for generation. They submitted an alternative that assigns embedded costs on an energy price (SEP-based) weighting basis.

In MH Exhibit #68, MH applied unit marginal cost for distribution to the entire load served from the distribution system. In a previous MH filing (Marginal Cost of Transmission and Generation Study of 2004), the authors suggested that the values derived were only applicable to load growth or reductions of 85 MW and should not be extrapolated further.

Accordingly, MH will be directed to revisit and re-file a better-formulated marginal cost/value, one reflecting the realities of covering embedded costs as well as future costs, and as to potential export revenues. The re-filing should include an in-depth discussion of assumptions and inputs to MH's marginal cost COS. The re-filing should also cover the marginal costs of the export class.

As for use of marginal costs and the use of RCCs in rate setting, the Board will require the additional information from MH before assessing the weighting for embedded cost RCCs and marginal cost RCCs. Presumably, the marginal cost recalculation will be equally applicable to the Energy Intensive Industry rate design.

Marginal Cost Confidentiality

MH declined to publicly present its key assumptions and specific input data that it employed with its SPLASH model in the determination of generation marginal cost. Similarly, the "avoided cost" calculations, employed in defining transmission marginal cost and distribution marginal cost, were also not made available to the proceeding.

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The Board will direct MH to make all this information available (however, on a confidential basis to the Board) and will assess whether the information should be further shared with interveners. The Board will not share the information with interveners without first engaging MH in discussion ahead of a meeting to involve all parties.

During the hearing process, MH invoked a confidentiality constraint on the specifics of:

- a) How forecast export prices were determined;
- b) SPLASH model inputs and assumptions;
- c) Transmission marginal cost assumptions and avoided cost calculations;
and
- d) Distribution marginal cost assumptions and avoided cost calculations.

The result is that none of the interveners were in a position to challenge the marginal cost determined by MH for generation, transmission, and distribution. While MIPUG provided an alternative to MH's calculation process, the intervener did not attempt and probably could not have challenged the unit marginal costs and/or forecast export prices.

This left the Board in the position of either accepting MH's forecast marginal cost, despite the absence of any serious testing, or directing MH to provide more detailed justification for the marginal cost calculations. The Board opts for the latter.

Forecast and Calculation of Marginal Cost

The Board suggests that MH's forecast of export prices is overstated and does not adequately recognize:

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- a) Current U.S. export market prices;
- b) Current USD/CDN exchange rates; and
- c) Current transmission inter-tie capacity to U.S. constraints.

Further, the Board has concerns about MH calculations of marginal cost for generation, specifically the total marginal cost value assigned to domestic generation. Also, as previously outlined, the Board has concerns about the lack of information (assumptions and inputs) on the transmission and distribution marginal cost provided to the proceeding.

Weighting of MC-COSS

Given this, the Board cannot establish, other than directionally, the value of the marginal cost (MC) as a COSS consideration. Much more marginal cost information and justification will be required from MH in advance of the next GRA, to allow the Board to place a weighting on the two sources of RCCs, and begin to differentially allocate future rate increases.

Therefore, the Board will not be assigning a specific weighting to the MC-RCC developed by MH, or for the amended approach proposed by MIPUG. However, after a review of the information put before it, the Board remains of the view that, in a proper form, marginal cost consideration should be given comparable weighting to that of the embedded COSS.

While previously the PCOSS was viewed to be a stand-alone tool for rate setting, it does not appear that a marginal cost determination could be other than a modifying procedure. In any event, appropriate generation and transmission costs should be allocated to the export class.

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The Board therefore directs MH to provide a revamped MC-COSS analysis, one reflecting needed refinements to generation/transmission/distribution marginal costs. One scenario to be explored, among others, should involve the addition of marginal cost to embedded costs in COSS for domestic classes and the export class, prior to comparison to class revenues.

Environmental Consideration in COSS

Despite MH's contention that export pricing automatically builds in environmental considerations, it is apparent that MH, at least to date, has been unable to gain significant revenue increases of any kind related to environmental factors. Environmental or green energy considerations do not, at least at present and by no means for lack of effort on the part of MH or the Province, appear to have affected base-load coal generation prices in the MISO market region.

MH's export price forecasts assume that GHG legislation will come into play as early as 2012, and boost export prices. The Board is concerned with this degree of optimism, with \$18 billion of capital expenditures lying in the future; 'best case' scenarios, while interesting and useful as goals, need to be balanced by other less positive views. The Board will direct MH to revisit its export pricing forecasts to reflect recent realities on market prices and exchange rates.

On a similar vein, MH has indicated that embedded costs incorporate substantial levels of mitigation efforts and costs. By capitalizing these costs, MH is deferring the impacts on the COSS, and on rates. The Board is mindful of the possible effects to arise out of the adoption of IFRS, and that one of those effects may well be less capitalization and more direct allocation and expensing of period costs; if this occurs, it means either less annual net income or it will require higher rate increases.

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The foregoing suggests explicit consideration of environmental factors is either not necessary, or that to do so would be a form of double-counting. This issue needs further definition and development.

14.0 Rate Design

14.0 Rate Design

14.1 Inverted Rates

In Order 117/06, the Board reiterated its directive to MH to move towards the elimination of declining block rates. MH has, with some notable exceptions, moved toward this objective.

MH introduced, on a very limited scale, an inverted rate structure for the residential class, where the tale block rate is to be greater than the first block by a modest 1% differential. MH has suggested a continued future GRA movement in the direction of marginal cost, through future gradual increases in the to the tale block closer to the marginal cost of energy (now 7.01¢/kW.h.).

MH proposed that the first block of energy consumption be set at 900 kW.h per month, regardless of the season or the energy source for residential space heating. MH did not propose any changes to the basic monthly charge block rate.

MH acknowledged that the future evolution of the inverted residential rate should take into consideration the needs and constraints of customers who currently use electricity as a primary heating fuel, while continuing to encourage natural gas as the appropriate fuel choice in areas of the province served by natural gas. MH indicated that to address heating loads, there are essentially three approaches that could be taken to provide for meeting these needs within a lower cost first block.

The more complex mechanism would be to design a separate residential rate for electric heating loads. MH stated that this is the method preferred by Mr. Chernick, the witness for RCM/TREE, and would provide existing electricity heating customers an allowance of an additional 6,400 GW.h/ year in the initial price block during the heating season. This would result in an increase in the

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percentage of heating energy served at the initial rate block of roughly 54% that non-electric heating customers receive.

MH cautioned that such a specific rate targeted at electric heat customers may create an incentive for customers to report electric heat capability though staying with natural gas, and may create increased administrative burden and cost to manage/police.

MH offered two alternatives that may be simpler to administer, and which may not specifically target all electric heat customers or exclude customers using other sources of heating. MH noted the simplest method would be to differentiate the size of the first block by season, with a larger first block in winter, as is done in Ontario. The other is to provide a larger first block in winter only in areas not served by natural gas (although this may be complicated by the uniform rates legislation). MH concluded that further review of the alternatives were required.

Given the significance of residential electric heat in Manitoba (natural gas distribution is limited), as well as higher degree-days compared to Ontario, the Board would consider it appropriate to set a winter “first block size” higher than that now set in Ontario.

14.2 General Service Small and Medium Classes (GSS and GSM)

MH is moving to consolidate the GSS and GSM rate structures, supported by previous Board direction. Both classes are served from MH-owned transformation and utilize similar voltages.

The following rate table illustrates the proposed changes as initially proposed by MH (1) and the revised rates (2) as per Order 90/08 as follows:

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	Small			Medium		
	March 2007	April 2008		March 2007	April 2008	
		1	2		1	2
Basic Charge Single Phase	\$15.60	\$16.50	N/C			
Basic Charge Three Phase	\$21.75	\$23.55	\$22.99	\$27.60	\$27.60	N/C
Energy Charge:						
1st 11,000 kW.h	6.18¢	6.31¢	6.48¢	all kW.h	5.90¢	6.13¢
Next 8,500 kW.h	4.00¢	4.30¢	N/C	@	4.07¢	4.30¢
Balance kW.h	2.55¢	2.65¢	2.73¢	2.55	2.65¢	2.73¢
					no charge	
Demand Charge:						
1st 50 Kva	no charge	No charge		all KVA @		
Balance of KVa	\$8.34	\$8.34	N/C	\$8.34	\$8.34	N/C

The proposed changes are the first step of two or three transitional moves to a single rate table for GSS and GSM.

A major rate component that currently differentiates the small and medium rate classes is the application of demand ratchets, which impact the determination of monthly billing demand. The general service small class is not subject to any ratchet provisions and the class' customers are only billed on their recorded demand above 50KV.a. General service medium customers are, on the other hand, currently subject to paying the higher of their recorded demand or the ratchet.

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Once the classes are fully consolidated, the ratchet would not impact current general service small customers as long as they remain below 200 KVa. In MH's Application, it did not propose that the 70% winter ratchet provision be modified, but that it would continue to be applied against loads in excess of 200 KVa.

14.3 Area and Roadway Lighting (ARL)

MH has proposed a 1% increase in the ARL rate.

City of Winnipeg raised its continuing claim of the overpayment by municipal lighting customers relative to costs being allocated to the class in the embedded cost COSS. As this class has almost always been charged more than 105% of its allocated costs, MH did not dispute the City of Winnipeg's suggestion that the accumulated sum of "overpayments", relative to an RCC of unity, totals in the multi-million dollars. The City of Winnipeg did not request a refund, but rather suggested that ARL rates remain unchanged until a RCC of 1.00 is achieved.

14.4 Time of Use (TOU) Rates

Over the last eight years, the concept of Time of Use energy charges has been a subject of debate. MH has commissioned several studies to address the applicability and consequences of charging customers different seasonal and/or diurnal energy rates.

The major stumbling block has been, and continues to be, the need for more sophisticated and expensive metering and billing systems (an investment of \$90 million was suggested as being required). At present, most GSL >30 customers have appropriate metering in place, however, that is not the case for GSL <30, GSM, GSM, and Residential classes.

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MH has and is currently running pilot studies in Selkirk and Steinbach, to test customer response to greater awareness of actual consumption levels; the results to-date have been somewhat confusing, and have failed to give support to a massive move to TOU for residential customers.

MH acknowledged that, on balance, a TOU rate for General Service customers would likely provide increased revenues for the Corporation. MH indicated that such a TOU program could take about 12 - 18 months for start-up studies and to obtain program approval for classes with TOU meters. And that implementation could take at least four more years for the classes currently without TOU meters.

For the residential class in particular, a TOU program would involve changes to meter reading frequency. While new technologies are possible, it would appear costs could be prohibitive.

14.5 Rebalancing of Demand and Energy Charges

MH's rate structure has for many years been over-collecting on demand charges and under-collecting on energy charges relative to COSS allocations. In response to Board direction, MH has, since 2003, been assigning rate increases entirely to the energy portion of rates.

The result has been a gradual shift of the source of customer revenues, with the change viewed as being conducive to be objectives of conservation.

The following table illustrates the March 2007 imbalance situation, when comparing PCOSS-08 allocated costs to revenue at March 2007 rates.

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	Demand (\$/KVA)			Energy (¢/kW.h)		
	March 7/07 Rate Revenue	117/06 Allocated Cost	Revenue/ Cost %	March 7/07 Rate Revenue	117/06 Allocated Cost	Revenue/ Cost %
GSS	8.34	6.92	120	2.55	2.65	96%
GSM	8.34	7.09	118	2.55	2.68	96%
GSL <30	7.08	7.94	89	2.38	2.61	91%
GSL 30-100	6.06	4.26	142	2.29	2.44	94%
GSL >100	5.40	2.21	244	2.26	2.41	94%

The table suggests that MH still has a considerable way to go before revenues and costs for GSL demand and energy are in balance. Of particular note is that GSL <30 KV class revenues and rates are under-collecting for both energy and demand.

MH's March 2007 Report suggests that over a four-year period, the movement toward "full balance" has eliminated 50% of the initial discrepancy. This infers it could require another four years of rate increases applied through energy changes alone to achieve balance.

For GSS and GSM customers, the demand charge partially offset the under-funded basic monthly charge for customer service and distribution plant.

14.6 The Basic Monthly Charge

All MH customers other than GSL pay a basic monthly charge, which is intended to cover (but does not) allocated customer service and local distribution costs.

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	Billing Rate	Allocated Unit Cost (Net of Export Credit)
Residential:		
- (<200 amp)	\$6.24/month	\$18.70/month
- (>200 amp)	\$12.48/month	
GSS-ND	\$16.50/month	\$31.25/month
GSS-D	\$23.55/month	\$51.22/month
GSM	\$27.60/month	\$227.78/month

The argument for not increasing the basic monthly charge is based on the premise that the under-charge is justified by the “incentive provided” in high energy charges to reduce consumption.

14.7 Diesel Rates

At one time, in excess of thirty northern Manitoba communities were provided electricity service by means of diesel-fired generation. Over time, the number of communities served by diesel generation fell, at first to thirteen and, eventually, to the now current four.

The remote Northern Manitoba Communities of Shamattawa, Tadoule Lake, Brochet and Lac Brochet, with a total population of approximately 2,000 people having 800 separate accounts with the Corporation, are not connected to MH’s transmission and distribution grid. While diesel fuel is very expensive, there are other problems with diesel generation such as winter road supply uncertainties, customer service levels and environmental issues.

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Diesel generation does not provide the quality of service represented by grid service, as the four diesel class communities are limited to 60 amp service and the 800 accounts are not supposed to use electricity service for space heating.

In Manitoba, the first 2,000 kW.h of electricity consumed monthly by residential and General Service customers in the diesel zone is billed at grid comparable rates. The subsidy from full cost rates is borne by "Government Accounts" by way of surcharges or premiums. In some other Northern Canadian jurisdictions, less than 900 kW.h of diesel generated electricity is provided at grid comparable rates.

Excepting for the first 2,000 kW.h of electricity, diesel class rates are very much more expensive than grid rates. Most diesel class customers are residential, but there are also General Service, Federal and Provincial Government and First Nations accounts.

In Order 159/04, dated December 22, 2004, the Board approved interim sales rates for the diesel communities based on MH's then-Application, which reflected a tentative settlement arising out of MH's negotiations with MKO, acting on behalf of the diesel communities, and Indian and Northern Affairs Canada (INAC).

The terms of the tentative settlement were summarized in Order 159/04 to include:

1. MH would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit which was approximately \$16.9 M as of March 31, 2004. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement;

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2. INAC would pay \$3.2 million to MH for the surcharge billed to INAC by MH between November 2000 and May 2004;
3. INAC, on behalf of the Federal Government, would pay MH 69% of the \$28.8 million of MH's diesel-related capital cost, the balance as at March 31, 2004, by July 7, 2005 without interest and by no later than January 7, 2006;
4. MH would request that other Federal and Provincial Government customers in the diesel zone (notably Health Canada, the RCMP, and the Province of Manitoba), pay MH a further 10% of MH's \$28.8 million of undepreciated capital costs;
5. MH would assume the remaining 21% of undepreciated capital costs on behalf of residential and General Service customers that are neither First Nations members nor Government accounts; and
6. for major future capital expenditures in the diesel zone, MH would consult with the diesel zone's First Nations communities, and secure funding prior to making further capital expenditures.

At the time of issuing Order 159/04 the Board was advised that the signing of the Settlement Agreement was expected on or before July 7, 2005 – now three years ago. Because of various factors, the signing date has been delayed.

If the Settlement Agreement is not concluded, MH has indicated a desire to reconsider its recommendation that the class receive an allocation of net export revenue in the COSS. The delay in the finalization of the Settlement Agreement relates to the Federal Government and is beyond the control of the Board, MH, the four communities served by diesel-fired generation and the Province.

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14.8 Surplus Energy Program (SEP)

MH was earlier provided with interim approval to extend the Surplus Energy Program to October 31, 2008. As part of the GRA process, MH requested that SEP be approved for five years to March 31, 2013, without any changes to the terms and conditions.

The SEP makes surplus energy available on an interruptible basis to MH's general service customers. Customers may be eligible for:

- Option #1** Industrial load >1,000 KVA monthly demand (<25% of total load);
or
- Option #2** Space and/or water heating >200 KW per month (separately metered with full back-up); or
- Option #3** Self generation displacement 200 KW to 50,000 KW with Load Factor of 25% (separately metered with full on-site back-up).

The program primarily displaces export sales, but the energy supplied to SEP customers may be supplemented from import supplies, though at much higher costs than domestically supplied energy. Energy prices (Spot Market) are forecast weekly and submitted for Board approval, for peak, shoulder, and off-peak prices.

Since December 2000, SEP has involved about 25 GSM and six GSL customers, with average (over seven years) sales of about 22 GW.h/year, average revenues of \$9 million (4¢/kW.h) and average net revenues of \$45,000/year (varying from a loss of \$35,000 to a surplus of \$210,000/year).

The customer usage of the SEP has been seasonally variable, with winter weekly high consumption being ten times summer weekly low consumption. Over the whole year, the daily usage pattern has been 24% peak, 40% shoulder, and 36%

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off-peak. Demands during the summer off-peak when prices are low have been well below average.

14.9 Curtailable Rate Program (CRP)

The Curtailable Rates Program provides incentives to MH's large industrial customers; these customers curtail electrical load when called upon by MH. Incentives are provided by way of a credit to the customer's monthly energy bill.

Under the CRP, MH looks to:

- Quickly re-establish contingency reserves that are required by MAPP-GRSP;
- Maintain planning reserve obligations;
- Protect firm Manitoba load from curtailment;
- Maintain spinning and non-spinning contingency reserves; and
- Meet firm energy requirements when MH has supply shortfall.

Different CRP options provide MH with the ability to curtail demand and energy for specified time periods. Customers are provided with power price discounts on the basis of the amount of load available for curtailment. The Board approves the reference discount on an annual basis.

Savings to MH resulting from the Curtailable Rates Program are available as long as the service offering continues, whether or not actual curtailments are made at the time of system peak or at any other time. The expected availability of this load, and not the timing of its dispatch, determines the future benefits of CRP.

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MH requested a change to the terms and conditions of CRP, to increase the notice period from 24 to 48 hours of anticipated plant operations shut down. This would affect the capacity reduction that could be achieved by MH.

14.10 Limited Use Billing Demand (LUBD)

The LUBD rate option was implemented July 1, 2000 and continues to be a relatively simple way for MH to address the concerns of low load factor customers and reduce demand charges they would otherwise face. Initially, the program was intended to mitigate the impact of the winter ratchet on seasonal, commercial, and light industrial winter operations. However, the program has attracted a considerable number of GS customers who are not affected by the winter ratchet. Only 5 of 123 GS customers were subject to the winter ratchet in 2004.

Currently, the customer list on LUBD is:

GSS-D -	68 (winter ratchet not applicable)
GSM -	22
GSL <30	17
GSL >100 -	<u>1</u>
	<u>123</u>

LUBD allows eligible customers to opt for higher energy rates and lower demand charges. For customers with a load factor of 18% or less, the revised rates are economically beneficial. The rate has turned out to be attractive to certain agricultural, recreational, municipal services, and wood product customers, which now account for 40% of the customers utilizing the program.

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From MH's point of view, LUBD customers with their low load factor generally have lower coincident system peaks. As such, they place a lesser demand on system transmission and distribution.

MH did not propose to alter the LUBD rate structure as it applies to GSS-D and GSM, but sought to revise the eligibility requirement from 36 months to 12 months.

14.11 Winter Ratchet

The winter ratchet refers to MH's demand billing practice of charging customers the greater of:

- Actual billing demand (KVA) in each month (measured on 15 minute interval); or
- 70% of highest demand in any previous months of December, January, and February; or
- 25% of the customer's contract demand; or
- 25% of the highest measured demand in any of the previous 12 months.

The rate is applicable to GSS-Demand/GSM, and GSL classes and particularly affects seasonal customers that have high winter demand and minimal summer demand. These customers have contended that MH was charging them a demand charge related to energy that they were not using and was thus available for export by MH.

MH contends that the energy freed up is unreliable and not always of value, and recent history suggests that the energy probably has similar value to DSM freed-up energy.

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The winter ratchet impacted about 700 customers in 2004, primarily in the GSM class, generating about \$2 M in billing revenue. Notably, schools, hospitals, senior's residences, and similar facilities are included in this class.

The Board found that with MH's system running at near capacity throughout the year, the winter ratchet was of questionable merit and, in Board Order 07/03, directed MH to eliminate the winter ratchet effective April 1, 2004. MH sought and was granted (Board Order 15/03) a deferral to allow further study. An August 2004 report by MH argued for the retention of the winter ratchet pending further review. MH suggested that time-of-use rates may be an alternative to the winter ratchet.

Since 2004, the situation has remained essentially unchanged. MH is still considering the preparation of a time-of-use study and has not advanced a detailed analysis supporting the retention of the winter ratchet.

14.12 Interveners' Positions

The City of Winnipeg

The City of Winnipeg indicated that the rates charged the city for area and roadway lighting have been consistently above the zone of reasonableness (over the last 30 years, with the exception of one year). The City indicated that over the years MH has overcharged it approximately \$49 million.

The City noted that MH proposes to address the "\$620,000 excess" the City is now paying each year, or the \$1 million "over collected" province wide (other municipal accounts approximate 40% of the annual bills to the class).

The City urged Board action to correct the situation.

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The Coalition

Inverted Rates

The Coalition stated they are supportive of the concept of inverted rates but that for the intervenor significant equity concerns exist; concerns for the impact of all-electrical customer with no competitive options; concerns for low-income persons who lack the resources to pursue DSM; and concerns for renters who may lack the ability to pursue DSM or for whom energy efficiency is uneconomic due to split incentives.

The Coalition stated that most new homes in rural areas are installing electric water and space heat, and that many of the new all-electric homes are being built in First Nation communities (many of which being low-income households). The Coalition noted that many customers with all- electric homes don't have access to competitive alternatives such as natural gas, and would not be able to adjust consumption with changes in prices and would be negatively impacted by an inverted rate scheme.

The Coalition opined that residential consumers have an inelastic demand for electricity, which means a change in consumer demand should be expected to be less responsive to a change in price. The Coalition cited a study by the Rand Corporation that dealt with electricity consumption in the US, which stated:

"Locations where particular energy uses are very valuable, such as air conditioning in southern states or winter heating in northern states, could have price elasticity smaller in absolute magnitude because air conditioning and heating are so valuable during periods of extreme climate. The consumers are unwilling to change their use when prices change."

The Coalition underscored the importance of price signals, indicating that, in particular, commercial and industrial customers were more responsive to changes in price in adjusting their consumption.

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The Coalition further suggested that there is a low-income context that needs to be addressed related to inverted rates. The Coalition suggested that MH currently has over 18,000 customers earning less than \$30,000 a year that are consuming more than 18,000 kW.h per year, of which over 16,000 of those customers are all-electric customers.

The Coalition noted that this group would be negatively impacted by an inverted rates scheme, that is unless the current barriers to participation in energy efficiency DSM programs are addressed. The Coalition stated there are substantial barriers faced by low-income individuals that discourage their participation in energy savings initiatives.

Mr. Harper noted that the inverted rated proposal put forward by MH has a modest differential between the first and the second blocks, but that the modest differential does at least begin to send the correct message, i.e., that increased use is more expensive. Mr. Harper further stated the issue of bill impacts is important and should be addressed before MH makes further changes in implementing inverted rates.

Mr. Harper proposed a gradual implementation of inverted rates, and proposed that before any further changes are made MH should first ensure that its DSM programs are focused in fully supporting those low-income customers who will be most notably impacted by inverted rates, and customers who typically use more than 1,500 kilowatt hours a month (over 18,000 kW.h annually).

The Coalition stated that it would be unfair to implement inverted rates before giving vulnerable groups the tools to achieve energy efficiency. The Coalition recommended delaying inverted rates until adequate DSM programs are in place for low-income households with high consumption levels, tenants, and all-electric space heat customers that have no competitive space-heating options.

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To address the inequity faced by all-electric customers, the Coalition suggested the focus should be on the differentiation between the all-electric block and the standard-use block, providing the all-electric block a larger first block during the heating season. From its perspective, the key issue is addressing the vulnerability of those customers who rely upon electric heat for their home heating.

Time of Use Rates

The Coalition expressed interest in advanced metering technology, which would be required to implement time of use rates. The Coalition urged the Board to direct MH to report on developments in terms of such metering, including the potential for the Utility controlling thermostats for peak shaving purposes.

Energy Demand Rebalancing /Basic Monthly Charge

Coalition opined there should be no increase in the BMC and suggested that the cost allocation process be changed for residential customers.

As well, the Coalition recommended the BMC recover only a percentage of customer costs, excluding customer related distribution costs, and recover only in part customer service and metering costs, with the balance of costs to be recovered through energy charges

MIPUG

Inverted Rates

MIPUG suggested that MH's inverted rate proposal for the Residential Class was inadequate, and that the small differential would not send a meaningful price signal to customers.

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MIPUG suggested that MH implement inverted rate proposals for other customer classes, including the General Service large class and sub-classes. MIPUG recommended the Board direct MH to develop an inverted rate proposal for the General Service large class, in consultation with customers, and file it with the Board for consideration.

Time of Use Rates

MIPUG recommended MH be directed to develop seasonal time-of-use rates. Mr. Bowman and Mr. McLaren stated that for customers with some ability to shift their loads, a rate design that includes time-of-use components could reduce MH's costs and that these cost savings could flow, at least in part, to the load-shifting customer. For MIPUG, properly designed time-of-use rates would provide incentives to optimize the use of the generation and transmission system, resulting in cost savings and/or increased export revenues to the mutual benefit of MH and its customers.

MIPUG stated that TOU rates meet a valid regulatory objective of promoting efficiency and conservation and would provide customers the right price signal for every kilowatt hour of consumption. MIPUG stated that such an approach would be an improvement over the winter ratchet, which, for MIPUG, sends too strong a price signal for some, and none to others.

Energy Demand Rebalancing /Basic Monthly Charge

MIPUG noted that MH sought applying the Industrial rate change entirely to the energy component (and not the demand component). Given the substantial outstanding issues arising from the lack of contemporary pricing mechanisms, MH's efforts at improving the price signal were, for MIPUG, effectively irrelevant and should be rejected.

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MIPUG recommended the Board reject the proposed allocation and direct MH to propose a logical process for implementing, in consultation with customers, rates that address contemporary elements of industrial rate design. In the meantime, any rate increases for industrial customers should be implemented as an equal percentage increase to the demand and energy components of the existing rate structure.

MIPUG did not take a position on whether any changes should be made to the BMC.

Winter Ratchet

MIPUG recommended the elimination of the Winter Ratchet, with it to be replaced by time of use seasonal rates.

MKO

Inverted Rates

MKO stated general support for the concept of inverted rate structures, to encourage demand and improved energy management. However, MKO shared the concerns expressed by the Coalition that inverted rates for residential customers may disadvantage consumers with electric water and space heating - customers that include MKO consumers, most of which were reported to be of low income.

MKO also noted the inelastic demand response residential customers have to electricity price changes, as noted in studies referenced by the Coalition. MKO supported the Coalition's comments on addressing the barriers to entry to DSM measures noted by Mr. Dunskey, and supported making DSM and energy efficiency programs universally available to all MH residential customers,

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including those in the diesel communities. MKO suggested that DSM in the diesel zone would likely have a greater impact on reducing domestic demand growth and providing for increased net export revenues than inverted rates for residential customers.

MKO proposed a more gradual inverted rate be applied to the diesel communities, and suggested such an approach may accomplish the objectives of MH without the controversy that would be inherent in trying to set and administer baselines.

MKO cautioned the Board that the inverted rate design proposed by RCM/TREE requires further testing and review to ensure that low-income and remote community MKO customers are not unduly disadvantaged.

MKO suggested the Board direct MH to propose inverted rates structures in the next GRA across all customer classes.

Basic Monthly Charge

MKO did not provide a position on changes to the BMC.

RCM/TREE

Inverted Rates

RCM/TREE recommended changes to the inverted rates program as proposed by MH, and suggested that the BMC be reduced to approximately \$4.70 per month and the first block of energy be reduced from the 900 kW.h per month allowance to 600 kW.h.

RCM/TREE suggested that the rate for the initial energy block should be set at 6¢ per kW.h for 600 kilowatt hours per month for non-heating customers, and for

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all customers in non-winter months. In addition, to counter the impact of the inverted rates on all-electric customers, RCM/TREE proposed a 6,400 kilowatt hour annual allowance be distributed over the heating season, and be priced at the initial block rate.

RCM/TREE proposed that the rate for additional energy should be set at approximately 6.28¢ per kilowatt hour.

RCM/TREE discounted MH's concerns about the accuracy of the Corporation's customer database for identifying customers with electric heat capability, and suggested that exceptional cases and administrative gaps should not obstruct sound policies. RCM/TREE stated it advocates an integrated approach to affordability and efficiency.

Paul Chernick, a witness for RCM/TREE, stated inverted rates are a good and sound economic policy, and observed that while there are low-income customers that would be affected by the implementation of inverted rates that should not act as a "veto" for the program's implementation.

Mr. Chernick stated proper steps to protect lower income individuals should be put in place. Mr. Chernick proposed the implementation of targeted low-income conservation programs and bill assistance, the latter through vouchers, as mitigation measures, enabling the Corporation to move more quickly to implement conservation measures. "There is no time for the extreme gradualism advocated by Mr. Harper", according to Mr. Chernick.

RCM/TREE stated that if MH requires time to prepare education materials and mitigation measures with respect to the introduction of inverted rates, it might be possible to begin introduction by residential rate increases under a flat rate structure, and then implement a revenue neutral inverted rate structure in the fall.

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RCM/TREE did not agree with the Coalition that gradualism in the implementation of inverted rates is a good idea.

Energy Demand Rebalancing/ Basic Monthly Charge

RCM/TREE proposed the elimination of the BMC over time, and the recovering of those costs through volumetric energy charges to be applied on the tail block of inverted rates.

RCM/TREE countered concerns raised by MH that lowering the BMC for electric customers might encourage customers with small gas usage to switch to all electric appliances to avoid the recently increased gas BMC. However, RCM/TREE noted, since gas customers are also electric customers, such an incentive to switch is already built into the BMC for small users of gas. Lowering the BMC for electric customers and increasing the tail block rate provides a counter incentive for that move, according to RCM/TREE.

RCM/TREE also countered concerns raised by MH that suggested that because customer-related costs are real costs, larger consumers of energy will subsidize costs of smaller energy consumers. RCM/TREE noted that all customers are subsidized from export profits, and that credits applied to the BMC rather than energy would be a more equitable approach, and also provide a stronger price signal to conserve.

Time of Use Rates (TOU) & Demand Ratchets

RCM/TREE recommended MH should implement TOU rates, starting with the largest customers, and move revenue collection from demand charges to time-of-use energy charges. RCM/TREE acknowledged that time of use rates will require appropriate metering, but held that they should be implemented as soon as feasible. The intervener also recommended that MH eliminate demand ratchets.

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Mr. Chernick noted that in jurisdictions where TOU rates have been implemented a parallel billing system was utilized, where a customer would, along with the existing bill, receive a bill as if they were on time of use rates. This allowed the customer to gauge the impact the TOU system had on their consumption and billing, and allow them time to make changes in energy use behaviour.

14.13 Board Findings

Inverted Rates

The Board encourages MH to develop plans to employ an inverted rate structure for all customer classes, initially to be designed on a revenue neutral (to MH) basis and to send a “price signal” for every kilowatt hour of energy used, to promote conservation.

MH suggested that too large an inversion would be prejudicial to all-electric customers. However, the nominal inversion of the Residential Rate approved by Order 90/08 can be expected to cost an all-electric customer approximately \$45/year.

In comparison, a natural gas space-heated home, with a conventional furnace, can expect to pay hundreds of dollars more for space heating this upcoming winter as compared to a similarly adequately-insulated, electrically-heated home.

The Board agrees with the principle of inverted rates but notes, based on demand studies presented, that residential customers, in particular, do not significantly change their consumption patterns upon a price increase.

The Board shares the concerns expressed by all parties on the impact that sharply inverted rates would have on both low-income customers and all all-electric heat-load customers, who are unlikely to diminish consumption with

14.0 Rate Design

increases in electricity prices. So, if the inversion were to be sharper, to promote conservation, this could be expected to result in a relatively high proportion of consumption being exposed to the higher second-block rate.

The Board notes that (with respect to the identified problem which electric heat customers could incur with sharply-inverted rates) there are methods to address what could be considered the inequity that could result from such sharply-inverted rates. The Board is aware of the complexities that MH will face in addressing this concern, but it warrants a fulsome analysis.

In particular, the Board is interested in MH providing additional information on seasonal variations in the size of the first electric block for electric heat-load customers. The Board agrees with MH that the size of the first rate block for Manitoba, as compared to the one utilized in Ontario, will likely have to be higher to take into consideration the greater heating load factor due to Manitoba's colder winters. The Board will direct MH to file a plan by January 15, 2009 outlining the pros and cons of the various potential inverted rate strategies under consideration, and the MH-proposed course of action to address this issue.

The Board is quite concerned with the impact that sharply-inverted rates will have on low-income customers. The Board shares the concerns raised by the Coalition that barriers exist that preclude low-income customers from taking actions to reduce electricity consumption. Given that the proposal currently under consideration only reflects a nominal differential between the first and second block, the implementation of inverted rates should not be delayed, and the Board will address the problems of higher energy costs for low-income households in a broader way.

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Nonetheless, the Board will expect MH to put forward more comprehensive plans to shield low-income customers from the impacts that will result from higher electricity rates in a sharply-inverted rate scheme.

With respect to the level of the basic monthly charge, the Board will direct MH to increase the Basic Monthly Charge by 5% on July 1, 2008 and a further 5% on April 1, 2009, by way of Order 90/08. The increases will result in BMCs that will still be well below a representation of MH's actual customer-based costs.

MH is to continue with the process of the GSS and GSM customer class consolidation, and provide the Board with a proposal by June 30, 2009 for a stepped-up program and a timeframe for completion.

Time of Use (TOU) Rates should be fast-tracked for customer classes where the required meter technology is currently installed. TOU rates assist in defining marginal cost, and therefore, should be included in any new proposed energy-intensive industry rate for consideration by the Board.

The Board will direct MH to provide a planned implementation strategy outline by September 30, 2008 for TOU rates, as appropriate to the classes with required metering technology already in place. Alternate rate strategies should be included for consideration at the upcoming Energy Intensive Industry rate hearing.

Energy and demand balancing is a policy issue that speaks to the fairness of rates to individual customers within a class. The argument for reducing demand charges, and increasing energy charges, is that it does send an improved price signal and thus promotes conservation. As the change occurs, Demand and Energy Cost recoveries will be brought more into line with cost causation principles. The Board will therefore direct MH to plan to re-balance demand and

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energy charges on a revenue-neutral basis, and submit a 5-year transition plan for the Board's approval at the earlier of December 31, 2009 or the next GRA.

Diesel Zone: MH has indicated it will apply to the Board for finalization of the 4 interim Orders related to Diesel Rates. In such an application, the Board will also direct that MH provide reports on:

- a) the fairness of the rate approach with respect to non-senior government accounts (the Board is concerned that the rates restrict the economic development prospects for the communities and drive up service and commodity costs);
- b) the efficacy of the current rate schedule for non-government accounts (data on aged accounts receivable, delinquency and bad debts together with the collection policies in place for the four communities will be required);
- c) the effects of the current approach to rates and consumption restrictions on the four communities, a detailed review of consumption levels and collection practice from the former Diesel communities that have been connected to the Grid which will serve as a comparison; and
- d) MH to report to the Board by September 1, 2008, as to the balances and status of the diesel zone accounts; to ascertain whether existing interim rates are fully recovering operational costs.

Area and Roadway Lighting (ARL)

The Board agreed with the position advanced by the City of Winnipeg and, by Order 90/08, did not approve any rate increase for the Area and Roadway Lighting class for either July 1, 2008 or April 1, 2009.

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SEP

The Board is concerned with MH's marketing practices that yield extremely low prices for off-peak exports, and suggests that retaining energy in storage may prove more beneficial in the longer term than selling power for extremely low prices. The Board acknowledges that MH may be operating the system at near optimal levels to avoid "spilling" water, but there may be a benefit to spilling when prices get too low.

MH will be directed to provide a report to the Board by January 15, 2009 evaluating the Surplus Energy Program; the report should employ monthly historical data from 2000 to 2008 to analyze and compare the benefits and costs of the actual operation of the hydraulic generating system pursuant to various less aggressive sales strategies. This report should address the relative merits of withholding surplus energy from sales at off-peak periods.

The report may show whether selling at any cost increased the financial losses in 2003/04; and may also have resulted in foregone opportunity exports in 2004/05 because of low energy in storage.

In the interim, and by Order 90/08, the Board approved the extension of the SEP until October 31, 2008, on the condition that annual reports will continue to be provided.

The Board also approved all weekly interim SEP Orders, from August 1, 2007 (Order 100/07) through and including May 21, 2008 (Order 61/08), by way of Order 90/08.

14.0 Rate Design

CRP

Having heard no opposition to the request, the Board approved the requested change in the Terms and Conditions for the CRP by way of Order 90/08, with annual reports to be provided as previously.

LUBD

By Order 90/08, the Board also granted final approval of the revisions to the Terms and Conditions of LUBD, reducing the eligibility requirement from 36 months to 12 months. This revision will provide customers with increased flexibility to opt out and into the LUBD option, with minimal financial impact on MH or other participating ratepayers. The Board will, however, require annual reports on this program to illustrate the economic impact on MH and customers.

Winter Ratchet

The winter ratchet should be eliminated, such that customers are billed actual demand. With MH's summer and winter demands being nearly equal, there is not a strong case for retention of the ratchet. The ratchet does not send a strong price signal and is a source of considerable customer complaint. The ratchet can be removed with only a negative \$2 million a year financial impact. Unless MH provides an acceptable TOU implementation process, the ratchet is to be removed ahead of the winter of 2009/10, and the change will be confirmed in an Order to follow in due course with respect to the conditional rate increase for April 1, 2009.

As previously mentioned, MH should file an implementation program for TOU rates for GSL customers with a fast-tracking of the subclasses that have the necessary metering technology in place.

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It is currently the Board's intention to direct the elimination of the winter ratchet by September 30, 2009; the matter will be addressed in the Order related to the conditional April 30, 2009 rate increases.

15.0 Class Rate Impacts

15.0 Class Rate Impacts

15.1 Rate Changes/Rate Impacts

MH increases as of July 1, 2008 approved in Order 90/08 were::

	2008/09	Range of Bill Impacts	
Class		Low	High
Residential	5.06%	3.8%	5.52%
General Service Small Non-Demand	5.08%	4.88%	5.08%
General Service Small Demand	4.83%	3.98%	6.10%
General Service Medium	5.01%	3.22%	5.53%
General Service Large <30 kW	5.16%	3.35%	6.27%
General Service Large 30-100 kV	5.04%	3.21%	5.77%
General Service Large >100 kV	5.07%	3.07%	5.33%
Area and Roadway Lighting	0.0%	-	-
Overall General Service	4.95%		

Based on the approved July 1, 2008 rates, residential customers will experience increases ranging from 3.8% to 5.5%, depending on monthly consumption. Customers using more energy will experience higher than average increases.

15.0 Class Rate Impacts

For example, a typical residential customer without electric space heat consumes approximately 1,000 kW.h per month on average and will note an increase in their monthly bill of \$3.03 or 4.7%. A residential customer with electric space heat, using on average 2,000 kW.h per month, will note an increase of \$6.36 or 5.2% per month.

General Service Small commercial customers will experience increases ranging from 3.98% to 6.10% depending on monthly consumption and/or load factor; the overall class average increase is 4.94%.

General Service medium: commercial/industrial customers will experience rate increases ranging from 3.22% to 5.53%, depending on monthly consumption and/or load factor; the overall class average increase is 5.01%.

Increases to General Service large customers vary depending on the voltage level served and the load factor of each customer. MH proposed that the demand charge applied to the General Service large classes remain the same with only the baseline energy charge to increase. This charge results in higher load factor customers receiving a higher percentage increase.

For rates effective July 1, 2008, customers served at 750 V – 30 kV will have increases in their monthly bills ranging from 3.35% to 6.27%, with the average increase being 5.16%. Customers served at 30 kV to 100 kV will experience increases ranging from 3.21% to 5.77% with the average being 5.04%. General Service large customers served at over 100 kV will note increases ranging from 3.07% to 5.33% per month, with the average being 5.07%.

15.0 Class Rate Impacts

15.2 Differential Rate Increases

MH did not propose any class differential rate changes in its application other than for ARL, as it was MH's position that the current COSS has not been sufficiently tested to justify relying solely on the RCC results indicated therein. Furthermore, MH noted that the Board had not given MH any indication as to how marginal cost and environmental considerations will be reflected in Rate Design.

15.3 Interveners' Positions

RCM/TREE suggested that only marginal costs be considered in Rate Design, while the Coalition took the position that while the COSS should be the primary basis for rate setting, marginal cost should also be considered.

MIPUG took the position that the COSS has been adequately vetted to allow it to be established as essentially the entire basis for rate setting. MIPUG strongly supports the concept of moving RCCs to unity over five years, and suggested that a five year migration based on a 2.9% annual rates increase would bring about annual rate increases of:

- Residential 3.78%
- GSS-ND 1.92%
- GSS-D 1.26%
- GSM 2.65%
- GSL <30 5.36%
- GSL 30/100 2.04%
- GSL >30 0.93%
- ARL 1.31%

15.0 Class Rate Impacts

15.4 Board Findings

The Board has accepted MH's proposal for across-the-Board increases for 2008/09 and 2009/10, in order to allow further consideration of marginal cost factors for subsequent GRA's, and, by Order 90/08, directed a 5% across-the-board increase for all customer classes except for Area and Roadway Lighting, which is to receive no increase.

Also, by Order 90/08, the Board has indicated, on a conditional basis, subject to a number of reports to be required of MH, a further 4% across-the-board increase as of April 1, 2009, except for Area and Roadway Lighting which is to receive no increase.

16.0 Energy Intensive Industry Rate

16.0 Energy Intensive Industry Rate (EIIR)

16.1 Background

In the public hearing that resulted in Board Order 117/06, MH raised a concern related to energy consumption by energy-intensive firms, using energy as a manufacturing input. MH foresees its revenue position and the rates of other customer classes as being threatened by new or expanding industrial loads.

MH outlined its concern by considering its energy sales to energy intensive industrial customers, typically earning the Utility approximately 3.2 cents per kW.h while energy to secure such new or expanding load may be diverted from profitable export markets, which MH forecasts to return approximately 5.39 cents per kW.h. MH's example was a new or expanded load of, say, 100 MW causing a reduction of up to \$18,000,000.00 per year in MH's net income, which would, according to MH, likely necessitate a rate increase of approximately 1.8% to all domestic customers served by the Utility (to recover such a revenue deficiency).

The issue compounds in the longer term, when MH assumes the risks of advancing construction of a major new generating station to meet new industrial load at prices below marginal costs. The decision that lies ahead following MH's refiling of its application potentially has large economic consequences.

While identifying the problem is relatively straight forward, the solution(s) is/are more elusive.

Against that background, the Board notes that it provided direction in Order 117/06, including that:

- MH to consult broadly, and in particular with government and industry, prior to advancing a proposal;

16.0 Energy Intensive Industry Rate

- MH to develop its proposal taking into account that existing industry came, remained and expanded in Manitoba with certain assumptions as to energy prices and supply – and therefore a distinction between new and existing industry is reasonable; and
- MH to provide a report and recommendations with respect to establishing a new energy – intensive industry class, including criteria developed after broad consultations with industry and government, and rate design recommendation.

16.2 MH'S Proposal

In its GRA, and in response to Order 117/06, MH proposed a new General Service Large rate schedule that would limit the application of “heritage” energy rates (based on embedded costs) to industrial customers specific baseline energy quantities per year.

Beyond the specific baseline energy quantities, higher rates, based on the marginal value of the energy, would be applied unless the industrial customer qualifies for an exemption to raise its baseline.

In essence, MH's new energy intensive rate proposal has three interrelated components:

1. new rate based on marginal value of foregone export revenue and marginal cost of generation;
2. a baseline, which would be set as an annual quantity based on a customer's prior maximum usage; and
3. exemptions, based on economic factors which would result in an increase in that customer's baseline if the exemption criteria was satisfied.

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MH initially included the proposed rates and method of calculation of the baseline within its GRA; the exemption criteria was filed subsequently.

Underpinning MH's new energy intensive industry rate proposal was the principle that the revenue from such new rates would equal the foregone revenues of the same energy if it had been sold on the export market.

In short, MH sought to make the new energy intensive rate "revenue neutral" to the Utility.

16.3 MIPUG Motion

After MH's GRA filing, and also after the filing of the exemption criteria, the MIPUG advanced a motion to the Board seeking to sever the portion of the industrial rate that deals with new and expanded loads, from the GRA proceedings.

Following oral submissions on MIPUG's motion, the Board issued Order 8/08, which severed in part consideration of the new industrial rate from the GRA proceeding. At the GRA hearing, the Board and Interveners were provided the opportunity to cross-examine MH on the Utility's full proposal.

The Board, in Order 8/08, agreed that, at a minimum, consideration of the exemption criteria would occur at a special hearing. Interveners were also advised that if they so wished, they could bring new evidence forward at a separate hearing. To that end, the Board was advised, during the GRA hearing, that at least MIPUG intends to bring new evidence forward on this issue.

16.0 Energy Intensive Industry Rate

16.4 MH's Revised Position

While the Board and Interveners had the opportunity to explore the strengths and weaknesses of MH's proposed rates for new or expanding industrial load, so too was MH afforded the opportunity to continue to consider the issue.

During the proceedings, MH advised the Board and all parties that MH would not seek, through the GRA hearing, approval of the proposed energy intensive industry rates. Rather, MH indicated that it wanted an opportunity to review the information provided through the GRA process and have further discussions with its large industrial customers.

And, following further consideration and discussions, MH advised that it "..... may well refile or refine [its] proposal once the new hearing date is set and the process is established".

MH further advised that its request of the Board related to this issue, flowing from the GRA, would be for the Board to endorse in principle, the end date of December 31, 2007 for the setting of any baseline that may relate to a new rate for energy intensive industry. By the Board endorsing the date of December 31, 2007, as the end date for establishing a baseline, MH wants to put customers on notice for their planning purposes.

16.5 Service Extension Policy

In June 2005, MH suspended a long standing service extension policy which provided that MH would invest up to three times the anticipated annual revenues on facilities required to strengthen or extend the common grid to service customers (not including dedicated facilities). MH did not seek Board approval of this policy suspension.

16.0 Energy Intensive Industry Rate

MIPUG has suggested that the suspension may not be valid, or at the least, requires Board approval. Furthermore, MIPUG requested consideration should be given to refunding the costs incurred by customers due to the suspension.

16.6 Interveners' Positions

The Coalition

New and Expanded Load

The Coalition attributed the pressure on MH's load growth to load growth related to electricity intensive industry, and noted that load growth for electricity intensive industry for the next five years was projected to amount to 57% of the total load growth.

The Coalition stated that large energy intensive industry has been attracted to Manitoba on a scale large enough to threaten the Corporation's revenue position. Coalition noted that in the short-term this would impact by loads being diverted from the export market. In the long-term, for the Coalition the impact would not only be load diverted from the export market but also the implications of advancing costs in terms of new Generation and Transmission.

Energy Intensive Industry Rate

With respect to the energy intensive industry rate base line exemption criteria, the Coalition raised concerns with the MH's proposed dispute resolution process, which would come into effect in the event that there was a dispute with the establishment of the baseline or the granting an exemption between the Corporation and an industrial customer.

The Coalition held that if exemptions are to be granted they should be brought before the Board or be testable in some public forum. The Coalition opined that

16.0 Energy Intensive Industry Rate

transparency is important because, to the extent exemptions are granted, there will be an impact on customer bills. The Coalition suggested MH address this issue when it refilled its proposal.

MIPUG

New and Expanded Load

MIPUG rejected MH's premise that new and expanded load from industry negatively affects all other customer classes, and held that such a premise would compromise in a material way fundamental ratemaking principles.

MIPUG stated that, should MH propose this ratemaking premise in future hearings, more detailed and comprehensive analysis is required. MIPUG contended that the Board will only be in a position to rule on such an important issue if it is presented with detailed analyses of both the expected short-term and long-term implications of the measure.

MIPUG contends that in the short-term, and due to export tie-line constraints, MH's ability to export additional power at times of high export prices is limited, and, as such, industrial load expansion would result in only minor impacts on MH's revenues over the short-term. Over the long-term, and in an era of expansion, MIPUG contends that the benefits arising from developing assets sooner should be included in the analysis, to allow the Board to properly assess the impacts that increased domestic loads have on long-term rate levels.

With respect to the Service Extension Policy, MIPUG opined the Utility neither had the authority nor should have suspended the policy without Board approval. Furthermore, for MIPUG, consideration should now be given to refunding costs that were disallowed by MH's unilateral suspension of the policy.

None of the other Interveners pursued this issue.

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Energy Intensive Industry Rate

MIPUG accepted that MH had withdrawn its new industrial rate proposal and planned to refile an application, and that there is, therefore, no need for the Board to comment on this issue at this time. MIPUG stated that the Board should not set a date for the Corporation to return with its application, to allow MH to “take the time it needs” to properly support its proposal.

With respect to MH’s proposed date of December 31, 2007 to establish a baseline for energy intensive industry rates, MIPUG’s view was that the only benefit of establishing the baseline at that date would be to prevent “gaming” (i.e. new load being “rushed into service” ahead of a new rate and class being established). MIPUG’s view was that the baseline should not be based on that date as other measures can be used to prevent “gaming”, if and when a new rate and rate class was ultimately adopted.

MIPUG stated that the level of consultation with affected stakeholders should be commensurate with a rate proposal of this magnitude, and that the Corporation should take the time it requires to consult with the businesses and communities that may be affected by its proposal.

MKO

New and Expanded Load

MKO submitted that charging higher rates to new energy intensive general service customers would increase MH revenues and potentially provide for lower rates for all customers and greater “dividends” to the Manitoba government.

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Energy Intensive Industry Rate

With respect to the energy intensive industry rate base line exemption criteria, MKO limited its comments to its view of the rate design principles that should be considered by MH in setting an energy intensive industry rate.

Firstly, MKO submitted that the proposed energy intensive industry rate violates several fundamental rate design criteria in that having such a rate would result in the charging of different rates to similar customers, and that the implementation of such a rate should only be done after the Manitoba government has set and communicated clear policy direction that such a rate is in the best interests of Manitoba.

Secondly, MKO advised of its concern that the proposed rate design will have a fixed implementation date that could “create a price cliff and intergenerational inequities”.

Thirdly, for MKO, the proposed energy intensive industry rate will differentiate customers based on “who” should receive net export benefits and “who” should not. MKO expressed a concern that MH would be “moving away” from the fundamental principle that all MH customers, including diesel community customers, should share the net export benefits, and that such a move may be a dangerous precedent and a decision to proceed with MH proposal should not be taken lightly.

Fourthly, MKO advised of a concern that the proposed rate will only apply to the large general service customer class. MKO submits that limiting the rate to one customer class violates standard rate design principles. MKO suggested that if limiting the sale of electricity to new energy intensive industry customers is a policy objective of the Manitoba government, then a more appropriate mechanism should be used instead of altering MH’s rates.

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RCM/TREE

New and Expanded Load

RCM/TREE submitted that Energy Intensive Industry load growth will have a significant impact on MH's other customers, and that MH's load growth continues to exceed past projections with negative impacts on MH's finances, customers and the environment.

RCM/TREE further opined that MH may face energy shortages in 2009 to 2011, due to accelerated load growth.

Energy Intensive Industry Rate

RCM/TREE observed MH has acted on the energy-intensive industry issue by proposing a new rate for the general service large category. RCM/TREE also noted that the complexities of the proposed rate calculation are subject to consideration by the Board in a subsequent hearing.

Mr. Chernick suggested that MH's industrial rate proposal and exemption criteria were flawed, in that:

- a) the baseline consumption level proposed was too high; and
- b) the proposal allowed the baseline to increase to cover large amounts of increased load, with a total growth allowance of up to 39 GW.h (to qualifying companies).

Mr. Chernick noted that under MH's proposal if the industrial customer exceeded its baseline, the baseline in future years would be increased, so that marginal cost based rates would apply only in the first year of the load growth.

With respect to the proposed exemptions and/or discounts for economic development (payroll and taxes), Mr. Chernick suggested these would be the

16.0 Energy Intensive Industry Rate

“wrong mechanism, implemented by the wrong entity”, and would not be properly designed to meet the targeted objective, in that the discounts would destroy the conservation incentives of marginal-cost pricing and the computation of the cost of additional load would fail to count the environmental costs of reducing exports, and the lost benefits of the export revenues while new loads would be eligible for exemptions, regardless of the efficiency of the equipment and process installed.

Mr. Chernick stated that the baseline proposed to be established was too high and that the base usage for which a customer would be charged embedded rates should be less than a fixed historical base usage, such as the maximum annual usage in 2005-07 as proposed by MH. For Mr. Chernick, the base usage might better be set as 95% of the historical value in 2008, falling by 2% or so each year thereafter and with no future growth allowance.

Mr. Chernick stated the growth allowance eliminates any efficiency incentive provided by MH's proposal, and that “the only qualification for the growth allowance appears to be that the customer's load is less than 78 GW.h”. Mr. Chernick opined that this proposed provision appears to eliminate any efficiency incentive for any customer adding less than 39 GW.h.

Mr. Chernick did not agree that incentives for economic development (exemption from the new rate due to economic development considerations) should be included in MH's rate structure. For him, the allocation of incentives should be the responsibility of an agency of the Manitoba government, not MH.

Mr. Chernick further suggested that if the Board were to want to use some of MH's revenues to support economic development; it should designate an amount to be collected and then direct that sum to be paid to the designated economic development agency, which should then decide which development projects are desirable and economically efficient.

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Mr. Chernick suggested that revenues for economic development can be collected from the higher blocks of inclining-block rate structures, and that this proposal for the collection and disbursement of economic-development incentives would retain marginal-cost pricing for industrial rates, for both new and expanded loads, while not burdening MH with an economic-development role for which it has no special expertise or mandate.

RCM/TREE stated that each GSL customer should be charged the embedded energy rate for usage up to a baseline, and that marginal cost, including environmental costs, should be charged for consumption above that level. For Mr. Chernick, new general service large customers should be charged entirely at the marginal energy rate.

RCM/TREE proposes that the Board direct MH to participate in a collaborative effort with interested parties to determine if there are areas of agreement for the design of a new industrial rate proposal, and agreed with MH's proposal to fix December 31, 2007 as the end date for determining baseline levels.

16.7 Board Findings

Energy Intensive Industry Rate

The issue of the fairness of embedded cost rates being considerably lower than marginal costs or marginal values of energy, and the potential financial impact on the Utility, is not unique to Manitoba. The Board understands that other jurisdictions have, and continue, to face this issue.

And while the issue, in its basic form, exists for each new or expanded load by any customer, the financial implications of expanded load are magnified in the case of industrial customers.

16.0 Energy Intensive Industry Rate

While how best to address the issue in Manitoba remains an open question, one that will be pursued at a subsequent proceeding following MH's expected refiling of an application for a new industrial rate, it is an important issue that the Board is deeply interested in.

MH proposed a calculated rate for energy consumed above a baseline level, with that rate comprised of a marginal value of generated energy based on a "normalized" forecast of export values (i.e. 5.58¢ per kW.h), together with a marginal cost of transmission based on avoided costs (i.e. 0.816¢ per kW.h).

There was neither a marginal cost nor a marginal value for distribution included in MH's proposed new energy-intensive rate, this, because general service large customers have only nominal use of MH's distribution assets. The energy rate to recover the marginal cost, as proposed by MH, was also adjusted by the current demand charge of 0.740¢ per kW.h, providing for a proposed rate for new or expanded load for GSL > 100kV customers of 5.656¢ per kW.h ($5.58 + 0.816 - 0.740 = 5.656$).

While the Board appreciates that MH is not asking for approval of the energy-intensive rates at this time, the Board is concerned about the use of forecast export prices (as opposed to actual export prices) in the determination of marginal costs, and encourages MH to explore and advance other options for consideration at the separate hearing into this rate matter.

To explore other options and to avoid some of the concerns with the current calculation of an energy intensive rate, MH should consider:

- Baseline and growth allowance, and whether new industry coming to Manitoba [and existing industry] should get any growth allowance at heritage rates;

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- Using data that is transparent and available to all customers and is not protected by a claim of confidentiality. The Board does not accept the bid for confidentiality when the information is publicly available from other industry or regulatory sources;
- Including time-of-use alternatives and variations to reflect the different values of energy at different times;
- Keeping the overall implications for revenue requirement neutral. The Board does not consider MH's proposal revenue-neutral as presented in MH's filed Proof of Revenue and IFF; and
- Perhaps including a marginal cost component or signal in rates for all classes, not just GSL. MH has identified that over the past ten years, more than 50% of the growth in Manitoba industrial loads is attributable to expansions in the electrochemical processing industry, an industry in which 70% of the costs can be incurred for electric energy used for processing purposes. The other major energy-intensive industry load (forecast by MH to significantly increase) is the pipeline compressor load.

A question to be considered is whether these specific industries should be targeted, or whether the concern is best addressed across the entire class, or perhaps all classes, served by MH.

Therefore, for the special hearing, MH will be expected to provide options, including its preferred option. The Board notes that MH may change its preferred option from what was presented at the GRA.

Export Contracts

MH should be required to reconcile its proposed treatments of energy-intensive industries with existing and proposed export contracts. Export sales do not

16.0 Energy Intensive Industry Rate

create any direct or indirect Manitoba employment in the sense that domestic industry does.

It can be argued that MH should be pricing energy for domestic industry at average export price minus appropriate credits for direct and indirect job creation. While this might be difficult to administer, it would reward job creation and economic values input to Manitoba.

Further to the above, it would appear that the proposed energy-intensive rate may well discourage the further growth of existing industries. For example, if an industry added work shifts it would attract substantially-higher energy prices, in addition to shift premium payroll costs, even though this growth might well be employing off-peak energy (that being of low value as an export product).

TOU rates would significantly reduce the cost to industry for such expansion, and MH could benefit by gaining more value for its off-peak energy.

Time of Use (TOU) Rates

MH has suggested TOU rates will be considered after the new intensive-energy rate is implemented. This approach avoids addressing the issue of uneconomic exports and the considerable differences in domestic customer energy usage patterns. The Board, while recognizing that the implementation process for TOU may be protracted, believes that TOU should be built into the initial concept for the new rate.

In addressing confidentiality issues, MH has suggested that there is sufficient publicly-available information for the Board and Interveners to make informed judgements on the validity of MH's marginal cost forecasts. This information (sources: SEP/NEB/etc.) should also allow MH to define time-of-use pricing on a conceptual basis for Board consideration in the new rate design.

16.0 Energy Intensive Industry Rate

MH has acknowledged that TOU billing could have favourable revenue results for the utility in most years. On the other hand, TOU rates should provide an opportunity to industry to optimize its energy usage and thus benefit from TOU rates.

Marginal Cost Values for Export

MH's case for increased rates to energy-intensive industry assumes that all energy used by industrial growth could alternatively be sold as peak market exports. Contract prices (generally below peak market values) apply during low flow years; only part of the exports achieve better than contract prices in average flow years, and surplus energy prices tend to fall below contract prices in high flow years. In light of the transmission tie-line constraints, the Board questions MH assumptions on the relative value of export sales and domestic load growth during the off-peak period.

Accordingly, the Board directs MH to provide an in-depth analysis of the value of peak versus off-peak energy sales into the MISO market.

MH also employs an element of avoided costs in determining the marginal cost of energy to be employed for intensive-energy usage rates. This would be appropriate if MH was actually contemplating deferral of new generation or transmission on the basis of reduced domestic load growth. In reality, MH is advancing new generation and transmission to meet new export contract sales now under negotiation.

he Board directs MH to report on the specific deferral values that could be achieved by constraining industrial load growth.

16.0 Energy Intensive Industry Rate

Consumption Baseline

In defining the new intensive-energy rate and by its application, MH focussed on industrial customers using more than 39 GW.h of energy per year. However, the proposed rate schedule provided marginal cost second block rates for all GSL customers.

In the Board's view, MH should have provided the impact analysis for all GSL customers, in order to justify the proposed 39 GW.h floor for new rate exemption. Accordingly, the Board directs MH to provide an analysis for all GSL customers, to justify the 39 GW.h floor for new rate exemption, and to report on the potential extension of the rate and or lowering of the threshold.

Fairness Principles

There was at least a sense of a degree of consensus from all parties that selling energy domestically at prices well below the average export market value is an issue that must be addressed. Beyond that, the Interveners were quite divided on what is a fair price level and who should pay the higher price if there is to be one.

Currently under the COSS, all domestic customer classes are allocated about 3.0 to 3.5¢/kW.h in costs for generation and transmission. Some customers pay more and others pay less than their allocated costs. No class pays the average export market value. The issue is further distorted because different classes are allocated varying amounts (zero and upward) for local distribution services. The Board will be looking to reconcile the current rate proposal with cost causation principles.

16.0 Energy Intensive Industry Rate

Service Extension Policy

It would appear that the policy (pre-2005) was intended to support industrial expansion in areas of the Province that did not have access to 30 kV or greater power. The scale of the investments incurred and revenues gained under this policy were not identified at this hearing. MH did not carry out a detailed feasibility test prior to suspending the policy; for the longer term, and in light of the proposed new energy-intensive rate, that policy may be reconsidered by MH.

The Board considers that the service extension policy logically falls under the Terms and Conditions that are generally believed to be integral with rate setting. Without reaching a conclusion on legal jurisdiction at this time, the Board will direct MH to file an economic feasibility test report with the Board on September 30, 2008, on the historical application of the service extension policy. In that report, MH is to define the underlying rationale for the existing policy, as it existed and explain why that rationale apparently no longer exists, together with an accounting of instances since the policy was suspended where customers paid more to have a service connection than other previous customers.

17.0 Presenters' Positions

17.0 Presenters' Positions

17.1 Mr. Ciekiewicz

Mr. Ciekiewicz's view is that the March 31, 2007 interim rate increase was not justified because it was prompted by the occurrence of only a short period of low water levels in 2005/06, rather than the "long established method" of using longer periods of time to set rates.

Mr. Ciekiewicz also indicated that MH's proposed residential rate increase, and the approach the Corporation used to develop its inverted rate structure proposal penalizes home owners who are dependent on electrical heating, and/or have converted to electrical heating. He was concerned that all-electric rate-payers will face an increase greater than the rate of inflation. He argues that those who do not have the option of other fuel sources for heating should get a rebate, rather than an increased rate. As well, he predicted that inverted rates will result in heating choices by rate-payers that are not friendly to the environment.

Mr. Ciekiewicz was also concerned that it is the nature and length of the firm export contracts that constitutes the main risk affecting the financial well-being of MH, and that in years of drought the costs associated with fulfilling firm export commitments could wipe out the retained earnings.

He opined that the Board has jurisdiction over MH's export contracts, by way of section 47 of *The Public Utilities Board Act*. He recommended that the firm export contracts negotiated by MH include clauses that the contracts can be cancelled in the event of drought conditions, or that certain incentives on export prices be included in the contracts as a concession to the export customers for this cancellation clause.

Mr. Ciekiewicz also challenged the meaning of firm contracts as interpreted by MH, he based his challenge on a definition from the North American Electric

17.0 Presenters' Positions

Reliability Corporation that implies that the obligation to provide power ceases when the "system reliability is threatened, or during emergency conditions".

Mr. Ciekiewicz also questioned MH assertions that the incremental costs of new office building over the efficiency savings will be cost neutral, and never affect rates. He did not accept that the \$278 million price tag for the new head office will not adversely affect retained earnings, and by extension, rates.

Mr. Ciekiewicz was unclear as to whether NCN will be liable for one-third of any losses that may materialize if a future drought prevents MH from meeting its export sale commitments, and sought to have the issue clarified.

Mr. Ciekiewicz made reference to what he termed contradictory responses from MH on some Information Requests with respect to the Brandon Coal Fired Thermal Generating Station Unit 5. One apparent contradiction cited appears that MH has stated that the closure of the Unit 5 would result in firm energy deficits in 2013 to 2025 and would reduce the surplus available for export, while MH stated elsewhere in its responses to interrogatories that the thermal plants were not constructed to support export sales. Another contradiction in MH responses noted by Mr. Ciekiewicz was that MH stated in one Information Request that Unit 5 produces an average \$20 million to \$30 million in net income per year, while the Corporation's response to another Information Request stated that MH does not calculate the annual revenues or net income for the unit.

17.2 Mr. Forrest

Mr. Robert Forrest provided an electronic submission; he indicated opposition to MH's proposed rate increase.

17.0 Presenters' Positions

Mr. Forrest stated that rates were already too high and that the current increase was not justified because MH had reported in the news a large surplus and that an increase had already been granted.

17.3 Mr. Rader

A written presentation in the form of a letter from Mr. Robert Rader, Managing Director, Koch Fertilizer Canada, Ltd., to Mr. Bob Brennan, President and Chief Executive Officer, Manitoba Hydro and to Public Utilities Board, dated February 11, 2008 was read into the record of the proceeding.

Mr. Rader made reference to the document entitled General Service Large – New or Expansion Rate Baseline Energy Consumption Level and Exemption Application Discussion Paper. He did not agree with the proposed annual growth allowance of GW.h, and recommended the growth allowance be a percentage of the base versus a fixed number.

Mr. Rader also recommended that expenditures made to reduce energy consumption should be credited at 100% rather than the 50% contemplated in the document.

Mr. Rader also stated that while his company may expand its production volume without increasing its payroll, it would still be providing secondary benefits to truck and rail companies, and that such economic benefits should be taken into account in considering exemptions from any new industrial rate.

17.0 Presenters' Positions

17.4 Mr. Svidal

Mr. Kaare Svidal is the manager of the Energy Management Group of Enbridge Pipelines, and he stated that MH had made presentations across the province on the proposed new industrial rate, and that in these presentations MH had indicated that pipeline companies provide very little economic benefit to the province. He disagreed with MH on that issue, and argued that Enbridge has provided considerable value to Manitoba in the last 58 years.

He stated that Enbridge pays annual salaries of \$5 million to Manitobans, and \$7 million of annual property taxes in the province. He also noted that Enbridge benefits industry in Manitoba in that it delivers all the refined products to Manitoba in a reliable and economical way.

He also noted that the growing Manitoba oil producing industry, which generated \$400 million in capital expenditures in 2006, relies on Enbridge to deliver their product to US markets.

He pointed out that Enbridge is a long-term financially stable A-rated base load customer of MH whose continued presence in Manitoba is required to justify the MH infrastructure in place today. He reminded the Board that his firm had switched from diesel to electrical pumping stations in 1965 at the request of the government of Manitoba, and that Enbridge was a long-term and committed customer of MH.

17.5 Mr. Turner

Mr. Bill Turner is plant manager of Canexus Chemicals at Brandon and the Chairman of MIPUG. He indicated that low-cost electricity is necessary for industry to remain competitive in Manitoba because it offsets existing geographic,

17.0 Presenters' Positions

climatic and other disadvantages of locating in this province, disadvantages that also include higher taxes and a growing foreign exchange problem.

Mr. Turner stated that MIPUG members pay rates that are 8% greater than the cost to MH of providing the firms the electricity they consume; MIPUG member firms were reported to consume 5,000 GW.h. annually at a cost in excess of \$150 million.

Mr. Turner further advised that MIPUG members employ 4,500 Manitobans, and that the association's membership have capital assets employed in Manitoba greater than \$2 billion. Mr. Turner also stated that 90% of MIPUG members' sales were exports.

Mr. Turner indicated that the new industrial rate is a new policy direction from MH with major implications for the use of energy and the development of industry within the province. He expressed frustration that the discussion meetings between MIPUG and MH on this issue were ineffectual, and that the discussions were not open and transparent. He expressed concern that the Province of Manitoba has not participating directly in the new industrial rate discussions, and stated his view that the Province may be poorly informed on the issue.

He suggested there will be far reaching impacts if the new industrial rate is adopted, in particular to the employees of affected companies and their families, and to rural and northern communities in which the firms are located.

Mr. Turner explained that with respect to his company, Canexus, 60% of the firm's manufacturing costs are for electricity (\$48 million annually). He stated that 100% of his firm's product is exported, with 95% going to the US. Mr. Turner noted that the recent strengthening of the Canadian dollar had resulted in major income losses for Canexus.

17.0 Presenters' Positions

He stated that his company has 6 plants in other provinces and one in Brazil, and that when the firm is not required to operate at full capacity, the firm will operate the factories with the lowest electricity cost. He also pointed out that his company is one of MH's largest DSM participants.

Mr. Turner stressed that companies such as Canexus require stability and certainty in electrical rates in order to make sound business decisions as to where they locate. He indicated that his company relocated a plant from Louisiana to Manitoba in 2004, at a cost of \$55 million, because of electrical rates. He stated that further expansion plans are now being reconsidered due to the uncertainty of rates in Manitoba over the last 3 years.

He further stated that through his association with various industry groups, that business in general is concerned with the new industrial rate issue. He declared his disappointment that MH has stated that sodium chlorate companies and pipelines provide very few economic benefits in this province, and he advised of benefits being provided to the people of Brandon and the related construction trades.

18.0 Board Recommendations

18.0 IT IS THEREFORE RECOMMENDED THAT

1. MH seek independent advice as well as advice from government and its credit rating agencies as to the merits of a possible elimination of the sinking fund requirements;
2. The Board remains concerned with the Corporation's ongoing aggressive deferral and capitalization accounting practices, and recommends that MH consider an early adoption of IFRS standards. The Board further recommends that both the Board's prior concerns and current views, as expressed in this Order, be brought to the attention of both MH's external auditors and its independent consultant assisting the Corporation with its IFRS transition strategy;
3. Because of the current and future impact on rates of the unprecedented capital program and related tentative export sales contracts, the Board repeats its recommendation to government that *The Public Utilities Board Act* be amended to make the Board's regulation of MH equivalent to the Board's regulation of Centra Gas, by removing the exemption now provided under Section 2(5) of the Act;

Or alternatively, the Board recommends that government renews the mandate provided to the Board in 1990 (via OIC 1990-177), a mandate that provided for a detailed and comprehensive integrated review of MH's Major Capital Projects in light of pending export commitments (then-covering the period 1990 to 2009). Such an updated mandate would allow for a similar review covering the period 2009 to 2028;

4. Because of the impact (and potential impact) on consumer rates, the Board recommends MH seek the Board's prior review and approval of

18.0 Board Recommendations

future agreements involving the joint ownership of Generation and Transmission assets;

5. With respect to DSM and Low-Income Energy Efficiency Programs:

- a) MH accelerate its DSM plans to achieve targets earlier than presently scheduled, and at the same time, consider changing its accounting approach to one that provides for the amortization of DSM costs over a period no longer than five years;
- b) MH to continue to pursue environmental objectives on an integrated natural gas electricity basis, and in particular, to consider the position of low-income customers increasingly faced with higher energy costs and too often lacking the funds and know-how to achieve needed upgrades that would reduce their energy bills and GHG emissions;
- c) MH undertake changes to its furnace replacement program so as to increase low-income household participation in the early replacement of inefficient natural gas furnaces. Changes to the program, as recommended by the Board by way of Order 99/07, would better provide this opportunity and should provide energy savings for low-income customers and significant non-energy benefits to society (reduced GHG emissions), the Utility (in the form of less risk of the conversion of natural gas space heating to space heating by electricity), as well as to all participants in the program;
- d) MH incent landlords to participate in the low-income DSM program, to improve the energy efficiency of their properties for the benefit of their tenants and the environment;

18.0 Board Recommendations

- e) MH expand finance options for low-income customers, including subsidized Power Smart loans for the furnace replacement program, with an option either requiring repayment on the sale of the residence or, alternatively, a 10-year lease financing program as suggested by Mr. Dunsky;
6. The Board recommends government consider:
- a) Seeking from the Federal government an exemption from GST for residential customers for space heating, as heat in Manitoba in winter is a necessity like food; and
 - b) Funding low-income and DSM programs, by setting aside all or a portion of provincially and or municipally-sanctioned sales taxes charged to residential customers on energy used for heating purposes.
7. The Board recommends government consider establishing a separate entity to manage the Corporation's DSM and low-income initiatives. The Board concludes that MH's full energies and focus should be placed on the effective implementation of its long-term expansion plans toward meeting the demand for electricity and natural gas to develop over the next few decades. The Board can envision MH establishing aggressive goals for the reduction of domestic energy consumption for such a new entity to meet or exceed, together with providing adequate funding to meet those goals (energy conserved is energy available for export).

19.0 Board Directives

19.0 IT IS THEREFORE ORDERED THAT:

1. MH file with the Board, MH's 2007/08 Annual Report, with audited financial statements, immediately after the Corporation meets its statutory filing requirement with respect to the Legislature;
2. With respect to MH's export program, MH to file a report with the Board by January 15, 2009 on the following:
 - a) Overview of strategy, options, historical costs and revenues;
 - b) Monthly historical export prices for the last five years, disaggregated for both peak and off-peak periods;
 - c) Existing and pending export contract commitments, with annual forecast revenues both aggregated and also disaggregated (in confidence if necessary);
 - d) Forecast export revenues until 2028, identifying opportunity sales distinct from firm contract sales and broken down by peak/off-peak;
 - e) Detailed assumptions used in export market price forecasts (filed in confidence if necessary). MH to resubmit its export pricing forecasts to reflect recent realities of market prices and exchange rates;
 - f) A testing of MH's assumptions through detailed sensitivity analyses for upper/lower quartile water flows, foreign exchange, domestic load growth and natural gas prices; and
 - g) Given the crucial nature of the Corporation's export contracts and assumptions, with potential impacts on domestic rates, MH file for Board review all proposed export contracts;

19.0 Board Directives

3. MH to provide the Board with:
 - a) Specific quarterly reports on energy supplies (including imports), domestic demand, and export sales (e.g., similar to NEB volume and price data); and
 - b) Annual reports on the LUBD Program performance;
4. MH to provide the Board an independent assessment of the Corporation's relative weighting of fixed vs. floating debt, and file a report with the Board on or before June 30, 2009 ;
5. With respect to IFRS, the Board requires MH to file on or by January 15, 2009 :
 - a) A report explaining and quantifying the proposed transition to IFRS;
 - b) A copy of MH's consultant's report indicating the projected impact of the adoption of IFRS on the Utility, specifically with respect to MH's current deferral and capitalization approaches, and as to the likely status of goodwill now recorded in its accounts;
 - c) An articulation of the new proposed MH accounting policies detailing how they comply with IFRS;
 - d) An explanation of any changes to the internal operations of MH which may be planned or contemplated to offset any increased annual expenses expected as a result of the adoption of IFRS, together with MH's and its consultant's views of the Board's regulatory options, including a review of the pros and cons of special purpose financial reporting for utilities for rate setting purposes; and

19.0 Board Directives

- e) An updated IFF and CEF (covering the years 2008 to 2028) reflecting the expected impact of the new standards and assumptions of related operational changes as may be planned or contemplated by MH;
6. MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most currently-available data and including:
- a) Primary key drivers of OM&A in each operational division [Board preference is for a divisional break-down to allow for a comparison with other utilities, even if the comparison needs to be limited to specific divisions/activities],
 - b) Comparable other Canadian Utility data for each of the drivers;
 - c) Key comparison indicators, including staffing levels;
 - d) A comparison with and discussion of industry best practices; and
 - e) Potential improvement areas.

The Board expects to be apprised of the scope of the benchmarking study in advance of it being undertaken, and will anticipate being provided a study outline on or before January 15, 2009, to allow the Board the opportunity to provide direction and/or comment.

7. MH to undertake and file with the Board an Asset Condition Assessment Report by June 30, 2009, that defines:
- a) major assets and categories of assets;
 - b) the estimated remaining economic life of each major asset and category of asset;
 - c) an indication of the implications for OM&A costs related to required and scheduled maintenance;

19.0 Board Directives

- d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;
- e) forecast expenditures for planned renovations and/or replacements with respect to now available energy supply and transmission; and
- f) Dam Safety Condition Assessment and Maintenance requirements.

In advance of the commencement of the Asset Condition Assessment Study, MH to file with the Board detailed Terms of Reference containing the scope for undertaking such a study and a definition of the resources to be employed, on or before January 15, 2009.

- 8. MH to file a report with the Board by June 30, 2009 detailing the final all-inclusive capital cost of the corporate head office project (including such things as construction cost, furniture and equipment, telecommunications, equipment leases, etc.), and the contemplated or planned operating actions to recover incremental costs related to the new head office. (The Board reaffirms that no additional incremental costs are to accrue or be allocated to Centra as a result of the new MH head office.)
- 9. MH to file a report with the Board by January 15, 2009 indicating:
 - a) whether the current depreciation rates for the Generation, Transmission, Distribution and other assets purchased from Winnipeg Hydro [including Slave Falls] and the Brandon Coal Plant remain appropriate; and
 - b) the related proposed capital replacement, expansion and decommissioning costs;

19.0 Board Directives

10. To gain a further understanding of the implications of the capital expenditures now contemplated, MH is to file with the Board by January 15, 2009 :
 - a) An updated Capital Expenditure Forecast, and Integrated Financial Forecast covering the fiscal years 2007/08 to 2027/28;
 - b) An updated Power Resource Plan covering the years 2008 to 2028. The updated Power Resource Plan should provide alternative scenarios with/without implementation of the pending new export contracts and related capital spending. The report should also indicate the remaining feasible hydro generation opportunities, following Wuskwatim, Keeyask and Conawapa, where and what possible quantity of energy would be expected, and the assumed development timeline; and
 - c) An updated Load Forecast covering the fiscal years 2007/08 to 2027/28; the Load Forecast should reconcile projected and actual DSM savings;
11. The Board will direct MH to propose to the Board on or before January 15, 2009 the terms of reference for a regulatory review of MH's planned Capital Program and its impact on consumer rates;
12. MH to prepare a study, and file it with the Board by January 15, 2009, a thorough and quantified Risk Analysis, including probabilities of all identified operational and business risks. This report should consider the implications of planned capital spending and take into account revenue growth, variable interest rates, drought, inflation experience and risk, and potential currency fluctuation;

19.0 Board Directives

13. MH to file by September 30, 2008, for Board approval, a conceptual outline for an in-depth and independent study of all the operational and business risks facing the corporation set out in the previous directive (12);
14. MH to provide the Board, by June 30, 2009, recommended risk mitigation measures and a review of possible suitable capital structures, given the capital expansion now planned or contemplated, with risks quantified;
15. MH to provide the Board by June 30, 2009, a summary of existing programs and potential future programs defining the arrangements for increased or modified (augmented) water flows within and external to Manitoba. The summary should include the specifics of each program and mitigation and compensation related thereto;
16. MH to submit a report to the Board on January 15, 2009 on the 300 MW of additional wind energy project(s), with a discussion of the business case, general wind strategy, prospects and timelines for the project, as well as with respect to the prospect for a further 600 MW consistent with the government's identified longer-term target of 1,000 MW of wind energy. The Board will also require access to the agreements for the existing 100 MW St. Leon wind project, and an opportunity to review the pending agreements for the 300 MW project(s);
17. MH report to the Board before June 30, 2009, as to whether there are greater global environmental (GHG) and economic benefits to be achieved by exporting hydraulically-generated electricity than would be achieved by fuel switching (from natural gas to electricity) and/or

19.0 Board Directives

geothermal within Manitoba. The report should address and clearly define the relative environmental and economic benefits of these exports. The overall assumptions and impacts on the Load Forecast should also be included in the report;

18. With respect to low-income programs, MH to prepare and report on the following:

- a) MH to consult with stakeholders on its enhancements to its low-income programs to ensure it adequately addresses low-income needs, and to report to the Board by September 30, 2008 on the results of the consultation and subsequent development of and implementation of this program;
- b) MH to provide an update on the status of the current natural gas furnace replacement program (including actual and forecast take-up rates), as well as reports of possible changes to the program relative to the suggestions put forward by Mr. Dunskey, on or before September 30, 2008;
- c) MH to meet with MKO and representatives from the diesel communities to discuss the issue of the access of those communities to MH's low-income programs, and to report to the Board on the outcome of these discussions on or before September 30, 2008;
- d) MH to propose for Board approval (as soon as possible but no later than September 30, 2008) a low-income bill assistance program, where such a program would occur in conjunction with and complimentary to an expanded low-income DSM program;

19.0 Board Directives

- e) MH to file with the Board on or before June 30, 2009 a draft plan, with projected implications, to increase the Corporation's integrated (natural gas and electricity) energy-efficiency initiatives with respect to low-income households, so as to allow for reduced energy consumption for all such households within a decade;
- f) MH to report back to the Board on the potential for a low-income and a general refrigerator replacement program, and provide the merits of such programs, on or before June 30, 2009; and
- g) MH to accrue interest on the AEF balance, to ensure additional funds are available to fund expanded low-income energy efficiency programs and to avoid the loss of "purchasing power" of the AEF due to continuing inflation;

19. MH to refile the COSS by January 15, 2009 on the following basis:

- a) As defined by Order 117/06;
- b) Incorporating diesel and exports in the same fashion as other domestic customer classes;
- c) The assigning of 50% fixed and 100% variable thermal plant costs to the Export class;
- d) Assign DSM cost directly to export class and add DSM energy savings to domestic load for Generation cost-sharing purposes;
- e) Use the most recent actual [not forecast] export prices to establish export revenue in the COSS; and
- f) Use actual [eight year] energy [SEP] prices and energy use profiles in Generation energy weighting process;

19.0 Board Directives

20. MH to provide and file with the Board by January 15, 2009 a revamped Marginal Cost (MC)-COSS analysis, one reflecting needed refinements to generation, transmission and distribution marginal costs. This should include specific demonstrations of how alternative MC adjustments could be applied to an embedded COSS. Among the scenarios to be explored, MH should consider the addition or blending of marginal costs to embedded costs prior to comparison to class revenues;
21. MH to file all appropriate data [e.g. SEP/ NEB/ MISO clearinghouse information and avoided cost information etc.] required for input to the marginal cost determinations for generation, transmission and distribution and to further define the key assumptions employed by MH in support of this process, with the Board [on a confidential basis if necessary] on or before September 30, 2008;
22. MH to provide a planned implementation strategy outline by September 30, 2008 for TOU Rates as appropriate to the classes with required metering technology already in place. Alternative rate strategies should be included for consideration at the upcoming Energy Intensive Industry rate hearing;
23. MH file a plan by January 15, 2009 outlining the pros and cons of the various potential inverted rate strategies under consideration, and the MH-proposed course of action to address this issue over the next five years;
24. MH to plan to re-balance demand and energy charges on a revenue-neutral basis, and submit a 5-year transition plan for the Board's approval at the earliest of June 30, 2009, or the next GRA;

19.0 Board Directives

25. MH to continue with the consolidation of process of the GSS and GSM customer class consolidation, and provide the Board with a proposal by June 30, 2009 for a stepped-up program and a timeframe for completion;
26. MH to include in its future application to finalize the four interim Orders related to Diesel Rates, reports on:
 - a) the fairness of the rate approach with respect to non-senior government accounts (the Board is concerned that the rates restrict the economic development prospects for the communities and drive up service and commodity costs);
 - b) the efficacy of the current rate schedule for non-government accounts (data on aged accounts receivable, delinquency and bad debts together with the collection policies in place for the four communities will be required); and
 - c) the effects of the current approach to rates and consumption restrictions on the four communities, a detailed review of consumption levels and collection practice from the former Diesel communities that have been connected to the grid which will serve as a comparison; and
 - d) MH to report to the Board by September 1, 2008, as to the balances and status of the diesel zone accounts; to ascertain whether existing interim rates are fully recovering operational costs;
27. MH to provide a report to the Board by January 15, 2009 evaluating the Surplus Energy Program. The report should employ monthly historical data from 2000 to 2008 to analyze and compare the benefit and costs of the actual operation of the hydraulic generating system

19.0 Board Directives

pursuant to various less aggressive sales strategies. This report should address the relative merits of withholding surplus energy from sales at off-peak periods;

28. MH to file an economic feasibility test report with the Board by September 30, 2008, on the historical application of the service extension policy. In that report, MH is to define the underlying rationale for the existing policy, as it existed, and explain why that rationale apparently no longer exists, together with an accounting of instances (since the policy was suspended) where customers paid more to have a service connection than other previous customers;
29. With respect to an Energy Intensive Industry rate for new and expanded load, MH is to file an updated application with the Board on or before September 30, 2008. Such an application should include:
 - a) An in-depth analysis of value of on-peak versus off-peak energy sales into the MISO market;
 - b) A report on the specific deferral values that could be achieved by constraining industrial load growth; and
 - c) An analysis for all GSL customers, to justify the proposed 39 GW.h floor for new rate exemption, and report on the potential extension of the rate and/or lowering of the threshold;
30. MH to file before January 15, 2009, supporting information for Board review of the 4% April 1, 2009 conditional increase. In addition to the information identified above to be filed by January 15, 2009, MH is to include:
 - a) first ,second and third quarter 2008/09 unaudited financial results and statements; and

19.0 Board Directives

- b) an updated forecast of net income for 2008/09, reflecting existing water energy in storage conditions.

THE PUBLIC UTILITIES BOARD

"GRAHAM LANE, CA"

Chairman

"H. M. SINGH"

Acting Secretary

Certified a true copy of
Board Order 116/08 issued by
The Public Utilities Board

Acting Secretary

Appendix A

Appearances

R. Peters	Counsel for The Manitoba Public Utilities Board (Board)
O. Fernandes P. Ramage	Counsel for the Manitoba Hydro Electric Board (Hydro)
B. Williams	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc./Winnipeg Harvest (COALITION)
T. McCaffrey J. Landry	Counsel for Manitoba Industrial Power Users Group (MIPUG)
M. Anderson	Representing Manitoba Keewatinook Ininew Okimowin. (MKO)
W. Gange D. Rempel P. Miller	Counsel for Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
D. Buhr	Counsel for the City of Winnipeg (CITY)
J. Scott (np) T. Trull (np)	TransCanada Keystone Pipeline GP Ltd.
(np)- not present at the hearing	

Appendix B

Witnesses for Hydro

V. A. Warden	Vice-President, Finance & Administration and Chief Financial Officer
H. M. Surminski	Section Head, Generation System Studies, Resource Planning and Market Analysis,
K. R. Wiens	Division Manager, Rates & Regulatory Affairs
W. J. Derksen	Manager, Corporate Accounting
C. S. Thomas	Manager, Electric Rates & Regulatory Department
L. J. Kuczek	Division Manager, Consumer Marketing and Sales
I. S. Page	Manager, Financial Planning Department
W. Hamlin	Senior Energy Policy Officer, Energy Policy & Emissions Trading, Power Supply

Appendix C

Interveners of Record

1. Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors/Winnipeg Harvest (Coalition)
2. Manitoba Industrial Power Users Group (MIPUG)
3. Manitoba Keewatinook Ininew Okimowin (MKO)
4. Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
5. City of Winnipeg (CITY)
6. TransCanada Keystone Pipeline GP Ltd. (KEYSTONE)

Appendix D

Intervener Witnesses

Coalition

W. Harper

Manager, Econalysis Consulting Services, Inc.

P. Dunsky

President, Dunsky Energy Consulting

MIPUG

A. McLaren

Consultants, InterGroup Consultants Ltd.

P. Bowman

RCM/TREE

P. Chernick

President, Resource Insight Inc

S. Weiss (np)

Sr. Policy Analyst, NW Energy Coalition

Appendix E

Presenters

Mr. A. Ciekiewicz	Citizen
Mr. B. Turner	Chair, Manitoba Industrial Power Users Group
Mr. K. Svidal	Manager, Energy Management Group, Enbridge Pipelines
Mr. R. Rader (written only)	Managing Director, Koch Fertilizer Canada, Ltd.

TAB 7

MANITOBA
THE PUBLIC UTILITIES BOARD ACT
THE MANITOBA HYDRO ACT
THE CROWN CORPORATIONS PUBLIC
REVIEW AND ACCOUNTABILITY ACT

Board Order 7/03

February 3, 2003

Before: G. D. Forrest, Chair
R. A. Mayer, Q.C., Vice Chair
Dr. K. Avery Kinew, Member

**A FILING BY MANITOBA HYDRO TO PROVIDE AN INFORMATION
UPDATE REGARDING FINANCIAL RESULTS, FORECASTS,
METHODOLOGIES, PROCESSES, AND OTHER MATTERS
RELATING TO SALES RATES CHARGED BY MANITOBA HYDRO**

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Executive Summary

The Manitoba Hydro-Electric Board ("Hydro") filed a status update with The Public Utilities Board ("the Board") on November 30, 2001. The purpose of the filing was to provide the Board and interested parties with an information update on Hydro, including its financial results, forecasts, methodologies, processes, and events that have transformed the electricity industry over the last few years. Hydro was not seeking any general rate changes, stating that for 2002/03, rates will have effectively been frozen for six years for residential customers and for eleven years for large industrial customers, except for the rate reductions to certain consumers as a result of province-wide implementation of Uniform Rates on November 1, 2001.

Hydro last requested a general rate increase in the fall of 1995, followed by a public hearing in early 1996. The Board's decisions from that hearing are set out in Order 51/96. In light of the long passage of time since Hydro's sales rates were last reviewed in a public forum, the Board determined that one of the purposes of this hearing would be to determine whether the existing sales rates continue to be just and reasonable and whether any changes to existing sales rates may be required.

On February 8, 2002, Hydro announced its intention to acquire the assets and business of Winnipeg Hydro, which had approximately 570 employees and served about 94,000 customers in the City of Winnipeg. The acquisition may have a significant impact on the future overall operations of Hydro.

Hydro believes holding rates constant is a more prudent course of action than offering rate reductions because of the robust export markets and favourable water conditions, which underpinned Hydro's strong financial performance, may not continue at present levels. Rates at or near their current levels will assist Hydro in achieving its longer term financial objectives. Hydro also stated domestic rates are less than market prices in nearby interconnected markets. Current rates are, on average, the lowest of any utility in North America. Lower rates may encourage more domestic consumption, which would reduce revenues as profitable export sales are foregone. Hydro agreed, however, that lower rates could attract more energy intensive industry to the Province.

During the course of the public hearing, the Board examined a number of specific areas related to Hydro's operations including operating results and financial projections, financial targets and risk, capital expenditures, extra provincial revenues, payments to the Province of Manitoba, operating, administrative and finance expenses, transmission tariffs, load forecasts and overall revenue requirements. As a result of this review, the Board identified a number of areas of concern, and made a number of recommendations including:

- Hydro limit its capital expenditures not related to new major generation and transmission, where safety and reliability constraints allow, and focus on reducing long-term debt.
- Hydro pursue short-term financing options to expeditiously pay down the debt incurred for the special export profit payment to the Province of Manitoba.
- Hydro continue to monitor and control operating and administrative expenses.
- Hydro consider ways to diversify and supplement its hydraulic generation with an appropriate mix of other forms of energy.

In addition to the above recommendations, the Board directed Hydro to:

- File an updated Integrated Financial Forecast reflecting the integration of Winnipeg Hydro and the in-service dates of all new generation within the eleven-year planning period;
- File a detailed debt management strategy;
- Undertake a study to quantify specific reserve provisions required to cover major risks and contingencies;
- Undertake a study on the merits of implementing an inverted rate structure for all customer classes;

- Undertake a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge;
- Undertake a study which considers time of use rates for General Service classes based on a seasonal, weekly, daily, and hourly basis;
- Identify and specifically account for all export-related capital expenditures in its capital forecasts to ensure that export revenues are appropriately matched against the full cost of production;
- Undertake a study on the methods and impacts with respect to the classification of generation costs in the Cost of Service Study;
- Re-examine the current level of Demand Side Management programs and pricing strategies to encourage conservation, develop a program with more aggressive targets, and report to the Board;
- Consider the use of wind power in remote diesel electric communities and file a report with the Board; and

A considerable amount of time at the hearing was directed towards a review of the various cost of service studies filed by Hydro, and in particular, the proposed changes in methodology from the methodologies previously approved by the Board. The most contentious issue, and the issue with the greatest impact on cost of service results, is the allocation of net export revenues between customer classes. In this Order, the Board has not accepted Hydro's proposed cost of service methodology. The Board has directed Hydro to file an actual cost of service study for the year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the year ended March 31, 2004 by no later than September 30, 2003 which reflects a number of specific directives as set out in the Order including the cost treatment of export classes.

Although Hydro is not seeking any change to firm rates currently charged to customers, the Board noted that certain customer classes have consistently paid rates higher than their allocated costs. Therefore, the Board has directed Hydro to file for Board approval a revised schedule of rates to be effective April 1, 2003 that reflects:

- (a) A 1% rate decrease for General Service Small customers;

- (b) A 2% rate decrease for General Service Large ("GSL") customers greater than 30 kV; and
- (c) A decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.

The Board understands that this change will likely bring the General Service Medium class and the GSL <30 kV class closer to unity. Therefore, no further rate adjustment will be ordered for this class.

Given that uniform rates have provided recent rate decreases to some residential customers and the residential class revenue to cost coverage ratio has been consistently below unity (i.e., subsidized by other classes), no further rate changes are ordered for the residential rate class at this time.

The Board also directed Hydro to file a separate application for approval of an open access transmission tariff by no later than June 30, 2003.

The Board approved the Curtailable Rate Program, confirmed as final a number of interim ex parte Orders, and approved extending the Limited Use Billing Demand Rate option to March 31, 2004.

The Board also directed Hydro to establish a more regular schedule for periodic rate reviews, not exceeding three years between hearings even if no rate changes are required. This timeframe will improve the efficiency, effectiveness and timeliness of the regulatory process.

Subject to these and other specific rate directives contained in this Order, the Board has confirmed Hydro's remaining existing rate schedules to be in effect until March 31, 2006, or until otherwise amended by a further Order of the Board.

1.0 Appearances

R. Peters K. Kalinowsky C. McNicol	Counsel for The Manitoba Public Utilities Board ("the Board")
M. Murphy O. Fernandes P. Ramage	Counsel for the Manitoba Hydro Electric Board ("Hydro")
J. Feldschmid	Counsel for Canadian Centre for Energy Policy Incorporated ("CCEP")
B. Williams B. Froese	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc. ("CAC/MSOS")
T. McCaffrey	Counsel for Manitoba Industrial Power Users Group ("MIPUG")
M. Anderson	Representing Manitoba Keewatinowí Okimakanak Inc. ("MKO")
E. Fleming	Representing Provincial Council of Women of Manitoba, Inc. ("PCWM")
M. Buchar	Counsel for Time to Respect Earth's Ecosystems/Resource Conservation Manitoba ("TREE/RCM")
C. Henderson	Counsel for Indian and Northern Affairs Canada ("INAC")

2.0 Witnesses for Hydro

V. Warden	Chief Financial Officer, Vice President, Finance & Administration
L. Wray	Division Manager, Business Analysis & Regulatory Affairs
R. Kirk	Corporate Controller
H. Surminski	Section Head, Resource Planning and Market Analysis
R. Wiens	Manager, Rates Department
B. Poff	Manager, Transmission Services
G. Ross	Vice-President, Customer Service and Marketing

3.0 Intervenor of Record

Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc.

The City of Winnipeg

Manitoba Industrial Power Users Group

Communications, Energy and Paperworkers Union of Canada

Provincial Council of Women of Manitoba Inc.

Canadian Centre for Energy Policy Incorporated

Manitoba Keewatinowi Okimakanak Inc.

Time to Respect Earth's Ecosystems/Resource Conservation Manitoba

Subsequent to the City of Winnipeg registering as an Intervenor, Hydro entered into negotiations with the City of Winnipeg to purchase all of the assets of Winnipeg Hydro. As a result of this transaction, the City of Winnipeg withdrew from active participation as an Intervenor in this hearing.

4.0 Intervenor Witnesses

4.1 CAC/MSOS

J. Todd	President, Econalysis Consulting Services, Inc.
B. Harper	Manager, Econalysis Consulting Services, Inc.

4.2 MIPUG

J. Osler	Principal Consultant & Manager, InterGroup Consultants Ltd.
P. Bowman	Consultant, InterGroup Consultants Ltd.

4.3 TREE/RCM

J. Lazar	Consulting Economist, Micro Design Northwest
P. Miller	Professor, University of Winnipeg
B. Wild	Homesteader, Lake Winnipegosis

4.4 MKO

F. Mills	Manager, Program Planning and Allocation, Funding Services Directorate, INAC

5.0 Presenters

J. Knowles	Chief Financial Officer Hudson Bay Mining and Smelting Co. Ltd. ("HBMS")
W. Schroeder	Chief Power Engineer, Inco Limited, Thompson "Inco")
C. Weiss-Bundy	Systems Engineer, Simplot Canada, Brandon Complex ("Simplot")
B. Turner	Plant Manager, Nexen Chemicals Canada Limited Partnership, Brandon Plant ("Nexen")
Dr. C. Nicolaou	Member, Canadian Centre for Energy Policy ("CCEP")

6.0 Background

Hydro filed a status update with the Board on November 30, 2001. The purpose of the filing was to provide the Board and interested parties with an information update on Hydro, including its financial results, forecasts, methodologies, processes, and events that have transformed the electricity industry over the last few years. Hydro was not seeking any general rate changes, stating that for 2002/03, rates will have effectively been frozen for six years for residential customers and for eleven years for large industrial customers, except for the rate reductions to certain consumers as a result of province-wide implementation of Uniform Rates on November 1, 2001. The last time Hydro sought a general rate increase was in the fall of 1995, followed by a public hearing in early 1996. The Board's decisions from that hearing are set out in Order 51/96.

Hydro sought final approval of a new Curtailable Rate Program and numerous interim ex parte Orders dealing mainly with setting the monthly reference discount prices for curtailable service program customers, establishing weekly spot market replacement energy rates under the former dual fuel heating surplus energy to self-generators and industrial surplus energy programs, and establishing weekly spot market replacement energy rates for surplus energy program customers. Hydro also requested final approval extending the Limited Use Billing Demand Rate Option.

A pre-hearing conference was held on January 14, 2002 to define the scope of the hearing, and to establish a timetable for the orderly exchange of information. As a result of the hearing, the Board issued Order 9/02 in which the Board found that, in light of the long passage of time since Hydro's sales rates were last reviewed in a public forum, one purpose of this hearing would be to determine whether the existing sales rates continue to be just and reasonable and whether any changes to existing sales rates may be required.

A public hearing was held on various dates between May 27 and September 30. The Board heard final arguments on June 11, 2002 to deal with the revenue requirement aspects of the application and September 30, 2002 to deal with Cost of Service and Rate Design.

A separate hearing was held to review matters related to the Integration of Contra Gas Manitoba Inc. and Hydro. Order 208/02 dated December 6, 2002 addresses Integration matters.

7.0 Operating Results and Financial Projections

7.1 Comparison of Actual Operating Results with IFF 95-2

The Integrated Financial Forecast ("IFF 95-2") reflected the forecasted financial results of the Board's decisions in Order 51/96. Hydro's actual operating results from 1996 to 2001 and forecast results for 2002 through 2006, as stated in IFF MH 01-1, are compared to IFF 95-2 in the following table:

Statement of Operations & Retained Earnings (Millions)	Actual						Forecast IFF 95-1				
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Revenue											
Domestic	740	756	745	757	748	703	766	802	832	853	880
Export	240	268	287	320	330	400	638	833	938	967	1034
	980	1,024	1,032	1,077	1,124	1,273	1,424	1,533	1,560	1,624	1,739
Expenses:											
Finance	420	418	419	411	402	387	406	384	389	403	411
Depreciation	160	178	191	198	215	227	237	236	269	280	286
Operating & Administrative	224	226	214	226	234	245	234	262	266	268	273
Water Rentals	47	37	56	50	30	36	112	101	97	93	93
Tax Expenses	26	37	37	39	41	43	40	41	41	42	42
Fuel & Power Purchased	14	13	14	39	33	48	53	81	88	88	75
	866	923	921	883	925	1,006	1,284	1,285	1,268	1,268	1,279
Net Income	70	101	111	100	148	267	230	110	91	58	68
IFF 95-2	59	49	31	11	42	41	68	89	120	128	66
Annual Difference	11	52	80	89	106	226	162	21	(29)	(69)	2
Retained Earnings Balances											
Opening Retained Earnings	390	354	455	366	660	814	1,081	1,381	1,680	1,218	1,272
Net Income	70	101	111	100	148	267	230	110	91	58	68
Special Payment to Province	-	-	-	-	-	-	(1,391)	(135)	(83)	-	-
Retained Earnings - MH01-1	354	455	566	666	814	1,081	1,181	1,496	1,614	1,232	1,341
Retained Earnings - IFF 95-2	343	352	423	434	475	516	576	665	795	921	987
Cumulative Difference	11	63	143	232	339	565	605	831	819	311	354

Hydro's operating results since 1996 have been substantially better than forecasted in IFF 95-2. Hydro attributed the improvement in financial position to increased export revenues coinciding with periods of above average water flows, and controls over operating and administrative costs relative to inflation. Actual net income for each of the years 1996 through 2001 exceeded that forecast in IFF 95-2, by \$11 million in 1996 to \$226 million in 2001. The better than expected operating results have provided retained earnings forecast at \$1.15 billion at the end of fiscal

2002, compared to the retained earnings forecast for 2002 in IFF 95-2 of \$576 million. On an overall basis, Hydro is now forecasting to have \$1,341 billion in retained earnings by March 31, 2006 in IFF MH 01-1 compared to the amount forecasted in IFF 95-2 of \$987 million at March 31, 2006.

7.2 Integrated Financial Forecast ("IFF MH 01-1")

Hydro filed its most current financial forecast (IFF MH 01-1) for its electric operations, which included a projected operating statement, balance sheet, financing requirements and financial ratios, as well as a capital expenditure forecast (CEF 01-1) for the eleven-year period 2002 to 2012. The purpose of the IFF and CEF was to provide an indication of Hydro's long-term financial direction and for use in future planning. The forecast was revised during the hearing to reflect the impact of a \$288 million payment to the Province and accounting policy changes related to foreign currency transactions including the Exposure Management Program. IFF MH 01-1 and CEF 01-1 are attached as Appendix A and B to this Order.

IFF MH 01-1 reflects no requested rate increases for fiscal 2002 or 2003, but includes a rate increase scenario of 2% annually for fiscal years 2004 to 2009. Hydro is not seeking approval from the Board for any rate changes in this application, but will file a future rate application with the Board for its approval if rate changes are subsequently determined to be required.

On February 8, 2002, Hydro announced its intention to acquire the assets and business of Winnipeg Hydro, which had approximately 570 employees and served about 94,000 customers in the City of Winnipeg. The acquisition will have a significant impact on the future overall operations of Hydro. The impact of this transaction is not reflected in IFF MH 01-1.

8.0 Financial Targets

8.1 Background

In September 1995, Hydro adopted the following financial targets, which were reviewed by the Board at the 1996 General Rate Application ("GRA").

1. To achieve and maintain a minimum debt to equity ratio target of 75:25 by no later than 2005/06.
2. To achieve and maintain an annual gross interest coverage ratio in the range of 1.20 to 1.35 as soon as possible.
3. To fund all capital construction requirements from internal resources, except during periods when major new generation and/or major transmission facilities are being added to the system.

At that time, Hydro stated that in adopting its financial targets, a number of factors were considered including the following:

- A cushion is required to absorb the impact of negative events so as to maintain rate stability for customers;
- Risks faced by Hydro have been increasing in complexity and size, noting that a major drought could cost in the range of \$1 billion;
- Credit rating agencies rely on Hydro's status as a self-supporting utility in determining the Provincial credit rating; and
- Hydro's financial targets are not out of line with the financial position and performance of several other Canadian government owned electric utilities.

These financial targets are consistent with the financial targets included in Hydro's Corporate Strategic Plan for 2002.

8.2 Risks

Hydro has identified a number of specific domestic risks that could have serious financial impacts on its operations including:

- Drought;
- Economic downturn;
- Lower than forecast domestic load related to weather;
- Decreased water flows from increased Alberta and Saskatchewan usage;
- Higher interest rates;
- Higher escalation rates; and
- Transmission or generation system outages.

During a drought, some of Hydro's non-firm export sales would be curtailed, and Hydro could be required to import power to satisfy domestic and firm export load requirements. Imported power would be significantly more expensive. An extended five-year drought has happened three times in the last 86 years. It is Hydro's position that the five-year drought scenario is the most substantial risk, with a possible \$1.3 billion negative impact on retained earnings. Other risks could increase this financial impact, especially if they occur concurrent with drought. However, other risks may be non-related, and hence not totally additive. In addition to the threats of water flows, weather, economic and market conditions, erosion of domestic load, major equipment failures, and increased government payments, Hydro's financial position could also be seriously impacted by competition and deregulation in the US.

Hydro has identified a number of specific export revenue risks that could also have a serious financial impact including:

- Economic downturn;
- New gas and coal generating stations coming on line in the US;
- Increased protectionism in the US;

- Changing US legislation and regulation;
- Transmission constraints, mainly in export markets;
- Lower export prices; and
- Open access transmission.

Since export revenues are approximately 40% of total revenue, any risks to export revenues must be considered seriously. With a drought, export revenues will be significantly diminished.

In response to the suggestion of CAC/MSOS witnesses that Hydro prepare a quantitative risk analysis, which would indicate an appropriate amount for required reserves, Hydro noted the breadth and complexity of its risks are vast, and to quantify each risk would be a near impossible task. Furthermore, Hydro stated its many risks are already evaluated and managed throughout Hydro on a day-to-day basis.

According to Hydro, the suggested aggregation of risks goes against including a reserve provision only for foreseeable and measurable contingencies. The nature of risk is precisely that it cannot be foreseen and measured perfectly. While the costs of drought are estimated at over \$1.3 billion today, the actual costs of a financial downturn may be greater, depending upon other factors such as domestic load, market prices, supply availability and transmission conditions at that time. In addition, other risks may occur simultaneously with the drought and all costs may have to be recovered through future rate increases. According to Hydro, the current financial targets are designed to provide a cushion to absorb the expected costs of foreseeable measurable risks, with some room to cover unforeseeable contingencies.

8.3 Debt to Equity Ratio

Hydro had a debt to equity ratio in 1996 of 91:09. The ratio has improved to 80:20 in 2001. The improvement is attributable to a growth in retained earnings, rather than a reduction in the level of debt. Total debt, net of sinking fund, increased from \$4.8 billion in 1996 to \$5.5 billion in

2002, while retained earnings increased from \$354 million in 1996 to \$1.15 billion in 2002, due primarily to increased operating profits over that forecasted in IFF 95-2.

In its credit rating report dated October 21, 2001, Dominion Bond Rating Services stated, "Hydro continues to generate sufficient cash flows to finance capital expenditures, but there's little surplus available for debt reduction.... The challenge is that high debt levels weaken most financial ratios."

Hydro attributed the high-debt level to its significant capital program and that internally generated funds first pay operating costs and then are allocated towards the capital construction program. Furthermore, the acquisition of Centra Gas Manitoba Inc. ("Centra") and the construction of the Brandon combustion turbine increased debt by \$748 million during this period.

Hydro has achieved and exceeded the debt equity ratio forecasted in IFF 95-2 as illustrated in the following table:

Fiscal Year	Actual						Forecast				
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Actual/IFF MH 01-1	91:09	88:12	86:14	84:16	83:17	80:20	77:23	78:22	78:22	77:23	77:23
IFF 95-1	91:09	91:09	90:10	89:11	88:12	87:13	86:14	85:15	82:18	80:20	79:21

In IFF MH 01-1, Hydro originally forecasted to achieve its target debt equity ratio of 75:25 by fiscal 2006 with a 74:26 debt equity ratio. After reflecting the \$288 million special payment to be made to the Province, the debt equity ratio in fiscal 2006 is now forecasted to be 77:23, and Hydro will not achieve a 75:25 ratio until 2008. Hydro stated that the current target is not attainable and that there would likely be a recommendation presented to its Board of Directors to establish a new target when the IFF is updated in the fall of 2002.

8.4 Interest Coverage

The Hydro Board of Directors revised the interest coverage target in 2001 from "a range of 1.20 to 1.35" to "maintaining a minimum gross interest coverage level greater than 1.20." Hydro stated that it was important that it operated with a gross interest coverage ratio of 1.20, noting that if it operated at break even, with no margin for adverse events, losses or unexpected costs, Hydro would be required to undertake additional borrowing for interest payments. According to Hydro, capital markets would not have a positive view of an interest coverage lower than 1.20, and operating at a break-even could have a negative impact on rate stability.

Hydro achieved its interest coverage ratio target of 1.20 in fiscal years 1997 to 2000, and exceeded the target in 2001 with an interest coverage ratio of 1.66. The actual results for fiscal 1996 to fiscal 2001 were significantly better than that projected in IFF 95-2 as illustrated in the table below:

Fiscal Year	Actual						Forecast				
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Actual IFF MH 01-1	1.16	1.23	1.25	1.23	1.35	1.66	1.41	1.21	1.18	1.12	1.13
IFF 95-2	1.13	1.10	1.06	1.02	1.08	1.08	1.12	1.18	1.27	1.27	1.14

The interest coverage ratio is projected to fall below the 1.2 target in 2004 for the remainder of the forecast period as a result of the additional financing costs related to the \$288 million special payment to the Province. The gross interest coverage ratio over the 11-year period 2002 to 2012 in IFF MH 01-1 ranges from a high of 1.41 forecast for fiscal 2002 to a low of 1.12 in fiscal 2005, ending at 1.13 in fiscal 2012.

8.5 Capital Coverage

Hydro's target is to fund all capital construction requirements from internal cash resources, except during periods when major new generation or major transmission facilities are being added to the system.

Since 1996, Hydro has funded all capital expenditure from internally generated funds. However, at the end of fiscal 2001, its overall debt had increased by approximately \$750 million. Hydro noted that its goal was to fund all capital construction, except major generation and transmission, from internally generated funds. However, there were other expenditures that fall outside the definition of capital construction expenditures that required financing such as inventory, mitigation expenses, vehicle purchases and the acquisition of Contra.

9.0 Capital Expenditures

9.1 Comparison of CEF 01-1 to CEF 95-1

Hydro's Capital Expenditure Forecast CEF 01-1 summarizes an eleven-year program of capital expenditures totalling \$3.75 billion, ranging from \$425 million in 2002 and declining to \$239 million in 2012. This compares with CEF 95-1 total program forecast expenditures of \$2.7 billion over the eleven-year period from 1996 to 2006. Over the same eleven-year period, Hydro's actual capital expenditures for 1996 to 2001 and projected expenditures for 2002 through 2006 is \$3.6 billion, approximately \$848 million greater than that forecast in CEF 95-1, as illustrated in the following table:

Capital Expenditures (\$ millions) For the years ended March 31	Actual						Forecast/Projected					
	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	Total
Actual/ CEF 01-1	256	297	252	308	310	335	425	367	376	338	330	3,594
Capital Expenditures CEF 95-1	314	297	285	239	222	207	204	207	220	229	322	2,746
Difference	(58)	0	(33)	69	88	128	221	160	156	109	8	848

At the 1996 GRA, capital expenditures averaged approximately \$250 million per year. In CEF 01-1, capital expenditures average approximately \$350 million per year.

In CEF 01-1 capital expenditure estimates in later years are less than in earlier years since future capital projects have not yet been identified. Hydro believes that in the absence of fortuitous events, capital expenditures in the later years of the forecast period will be significantly higher than forecast since new projects will be identified. According to Hydro, the higher level of annual expenditures has been, and will continue to be driven, in large part, by distribution system expansions and upgrades, and the repair and replacement of an ageing distribution system.

The capital expenditures forecast in CEF 01-1 do not include Wuskwatim, Gull or Notigi generating stations which are expected to come into service over the next 8-20 years. Hydro has already incurred approximately \$367 million in expenditures related to these future capital projects. These expenditures and related financing costs are deferred and will not be depreciated or amortized until the plant or facility is put into service.

9.2 Major Expenditures

Included in Hydro's current capital forecast are the following major projects:

<u>Project</u>	<u>Total Costs (\$ million)</u>
Brandon Combustion Turbine	183
Brandon Unit #5 Life Extension for Coal	23
Selkirk Conversion to Natural Gas	32
Selkirk Life Extension	29
Interconnection to Rugby ND	25
Radisson-Riel HVDC Line	352
Riel Station	98
Microwave Radio Replacements	141
Planning Studies (2002-2012)	130

Hydro has installed a new 260 MW natural gas combustion turbine at the existing Brandon generating station site. Hydro also plans to upgrade the coal-fired generator to extend its useful life to 2019, beyond its scheduled closing date. Whereas the coal facilities will assist in servicing the domestic load in Southwestern Manitoba, the new natural gas combustion turbines are largely to provide necessary reserve power to facilitate extra provincial sales. The investment in the Brandon combustion turbine is primarily based on increasing the value of Hydro's surplus hydraulic energy that would have otherwise been exported into the short-term opportunity market as interruptible power. After firming up this energy, it can be sold into the

more lucrative forward market. The primary benefit of the Brandon combustion turbine is to provide backup power when hydraulic generating capability is reduced during drought or equipment outages. It is expected to operate only 10-16% of the time, while hydraulic generation operates 65-80% of the time.

Citing environmental reasons, Hydro is converting the Selkirk generating station from a coal-fired to a natural gas-fired source of generation, in addition to extending its operating life. Selkirk is also scheduled to operate approximately 16% of the time.

Hydro is also embarking upon an ambitious transmission project which, when totally completed, will result in an additional HVDC line and converter stations on the east side of Lake Winnipeg. The new HVDC line (\$352 million) will stretch from the Radisson Converter Station to the proposed Riel Station (\$98 million) located outside Winnipeg. An HVDC paralleling line will be constructed to the existing Dorsey HVDC converter station. This will increase reliability and provide an additional 78 MW of capacity due to decreased line losses. This additional power may be sold on the export market. Ultimately two new converter stations will be added at an estimated costs of \$400-\$500 million each. These are not included in CEF 01-1 since their in-service date is beyond 2012. The total estimated costs for Bipole III are approximately \$1.35 billion.

Hydro has forecast spending \$130 million from 2002 to 2012 on planning studies for major new generation and transmission projects. In cross-examination, Hydro acknowledged paying for planning study costs commissioned by First Nations communities which will have an equity interest in the future generating stations. Planning studies are capitalized and attract carrying costs that may be significant since these studies are typically undertaken several years in advance of the planned in-service date of the project.

Costs associated with mitigation of environmental and social impacts are not included in the capital forecasts, but are included as a separate expense line item. To ameliorate the adverse

effects of hydro-electric projects on the Churchill River Diversion and the Lake Winnipeg Regulation, Hydro has incurred approximately \$471 million in mitigation costs. Four of the five First Nations have signed final agreements for compensation under the Northern Flood Agreement, and negotiations for settlement with Cross Lake First Nation are ongoing.

9.3 Justification and Prioritization

Hydro justified its capital expenditures within the following categories:

<u>Justification Category</u>	<u>% of Capital Costs</u>
Capacity	3.5
Load/Reliability	26.5
Safety	0.5
Reliability/Rehabilitation	10.0
Service	2.0
Efficiency	4.5
Other	4.0
Domestic Items*	48.7
	100.0

* Domestic items are non-specific domestic consumer-related expenditures.

Hydro has not attempted to specifically allocate capital costs associated with servicing the export market. Many of the existing capacity and load reliability items (i.e., connection to Rugby, North Dakota) may have an export component and future new generation may be built primarily for the export market. To date however, only the Brandon Combustion Turbine has specifically been justified solely for export purposes. Hydro stated that the majority of capital expenditures in CEF 01-1 have benefits associated with both export and domestic markets.

10.0 Extra-Provincial Revenues

10.1 Industry Changes Impact on Hydro

Over the past six years the North American electricity industry has changed significantly with the introduction of competition at the wholesale level. In response to the issuance of Orders 888 and 889 by the US Federal Energy Regulatory Commission ("FERC") in 1996, open access conditions were made mandatory for transmission carriers, along with a non-discriminatory wholesale tariff, which enabled wholesale competition in the electric industry in the US. By Order 2000, FERC mandated utilities to join Regional Transmission Operators ("RTOs").

The restructuring of the electricity industry in the US resulted in significant opportunities for Hydro, which prompted changes in Hydro's operations to better respond to increased deregulation. In 1996 Hydro reorganized its operations into three business units (Power Supply, Transmission and Distribution, and Customer Service and Marketing) and two support groups (Finance and Administration, and Corporate.)

Hydro's governing legislation was also changed by statutory amendments in 1997, expanding the mandate to include the marketing and supply of power outside the Province. Previously, Hydro's mandate was limited to supplying power adequate for the needs of the Province and promoting economy and efficiency in the generation, distribution, supply and use of electricity.

In response to the new opportunities, Hydro became an active member of the Mid-Continent Area Power Pool ("MAPP"), an electric reliability region and power marketing pool based in St. Paul, Minnesota. With MAPP unable to successfully transform into an RTO, Hydro then joined the Midwest Independent System Operator ("MISO"), which has become an RTO, serving 35 states.

The main consequences to Hydro resulting from electricity restructuring in the US include the following:

- Hydro now sells its transmission service under an open access transmission tariff;
- Significant increases in both the price and quantity of electricity exported;
- Annual export revenues have increased significantly;
- US customers have increased to more than 50 from 5;
- The operation of the main transmission grid is under the oversight of MISO which is responsible for operational reliability; and
- Standards of conduct limit the free flow of transmission information between the transmission operations with Hydro and the wholesale marketers within Hydro.

10.2 Extra-Provincial Revenues - 1996 to 2001

For the fiscal year ended 1996, extra-provincial revenues accounted for \$246 million or 25% of total revenues. For the fiscal year ended 2001, extra-provincial revenues were \$480 million representing over 40% of total revenue. The major increase in extra-provincial revenues since 1996 was primarily due to the changes in the electric industry with the evolution of competitive wholesale electricity markets discussed above. In addition, the shortage of generation supply caused spikes in prices during the high demand summer periods. This created the opportunity for Hydro to enter into forward contracts for export sales at higher prices. High natural gas prices also added to the volatility of the electricity prices.

Hydro maintains a mixed portfolio of export sales to reduce risk. These export products include long-term firm contracts and short-term opportunity sales. The opportunity sales are dependant upon water flows and can vary greatly from year-to-year.

The table below summarizes export revenues from 1996 to 2001:

Year	Export Revenues (\$ Millions)		
	Opportunity Export Revenues	Long-Term Firm Export Revenues	Total Export Revenues
1996	105	141	246
1997	126	142	268
1998	149	148	297
1999	146	180	326
2000	146	230	376
2001	219	261	480

The export revenues, GW.h exported and average sales price per kW.h for the years 1996 to 2001 are as follows:

For the years ended March 31	1996	1997	1998	1999	2000	2001
Revenue \$ million(s)	246	268	297	326	376	480
GW.h	10,496	12,531	14,341	10,694	10,776	12,082
Average sale price ¢/kW.h	2.34	2.14	2.07	3.05	3.49	3.97

10.3 Extra-Provincial Revenues – Future Outlook

Hydro stated that price volatility in the MAPP marketplace decreased significantly in 2001 due to the addition of new generation. In addition, the spike in natural gas prices subsided as a result of a downturn in the US economy. With much of the new electricity generated by natural gas combustion turbines, the resulting forward price of electricity decreased significantly in the last months of fiscal 2002. Hydro noted that with a continuance of the downturn in the US economy and lower natural gas prices, it is expected export prices will remain at lower levels in the near term. However, export prices are expected to increase gradually in the long term because of the greater reliance on generation from natural gas-fired combustion turbines in MAPP, rather than

generation from coal fired plants with lower fuel costs. In addition, the price of natural gas is forecast to increase in the long term due to high projected demand for natural gas, particularly in the electricity generation sector.

Extra-provincial revenues are forecast to increase to \$628 million in fiscal 2002. The major increase forecast for 2002 over 2001 was due primarily to a change in the exchange rate used for translating US extra-provincial revenues, discussed later in this Order. Of the \$148 million increase in 2002 over 2001, approximately \$110 million relates to the change in the accounting for US export sales. The remainder, approximately \$38 million, is due to forecast increases in volumes.

Longer-term sales volumes are forecasted at average levels with revenues of \$400 to \$500 million/year. Hydro did not provide a breakdown of its future export revenues forecast nor GWh information for fiscal years 2002 through 2012, since it considers the information to be commercially sensitive.

11.0 Payments to the Province

As a Crown Corporation, Hydro does not pay income tax, provincial sales tax or the Goods and Services Tax. Hydro does, however, pay the Provincial Corporations Capital Tax, similar to other privately held corporations employing capital in the Province. The Province of Manitoba also levies a number of other fees to be paid by Hydro. At the 1996 GRA, annual payments made to the Province from Hydro were in the range of \$96 million. Payments to the Province have now increased to \$128 million in 2001 and are forecasted to be \$354 million in 2002.

The total payments to the Province from 1996 through 2004 are summarized as follows:

For the year ended March 31	Actual						Forecast		
	1996	1997	1998	1999	2000	2001	2002	2003	2004
	(\$ millions)						(\$ millions)		
Debt Guarantee Fee	25	26	29	31	40	49	65	62*	61*
Water Rental Rates	46	50	53	46	46	50	107	96	92
Corporations' Capital Tax	25	26	26	27	29	29	31	31	32
Sinking Fund Service Charge	0	0	0	0	0	0	1	1	1
Special Export Profit Payment (\$288 million)	0	0	0	0	0	0	150**	75**	63**
Total	96	102	108	104	115	128	354	265	249

* The impact of the required borrowings related to \$288 million special payment to the Province is not reflected.

**Subsequent to the hearing, Hydro's 2002 financial statements indicated that the special export profit payment will be paid out in 2003 and 2004. The first instalment will be \$150 million plus an additional amount not to exceed 75% of net income for 2003. The remaining instalment in 2004 will not exceed 75% of net income for that year. In accordance with the legislation, the total distribution to the Province of Manitoba over the two-year period will not exceed \$288 million.

11.1 Special Export Profit Payment

In the April 2002 Provincial budget, the Province announced a special export profit payment by Hydro to the Province of \$288 million, payable in the amount of \$150 million in 2002, \$75 million in 2003 and \$63 million in 2004. These payments are to be funded from the high export profits Hydro is experiencing and is forecast to continue experiencing. Hydro indicated that general rates would not increase as a result of these payments.

Hydro intends to finance the \$288 million payment to the Province since its cash on hand is insufficient to make the payments. The interest costs to finance the payments are estimated to be an additional \$276 million during the eleven-year forecast period from 2002 to 2012. As a result of the special payment and additional finance charges, retained earnings is forecast to be over \$534 million less in 2012 than that originally forecast prior to the payment. When questioned as to whether Hydro had considered alternatives to financing these payments, Hydro responded it had only considered removing monies from its sinking fund. Hydro had not considered reductions to its capital expenditures nor revisions to its operations, maintenance and administration budgets.

The effect of the special export profit payment on the financial targets is to delay achieving the 75:25 debt equity ratio from 2006 to 2010, and to not achieve the interest coverage ratio target of 1.20 after fiscal 2003 through the remainder of the forecast period to 2012. Subsequent to the completion of the hearing the Hydro annual report for fiscal 2002 indicates that the \$288 million will now be taken out in fiscal 2003 and 2004. The first instalment will be \$150 million plus an additional amount not to exceed 75% of net income for 2003. The remaining instalment in 2004 will not exceed 75% of net income. Total distributions to the Province are limited to \$288 million, under the legislation.

11.2 Water Rental Payment

Hydro pays water rental rates to the Province for the use of water resources in the operation of its hydroelectric generating stations. Under *The Water Power Act* water rental rates increased by over 105% from \$1.6285/MW.h to \$3.34/MW.h effective April 1, 2001. The effect of this increase was to more than double the water rental fees from \$50 million in 2001 to \$107 million in 2002.

Hydro had previously negotiated an agreement with the Province whereby water rental rates would be frozen from 1989 to 2001 in exchange for Hydro undertaking a number of northern development initiatives. The total costs to Hydro of such initiatives were \$154 million over the 12 years. While Hydro noted the freezing of water rental rates was beneficial to Hydro, it did not plan to negotiate a similar agreement in the future.

11.3 Debt Guarantee Fee

Hydro pays the Province a debt guarantee fee in return for the Province guaranteeing Hydro's long-term debt. Previously set at 0.5% of the outstanding debt guaranteed by the Province, the fee was increased to 0.65% effective April 1, 2000 and 0.95% effective April 1, 2001. This increases the debt guarantee fee from \$25 million in 1996 at the last GRA to \$65 million in 2002.

Hydro stated that it receives a benefit of 15 basis points in Canadian capital markets and 75 basis points in US capital markets by financing with the backing of the provincial guarantee. All credit rating agency reports point to the provincial debt guarantee as a favourable factor in the credit rating of Hydro.

11.4 Sinking Fund

A sinking fund service charge of 0.075% of the sinking fund is paid to the Province for managing and servicing Hydro's sinking fund balance. This amounts to approximately \$1 million per year.

12.0 Finance Expenses

Finance expenses were \$426 million in 1996 representing over 46% of total operating expenses. Finance expenses declined to \$387 million in fiscal 2001. For the fiscal years 1996 through 2001 actual finance expenses were over \$226 million lower than that forecast in IFF 95-2 a result of declining long-term interest rates during the period.

Hydro has forecast finance expenses to increase in fiscal 2002 by \$109 million to \$496 million or 41% of annual operating expenses. The increase is attributable to an accounting policy change related to the Exposure Management Program ("EMP"), discussed below, additional debt related to the payment of the special payment to the Province, as well as an increase in the debt guarantee fee paid to the Province.

12.1 Exposure Management Program ("EMP")

Hydro employs an EMP which acts as a hedging program intended to limit the Corporation's net US dollar exposure within defined policy limits. Debt denominated in US currency is not subject to foreign exchange fluctuations as the exchange rate used has been fixed in accordance with the EMP. The program is necessary since \$2.9 billion or 45% of the Corporation's \$6.5 billion in long-term debt at March 31, 2001 is payable in US dollars.

As a result of the EMP, Hydro does not recognize gains or losses related to changes in the US currency exchange rate on its long-term debt or sinking fund. The EMP limits Hydro's exposure to foreign currency changes, and the sinking fund and export revenues act as a natural hedge for the retirement of the US denominated debt. Hydro has estimated that its US cash inflows will exceed the cumulative US cash outflows for interest, thermal fuel and sinking fund payments and will be sufficient to retire the existing US debt by March 31, 2023.

As a result of the program, the long-term debt and sinking fund were recorded at a designated exchange rate of (\$1.00 US = \$1.17 Cdn), rather than a year-end rate of (\$1.00 US = \$1.56 Cdn) at March 31, 2001. If long-term debt had been recorded at the year-end rate it would have been approximately \$1 billion greater than that reflected in Hydro's financial statements. The balance of the sinking fund would have been approximately \$200 million greater. US extra-provincial revenues and finance expenses were also recorded at the lower designated rate rather than current exchange rates.

Hydro revised its EMP to reflect a new accounting policy whereby revenues and expenditures resulting from transactions in foreign currencies are translated into Canadian dollar equivalents at exchange rates in effect at the transaction dates except to the extent revenues are used to hedge future long-term foreign debt obligations. Revenues used as formal hedges are firm US revenues which are translated at the embedded exchange rates of the respective US debt obligations to which the firm revenues are linked and for which they, together, form an effective hedge.

Previously, the US based transactions including net export revenues, interest revenues on US sinking fund investments, finance expenses on US debt and fuel purchases were translated at a designated exchange rate of \$1.00 US to \$1.17 Cdn, an exchange rate significantly lower than the rate of exchange prevailing during the year.

As a result of these changes, Hydro's export revenues increased from \$480 million in 2001 to \$628 million in 2002. Approximately \$110 million of the \$148 million increase was due to the change in accounting policy and the remainder, \$38 million was due to a forecast increase in the volume of extra provincial sales. In addition, net long-term debt increased by over \$403 million in 2003 and finance expenses also increased during the forecast period.

13.0 Operating and Administration Expenses

Operating and administration expenses include the costs associated with operating, maintaining and administering Hydro. Over 72% of these costs relate to labour costs including employee benefits. Hydro reorganized its operations into a business unit structure effective April 1, 1997, resulting in no practical means of comparing individual operating and administrative expense items for fiscal 1996 and 1997 to current expenses. The operating and administrative expenses for fiscal years 1998 to 2002 are as follows:

**Operating & Administrative Expenses
(\$ thousands)**

For the years ending March 31,	1998	1999	2000	2001	2002
Wages, salaries and overtime	205,299	213,732	219,702	259,162	274,079
Employee benefits	46,516	46,782	44,145	49,664	53,963
	251,815	260,514	263,847	308,826	328,042
Travel	18,301	19,992	20,327	22,146	23,302
Material & tools	18,089	18,280	18,674	22,135	22,212
Building and property services	13,967	13,393	13,410	17,221	17,493
Motor vehicle	11,045	12,050	13,048	15,052	12,785
Office and administration	8,358	9,299	9,858	13,604	12,624
Consulting and professional fees	8,151	9,515	8,413	9,229	9,290
Construction and maintenance services	7,765	10,691	8,482	10,242	10,797
Computer services	5,868	5,471	3,920	4,513	4,234
Purchased services	3,897	4,176	6,321	6,794	6,588
Customer and public relations	3,211	4,731	2,436	2,970	3,272
Equipment maintenance	2,761	2,870	3,730	5,096	5,760
Communication systems	1,545	1,586	2,133	2,211	2,242
Consumer services	1,109	1,203	1,339	5,333	5,656
Collections	1,054	1,329	1,445	3,260	2,757
Contingency	-	-	-	-	(1,632)
Operating expense recovery	(11,833)	(5,722)	(7,723)	(11,415)	(11,583)
	345,103	369,378	369,660	437,417	453,839
Less: Capital order activities	(87,280)	(91,617)	(88,065)	(99,660)	(107,814)
Centre costs of operations	-	-	-	(44,000)	(44,900)
	257,823	277,761	281,595	293,757	301,125
Electric costs of operations	257,823	277,761	281,595	293,757	301,125
Less: Capitalized overhead	(45,209)	(54,846)	(53,373)	(50,758)	(46,805)
Total	212,614	222,915	228,222	242,999	254,320

Total operating and administration expenses have increased from \$213 million in 1998 to \$254 million in 2002. Over the same period of time, Hydro's workforce has increased by 911 equivalent full-time ("EFT") employees, and labour costs have increased by \$76 million. This increase in staffing levels and related gross labour costs was largely due to the acquisition of Centra by Hydro and the integration of Centra's employees into Hydro's operations.

13.1 Operating and Administration Costs Per Customer

In the 2002 Corporate Strategic Plan, one of Hydro's stated goals is to improve corporate financial strength. One measure of this goal is to achieve an operating and administration cost per customer (electric) of \$600 by March 2003. Hydro stated that the target is a stretch target, calculated based on the average costs per customer in the proceeding five years. By relying on the average of the proceeding five years in calculating the target, productivity increases are automatically built in and accounted for in the target.

IFF MH 01-I indicates that over the eleven-year forecast period 2002 to 2012, operating and administration expenses per customer are projected to increase from \$584/customer to \$664/customer. Hydro has stated that to meet the target set out in the 2002 Corporate Strategic Plan, the operating budgets of the various divisions will be scrutinized on an overall basis to ensure the target is met.

13.2 Staffing Levels

Hydro indicated that between 1998 through 2003, staffing levels are projected to increase by 887 effective full time ("EFT") employees, from 4,030 to 4,917 EFT employees. The largest increase in EFT employees occurred in 2001 when staffing levels increased by 704 EFT employees, largely attributable to the acquisition of Centra and the integration of approximately 650 Centra employees.

According to Hydro, the projected level of EFT employees in 2002 and 2003 is optimistic and the actual increase projected for these years may be less. Hydro indicated that the number of EFT positions is closely monitored to maximize efficiency within the Corporation. Hydro stated that any new position has to be approved by the President and is subject to a rigorous process to make sure the position is justified.

13.3 Cost Control Process

According to Hydro, cost control measures are continuous through the utilization of a formalized cost control process that includes planning, budgeting, monthly reporting and variance analyses, which ensures costs and resource allocations are consistent and in line with operating and capital plans. Hydro uses this process to allow management to prioritize programs and projects; manage changing conditions; provide changes in corporate direction; establish communication regarding performance; and react to unforeseen conditions on a timely basis.

13.4 Capitalization of Operating and Administration Expenditures

Hydro segregates costs between operating activities, which are a direct charge against the operating income for the year, and capital activities, which are charged to future periods and amortized over the future life of a respective project. Hydro indicated that employees timecard their activities to specific capital projects. This amount, combined with other related costs, is charged to a capital order. In addition, Hydro also capitalizes overhead by applying the predetermined overhead rates to all capital projects.

Operating and administrative expenses were approximately \$454 million in 2002 before capitalized activities and overhead. Hydro indicated that approximately 25% or \$107 million would be charged to capital order activities and approximately 10% or \$46 million to capitalized overhead. Hydro stated that capitalizing approximately 35% of the total operating and administration expenses was reasonable and was the norm within the industry.

14.0 Transmission Tariffs

14.1 Hydro Transmission Tariff

To ensure access to the lucrative American export market, Hydro complies with certain FERC initiated demands, including reciprocity. Just as Hydro is able to obtain open access to other utilities' transmission systems in the US, Hydro now offers an open access transmission service and levies a transmission tariff to provide for the movement of electricity through Manitoba on its transmission grid. Offered as a service since 1997, the Transmission Tariff has been utilized, on occasion, by other entities and Hydro itself. Under Hydro's standards of conduct, the transmission function is separated from other functions and bills the other business units for use of the transmission facilities. Revenues have been received from use of this Transmission Tariff.

Hydro's Open Access Transmission Tariff has never been submitted for approval by the Board or the National Energy Board, but its associated rate schedules have been filed with FERC in the US. This tariff is based on the FERC pro forma Open Access Transmission Tariff. Approval of this tariff varies across other jurisdictions. Some provincial regulators, such as the British Columbia Utilities Commission, have approved open access transmission tariffs. In the restructured Alberta and Ontario marketplaces, provincial regulators approve provincial based open access transmission tariffs.

14.2 MISO Transmission Tariff

MISO also has its own open access transmission tariff to provide for the movement of electricity from Manitoba into, through, and from a MISO destination. Based on licence plate pricing, whereby the rate charged is that of the destination load zone, this tariff is also a FERC pro forma tariff. The MISO tariff does not apply to the Hydro transmission facilities – rather, it applies south of the border.

This MISO tariff has been approved by FERC, but has not been filed with either the Board or National Energy Board for approval.

14.3 Hydro's Position on Jurisdiction

Hydro noted the legislation is silent as to explicit approvals of transmission tariffs. Hydro argued the MISO tariff was beyond the provincial realm of constitutional division of powers. With respect to the Hydro Open Access Transmission Tariff, the only users are Hydro and parties outside of Manitoba. To retain the flexibility Hydro stated it must respond to rapid changes in the US markets, therefore the tariff should not be subject to direct PUB approval. Instead, the Board would review the tariff at a GRA to the extent that the tariff may affect domestic rates.

15.0 Load Forecasts and Power Resources

15.1 System Load

Hydro's domestic system load forecast is estimated at approximately 3,700 MW net peak demand, and 21,000 GWh energy for 2003. This is forecast to increase to approximately 4,100 MW peak demand and 24,000 GWh energy for 2012. Hydro's system load forecast has projected an increase of approximately 18% for energy and 13% for demand for the next 10 years. Over the last 16 years, actual domestic loads have been significantly below base forecasts in 13 of the last 16 years. In the other three years, actual loads have marginally exceeded base forecasts.

With relatively low generating costs and favourable export markets, Hydro is in a relatively advantageous situation to compete on the open market for the sale of power. Therefore, firm contracts negotiated by Hydro provide additional system load demands over and above domestic loads. Available power not required by domestic or firm contract export customers can also potentially be sold in the export market as opportunity sales.

15.2 System Capacity

Hydro currently has approximately 5,400 MW (winter demand) and 25,000 GWh (annual energy) capability within its hydraulic generation and thermal plants. Hydro has sufficient resources to supply domestic loads and existing firm export sales to the year 2019 under expected load growth conditions.

The capacity criterion for the Hydro system requires that planned generation capacity must not be less than forecast annual firm peak demand plus a reserve requirement of 12% of forecast firm loads. The energy criterion requires that the Hydro system be capable of a dependable supply of energy to meet forecast firm load demands. Specifically, there must be sufficient firm energy sources to meet firm energy demand in the event of a repeat of the lowest historic water flows.

Even with a 12% demand reserve requirement, the demand capability will not be exceeded until after 2020 for domestic load and energy capability will not be exceeded until 2014. Firm exports impose only a modest (100 to 200 MW in demand and 500 to 1,000 GWh in energy) addition to system capacity and energy demand because the nature of Hydro's firm export contracts (often involving an off-setting import commitment).

15.3 New Power Resources

In accordance with its mandate to pursue sales in the export market, Hydro is bringing new capacity online in 2003 including the Brandon Combustion Turbine. This facility will provide a total installed capacity of 260 MW.

As mentioned in the capital expenditures section of this Order, Hydro intends to embark upon an ambitious construction program over the next two decades with construction of several new generating stations: Wuskwatim (200 MW), Gull (650 MW), Notigi (100 MW), and possibly Conawapa (1,230 MW) which Hydro indicates will be subject to a separate hearing. It is Hydro's contention that new hydraulic generation should be viewed as "green" energy since it produces little or no greenhouse gases. As such, their new hydraulic facilities will contribute significantly to greenhouse gas reductions as contemplated in the Kyoto Protocol. Hydro is committed to maintaining the cumulative average net greenhouse gas emissions since 1990 at 6% below 1990 levels.

Hydro did not distribute its Power Resource Plan citing confidentiality due to the increased competitive nature of electricity trading in the US. Hydro has no wind generation in its current power resources nor plans to install any over the next decade. Witnesses for Hydro agreed the efficiencies and reliability of wind generation have increased substantially while costs have dropped simultaneously over the past few years. However, as yet, wind generation is more costly than Hydro's hydraulic generation, although there may be some other additional environmental and social benefits.

16.0 Revenue Requirement and Current Rates

16.1 Current Level of Rates

Hydro believes holding rates constant is a more prudent course of action than offering rate reductions because the robust export markets and favourable water conditions, which underpinned the strong financial performance, may not continue at present levels. Rates at or near their current levels will assist Hydro in achieving its financial objectives.

Hydro also believes domestic rates are less than market prices in nearby interconnected markets. Current rates are, on average, the lowest of any utility in North America. Lower rates may encourage more domestic consumption, which would reduce revenue as profitable export sales are foregone. Hydro agreed, however, that lower rates could attract more energy intensive industry to the Province.

In IFF 01-1 Hydro has forecast a 2% rate increases in 2004 and each year thereafter until 2009. Hydro indicated these future actual rate increases are at risk of being higher than those projected in the long range forecast in the absence of fortuitous events, such as higher export revenues or higher water flows. Furthermore, according to Hydro, a short-term decrease in rates may simply have to be recovered in future years, potentially leading to rate instability for customers. As rate stability was one of the overriding parameters, reducing and then subsequently increasing rates was not desirable. In response to the suggestion that rates should be set at a break-even level, Hydro stated domestic rates would have followed a widely fluctuating pattern with large rate decreases in 2001 during the windfall years followed by huge rate increases in the subsequent years. As such, it would be neither stable nor predictable.

17.0 Cost of Service Study

17.1 Purpose of a Cost of Service Study

A cost of service or cost allocation study is a tool used to assist in setting appropriate rates to be charged to each class of customer. The Cost of Service Study analyzes the components of Hydro's costs and assigns them to the various customer classes. The purpose of this analysis is to compare assigned costs to revenue by customer classes. The relationship of the revenues from a particular customer class to the assigned costs for that class is the revenue to cost ratio. A customer class where the revenues are equal to the assigned costs, would have a revenue to cost ratio of one. In Order 51/96, the Board stated in part that Hydro "should assume a revised zone of reasonableness target of 0.95 to 1.05" for all class revenue to cost coverage ratios. The results are used to provide guidance in establishing the rate levels and designing the rate structures for each customer class so that each customer class pays its fair share of costs incurred by Hydro to deliver service.

17.2 Methodology

Fully embedded cost of service studies generally employ a three-step process of cost analysis as follows:

- (a) Functionalization of costs according to services (or functions) performed by the utility. The major functions by which costs are assigned are generation, transmission, distribution and ancillary services.
- (b) Classification of each function's costs according to the system design or operating characteristics that caused those costs to be incurred. In the case of electric utilities, costs are generally classified as one of the following:
 - Demand-related costs - Allocated among the customer classes on the basis of demand imposed on the system during specific peak hours, and the maximum size (capacity) of facilities required to service the demand of customers.
 - Energy-related costs - Allocated among the customer classes on the basis of energy which the system must supply to serve the customers.

- Customer-related costs – Allocated among the customer classes on the basis of the number of customers, the weighted number of customers, or costs per customer.
- (c) Allocation of each functional and classified cost component to specific customer classes based on each class's contribution to the specific cost driver selected.

17.3 1997 Cost of Service Study

Hydro's 1997 Cost of Service Study generally follows the standard three-step process of functionalization, classification and allocation of costs to customer classes. The methodology was last reviewed in conjunction with Hydro's Application for 1996 and 1997 rates. In the resulting Order 51/96, the Board directed Hydro to make some methodology changes, to review a number of other matters, and to report to the Board by no later than the next GRA on a number of issues including the following:

- (a) An alternate method of solving the persistent problem of certain subclasses (e.g. Zone 3 Residential and General Service Large ("GSL") being outside of the zone of reasonableness.
- (b) The merit of considering GSL customers (over 100 kV) as a separate customer class for cost of service purposes.
- (c) An actual cost of service study for 1996/97 on Area and Roadway Lighting to determine actual conditions including the real coincident peak ("CP") factor.
- (d) The implications of using incremental versus embedded costs as they would apply to Hydro's rate design, including the impact on various customer classes.
- (e) Directly assign DSM costs for General Service Small ("GSS") and General Service Medium ("GSM") customers in future cost of service studies.
- (f) Continue with the present net export revenue allocation for cost of service purposes.
- (g) Develop a comprehensive rate policy which gives full consideration to all issues related to implementing time of use rates, including off-peak and seasonable rates. The study was also to include the implication of the phase out of the winter ratchet.

17.4 November 2001 Cost of Service Study

Hydro revised its cost of service methodology in the Cost of Service Study filed in November 2001 to:

- Recognize the changes in export energy markets that have taken place in the last several years;
- Recognize the significance of Hydro's participation in these markets to the pricing of its energy and transmission resources;
- Recognize the unique circumstances of Hydro's wholesale customer—The City of Winnipeg; and
- Address issues arising out of Orders 51/96 and 91/00.

17.5 March 2002 Cost of Service Study

Prior to the commencement of the hearing, Hydro indicated it was unable, for reasons of commercial sensitivity, to provide the information necessary to support its November 2001 proposed cost of service methodology. Also, subsequent to the original filing, Hydro and the City of Winnipeg entered into negotiations for Hydro to purchase the net assets of Winnipeg Hydro. Completion of this transaction would eliminate Winnipeg Hydro as a separate customer class and impact the cost of service analysis. As result, on March 27, 2002, and in accordance with Order 52/02, Hydro filed a revised cost of service study that included a number of modifications to its November 2001 filing. The Revenue Cost Average Analysis is attached as Appendix C and the Revenue Cost Variance Analysis is attached as Appendix D.

17.6 Functional Changes

17.6.1 Transmission Assets

In Hydro's 1996 cost of service methodology, all transmission lines and stations (including HVDC facilities) were included in the transmission function and, subsequently, allocated on the

basis of both demand and energy. In the March 2002 Cost of Service Study, Hydro proposed a number of changes in the functionalization of transmission assets:

- Hydro's HVDC facilities (with the exception of the Dorsey Converter Station which is considered transmission) are functionalized as generation;
- Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function;
- Four sets of AC transmission lines that serve as part of the HVDC collection system in the north to bring the power to the converter stations at Heday and Radisson are functionalized as generation;
- Radial (one way) transmission facilities, including those with voltages greater than 100 kV, are treated as sub transmission and included as part of distribution assets; and
- Local power lines and stations are treated as distribution.

The transmission lines and stations excluded from the transmission function continue to be treated as generation.

17.6.2 Ancillary Services

In its proposed cost of service methodology, Hydro has introduced a new function to capture the facilities and costs associated with providing the following ancillary services:

- Scheduling, System Control and Dispatch
- Reactive Supply and Voltage Control from Generation Sources
- Regulation and Frequency Response
- Energy Imbalance
- Operating Reserve-Spinning Reserve
- Operating Reserve-Supplemental Reserve

In previous studies the costs associated with these services were “bundled” as part of generation and transmission costs. To determine the costs of ancillary function, the assets and expenses associated with providing each of the above services were identified.

17.7 Classification Changes

17.7.1 Generation

Hydro’s pre-2001 cost of service methodology classified generation and transmission between energy and demand on the basis of system load factor. The methodology proposed in Hydro’s November 2001 study classified generation, transmission and ancillary service separately.

Generation costs were classified into four categories: winter energy, winter capacity, summer energy and summer capacity. The classification ratios were to be derived by multiplying the domestic energy and demand forecast by a five-year levelized forecast of Hydro’s marginal costs, which, in turn, reflected the export value of capacity and energy.

In its March 2002 revised cost of service methodology, Hydro generally returned to the pre-2001 approach and classified total generation and transmission (along with ancillary services) costs on the basis of system load factor. However, in the revised Cost of Service Study, transmission and ancillary services are classified wholly as demand-related. The balance of the demand-related

costs is assigned to generation and all other generation costs are classified as energy related. The result is that 21.2% of generation costs are classified as demand-related.

17.7.2 Transmission

Both the November 2001 and March 2002 cost of service studies classified all transmission costs as demand-related as opposed to classifying them on the basis of system load factor, as previously done by Hydro.

17.7.3 Ancillary Services

Hydro proposes to classify these costs on the same basis as transmission function costs - entirely demand-related.

17.8 Allocation Changes

17.8.1 Generation, Transmission and Ancillary Services Costs

Hydro's pre-2001 cost of service methodology allocated energy-related generation and transmission costs on the basis of annual energy use, including losses between the meter and the generators. Demand-related generation and transmission costs were allocated on the basis of each customer class' contribution to the coincident peak (where coincident peak was defined as the average load during the highest 50 hours of the year). Ancillary services were not separately identified in the previous Cost of Service Study.

In Hydro's March 2002 cost of service methodology:

- Energy-related generation costs are allocated to customer classes based on their share of the overall annual energy requirements (Non-Coincident Peak Methodology);
- Demand-related generation costs are allocated to customer classes on the basis of each customer class' share of the average of the top 50 coincident load hours during the months of December, January and February and June, July and August (2 Coincident Peak Methodology);
- Transmission costs are all classified as demand-related and allocated to customer classes based upon their monthly demands at the time of the system's monthly peaks, with all months given an equal weighting (12 Coincident Peak Methodology);
- Ancillary services costs (all considered to be demand-related) are allocated on the same basis as transmission costs (12 Coincident Peak Methodology).

17.8.2 Export Revenues

Hydro's net export revenues have grown from 17% of total revenues in 1993 to 43% of total revenues as forecast for 2002. As a result, the Cost of Service Study treatment of net export revenues now plays a significant role in the determination of revenue to cost coverage ratios for the various customer classes. For example, the revenue to cost ratio of the "GSL" customer class, based on the proposed methodology in the March 2002 Cost of Service Study, is 1.00, and allocated export revenues are approximately 39% of allocated costs. Alternatively, if export revenues are allocated to the GSL customer class using the methodology consistent with the Board's decision in Order 51/96, the revenue to cost ratio is approximately 1.12, and the allocated export revenues are approximately 49% of allocated costs. Different methodologies for allocation of export revenues can significantly impact customer class revenue to cost coverage ratios.

The previous cost of service methodology employed by Hydro in 1996, and approved by this Board, allocated export revenues as a credit to the various customer classes, based on the generation and transmission costs allocated to each customer class. The previous methodology was based on the premise that it was only the generation and transmission functions which

support the export of Hydro's surplus capacity and energy. The revised cost allocation study proposed by Hydro allocates net export revenues on the basis of each class of customer's share of all allocated costs (generation, transmission and distribution).

There was much discussion and debate during the hearing concerning the merits or otherwise of creating a separate export revenue customer class. While acknowledging that creation of an "Export Class" is theoretically possible, Hydro has not fully studied the matter and indicated there were issues, such as the identification of embedded costs, that would need to be determined and whether it is appropriate to include only long-term sales, all firm sales or all export sales in an "Export Class".

Hydro suggests its proposed change in the allocation of net export revenue yields results that:

- Are less distorting of the economic price signals for generation and transmission; and
- Address the Board's concerns as expressed in Order 51/96, including the concerns about class revenue to cost ratios falling outside of the "zone of reasonableness."

17.8.3 Winnipeg Hydro

The November 2001 cost of service filing by Hydro had proposed a number of modifications to the way generation and transmission costs were allocated to Winnipeg Hydro. However, as a result of the acquisition of Winnipeg Hydro, the revised cost of service methodology filed with the Board in March 2002 resulted in the following changes:

- Removal of Winnipeg Hydro as a class of service from the Cost of Service Study;
- Allocation of the costs formerly allocated to Winnipeg Hydro to all the retail classes on the basis of the appropriate allocators; and
- Allocation of the revenues anticipated from Winnipeg Hydro to all the retail classes on the same basis as export revenues.

Hydro's interim adjustment, to the Cost of Service Methodology, for costs and revenues associated with Winnipeg Hydro, was in recognition that the retail customers of Winnipeg Hydro will be incorporated into Hydro's retail classes in future cost of service studies. However, the load and cost data from Winnipeg Hydro was not available to permit such treatment in the March 27, 2002 amended methodology.

Both CAC/MSOS's and MIPUG's pre-filed evidence criticized Hydro's March 27, 2002 amended methodology for the treatment of Winnipeg Hydro as being inconsistent in its treatment of costs and revenues.

In its rebuttal evidence, Hydro acknowledged the inconsistency and suggested that a more appropriate interim cost of service methodology to exclude Winnipeg Hydro as a customer class, would be to subtract all costs expected to have been billed directly by Hydro to Winnipeg Hydro, from generation and transmission costs. Hydro also suggests it would be consistent with the balance of all costs incurred by Hydro's current customer classes.

Hydro has indicated that there is sufficient information available to revise the most recent Cost of Service Study and roughly assign Winnipeg Hydro data to the appropriate classes with a view to illustrating, on a directional basis, the impacts of the Winnipeg Hydro acquisition. A more precise prospective cost of service study for 2003/04 will be prepared.

17.8.4 Implications of Proposed Cost of Service Methodology

The March 2002 proposed Cost of Service Study includes the above-mentioned methodology changes. The results are at considerable variance from the results obtained under the methodology previously approved by the Board. The Revenue to Cost Coverage ("RCC") results under the proposed methodology are significantly affected by the proposed treatment of export revenues and the acquisition of Winnipeg Hydro. The RCC results by overall major customer class are shown in the following table:

Class	RCC Using Previous Methodology (51/96) For Year Ended March 31, 2002	RCC Using Proposed Methodology (March 2002) For Year Ended March 31, 2002
Residential	.884	.965
General Service Small (non-demand)	1.058	1.095
General Service Small (demand)	1.061	1.047
General Service Medium	1.073	1.044
Winnipeg Hydro	1.173	not applicable
Area and Roadway Lighting	.976	1.019
General Service Large	1.108	1.000

17.8.5 Zone of Reasonableness

One product of a cost of service study is a revenue to cost ratio by customer class, where unity, or revenue to cost ratio of 1, indicates that the costs allocated to a class is equal to the revenue earned from that class. The "zone of reasonableness" refers to the revenue to cost ratio range above and below unity that is acceptable. That is, the degree to which each customer class either underpays or overpays their share of allocated costs. Prior to 1996, the zone of reasonableness target was initially 0.85 to 1.15, then 0.90 to 1.10. In Order 51/96, the Board Findings stated in part that Hydro "should assume a revised zone of reasonableness target of 0.95 to 1.05."

The attached table summarizes revenue to cost ratios by major customer classes over the ten year period 1992 to 2002, and highlights certain customer subclasses that have consistently been outside of the zone of reasonableness for a considerable period of time.

**Revenue to Cost Coverage – Various Customer Classes
1992 to 2002**

PCOSS	1992	1993	1994	1995	1996	1997	1999	2000	2001	*2002
Res Z1	93.2	90.9	92.5	96.5	100.5	102.5	96.3	97.0	92.4	100.6
Res Z2	96.2	93.7	93.7	95.2	96.6	96.0	99.9	101.0	98.6	102.1
Res Z3	85.5	83.0	82.6	82.7	81.8	81.6	83.7	83.1	83.9	89.0
GSS	103.8	103.2	105.6	105.3	106.2	104.5	107.7	105.8	105.4	107.1
GSM	109.3	110.5	110.1	106.1	102.4	102.4	105.5	108.4	109.4	104.4
GSL<30kV	109.0	109.7	109.5	105.2	98.5	100.9	101.4	101.2	102.6	96.8
GSL: 30-100kV	122.5	117.5	114.8	111.8	109.4	108.1	110.3	112.0	118.8	109.4
GSL >100kV	110.9	111.8	111.6	110.9	109.5	111.1	110.8	111.0	116.7	100.1
OS Curtail							107.5	110.3	114.5	99.2

* Hydro's March 2002 proposed Cost of Service Study includes some methodologies, which have not been accepted by the Board.

18.0 Rate Design

18.1 Background

As part of its Status Update filing, Hydro is not seeking any change to firm rates currently charged to customers. Hydro's position is that any Board directed changes and modifications to the Cost of Service Study may impact rate design, and accordingly, the issue of rates should be deferred for future discussions at another hearing. However, Hydro agreed that this regulatory review was a good time to examine rate design issues on a purely principled basis, because Hydro was not requesting any rate changes.

In Order 51/96 the Board directed Hydro to "undertake a study and report to the Board by no later than the next GRA to develop a comprehensive rate policy which gives full consideration to all issues related to implementing time of use rates, including off peak and seasonal rates. This study should include consultation with interested parties and consideration of implications of the phase out of the winter ratchet." It was Hydro's position that matters relating to the problems of subclasses being outside the zone of reasonableness requires regulatory resolution before any other issues related to rate policy and strategy are considered. Hydro also indicated it has no intention of planning any major rate design changes over the next five years.

18.2 Uniform Rates

With the introduction of uniform rates by way of legislation in November 2001, rate zone distinctions for customers on the inter-connected grid were eliminated and all rates in the previous zones 2 and 3 were reduced to be the same as the rate charged in zone 1, which includes the City of Winnipeg. The financial impact of uniform rates is a decrease in revenues of approximately \$14.8 million in 2003, the first full year of implementation.

18.3 Residential Rates

The residential rate has a declining block structure which includes a higher energy charge for the initial 175 kW.h and a lower charge for the remaining block. Additionally a basic monthly charge of \$6.25 is intended to partially recover costs which do not vary with either demand or energy but which are incurred merely by being a customer on the system. These costs include those associated with billing, customer service, metering, meter service reading, and some portion of the distribution system. Currently the basic monthly charge recovers less than half of these actual costs, the balance of such costs being recovered by way of the energy charge.

18.4 General Service Small Demand and Non-Demand

These customers are the least homogenous of all rate groups. GSS customers are generally small retail and commercial operations. The basic monthly charge of \$14.00 for single-phase power or \$20.86 for three-phase power recovers substantially more customer related costs than does the residential basic monthly charge. The energy charge is also a declining block rate structure. GSS customers that exceed 50 kW.A are also subject to a demand charge.

18.5 General Service Medium

These rates contain a basic monthly charge, in addition to both demand and energy charges.

18.6 General Service Large

This customer class is broken into three different rate groups, depending upon consumption levels. There are no basic monthly charges for customers in this class. Those customers with the highest consumption levels are charged the lowest rates, because the largest consumers are served off the main transmission system, thereby not using sub-transmission or distribution facilities.

18.7 Time of Use Rates

A time of use rate varies according to the time in which the consumption occurs. During peak periods, customers are charged higher rates and are charged lower rates during off-peak periods. Time of use rates vary seasonally, weekly, daily, or hourly, and even extend to real time pricing. These rates provide a signal to customers of the variable costs of power.

In Order 51/96 the Board directed Hydro to undertake a comprehensive rate design study and include consideration of time of use rates, amongst other things. No such report has been prepared and no movement towards time of use rates is planned by Hydro in the near future. Hydro indicated it is planning to attach specialized meter reading equipment on more customers below the 1,000 kV.A threshold, namely the 250-1,000 kV.A level, of GSL and GSM, which will enable these customers to access time of use rates should Hydro develop such rates in the future. In doing so, this will remove a practical impediment to implementing time of use rates

18.8 Winter Ratchet

As part of the demand billing process, the monthly billing demand for general service customers is based on actual demand, with a minimum demand equal to 80% of maximum previous winter monthly demand measured in December, January or February. The rationale for the winter ratchet is to signal to customers the high costs of winter capacity and to ensure full winter demand costs are recovered. This issue is problematic for those customers with low off-peak energy usage relative to maximum demand.

The Board is aware that certain customers have been pressing Hydro for a waiver of demand charges during scheduled maintenance shutdowns. Their argument focuses on Hydro's ability to sell this available power on the opportunity export market. Under appropriate constraints with respect to timing and pricing, there could be merit in Hydro offering such a waiver to certain customers.

A report prepared by Hydro investigated alternatives to the winter ratchet including:

- Elimination or substantial reduction of the winter ratchet;
- Gradual reduction of the winter ratchet;
- Replacement of the winter ratchet with higher seasonal and/or peak prices; and
- Waive of the winter ratchet during selected periods.

If the winter ratchet were to be eliminated, the financial consequences would be approximately \$3-4 million less revenue annually for Hydro.

18.9 Limited Use Billing Demand

In seeking to address some issues with the winter ratchet, Hydro introduced the Limited Use Billing Demand ("LUBD") rate option in 2000. This allows eligible customers with low energy use relative to demand use to choose an alternate billing process. Under the LUBD program, customers may opt for a lower demand charge in exchange for a higher energy charge. The energy rate for a GSM firm customer is 2.12¢/kW.h whereas a LUBD customer pays 6.92¢/kW.h. The demand rate for that same firm customer is 8.32¢/kV.A whereas a LUBD customer pays 2.08¢/kV.A.

Originally approved for two years commencing June 30, 2000, Order 118/02 extended the LUBD on an interim ex parte basis so it could be considered in this hearing before the Board. Hydro is seeking final approval of Order 118/02 and to make the LUBD rate option a permanent rate offering.

The LUBD rate option is utilized by approximately 120 customers.

18.10 Surplus Energy Program

The Surplus Energy Program ("SEP") replaced the Dual Fuel Heating ("DFH") and Industrial Surplus Energy Programs ("ISE") in 2000. The rationale for those programs was that as a predominantly hydraulic utility, Hydro must plan to have sufficient energy capability to meet the demand of firm customers under the most adverse water conditions. As droughts occur intermittently, Hydro normally has surplus energy available most years. Hydro markets this surplus energy to Manitoba eligible consumers at rates comparable to export prices for similar energy services to enhance pricing options.

The ISE program permitted customers to obtain an alternate supply of energy through spot market energy when Hydro interrupted their supply. The spot market price was based on market conditions considering such factors as import and thermal costs, foregoing export revenues, transmission losses, a margin to account for overhead and administration, and a contribution to retained earnings. A minimum spot market replacement energy rate was in place, in addition to a varying weekly Energy Cost Adjustment and when the Energy Cost Adjustment was required Hydro would file such an application with the Board, on a weekly basis for interim ex parte approval.

The prices for the SEP are based on a forecast of the expected source of energy and associated costs. These are submitted to the Board on a weekly basis for interim ex parte approval, with rates broken into peak, shoulder, and off-peak hours.

At the time of closing arguments, a total of 116 interim ex parte weekly orders had been approved for the DFH and ISE programs, and 96 orders had been approved on an interim ex parte basis for the SEP. Hydro requested final approval of all orders issued on an interim ex parte basis prior to the Board issuing this order. No Intervenor addressed these orders in the hearing. A list of all ex parte orders relating to these programs is attached as Appendix E to this Order.

18.11 Curtailable Rates

Hydro has applied for approval of a new Curtailable Rate Program ("CRP") to supersede the existing Curtailable Service Program ("CSP"). The existing program, originally set to expire November 30, 2001, was extended to February 28, 2002 by Order 150/01 and then again by ex parte Order 55/02, until this Order was released. Hydro proposes the new CRP have a relatively short duration of until November 30, 2003 because the unknown impact of MISO's requirement for and value of reserves.

The CRP allows Hydro to curtail a portion of a large industrial customer's peak load in exchange for reduced rates on that same portion of the load when it was not curtailed. The objective of the CRP is to cut back on the electrical loads during specific periods when the overall electrical system was being taxed to its maximum capacity. As part of the Demand Side Management Program, the CRP reduces Hydro's peak load and assists in maintaining the essential power capacity reserves required for domestic and export operations.

Currently, nine curtailable rate options exist for customers, based on duration and notice for curtailment, in addition to price. Three customers now subscribe to the program, with a total subscribed load of approximately 100 MW. In 2001, the two customers who subscribed to the curtailable rates program saved \$1.96 million and \$380,000 respectively. Under the proposed CRP, five curtailable rates options will be offered to customers.

Under the proposed CRP, the rationale for curtailments will be altered to only instances required to meet reliability of the system and obligations to maintain operating reserves. There will be no curtailments to enable Hydro to make a high value opportunity sale; curtailments may, however, be made for firm export sales. Additionally, curtailments could occur for forecast errors, loss of facility, and restoring the operating reserve. Curtailments will not be conducted for peak shaving. In 2001, the overwhelming majority of curtailments (26 of 29) were for peak shaving and reducing imports. Since neither of those will be reasons for curtailment in the future, Hydro

expects only two to three curtailments per year under the new program, although there will be a maximum ceiling of 3 to 18 curtailments per year depending upon the option chosen.

The financial case for the CRP is based upon an expectation of 150 MW subscribed annually, for a \$4.3 million revenue savings to customers. With approximately \$1 million attributable to benefits easily quantifiable, the remaining \$3.3 million is attributable to reliability benefits not easily quantifiable according to Hydro witnesses. In 1998 (Order 153/98) Hydro presented an application to the Board to alter and extend the Curtailable Service Program. At that time, Hydro indicated there would be \$10.4 million in savings to ratepayers if the CRP were extended for a decade. With compounding effects, this would increase to \$26 million over that 10 year period. At this hearing, Hydro was unable to provide any tangible evidence whether part of this benefit had been achieved since 1998, noting that by their very nature, these benefits are difficult to quantify and reconstructing decisions made based upon existing circumstances at that time is nearly impossible with intervening events.

The proposed CRP has a reference discount which varies by percentage for each program option. Previously, the benefits had been calculated using the marginal cost values of capacity. The benefit of capacity curtailed over the winter peak was estimated to result from the ability to improve reliability and thus defer the timing of resource requirements. For summer, the benefit of capacity curtailed was estimated to result in increased revenues corresponding to short-term firm capacity sales. Previously the reference discount varied monthly, based on the US – Canadian dollar exchange rate.

In this application, Hydro has applied for a fixed reference discount of \$2.75/kW per month, to be adjusted annually for the Consumer Price Index. Hydro has also changed the calculation of the reference discount since Hydro now believes marginal costs are commercially sensitive information and the determination of a value was difficult. Now, Hydro is attempting to use reasonable judgment to balance the lowest value Hydro judges to be necessary to attract

sufficient curtailable load to make the CRP work, with the expectation that the load will be available in the long term where the capacity values to Hydro are expected to be higher. Accordingly, Hydro proposes the reference discount be ascribed a value of a reasonable relationship to an alternative least cost resource of capacity, namely a natural gas combustion turbine. In this instance, at \$2.75/kW, it is approximately 42% of the levelized cost of the combustion turbine.

With the reference discount previously subject to monthly fluctuations in currency exchange rates, Hydro had filed a number of interim ex parte applications for the CSP. In this application Hydro seeks final approval of the ex parte Orders listed in Appendix E of this Order.

18.12 Diesel Rates

There are approximately 800 customers in the four remote communities of Shamattawa, Tadoule Lake, Brochet and Lac Brochet, who are provided electrical service by diesel generation. These customers are not connected to the main grid due to remoteness of location. In 1997 nine other remote communities previously on diesel service were connected to the main grid. Recent upgrades have permitted the four remaining diesel communities to have similar residential service to those on the main grid with the exception of a prohibition of space and hot water heating.

The current full cost rate for providing diesel service was estimated at 35.9¢/kW.h. Residential diesel customers are charged the same rates as residential grid customers, thereby creating a shortfall of approximately 29¢/kW.h sold. Non-government General Service customers are charged the same rate as grid customers for the first 3,000 kW.h consumed per month and the full cost rate thereafter. Government customers pay the full cost rate. In addition to these full cost rates, all government customers pay a government surcharge intended to recover the deficit incurred by providing grid based rates to non-government diesel customers. The surcharge has

been in effect since 1984 and has escalated dramatically to 44.8¢/kW.h. This surcharge is in addition to the full cost rate of 35.9¢/kW.h.

Notwithstanding the government surcharge, a shortfall of \$250,000/month is accumulating since the costs of providing service greatly exceed the revenues generated. Up until 2001, the total revenue shortfall was \$7.4 million, with a \$3.2 million shortfall in 2001 alone.

Since November 2000, in response to a request by MKO, Hydro has billed all First Nations accounts, including government surcharges, directly to Indian and Northern Affairs Canada. In response, Indian and Northern Affairs Canada maintains it provides funding through a formula to the Bands to assist in paying their electricity bills, and returned the unpaid bills to Hydro.

Hydro filed an application for rates for diesel service dated December 2, 2002 and a public hearing is scheduled to commence on March 3, 2003.

19.0 Intervenor's Positions

19.1 CAC/MSOS

19.1.1 Financial Targets

CAC/MSOS questioned the need for Hydro to attain a 75:25 debt equity target to acquire capital at reasonable rates. CAC/MSOS stated the evidence presented by its witnesses, Mr. Todd and Mr. Harper, had confirmed that neither the debt equity ratio nor interest coverage ratios are determinative of Hydro's ability to access capital at reasonable rates. Rather, the key factor in establishing the credit rating is the health of the Provincial finances coupled with the sufficiency of the actual potential revenue streams. Mr. Todd stated neither the interest coverage ratio nor the debt equity ratio should impact Hydro's debt rating nor change Hydro's ability to issue debt, since Hydro's rating is primarily based on the existing Provincial debt guarantee. Mr. Todd noted Hydro's capacity to raise rates, if circumstances warrant, is the key indicator of its ability to meet its obligations in the event of a catastrophe, without posing a burden on the Province.

Further, as confirmed by Standard & Poors, "the existence of a strong and supportive Government and regulatory environment, including a debt guarantee fee, can outweigh somewhat weaker financial indicators." CAC/MSOS noted this was supported by the fact that Hydro's debt rating had remained unchanged, while its debt equity ratio has consistently improved, noting Manitoba still benefits from the same "A" rating now as in 1995 when its debt equity ratio was substantially weaker at 92:8.

Mr. Todd stated there was an inconsistency in Hydro setting an interest coverage ratio of 1.20 to collect an additional \$100 million cushion each year, when current reserves of over \$1 billion give Hydro sufficient financial protection from a drought. Mr. Todd further stated Hydro need not keep earning net income of \$100 million or more annually to be fiscally responsible and that instead of maintaining an interest coverage ratio of 1.20, building reserves even further, Hydro

could establish an interest coverage ratio of 1.0, resulting in lower rates set roughly in line with break even over the long run.

19.1.2 Risks

Mr. Todd stated that with more than \$1 billion in retained earnings, and 400,000 customers, each customer on average had contributed \$2,500 towards that retained earning. As a form of rate stabilization insurance, this was rather expensive according to Mr. Todd, and Hydro is seeking to increase the amount by another 50% to \$1.5 billion by fiscal 2008.

Mr. Todd stated it was not sufficient to justify seeking reserves of over \$1.5 billion on the basis of a cursory listing of risks. To determine analytically the extent to which it is appropriate to build financial reserves by setting rates that recover more than the normally allowed costs, it is necessary to define clearly the risks being mitigated. Defining the risks involves not only identifying them, but also quantifying the range of possible financial impacts of the relevant risk factors and the likelihood of different possible outcomes. In addition, it is necessary to understand clearly the purpose of mitigating the risk, so an assessment can be made of the appropriate risk tolerance to be adopted for purposes of establishing appropriate financial targets. According to Mr. Todd, risks which cannot be anticipated and built into the forecast should be the only risks requiring reserves.

CAC/MSOS suggested that Hydro's risk analysis consisted of identifying the financial impact of drought at \$1.3 billion and then merely listing other risks with no indication as to their impact or likelihood of occurring. Accordingly, such a superficial approach should be rejected in favour of a more vigorous quantitative risk analysis. CAC/MSOS supported its witnesses' recommendations on examining the risks to set an adequate reserve provision by undertaking the following:

1. Determine which risks require reserves – namely unanticipated and therefore not built into the forecast;
2. Consider the magnitude and probability of that risk occurring and recognize the relationship between the risks;
3. Consider the tolerable rate increase should the risks be realized; and
4. Ensure the risk analysis can justify the reserve provision.

19.1.3 Capital Expenditures

CAC/MSOS further suggested the current levels of reserves encourage higher than necessary capital expenditures and that Hydro could operate with a 5% lower capital budget without seriously impacting system capacity and reliability. Furthermore, Hydro's response to a worsening financial situation should be a decrease in capital expenditures rather than merely a requested rate increase.

19.1.4 Operating and Administrative Expenses

The evidence of Mr. Harper, on behalf of CAC/MSOS, suggested Hydro be encouraged to pursue aggressive cost control through productivity improvements to control operating and administration expenses. CAC/MSOS adopted the position of Mr. Harper in closing argument and advocated that Hydro should be evaluated on whether it could achieve annual productivity improvements of 1.5%. CAC/MSOS also suggested there exists opportunities for Hydro to reduce the operating and administration costs per customer.

Mr. Todd and Mr. Harper stated in their evidence that the target level for operating and administration cost per customer for rate setting purposes for the years 2000 to 2012 should be set at \$620/customer. Mr. Harper stated the \$620 benchmark would reflect a level of productivity typically expected of other regulated activities. Mr. Harper acknowledged Hydro

has built in a productivity factor in setting the operating and administration cost per customer target, but suggested that the bar be set higher, more in line with general industry expectations.

CAC/MSOS witnesses stated Hydro's performance in terms of operating costs per customer was in the middle to upper end of the cost range when compared to Hydro Quebec and BC Hydro. They also examined the operating and administration costs in IFF MH 99-1 and IFF MH 01-1, and suggested Hydro has room for improvement.

19.1.5 Load Forecast and Power Resources

CAC/MSOS witnesses highlighted that Hydro has adopted as an energy supply planning criteria that its system be capable of supplying sufficient energy from its thermal and hydraulic stations, under low flow conditions, to meet firm load demands (including firm exports). CAC/MSOS noted forecast export prices should be reflective of the price of natural gas. The cost of gas-fired generation is expected to increase with resulting increased opportunities for Hydro to export power, according to CAC/MSOS witnesses.

19.1.6 Revenue Requirement and Rates

CAC/MSOS argued that although a rate decrease would have been justified prior to the announcement of the special export profit payment, it would now be difficult to recommend one taking into consideration the impact of the payment on the net income of Hydro. CAC/MSOS suggested the Board consider a modest one-time only dividend of approximately 4% to reduce the net income forecasted for 2003.

19.1.7 Cost of Service

CAC/MSOS argued that one of the key questions in the proceedings is whether the Board should accept the narrow view of cost causation supported by MIPUG, or a broader view adopted by Hydro and supported by CAC/MSOS and CCEP. CAC/MSOS pointed out that historically,

export revenues were small relative to domestic revenues and costs, and at that time, export prices were less than domestic rates. Under that scenario, applying the principle of cost causality, efficiency, stability and public acceptability made some sense, as did the allocation of export revenues to generation and transmission only. Given the relatively low level of export revenues, this methodology was not distorting and was reasonably reflective of total costs.

CAC/MSOS pointed out that in the recent past, the export market has changed considerably, both in terms of the magnitude of sales, access to the market and Hydro's planning perspective. Net export revenues now offset over 52% of total generation and transmission costs. Mr. Harper stated the costs of generation and transmission allocated to customers have been increasingly underwritten by export revenues, causing an increasing disparity between costs allocated to high-voltage customers served off the transmission system and lower-voltage customers served off distribution.

Export sales now play a more prominent role in the planning and installation of generation and transmission resources, and rates from export sales are now higher than domestic rates in terms of dollars per megawatt hour. As a consequence, all things being equal, an increase in domestic loads will result in required increases in rates to the extent that export sales are reduced. This change in circumstance raises a fundamental question as to the fairness of the cost allocation process, and in the view of CAC/MSOS, a cost allocation methodology conceived in a far different time cannot endure. Mr. Harper stated since all customer classes contribute to the costs of covering risks associated with export revenues, it would be appropriate that all customer classes share in the benefit from net export revenues. Mr. Harper further noted Hydro's proposed methodology accomplishes this and eliminates the significant distortion the previous methodology created between the costs of generation and transmission versus distribution.

CAC/MSOS recommended not pursuing a separate export class at this point of time, suggesting two fundamental problems. The first problem was an analytical weakness, being that the export

rates are set by the market, and since the Board has no jurisdiction over these rates, there is a disconnect between the purpose of cost allocation, which is ultimately connected to the setting of rates based on embedded costs. The second problem was a technical weakness, being the difficulties and issues around the question of how to identify and allocate costs between export and domestic customers. This issue is further complicated by issues around commercial sensitivity of certain data related to export revenues and costs. CAC/MSOS acknowledged that although the concept of an export class of customer did not appear feasible or analytically defensible at the present time, that may change when future generation is built for export purposes.

Mr. Harper agreed with Hydro that capacity is the primary factor in determining the overall investment in transmission facilities and agreed that it was appropriate to classify transmission costs as 100% demand related.

CAC/MSOS also supported the allocation of demand related generation costs on a two CP method, which, in their view, is a major improvement in terms of cost causality. Given concerns regarding confidentiality to eliminate the need to rely on marginal costs and export prices to support the Cost of Service Study, Mr. Harper stated that it might also be appropriate to consider using the 12 CP method to allocate demand related generation costs.

CAC/MSOS also supported its witnesses recommendations for the Board to:

- Approve separating the costs of ancillary services from those associated with generation and transmission;
- Direct Hydro to study and report on whether these are alternative approaches to classifying and allocating generation costs that are more reflective of cost causation, and
- Accept the classification of ancillary services as 100% demand related and their allocation on the basis of 12 CP.

Mr. Harper further stated given the materiality of generation in the overall Cost of Service Study and the changes required with the integration of Winnipeg Hydro, it would be appropriate for Hydro to address the allocation of generation before the next GRA. Mr. Harper urged the Board to direct Hydro to study and report whether there are alternative approaches to classifying and allocating generation that are more reflective of cost causation. Mr. Harper further noted it would be inadvisable to adjust the relative rates of the retail customers based on the RCC results presented in the current Cost of Service Study.

19.1.8 Rate Design

With respect to the Curtailable Rates Program, CAC/MSOS adopted the four concerns of its witness:

1. The current reference discount price cannot be justified over the short, intermediate or long term, in terms of net benefit to firm customers;
2. The process for studying the reference discount price is excessively judgmental, which leads to issues of transparency;
3. The application of the load factor is overly generous and overcompensates customers, especially in light of the potential for new customers whose current patterns of usage may differ and diverge materially from the current customers; and
4. Given the uncertainty with MISO, it would be a more prudent regulatory course to continue with the current program until the position of MISO is more apparent.

CAC/MSOS recommended that the reference discount level be set such that it provides real financial benefits to firm customers over a defined period of not more than 10 years, that the reference discount should be benchmarked relative to a publicly available cross-reference that allows the continuing value of the program to be objectively monitored. Mr. Harper urged the Board to direct Hydro change its methodology for calculating the load factor adjustment basing it strictly on the load factor of the curtailable load. Mr. Harper further urged the Board to direct

Hydro to clarify the implications its association with MISO will have on the value of reserves and required terms and conditions, and file a proposal that reflects the anticipated value of the CRP program. CAC/MSOS further recommended that the current CRP should be extended to November 30, 2003, and no further.

On the subject of Uniform Rates, CAC/MSOS recommended that subclasses within the residential and general service categories be maintained, and there be a specific allocation of export revenues to the residential and general service classes to address the class revenue shortfalls arising from the implementation of uniform rates, sufficient to equate the revenue to cost ratios for zone 2 and zone 3 to zone 1.

Dealing with inverted rates, CAC/MSOS acknowledged that although an interesting concept whose time might come, the debate for inverted rates raises more questions than it resolves, and the time for inverted rates has not come yet. CAC/MSOS therefore recommended that the Board should direct Hydro to report back on the feasibility of adopting alternative rate designs, including inverted rates, for all customer classes that would encourage the efficient use of electrical energy, including an implementation plan for those alternatives considered appropriate.

19.2 CCEP

19.2.1 Capital Expenditures

CCEP agreed with the evidence of witnesses of CAC/MSOS that there appears to be less discipline being exercised over the level of capital expenditure as the overall financial position of Hydro improves. CCEP argued that when constrained by increased payments to the province and wanting to maintain financial targets, one option Hydro could explore, other than increasing rates, would be to control the level of capital expenditures. CCEP argued Hydro's capital budgetary requirements could be lowered if targets for export revenues were lowered and environmental initiatives such as the Selkirk fuel switching to natural gas project were deferred

until required by legislation. The justification for certain projects was not rigorous enough and as such, some other justifiable projects might be dropped.

Given the potential savings in operating and administrative expenses and capital expenditures and the potential for better than forecast export revenues, CCEP stated there is a possibility that there would be more funds available to provide rate relief to ratepayers.

19.2.2 Extra Provincial Revenues/Operating and Administrative Expenses

CCEP stated Hydro, since the last GRA, consistently underestimated export revenues citing evidence of CAC/MSOS that export revenue projections are likely conservative and Hydro will likely outperform its current financial forecast. CCEP also stated that Hydro could fare better than forecast and realize some \$100 million in savings if operating and administrative expenses were held to a benchmark of target \$620 per customer in 2012 as proposed by the witness for CAC/MSOS, rather than \$664 per customer currently forecast by Hydro.

19.2.3 Payments to the Province

Although outside the Board's jurisdiction, CCEP urged the Board to consider the financial effects of the increased payments to the Province. At \$354 million, just over 25% of Hydro's gross revenues are paid to the Province of Manitoba – amongst the highest in Canada. CCEP further stated the Province, as the shareholder of Hydro, has a role to play in assisting Hydro in reaching its appropriate targets without unduly or adversely affecting ratepayers.

19.2.4 Revenue Requirement And Rates

CCEP argued if the Province and Hydro are confident increased payments to the Province are sustainable, then a modest rate decrease of 1% to 2% to the benefit of ratepayers should also be included. This small rate reduction will still provide Hydro with sufficient reserves to face its greatest risk, the possibility of a five-year drought.

19.2.5 Transmission Tariff

In assessing the Board's jurisdiction over the wholesale Transmission Tariff, CCEP urged the Board to view the legislation broadly, and argued that the provision of power should include a transmission tariff as a necessary component of electrical power.

19.2.6 Cost of Service

CCEP stated that they have taken on the mandate of representing the interests of the GSS customer class, a non-residential customer class, whose demand and energy profiles are often similar to residential customers. CCEP also has a mandate to promote better energy policy and understanding of relevant energy issues. Accordingly, although CCEP advocated on behalf of the GSS customer class, it does not do so to the exclusion of improved energy policy.

In CCEP's view, the principles of equity and improved energy policy, in particular the principle that customer classes should pay rates in accordance with the costs of serving that class, require some redress at the earliest opportunity in favour of the GSS class. CCEP pointed out that the revenue to cost "zone of reasonableness" for Hydro customers has been established by the Board between 0.95 and 1.05, and the different cost of service studies reviewed show the GSS customers to be above the zone of reasonableness. The revenue to cost ratio for the GSS customer class, as a whole, is 1.07, and the non-demand sub-class, representing in excess of 40,000 customers, is 1.09. Since the GSS customer class has been outside the zone of reasonableness for some time, and is the only major customer class that remains outside the zone of reasonableness in accordance with the March 2002 study, CCEP strongly advocates immediate redress.

CCEP accepted Hydro's position that the entire Hydro system, including those portions of the system built to support export sales, are built at the risk of all Hydro domestic customers. It is therefore appropriate to allocate export revenues to all functions of the Cost of Service Study,

even though the position of the GSS class is nearly unaffected by the methodological change. Accordingly, CCEP disagrees with the MIPUG argument that the GSL customer class pays rates which are even greater than the GSS class, relative to cost of service, since this argument by MIPUG is based on the former methodology of allocating export revenues. CCEP also discounted the argument by certain MIPUG members that electricity costs comprises a large portion of their costs, arguing that issues of economic development and employment policy should not be an issue for cost of service and rate design proceedings.

CCEP argued that if the Board accepts the position of Hydro, supported by CAC/MSOS and CCEP, that Hydro's proposed COS methodology changes, including allocation of export revenues, are appropriate, then the only class continuing to pay more than their cost of service is the GSS class. CCEP further argued that Hydro's proposal to rebalance rates at the next GRA was unacceptable because the ultimate timing of that application was uncertain. Therefore, CCEP requested the Board to direct Hydro to institute a rate decrease to the GSS class at the conclusion of this proceeding of \$5.3 million, or 3.8%, in order to bring the GSS class to the top of the zone of reasonableness of 1.05. Alternatively, a rate reduction in the range of \$17.7 million or 12.5% would be required to bring the GSS class to unity. CCEP argued that such a rate decrease could be implemented without changing the rates of other customer classes, and with no adverse effects on other revenue to cost ratios.

19.3 MIPUG

19.3.1 Financial Targets

In MIPUG's view, achieving a 75:25 debt to equity ratio and an interest coverage target of 1.20 were laudable goals from an internal corporate perspective. However, they were not appropriate from a cost of service regulatory perspective. The issue to be considered is whether domestic ratepayers should contribute towards achieving Hydro's internal goals beyond that required to enable Hydro to provide safe and reliable electrical service. MIPUG further noted although

existing reserves exceed \$1 billion, the debt equity ratio would be impacted by the additional debt related to the purchase of Centra, and as a result, rate increases may be required to maintain the debt equity target.

19.3.2 Risks

MIPUG argued that evidence presented by its witnesses demonstrated the existing reserves are more than adequate to achieve the regulatory goals of running the utility and providing a safe and reliable electrical service, and agreed with the witnesses of CAC/MSOS that the existing reserves are beyond what is necessary to protect against the material risks faced by Hydro and are now more than adequate to deal with the risk of drought.

19.3.3 Capital Expenditures

MIPUG argued Hydro's capital program mirrors the rise in export revenues, and capital expenditures increase when export profits are high. MIPUG stated Hydro's capital expenditures have exceeded their 1996 forecast and are now expected to result in \$1 billion more in capital assets by 2006 than was expected at the time of the last GRA. MIPUG argued that given the strong export markets, the trend towards acquiring more and more capital assets is likely to continue, and there is not the same level of restraint in controlling capital expenditures that would be required in lean years. MIPUG stated Hydro's decisions about the amount of capital spending increases the burden on domestic ratepayers due to increased interest costs and depreciation in future years.

19.3.4 Operating and Administrative Expenses

The witnesses for MIPUG noted Hydro has been diligent in operating cost control through most of the period under review and that there have not been any increased operating costs, with the exception of fuel expenses, to parallel the increases in revenues. Mr. Osler and Mr. Bowman indicated throughout most of the period since the last GRA, Hydro has functioned with less

operating expenses than in the IFF H 95-2 forecast. The witnesses indicated the forecast future increase in fuel expenses is related to exports because the large amount of fuel to be used by the Brandon Combustion Turbine and the Selkirk Generating Station is used to produce power for export purposes.

19.3.5 Load Forecasts and Power Resources

MIPUG expressed concern about the potential shift in prioritization within Hydro from a domestic supply-oriented utility to an export sales-oriented utility, which discourages domestic use. MIPUG further stated Hydro is first and foremost here to serve Manitobans and low electrical rates can have the benefit of attracting more industry and associated job opportunities to Manitoba. MIPUG urged the Board to be vigilant, noting Hydro has signalled a shift away from a domestic focus, discouraging the use of power in Manitoba in favour of selling into the more lucrative extra-Provincial markets.

19.3.6 Payments to the Province

MIPUG agreed with CAC/MSOS that Hydro's risks are somewhat overstated and Hydro likely will continue to exceed its current revenue targets. MIPUG noted Hydro is nowhere near becoming a risk to the Province. Mr. Osler, who presented evidence on behalf MIPUG, stated that there has been a substantial improvement in Hydro's forecast revenues and financial situation, compared to the forecasts that were provided in the last GRA. Hydro had exceeded its 1996 forecast export revenues over the 10-year period 1996 to 2006 by some \$1.63 billion. MIPUG noted the biggest beneficiary from this improved financial position continues to be the Government of Manitoba rather than domestic ratepayers. MIPUG noted that payments to the Province have increased by \$800 million over the 10-year period 1996 to 2006, approximately half of the additional \$1.6 billion in export revenues, of which only 11% had actually gone to the general benefit of customers through foregone rate increases.

MIPUG suggested increasing payments to the Province is another risk faced by Hydro and that given the increased payments, the Province does not appear overly concerned with the current progress Hydro makes towards reaching its financial targets. MIPUG is satisfied Hydro could adequately address its risks, even with these increased payments to the Province, and further noted that increased equity levels would likely benefit the Province and not the ratepayers - something MIPUG urged the Board to consider in setting rates that may contribute to increased equity levels.

19.3.7 Revenue Requirement and Rates

MIPUG argued when forecasts are scrutinized, it is apparent that rates should not be increased. In addition, MIPUG argued there is some room for a rate decrease based on the fact that the future outlook suggests that the financial expectations of Hydro will be surpassed and that the current reserves are sufficient to protect customers without requiring them to contribute unnecessarily to the achievement of financial targets. Further, MIPUG argued Hydro has not discharged their onus of establishing that the overall level of rates are just and reasonable.

MIPUG argued that the revenue requirement was overstated by Hydro, the existing level of reserves are more than adequate, and rate decrease in the amount of approximately \$15 million could be achieved without increasing rates to other customer classes.

19.3.8 Transmission Tariff

MIPUG argued that since power was not part of the transmission service, the Board's jurisdiction over the tariff did not exist because the Board's jurisdiction was confined to reviewing rates for service for the provision of power.

19.3.9 Cost of Service

MIPUG asserted that Hydro's sales rates have long been set based on the principle of cost causation, and the Board, in fulfilling its responsibility to determine whether the rates charged by Hydro are just and reasonable, must consider the evidence in support of Hydro's revenue requirement and Cost of Service Study. MIPUG further stated that the principle of cost causation has long been used in this jurisdiction because it works, and because it satisfies the ratemaking principles of rate stability, predictability, transparency and public acceptability. MIPUG further argued that the cost causation principle has been refined over the years, has stood the test of time, and there is no reason to depart from that principle today.

With historic revenue to cost ratios generally exceeding 1.05, MIPUG argued for a rate reduction of \$15 million to comply with Order 51/96 and to bring the "GSL greater than 100 kV sub-class into the zone of reasonableness. MIPUG argued that a rate freeze does not address the problem of a sub-class paying rates that chronically exceed costs. The witnesses for MIPUG stated there is a demonstrable need and opportunity to provide substantive rate relief to industrial customers who have been paying rates above costs for more than a decade. MIPUG believes the time for solution is now, not only because rate relief for the sub-class is overdue, but also because Hydro's favourable financial situation at the present time creates an opportunity to make progress in bringing the sub-class towards the zone of reasonableness without negatively impacting other customer classes. MIPUG argued that there should be no further delay in rate relief.

MIPUG supported its witnesses' position that some changes to Hydro's Cost of Service Study have departed from cost causation, most notably the treatment of export revenues. The change in the methodology to allocate export revenues is also based on the premise that domestic rates in Manitoba are already as low as they need be, which in MIPUG's view, is a premise that has not been tested or accepted by the Board. MIPUG further argued that no other regulated jurisdiction

sets rates other than on cost based principles, and that cost based principles are resilient enough to apply to a range of changing circumstances, including a large increase or decrease in export revenues, and the future construction of Wuskwatim for export purposes. The witnesses for MIPUG stated that it is apparent that the revised methodology has mathematically achieved what Hydro has been unable to achieve through rate revisions over the past decade. MIPUG believes that a primary motivation for Hydro to depart from a cost based allocation methodology is Hydro's desire to bring the revenue to cost ratios for all subclasses closer to unity without having to reduce rates.

In MIPUG's view, the established practice of allocating net export revenues to generation and transmission is consistent with the costs of getting those export sales in the first place. Since generation and transmission are the only functions responsible for supplying the power to the export market, the revenues earned from the export market should be used to offset those costs. In addition, since all Hydro customers use the generation and transmission assets, all customers do receive a benefit from the export revenue allocation, in proportion to each customer classes use of those assets.

MIPUG stated that the non export revenues related changes to Hydro's cost of service methodologies have a relatively minimal impact on the revenue to cost ratios of the subclasses in comparison to the changes in allocation of the net export revenues. The witnesses for MIPUG stated the proposed changes to the Cost of Service Study methodology dramatically redefines the measurement of costs to service customer classes and serves to shift material net costs away from residential customer classes onto industrial customer classes.

MIPUG does not support the creation of a separate export customer class, noting the difficulty in identifying the embedded costs associated with earning the export revenues. MIPUG suggested that the Board could direct Hydro to study further the issue of embedded costs for export revenues, but noted that Hydro was directed to do this in 1999 and did not do so. MIPUG

requested that the Board's decision on this matter should not delay the issue of immediate rate relief.

The witnesses for MIPUG noted there is a minimum basis to adopt any of the proposed changes to the Cost of Service Study methodology and that the past cost of service practice remains suitable for the present domestic situation, and therefore recommended retaining the previously approved cost of service approach. The witnesses further stated that the classification of transmission costs on a basis of 100% demand (based on a continued allocation using a 1 CP methodology) may have merit. In addition, they recommended the assignment of some level of "system dividends" to all customers limited to net export revenues net of all embedded costs to serve these loads. However, MIPUG stated the proposed changes to not functionalising HVDC to generation, changes are perhaps not necessary, they can be supported by cost causation, and therefore, MIPUG is not opposing the proposed change. MIPUG also believes that the previous method of classifying each of transmission and generation on the basis of system load factor is preferable over the complicated and unprecedented two-step classification approach proposed by Hydro.

MIPUG also argued that there is only one key time of the year which drives the costs on the Manitoba system, and that is winter. Therefore, under the cost causation principle, the only approach that relies on established principled rationale is the retention of the 1 CP method, based on winter peak load, for both transmission and generation.

With respect to the treatment of Winnipeg Hydro costs and revenues as export sales, MIPUG's witnesses stated this ignores that Winnipeg Hydro's costs and revenues are matched with both entirely related to generation and transmission. Instead, Hydro's proposal results in the costs previously allocated to Winnipeg Hydro's being reallocated back to other customers on the basis of generation and transmission, while the revenues are reallocated back to other customers on the basis of generation, transmission and distribution. This fails to maintain the matching of costs

and revenues and fails to reflect cost causation. Accordingly, there is no basis to adopting this interim approach.

19.3.10 Rate Design

With respect to the CRP, the witnesses for MIPUG stated the CRP continues to be the most substantial capacity related Demand Side Management program offered by Hydro and continues to provide value to the utility and its customers in terms of reliability and support of increased high-value firm export sales. MIPUG argued that although the program is relatively small program compared to Hydro's firm rate offerings, it is none the less an important program for certain large industrial customers and strongly supported approval of the Curtailable Rates Program on a permanent basis, subject to the reference discount being adjusted to remove the 12% reduction, to revert to an 80% equivalency factor, and to re-introduce the U.S. exchange rate for the summer generation portion of the benefits.

19.4 TREE/RCM

19.4.1 Capital Expenditures

TREE/RCM argued that Hydro's capital requirements could be lowered if appropriate incentives for reduced energy usage were put in place. With enhanced energy efficiency major new transmission and generation would be unnecessary.

19.4.2 Extra Provincial Revenues

TREE/RCM commended Hydro for its efforts in expanding export sales and stated Hydro had been successful in exploiting opportunities in the North American energy market through their initiative and would like to see Hydro apply such similar talents and skills to an aggressive demand side management policy. TREE/RCM noted that an aggressive demand side management policy and the inverted rate structure may be unduly harsh on the 35% of

households in Manitoba reliant on electric heat and that some revenues would be required to mitigate these effects in the short run. Accordingly, some revenues from the export market should be used to enhance energy efficient installations in Manitoba homes.

19.4.3 Load Forecast and Power Resources/Revenue Requirement and Rates

TREE/RCM argued the Board should consider the conservation interest and sustainable development in its rate-setting, and realize that low rates are not necessarily the only or even prime consideration in determining rates. TREE/RCM argued for an overall rate increase to enhance the revenue requirement such that the additional monies could be used for conservation purposes, to enhance DSM programs for residential customers, and, in particular, to finance the transition to the inverted rate structure, especially for residential customers reliant upon electric heat.

19.4.4 Rate Design

The intervention by TREE and RCM was to examine Hydro's operations and rates for their impact on energy conservation and consequent impacts on local and global eco-systems. TREE/RCM stated that Hydro has sales rates that are amongst the lowest in the world, and generally speaking, low rates have a negative impact on energy efficiency because it is affordable to waste energy. Peter Miller, a witness appearing on behalf of TREE/RCM, noted because of the low rates, it is more cost effective, or at least affordable, for the consumer to waste energy than to spend money on energy conservation. TREE/RCM's objective is to get Hydro to adopt policies that better promote principles of sustainability, emphasizing energy conservation and environmental impact reduction and mitigation. Peter Miller, on behalf of TREE/RCM, stated in setting rates Hydro should interpret its mandate as being to secure the best possible "triple-bottom-line" including social, environmental and economic outcomes in its

operations. TREE/RCM argued that despite well-expressed intentions, Hydro has not been aggressive in their DSM efforts and in promoting conservation and efficiency.

TREE/RCM brought forward Mr. James Lazar, a regulatory consulting economist, as a witness to address the benefits of adopting an inverted rate structure for residential customers. This would have an initial rate inversion based on the low cost power on the older Winnipeg River System which has no high cost lengthy HVDC transmission lines. It would then be enhanced by an additional rate inversion based on the relative load factors of different size residential customers, which consumes higher cost more modern Northern generation with associated lengthy transmission facilities.

Mr. Lazar, appearing on behalf of TREE/RCM, proposed the adoption of an inverted rate structure. The structure provides each customer a limited amount of power at one lower price per kilowatt hour and additional usage provided at a higher price per kilowatt hour. This contrasts with the current rate structure utilized by Hydro; a declining block structure, where larger customers pay a lower rate per kilowatt hour than smaller customers. Mr. Lazar noted that an inverted rate structure would be appropriate in Manitoba because it communicates the fact that the utility has only a limited supply of low-cost power and distributes the benefit of low-cost hydro resources uniformly among customers while the current declining block rate structure gives the largest users the largest share of the benefit.

Mr. Lazar further stated the inverted rate structure was most appropriate for Hydro, because it has two very different sources of power supply, including the older system on the Winnipeg River that provided a limited supply of low-cost power that could be recovered by the lower block rate and newer more expensive facilities in the north which provide a larger supply of power at higher debt service costs on dams and transmission, that could be recovered at a higher block rate.

Mr. Lazar recommended the following changes be made to implement an inverted rate structure:

- Flatten the customer demand charge to \$6.25/month regardless of the connected average.
- Provide each customer an initial block of 250 kW.h/month at a rate of \$0.02/kW.h lower than the rate for additional usage. Any further revision could await cost studies on the amount of low cost power and how to distribute export profit.
- Hydro undertake a stratified load research study of its customers and their respective end use electricity to determine if large use customers have a diversified load factor that is different from small customers to develop de-averaged distribution rates.

Mr. Lazar stated the impact on residential customers would result in those using less than 250 kW.h/month realizing a rate decrease of 32%. Large use residential customers (3,000 kW.h/month) would receive an increase of 8% noting further that very few customers would see large changes to their bills. However, as a result, all consumers would have a greater incentive to conserve electricity. Mr. Lazar stated the benefit of such a structure would be approximately a 4-5% less usage per customer than the current residential rate design.

Citing the principles of the Sustainable Development Act which TREE/RCM argued was applicable to Board decisions, TREE/RCM made nine recommendations as follows:

1. An explicit goal be added to the Power Smart program to increase the eco-efficiency of the energy supplied by Hydro.
2. Adopt methods for measuring absolute and relative efficiency performance for different customers and end use classes.
3. Consider for adoption comparative efficiency performance measures.
4. Adopt a more aggressive conservation program for the residential sector.
5. Create a rate regime in which each customer faces tail-block rates that are much closer to the marginal costs of electrical demand and energy.

6. Hydro be directed to file an inverted rate for residential customers holding the customer charge to \$6.25, providing the first 250 kW.h block of power at a rate of \$0.038/kW.h and additional power at the level needed to make Hydro revenue neutral, estimated to be approximately \$0.059/kW.h. Alternatively, the Board could direct Hydro to file an inverted rate structure to give a larger low-cost block to all electric residential customers. A third alternative would be to have a minimum bill to replace the basic charge.
7. Hydro be directed to prepare load research on the relative load shape and load factor of large versus small use residential customers on the generation, transmission and distribution system.
8. Hydro be directed to study options for general service rate design changes to improve the efficiency of pricing information to customers.
9. Hydro be directed to implement an energy efficiency grant program funded from initially up to one quarter of the net export revenues.

TREE/RCM believes that adoption of their recommendations will strengthen the economy of Manitoba and reduce the adverse environmental impacts of energy production and consumption in the region and globally.

19.5 MKO

19.5.1 Rate Design

MKO stated that with the exception of the hydroelectric operations on the Winnipeg River, all of the existing and planned hydroelectric stations of Hydro are within the MKO region and directly affect the rights, interests, communities and traditional territories of the 12 MKO First Nations. MKO generally supports the basic principle of uniform rates established by legislation effective November 1, 2001. MKO further stated that, in respect of the rate rebalancing proposed by some interveners, as long as rates are less than those approved to be effective November 1, 2001, it appears doubtful the Board can alter the rates that went into effect after November 1, 2001 until Hydro applies by way of a GRA to change rates.

With respect to diesel rates, MKO argued that the First Nations communities do not have the financial resources to pay their electricity bills that are being assessed, which creates a circumstance that must be addressed. Although all residential customers in the diesel communities do pay the equivalent zone 1 rate, all consumption over 3,000 kWh for non-government customers and First Nations facilities are assessed a surcharge, which in the view of MKO, is not consistent with the legislation. Therefore, the intent of uniform rates should be extended to all remaining customers in the diesel communities and all ratepayers, regardless of geography to pay the same rates. MKO further argued that Hydro has not exercised its duty to diesel community customers to promote economy and efficiency in the use of electricity. On that basis, customers have been exposed to substantial costs, and Hydro should assume the costs to the remaining customers in the diesel communities, and provide benefits to those customers that are being shared by other Manitobans.

MKO also suggested that Hydro should aggressively promote demand side management initiatives in the diesel communities, as well as seek alternative sources of supply to serve the communities in a more cost effective way.

MKO issued a subpoena to Mr. Fred Mills of Indian and Northern Affairs Canada to discuss the nature of the funding provided by Indian and Northern Affairs Canada to First Nations in respect of electricity costs. Mr. Mills testified that a formula pays for what is, in essence, a nominal amount of the electricity bills incurred by all First Nations government accounts, which could include schools, police stations, band offices, social services offices, etc. Mr. Mills also testified that Hydro and Indian and Northern Affairs Canada are really not involved in trying to resolve issues arising out of diesel rates.

19.6 PCW

19.6.1 Rate Design

PCW did not speak to the specifics of the status update, but expressed particular interest in the future regulation and public accountability of Hydro. PCW expressed concern for the increasing instances where the Government of Manitoba has denied Manitobans the opportunity for public scrutiny, and referred specifically to the implementation of Uniform Rates, the increases in government charges to Hydro, and the acquisition of Winnipeg Hydro, all done outside of the scrutiny and review of the Board. PCW argued that by far the most effective oversight of Hydro is by public process directed by the Board, and expressed concern that it took over six years for Hydro to apply to the Board for this Status Update hearing. PCW also expressed concern as to what future legislation the government might introduce to further diminish the Board's oversight role.

PCW endorsed the Board's role as a proxy for competition, and stated that Manitobans need regular review of Hydro by an informed watchdog, looking out for the public interest. PCW requested the Board to consider the timing of future reviews of Hydro.

20.0 Presenters' Positions

20.1 HBMS

HBMS is a base metal mining, smelting, and refining business in northern Manitoba. Together with the Mining Association of Manitoba, in 1999 HBMS proposed a variable rate structure that would strengthen its operation in low price periods and share the benefit of high price periods with Hydro. Applying this approach to multiple industries would diversify the utility's risk while ensuring continued strength of the Province's major economic drivers and Hydro customers.

HBMS argued that large power users in this Province have paid a disproportionate portion of the rates charged to Hydro customers over the last decade. Hydro's industrial rates should more closely reflect the costs of producing and delivering electricity. A 10% reduction of GSL (over 100 kV) rates, to reflect more closely Hydro's actual cost of service, would have significant beneficial effect on any decision for future energy-intensive capital projects and improve the allocation of rates in the Province and enhance the long-term strength of significant customers and economic drivers of the Manitoba economy.

20.2 Inco

Inco, is a nickel mining company in Thompson. Inco stated increased debt guarantee charges, water use rates, and other cash extractions have resulted in a net transfer to the Manitoba Government. Inco stated that short-term export profits or long-term direct employment in Manitoba is a government policy choice. The 1,400 direct jobs, the support services jobs, and the revenues that they create for Hydro, as well as the taxes this employment generates affects Inco's competitive position. Inco believes that leveraging electricity rates to create and maintain jobs is paramount to protect the ratepayers from volatile energy markets.

Inco pays a demand charge winter ratchet for unused electricity in their scheduled summer shutdown. However, this electricity is sold again on the spot market. Inco suggested that Hydro stop charging twice for the same products.

20.3 Simplot

Simplot is an integrated fertilizer plant which manufactures nitrogen and sulphur based fertilizers as well as a limited range of industrial nitrogen products. Simplot submitted that Hydro costs and rates must remain subject to rigorous examination by the Board. Simplot is concerned that, while Hydro is not requesting a rate increase with this submission, it appears to be positioning itself for a series of rate increases over the immediate future. Simplot was disturbed that the provincial government continues to increase its revenues through special levies on Hydro.

The apparent shift in Hydro's priorities, away from its domestic customers to its export sales is of concern to Simplot. This shift has resulted in Hydro's stated position, in this filing, that domestic electricity rates are "as low as they need to be", and the further assertion that failure to recognize the real value of electricity (i.e., export value) could result in the diversion of energy from profitable export sales to energy intensive domestic industries.

Simplot, together with other members of MIPUG, have maintained that Hydro's rate structures impose an unfair burden on the GSL (over 100 kV) rate class. Hydro's response to the Board's Order, as evidenced by its Prospective Cost of Service Study, has been to develop a new method of service calculation to bring all rate classes with the zone of reasonableness, rather than to adjust the rate structure itself. Reducing firm power costs by 11% would significantly improve the competitive position of all large industrial power users in Manitoba.

Simplot optimistic that Hydro will be able to agree on a proposal that would provide Simplot and other large industrial customers some relief from the demand charge winter ratchet during scheduled plant maintenance shutdowns.

20.4 Nexen

Nexen uses an electrolytic process to produce sodium chlorate, which is used to bleach wood pulp. Nexen requested that the Board consider the presentations made by MIPUG in light of the competitive challenges faced by Nexen, and other energy intensive industries in Manitoba, and help them retain their competitive positions. Nexen is currently a curtailable rate program customer. In 1998-2000, Nexen participated in the Industrial Surplus Energy program. However, as export power prices continued to rise, Nexen could not justify participating in the program. The introduction of Curtailable and Industrial Surplus Energy programs in the latter years has also been a positive factor in convincing Nexen's Board of Directors that expansions should occur in Manitoba. Dedication to providing reliable firm power at fair and reasonable rates that reflect cost of service and commitment to innovative rate options that benefit both industry and Hydro are important for the future growth of large industry in Manitoba.

Competitive power rates encourage new growth in the industrial sector. In 1994, the Board's direction to move firm industrial rates as close to cost as possible, and the subsequent 1994 reductions in provincial taxes on manufacturing energy purchases have both had significant positive impacts on Nexen's production in Manitoba, and in Nexen's commitments to capital expansion in this province.

20.5 Presentation of C. Nicolaou

Dr. Nicolaou, a Professor of Economics at the University of Manitoba, stated that the GSS class needs serious attention by the Board. Rates for the GSS class require modification to relieve the sector from a long-term burden.

Growth prospects of the Province rest squarely upon the small business sector. The typical small business is often, by its nature, ill-prepared to deal with adverse conditions. Without pressure from the unrepresented small business sector, and without representations to the Board, the small

business sector has the highest revenue cost coverage above the Board's zone of reasonableness. Small business over pays \$15-17 million annually.

The simplest, most direct and immediate redress of this long-term disadvantage imposed on small business is for Hydro to be ordered to lower rates for GSS, to bring the RCC to unity. The current and long-standing overpayment by the small business sector must end immediately. However, even this measure would not return past overpayments. Relief should be given to the class which is not only crucial for Manitoba's economic development but is also in need for even the smallest amount of assistance.

21.0 Board Findings

21.1 Operating Results and Financial Forecasts

The Board notes that for the fiscal years 1996 to 2001, Hydro has experienced actual financial results that are dramatically better than the results forecasted in IFF 95-2. The improvement in Hydro's financial results is due primarily to favourable water levels and market conditions, and the successful implementation of a strategy to develop extra-provincial sales opportunities. The Board commends Hydro for its proactive approach and effective execution of a strategy to capitalize on and adapt to the changes in the export market, brought on in part by the introduction of competition in the wholesale export market. Through membership and participation in MAPP, MISO and other key committees and organizations, and proactive marketing efforts, Hydro has been able to represent its interests and more than double the revenues related to extra-provincial sales since 1996. This has resulted in record profits, improved financial strength and stable rate levels for Manitoba consumers. The Board encourages Hydro to continue its active participation in MAPP and MISO and marketing efforts, which have resulted in benefits to Manitoba ratepayers.

Extra-provincial revenues now have a greater prominence within Hydro than in 1996, representing an increasingly significant portion of Hydro's total revenues. Risks related to losing those revenues have also increased substantially since 1996.

The Board notes that IFF MH 01-1 is based upon many assumptions which are beyond the control of Hydro. In the Board's view, IFF MH 01-1 represents a conservative forecast using reasonable assumptions. The IFF assumes a decline in export revenues through 2010 with a subsequent increase in 2011 and 2012. The Board believes Hydro has been conservative in its planning and its projection of future export revenues given historical increases in extra-provincial revenues, the current export market and Hydro's competitive hydraulic power advantage. The Board however recognizes the level of export revenues depends on a number of

factors including available water flow, market prices, and a proper balance between demand and supply. Conservative assumptions are, in the Board's view, an appropriate and prudent strategy given the nature and magnitude of the risks involved.

The Board accepts IFF M11 01-1 is a general indication of Hydro's long-term financial direction for decision-making purposes. The Board notes that the IFF does not reflect any future major generation projects within the planning period, nor the impact of the acquisition of Winnipeg Hydro, both of which may significantly impact the financial forecast and plans of Hydro. The Board will direct Hydro to file an updated IFF reflecting new generation in-service dates within the planning period, and the financial consequences of the integration of Winnipeg Hydro's operations by no later than December 31, 2003.

21.2 Financial Targets

The Board has previously stated a debt equity ratio of 85:15 is a reasonable short to medium term financial target and agrees with Hydro that a long-term target ratio of 75:25 is appropriate. The Board notes that the achievement of the 75:25 debt equity target should include a strategy for the reduction of the level of its debt.

The Board remains concerned with the current high level of debt and the additional risk posed to Hydro of incurring higher finance charges due to increases in interest rates and fluctuations in the US exchange rate on its US denominated debt. The Board is particularly concerned with the dramatic increase in long-term debt from \$5.17 billion in 1997 to \$6.43 billion in 2002, especially during a period of limited major capital expansions in generation or transmission. The Board encourages Hydro to consider appropriate debt minimization strategies. The Board notes the Corporate Strategic Plan includes a reference to reducing debt and improving equity to meet this target. Accordingly, the Board will direct Hydro to file a detailed debt management strategy with the Board by no later than December 31, 2003. This strategy should include the

implications of major new generation contemplated within the planning period, and the related financing implications.

The Board is of the view that a gross interest coverage target ratio of 1.20 and the capital coverage target of funding the capital program (with the exception of new generation) from internally generated funds are appropriate financial targets which assist Hydro in achieving its long-term target of 75:25 debt equity ratio. However, the Board is also of the view that once the debt equity target has been reached, the current interest coverage target may, at that time, no longer be required or appropriate, and a lower target should then be considered.

21.3 Risks

In the Board's view a five-year drought represents the greatest threat to Hydro's financial position. It has been estimated that retained earnings reserves of approximately \$1.3 billion may be required to withstand the financial impact of such an event. Although the actual amount might be mitigated somewhat by certain strategies, Hydro's net revenues are nevertheless subject to the vagaries of weather and water flows. Establishing an adequate reserve level is an appropriate strategy to mitigate the financial impact of a drought.

If Hydro experiences a drought, most opportunity sales will be foregone, thereby reducing export revenues. The Board generally supports Hydro's conservative approach to forecasting export revenues. The Board notes that although high export revenues have brought positive financial impacts, it has also increased the risk to Hydro. Continued high export revenues may permit Hydro to offset the need for rate increases in the future.

While there may be some risk of an export market collapse due to US legislation, regulatory changes or energy subsidies, amongst other things, there is also a probability of increased market prices, and therefore, increased export revenues. Export revenues on average over the last seven years have been 15% higher than forecast under the mean flow scenario. If this trend

continues over the next few years, Hydro will achieve its targeted debt equity ratio earlier than forecasted and a retained earnings level in excess of \$1.5 billion. According to Hydro this level of retained earnings should be sufficient to deal with identified risks. As another risk, the Board would agree that higher interest rates could have a modest negative impact on Hydro's financial position, as could higher inflation rate than forecast. Similarly, major system outages could negatively impact Hydro's finances.

21.4 Risk Analysis and Reserve Levels

The Board understands the difficulty of preparing a comprehensive quantitative analysis of all risks facing Hydro, as recommended by Mr. Todd. The Board believes, however, there is merit in quantifying specific reserve provisions required to cover the major contingencies Hydro faces. The specific amounts should be based on a process that identifies and quantifies at least the major risks at a high level. To do otherwise would be tantamount to establishing a reserve provision at an arbitrary amount. Defining specific reserve amounts for contingencies may also help prevent reserve provisions from being depleted for other purposes.

Although each risk has its own financial quantification, one cannot simply consider all risks together as additive, since many of the risks are inter-related. In reviewing risks, Hydro is urged to further examine their inter-relationships.

The Board believes that Hydro should develop a policy to identify a reserve provision amount and, in particular, to set the circumstances under which it can be drawn down or increased, keeping in mind the statutory limitations in *The Manitoba Hydro Act*. The Board expects that Hydro has most, if not all, of the required data in one form or another as part of its ongoing planning and risk management. The Board will therefore direct Hydro to prepare a document to quantify specific reserve provisions required to cover the major risks and contingencies faced by Hydro, and file that document with the Board by no later than December 31, 2003. A more disciplined approach to risk quantification can only be beneficial to the financial planning of

Hydro and assist the Board in its rate setting obligations, particularly with regard to the objective of determining an appropriate rate reserve level.

21.5 Capital Expenditures

Order 51/96 recommended that Hydro "stringently limit its capital expenditures where safety and reliability constraints allow and apply itself to reducing long-term debt with urgency." The Board remains concerned with the progressive growth in capital expenditures, and notes the dramatic increase in capital expenditures from \$250 million in 1996 to \$425 million in 2002. The Board reiterates its concerns expressed in Order 51/96.

The Board is particularly concerned with planned future capital expenditures that are justified primarily by export revenue opportunities. While very few projects are now justified exclusively for export, many projects nevertheless have a substantial export component. Hydro has indicated that certain future major capital projects will initially be for export purposes. The Board directs Hydro to appropriately identify and specifically account for all export-related capital expenditures in their capital forecasts. This information is required to ensure that export revenues are appropriately matched against the full costs of production and to ensure that Hydro's domestic ratepayers do not subsidize export market costs in the future.

Planning studies attracted substantial review in this hearing. Not only was the total amount spent of some \$130 million of concern to the Board, but also the amount spent on particular projects (i.e., \$34.1 million on Gull, \$22.3 million on Wuskwatim). Hydro has agreed to pay for certain costs of the First Nations' participation in planning for new generation stations. Of concern to the Board is the very real likelihood of Hydro paying for what are, in essence, duplicate studies, by undertaking their own studies on aspects of new generating facilities and then paying for the First Nation partner to conduct a similar study. Given that such payments in 2002 are in the range of \$1 million per month for the Wuskwatim generating station, and nearly \$2 million per

month for Gull, the Board urges Hydro to be diligent in how the ratepayers' monies are being spent and minimize such duplication.

21.6 Payments to the Province of Manitoba

Payments to the Province of Manitoba have increased dramatically, which impacts Hydro's revenue requirements. As many of the increases are legislatively enacted, Hydro has no choice but to make such payments. Nevertheless, such dramatic increases in payments have a negative effect on the ability of Hydro to achieve its financial targets, and may ultimately affect the level of rates paid for electricity. That having been said, the Board recognizes that dividend payments similar to the special export profit payments are not uncommon in publicly owned utilities.

Hydro does not intend to increase its sales rates as a result of the special export profit payment, or the increases in water rental rates or the debt guarantee fee. Hydro will be financing its payments to the Province of Manitoba. The costs of borrowing the \$288 million for the special export profit payment over the next ten years is \$276 million. Therefore, the total impact of that payment alone is \$564 million over the next 10 years. Ultimately, future ratepayers will pay the financing costs. The Board encourages Hydro to pursue short-term financing options to pay down this debt expeditiously and reduce the impact of such charges to future domestic ratepayers.

21.7 Finance Expenses

The Board notes that a significant dollar value of transactions are conducted in US dollars including US extra-provincial sales, US sinking fund investment income and finance expenses. In addition, over \$2.9 billion or 45% of the Corporation's debt is denominated in US currency, which exposes Hydro to risks related to the change in US exchange rate. The Board further notes that the exposure management program is in place to act as a hedge in protecting Hydro from the significant foreign currency risk related to the change in the US currency. As a result of

the program, prior to the change in accounting policy, Hydro had reflected the balance of the US debt, and sinking fund at a designated US exchange rate, which has been significantly below the rates currently experienced. As a result of this policy, the debt of Hydro at March 31, 2001 was valued at approximately \$1 billion less in the financial statements than it would have been if the year-end exchange rate had been used to translate the US denominated debt into Canadian dollar equivalent.

The Board notes that as a result of the accounting policy change, US denominated transactions and balances will better reflect the true economic costs and benefits and more clearly reflect the risks faced by Hydro to US denominated transactions and balances, which in the Board's view, are significant.

21.8 Operating Expenses

Although Hydro's operating and administration expenses appear reasonable, the Board encourages Hydro to continue to control these expenses through aggressive cost control initiatives and management of the labour force. The Board appreciates that some operating and administration expenses, particularly payments to the Province, are beyond Hydro's control. However, it remains necessary for Hydro to continue to be diligent in taking steps to control all such costs and improve efficiencies.

Corporate performance measures such as the operating and administration costs per customer or per kW.h targets are of great assistance in assessing the performance of Hydro's cost control initiatives compared to other utilities. The Board recommends Hydro aggressively pursue meeting its operating and administration costs per customer target while finding ways to increase productivity. The Board also encourages Hydro to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements in its operations as compared to other utilities. Hydro should actively pursue all possible synergy savings in

operating and administration expenses as a result of Hydro's recent acquisition of Winnipeg Hydro.

21.9 Transmission Tariffs

The jurisdiction of the Board over transmission tariffs is an area of concern to the Board and parties were requested to address this issue in their closing argument.

The MISO tariff does not apply to the Hydro transmission grid, but only outside the Province. Therefore, there is no provincial authority over the MISO tariff, and accordingly, no role for the Board.

The Board receives its jurisdiction and obligations for Hydro rates mainly from *The Crown Corporations Public Review and Accountability Act*. Rates for services provided by Hydro shall be approved by the Board, which rates for service means the provision of electrical power. Even though Hydro can issue its own tariff under s. 15 of *The Manitoba Hydro Act*, Hydro is still obligated to have such a tariff as a rate for service for the provision of electrical power approved by the Board. Whether the provision of power is bundled or unbundled between generation, transmission and distribution, the Board retains the jurisdiction to approve rates for service if offered in this province.

Accordingly, the Board will direct Hydro to make a separate application to the Board for approval of the Hydro Open Access Transmission Tariff. Hydro is ordered to file such an application by no later than June 30, 2003. Such an application should contain tariff and rate schedules, and a comprehensive explanation of the pricing and costs included in designing the rates.

21.10 Power Resources

Hydro stated that any periodic failure to meet base domestic plus firm export load is unacceptable. Base domestic load growth and firm export load growth are the primary drivers for new and additional power resources. Therefore a strategy to avoid brown-outs under all normal circumstances will result in substantial energy surpluses in most years. This surplus can then be sold as an opportunity sale on the export market.

If Hydro were to employ a median water flow scenario, instead of mean flow, in its energy forecasts, the amount currently available for export could be increased. By employing relatively conservative forecasting processes for supply and demand, Hydro will continue to enjoy more favourable financial results than forecast, except when droughts actually happen. From 1997 to 2001 there was an additional 10,000 GWh of export energy due to hydraulic generation being above-median water supply, resulting in incremental annual revenues of approximately \$200 million. Nevertheless, the Board considers it appropriate for Hydro to continue employing the conservative mean water flow scenario.

The Board notes the concerns expressed by intervenors that Hydro may be paying less attention to creating competitive opportunities and developing energy conservation initiatives in the domestic market. While the Board encourages Hydro to pursue export markets and the corresponding revenue opportunities, Hydro's primary purpose continues to be the supply power adequate for the domestic needs of the Province.

The Board urges Hydro to explore ways to diversify and supplement its hydraulic generation capabilities by applying an appropriate mix of other forms of energy, including wind turbines, solar panels, ground source heat exchange, and hydrogen cells. Hydro should give particular consideration to exploring alternatives such as wind turbines for the four remaining diesel generation communities. Here, the back-up diesel power generator is already in place and an alternative energy supply may be justified on either an environmental or cost basis.

Hydro no longer supplies copies of its Power Resource Plan, citing confidentiality due to the increased competitive nature of electricity trading in the US. Should the Board be seized with a needs and justification hearing for major new generating stations, arrangements may need to be made to examine the Power Resource Plan.

21.11 Cost of Service Study

21.11.1 General

A cost of service study is one of the fundamental tools used by utilities in the overall rate design process. Much judgment is applied in completing a cost of service study. The results of a cost of service study are used in designing rates that are fair and equitable to customer classes.

Generally, fairness is attained when revenues from each customer class approximates the net allocated costs of serving that class.

Hydro has made numerous changes to its proposed Cost of Service Study since it was last reviewed by the Board in Order 51/96. The Board will direct Hydro to file two cost of service studies; an actual cost of service study for the fiscal year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the fiscal year ending March 31, 2004 by no later than September 30, 2003. The following sections contain the Board's comments and directives with respect to changes proposed by Hydro, and requirements for the Cost of Service Studies to be filed with the Board in the future.

21.11.2 Winnipeg Hydro

Hydro has acknowledged that adjustments will be required to the proposed Cost of Service Study to accommodate the recent purchase of Winnipeg Hydro assets by Hydro. Hydro has stated it will have a better understanding of Winnipeg Hydro costs by late 2002. Achieving a precise understanding of detailed customer load and revenue cost information may take longer. Hydro did not rule out that methodological changes to the Cost of Service Study may be required. The

Board expects that the acquisition of Winnipeg Hydro may have a dramatic impact on the RCC's of the various customer classes. The Board also does not accept the methodology applied to Winnipeg Hydro matters in the March 2002 Cost of Service Study. The Board will therefore direct Hydro to treat Winnipeg Hydro customers in the same fashion as current Hydro customers in the March 2003 Actual Cost of Service Study and the March 31, 2004 prospective Cost of Service Study. It is important to know the impact of Winnipeg Hydro on the Cost of Service Study as soon as possible.

21.11.3 Allocation of Export Revenues

A major change to the Cost of Service Study methodology proposed by Hydro is to allocate net export revenues to customer classes on the basis of total allocated costs, being each class's share of generation, transmission and distribution costs.

The Cost of Service methodology approved in Order 51/96 allocates net export revenues to rate classes in proportion to class responsibility for generation and transmission costs. Distribution costs, of which a large percentage is allocated to residential customers, were not part of the allocation formula. It has long been argued by Hydro that it is primarily the generation and transmission assets that create the opportunity for export sales. Therefore, based on accepted cost causation principles, the benefits from export sales in the past were shared by the rate classes in proportion to each rate class' responsibility for generation and transmission costs.

In the public hearing related to Hydro's 1994 GRA, CAC/MSOS submitted that allocation of net export revenues on the basis of total cost responsibility (i.e., generation, transmission and distribution costs) would be more beneficial to the residential class. In 1994 Hydro opposed the CAC/MSOS cost of service methodology that Hydro now proposes in 2002. Hydro's position in 1994 was that export revenues are derived from generation and transmission capacity built to provide firm service to domestic loads, and since the costs of these facilities are allocated totally

to domestic rate classes, it is proper to share the export revenues derived from this capacity in proportion to cost responsibility of such classes.

In Order 64/94, the Board stated at page 33, "...Hydro's method of allocating net export revenues is appropriate for Hydro's system, because it proceeds from the principle of cost responsibility rather than mere judgment." The Board further stated "... that it would be inappropriate to allocate any portion of export revenues as an offset to distribution costs within the central system or to costs in the Diesel Zone."

The Board has heard no new evidence at the current hearing to support or justify a departure from the principles of cost causation previously adopted for allocating net export revenues. Because export revenues arise from generation and transmission capacity, the Board believes that it continues to be appropriate to allocate the net export revenues derived from that capacity in proportion to class responsibility for generation and transmission costs.

In the Board's view, many direct and indirect costs related to export power sales are currently not included in Hydro's calculation of net export revenues. The Board notes that this matter was the subject of a recommendation in its March 31, 1988 Report to the Minister, at page 51 and 52, where the Board stated:

"The Board recommends that revenues and costs related to export sales should be segregated in Hydro's accounting records. Costs include direct costs as well as indirect or allocated costs. The purpose of this segregation is to ensure that the Manitoba ratepayer is not subsidizing export sales.

A possible method would be to treat export sales as a separate customer class in the Cost of Service Study. The result would not be used in designing rates for export sales because of the fact that such sales are open market negotiated sales. The only relevance to the resulting export class revenue/cost ratio would be to ensure that Manitoba customers are not allocated costs related to export."

This Board believes these comments remain appropriate today, and accordingly will direct Hydro to file an actual cost of service study for 2003 and a prospective cost of service study for 2004, that reflects:

- (a) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as employed for general service customers; and
- (b) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

These Cost of Service Studies should include the impact of allocating net export revenues determined in accordance with the above directives on the basis of transmission and generation costs. Once these submissions have been filed, the allocation methodologies may require further consideration by the Board.

21.11.4 Functional Changes to the Cost of Service Study

Previously, all transmission lines and stations, including HVDC facilities, were included in the transmission function. In the March 2002 Cost of Service Study, all HVDC assets, with the exception of the Dorsey Converter station, were assigned to the generation function. The Board accepts this methodology and Hydro's reasoning that the primary function of the HVDC facilities is to move energy from the remote generation sites into the backbone transmission system and therefore serve as an extension of the generating facilities.

The Board, however, has some concerns about the exclusion of the Dorsey Converter Station from the HVDC assets assigned to the generation function. While the assignment of the Dorsey Station to the transmission function has relatively minor impacts to revenue cost coverage ratios under current operating circumstances, the Board has concerns this may change as additional generation and transmission facilities are constructed in the future. The Board will expect Hydro to re-evaluate the continued appropriateness of this treatment in the future.

Hydro has also assigned the AC transmission lines that provide power to the northern converter stations as generation. The Board accepts this methodology since these lines are required to bring generated power to the HVDC converter stations in the north.

The Board also accepts Hydro's proposed assignment of only those transmission facilities, which would be recognized for inclusion in Hydro's Transmission Tariff, to the transmission function. Radial transmission facilities, including those with voltages greater than 100 kV, are included in the sub-transmission function.

The Board accepts Hydro's creation of a new ancillary services function necessary to support the transmission of capacity and energy to the load.

21.11.5 Classification Changes to the Cost of Service Study

Hydro's November 2001 Prospective Cost of Service Study used marginal costing to classify generation costs to energy and demand. For reasons of commercial sensitivity, Hydro was unable to provide information supporting its determination of relative marginal costs. Hydro therefore proposed to revert back to the previous methodology. The Board accepts this approach given the commercial sensitivity of marginal cost information.

In the March 2002 revised Cost of Service Study, Hydro returned to the pre 2001 approach and classified total generation and transmission costs (including ancillary services) on the basis of the system load factor. However, in the March 2002 approach, transmission and ancillary services are classified as 100% demand related. The balance of demand related costs are then assigned to generation. This results in a demand to energy classification division of transmission and generation costs of approximately 36% to 64% respectively. If, however, transmission costs are classified as 100% demand and the system load factor is applied to generation costs only, this approach would result in a demand to energy classification division of generation and transmission costs of approximately 48% to 52%.

The Board accepts the classification of transmission assets at 100% demand related, however, the methodology used to classify generation costs is of concern to the Board. Hydro has stated it is prepared to undertake a further review with respect to the appropriate classification of generation costs. The Board will therefore direct Hydro to complete this review of generation cost classification methodologies by December 31, 2003. This review should critically examine the impacts of the various methods of classifying generation costs, and describe how such classification methods would impact the overall rate design process in terms of setting demand and energy charges.

The Board accepts Hydro's proposed methodology with respect to classifying ancillary services as 100% demand.

21.11.6 Allocation Changes to the Cost of Service Study

The process of allocation takes functionalized and classified costs and assigns the costs to the various customer rate classes and subclasses. Hydro has proposed a number of changes in cost allocation methodologies.

In the November 2001 allocation methodology, energy related generation costs were allocated to each customer class according to the class contribution of the highest integrated 50 hour load during the winter and summer seasons. This treatment was changed in the March 2002 where energy related costs of generation were allocated to customer classes on the basis of their share of overall annual energy requirements, the same methodology used in the Cost of Service Study approved in Order 51/96.

The March 2002 Cost of Service Study proposed to allocate generation demand costs on the basis of each class of customer's share of the average of the top 50 coincident load hours during the months of June, July and August and the top 50 coincident load hours during the months of December, January and February (2 CP Methodology). Hydro stated this treatment recognized

the value of energy and capacity during the summer and winter seasons. Although the domestic peak continues to occur in winter, loads can be as high as other times of the year, particularly the summer months. With a strong export market during the summer months, transmission and generation assets can be fully utilized at the time of summer peaks. Based on this reasoning, the Board accepts Hydro's methodology to allocate demand related costs of generation on the basis of the 2 CP method.

Hydro has proposed to allocate transmission and ancillary services related costs to customer classes on the basis of the 12 CP method with each month being given equal weight. Hydro argued that this approach is consistent with the treatment in the Transmission Tariff in which transmission pricing in the open access market is based on the 12 CP method. The Board is of the view that allocation of costs on a 2 CP basis would be a stronger correlation to cost causation. Participation in MISO does not oblige Hydro to adopt similar pricing structures for the domestic market. The Board therefore rejects the allocation of transmission and ancillary service costs on the basis of the 12 CP and directs Hydro to allocate these costs on a 2 CP basis similar to that used for the generation demand costs.

The Board also supports the continued practice to allocating DSM costs to the customer classes that receive the benefit.

21.11.7 Future Cost of Service Studies

Given the above comments, the Board has fundamental concerns with both the November and March Cost of Service Study submissions. Therefore, the Board will direct Hydro to file an actual cost of service study for year ending March 31, 2003 by September 30, 2003 and a prospective cost of service study for the fiscal year ending March 31, 2004 by September 30, 2003 reflecting the following:

- (a) The former Winnipeg Hydro revenues and costs are appropriately assigned to the various customer classes in the same fashion as current Hydro customers.

- (b) Net export revenues are allocated on the basis of generation and transmission costs only in accordance with Order 51/96.
- (c) Transmission costs, including Dorsey, are classified as 100% demand.
- (d) Transmission and ancillary services costs are allocated on the basis of the 2 CP.
- (e) Generation demand costs are allocated on the basis of the 2 CP.
- (f) Energy related costs of generation are allocated on the basis of class annual energy (Non-Coincident Peak).
- (g) HVDC costs (other than Dorsey) are functionalized as generation.
- (h) Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function.
- (i) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as employed for general service customers; and
- (j) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

21.12 Rate Design

21.12.1 General

Although Hydro did not apply for any changes in rate design, the Board and the Intervenor considered the issues of rate design to be of considerable importance in this status update filing. As part of the Board's review as to whether the rates charged remain just and reasonable, the Board not only examined the overall revenue requirement, but also the cost of service methodology, and the rate structure itself.

The Board is disappointed with the inaction of Hydro to comply with the spirit of Order 51/96 with regard to undertaking a study and reporting to the Board by no later than the next GRA to develop a comprehensive rate design policy. More than six years have elapsed since that directive was issued, and Hydro stated at this hearing that it has no intention of preparing such a

study in the near future. Such inaction is a disservice to the many Hydro customers, particularly those who might benefit from such a comprehensive rate design policy.

Having reviewed rate design issues as part of this status update, the Board believes that certain rates require adjustment.

21.12.2 Rates

After examining the overall revenue requirement of Hydro, the Board finds that there is no need for an overall rate adjustment for all customer classes. However, the Board is of the view that rates for certain customer classes should be adjusted.

Much time was spent at the hearing reviewing the Cost of Service Study. A revenue to cost ratio of 1.0 indicates that costs allocated to a customer class equal the revenues earned from that customer class. While unity may be the desired goal, Order 51/96 sets a zone of reasonableness target at 0.95 to 1.05 for revenue to cost coverage ratios. The Board is of the view that this zone of reasonableness of 0.95 to 1.05 continues to be an appropriate target for rate setting purposes.

As demonstrated in the table in Section 17.8.5, certain customer classes and subclasses have consistently remained outside of this zone of reasonableness for long periods of time, in some cases more than 10 years. Therefore, the Board is convinced that directional rate adjustments are appropriate now to address these inequities. Accordingly, the Board will order a 1% decrease in rates for GSS customers and a 2% decrease in rates for GSL customers in subclasses greater than 30 kV. Such rate decreases are to be effective April 1, 2003. The Board will direct Hydro to file new rate schedules for Board approval reflecting these rate adjustments.

The Board will also eliminate the winter ratchet over the next two years, which will reduce revenues to Hydro by approximately \$3 to 4 million. The Board understands that this change will likely bring the GSM class and GSL subclass less than 30 kV closer to unity. Therefore, no further rate adjustment will be ordered for the GSM or GSL less than 30 kV subclass at this time.

The Board is confident that these rate adjustments will not impact the overall financial strength of Hydro, or its ability to achieve its financial targets.

21.12.3 Inverted Rates and Rate Structure

The declining block structure is largely the result of the historical circumstances of electrification throughout the Province and the construction of major generating plants on the Northern rivers. While the Board is not prepared at this time to support an inverted rate structure, the Board accepts that certain concepts of an inverted rate structure for residential customers may have merit for consideration in the future. The Board compliments both Mr. Lazar and Hydro for preparing thoughtful evidence on this matter and raising interesting new approaches. The Board believes that more study is required before an inverted rate structure can be considered for any customer class. The Board will direct Hydro to prepare a study on the merits of an inverted rate structure across all rate classes including transition and implementation issues. As part of this study, Hydro should evaluate the impact of an inverted rate structure on electric heat customers and residential customers with higher than average loads. This study should be filed with the Board by no later than December 31, 2003.

While the issue of inverted rates was largely confined to residential rates, the Board investigated demand and energy charges levied on larger General Service customers as part of the overall rate design. In the Board's opinion, some of Hydro's demand charges are in the mid to high range as compared to other jurisdictions in Canada, while the energy charges are amongst the lowest in Canada.

The Board is of the belief a lower demand charge and higher energy charge may serve as an impetus to further conservation of electricity since the users may become more aware of their consumption and hence, may attempt to minimize usage. Accordingly, the Board will direct Hydro to prepare a study on the impact of decreasing the demand charge and increasing the tail

block of the energy charge and include recommendations and a timetable for possible implementation. The study should be filed with the Board by no later than December 31, 2003.

21.12.4 Winter Ratchet and Limited Use Billing Demand

In the 1996 GRA, Hydro sought to eliminate the winter ratchet with the implementation of seasonal rates. However, with little actual evidence and no customer consultation, the Board did not support the implementation of seasonal rates, and directed further study by Hydro. Since then, the LUBD program was introduced to alleviate some irritants posed by the winter ratchet. The Board is of the view that winter ratchet continues to pose problems for customers unable to benefit from the LUBD program.

The traditional rationale for the winter ratchet is that additional winter capacity to meet peak demand requires significant and costly capital expansions. The winter ratchet is designed to recover capacity costs incurred to meet this peak demand. The current system load runs nearly at capacity throughout the year as any additional capacity beyond domestic use is sold on the export market. Therefore, the Board finds that the use of the winter ratchet is not valid in the current circumstances. Accordingly, the Board will order Hydro to phase out the winter ratchet in two steps. On April 1, 2003, the winter ratchet is to be decreased to 70% of the maximum previous winter demand measured in December 2002, and January and February 2003. On April 1, 2004, the winter ratchet is to be eliminated. The Board will order Hydro to file the resulting rate schedules, for Board approval, prior to the above dates.

The Board will order the LUBD be eliminated on April 1, 2004. All LUBD customers will then revert to the billing rate of their appropriate class. Until April 1, 2004 the LUBD rate option will be considered a temporary rate offering. The Board also expects Hydro to inform all LUBD customers of this decision and its implication. The Board will grant final approval of Order 118/02 which extended the LUBD rate option on an interim ex parte basis.

21.12.5 Time of Use Rates

In Order 51/96 the Board directed Hydro to prepare a comprehensive rate policy including time of use rates which remains outstanding. The Board heard testimony that Hydro continues to install specialized metering equipment for certain general service customers with time of use capability. Accordingly, the Board considers it important to proceed with the development of time of use rates and directs Hydro to prepare a study, including a timetable and a plan for implementation, for a time of use rate program. Such study should also consider time of use rates for general service classes based on a seasonal, weekly, daily and hourly basis, including an evaluation of each alternative. The study should be filed with the Board by no later than December 31, 2003.

21.12.6 Diesel Rates

Any determination of whether rates are just and reasonable must include an examination of rates charged to those customers serviced by Hydro's diesel generation. The Board cannot make a determination on which customer should be included in a specific rate class of government versus non-government or whether a customer has sufficient resources to pay the bill, or funding formulas are appropriate.

During the hearing, Hydro stated it would be filing a separate application for diesel rates in December 2002. Such an application has now been filed and the Board will consider diesel rate issues at a future public hearing to review this filing.

21.12.7 Curtailable Rates

Hydro applied for a new CRP which included only minor variations from the existing curtailable service program. The rationale for curtailments has changed and, as stated by Hydro witnesses, the number of curtailments will likely decrease sharply. However, the Board is reasonably satisfied with the rationale used in the calculation of the Reference Discount.

Hydro has applied for the CRP to be a temporary program with an expiry date of November 30, 2003, given the unknown impact of MISO's requirement and the value of reserves. In the interest of rate stability, the Board will approve the CRP on a permanent basis.

21.12.8 Surplus Energy Program and Interim Ex Parte Orders

The Board will approve, on a final basis, all interim ex parte Orders relating to the DFH, ISE, SEP and CSP programs as attached in Appendix E.

21.12.9 Demand Side Management - Energy Conservation

The Board acknowledges that Hydro's initiatives on DSM since 1989 have achieved approximately 50% of targets set for 2012 of 356 MW and 1,272 GW.h. However, it is the Board's view the new DSM programs may not be effective for achieving DSM targets for 2012.

In this period of potential generation expansion the Board is concerned that Hydro may reduce efforts for DSM. It would appear that other utilities are more proactive in pursuing energy conservation measures. A program target for energy use reduction of 3% does not seem to be sufficiently aggressive.

The Board is of the view that, at present, Hydro provides few incentives for either residential or general service customer energy conservation. Financial incentives such as a movement toward lower demand and higher energy charges could encourage more efficient energy usage. Greater energy conservation within Manitoba opens the door for increased power exports with good financial returns. The Board views this as a positive process, particularly if the exported energy displaces coal or other greenhouse gas producing generation within other jurisdictions.

Therefore, the Board directs Hydro to re-examine the current level of DSM programs and pricing strategies to encourage conservation and develop a program with more aggressive targets to be filed with the Board by December 31, 2003.

Wind power offers potential fuel consumption reductions where the primary source of power is coal, natural gas, propane, or diesel. It can be a lower cost supplier of electricity where a primary fuel-based generator already exists and is available as a full back-up when the wind velocities are too low. The Board directs Hydro to consider the use of wind power in remote diesel electric communities where energy costs are high and file a report with the Board by December 31, 2003.

21.12.10 Future Regulation

The Board recognizes the many parties who expressed frustration with Hydro's absence from public review for over six years. The Board reiterates the statement made in Order 208/02 that Hydro establish a more regular schedule, not exceeding three years, for periodic rate reviews. This regular schedule should improve the efficiency, effectiveness and timeliness of the regulatory process, even if no rate changes are requested. Subject to other specific directives contained herein, the Board will approve Hydro's existing rate schedules to be in effect until March 31, 2006 or until otherwise amended by a further Order of the Board. The Board will direct Hydro to file a GRA for rates to be effective April 1, 2006 whether or not rate adjustments are sought. This directive does not preclude Hydro from filing applications for rate adjustments prior to this date.

22.0 It Is Therefore Recommended That:

1. Hydro limit its capital expenditures not related to new major generation and transmission, where safety and reliability constraints allow, and apply itself to reducing its long-term debt.
2. Hydro be diligent in ensuring it does not pay for duplicate planning studies for new generation projects.
3. Hydro pursue short-term financing options to expeditiously pay down the debt incurred for the special export profit payment to the Province of Manitoba, and thereby reduce the impact of such financing charges to future domestic ratepayers.
4. In respect of operating and administration expenses:
 - (a) Hydro pursue with vigour meeting the operating and administration cost per customer target of \$600 by increasing productivity.
 - (b) Hydro continue to participate in benchmarking initiatives.
 - (c) Hydro actively pursue all possible synergy savings in operating and administrative expenses as a result of its recent acquisition of Winnipeg Hydro.
5. Hydro consider ways to diversify and supplement its hydraulic generation with an appropriate mix of other forms of energy, including wind turbines, solar panels, ground source heat exchange and hydrogen cells.

23.0 It Is Therefore Ordered That:

1. The interim ex parte Orders listed in Appendix E of this Order BE AND ARE HEREBY CONFIRMED AS FINAL.
2. The Curtailable Rates Program as applied for by Hydro BE AND IS HEREBY APPROVED.
3. Hydro file for Board approval a revised schedule of rates to be effective April 1, 2003 including revenue impacts that reflect:
 - (a) A 1% rate decrease for General Service Small customers;
 - (b) A 2% rate decrease for General Service Large customers in subclasses greater than 30 kV; and
 - (c) A decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.
4. Hydro eliminate the Limited Use Billing Demand Rate option on April 1, 2004 and inform all affected customers of the changes to the winter ratchet and the Limited Use Billing Demand Rate option.
5. Hydro file an application with the Board by no later than June 30, 2003, for approval of Hydro's Open Access Transmission Tariff.
6. Hydro file the following information with the Board by no later than December 31, 2003:
 - (a) An updated Integrated Financial Forecast reflecting the integration of Winnipeg Hydro and the in-service dates of all new generation within the eleven-year planning period;
 - (b) A detailed debt management strategy;
 - (c) A study to quantify specific reserve provisions required to cover the major risks and contingencies faced by Hydro;
 - (d) A study on the merits of implementing an inverted rate structure for all customer classes;
 - (e) A study on the impact of decreasing the demand charge and increasing the tail block of the energy charge;

- (f) A study which considers time of use rates for GS classes based on a seasonal, weekly, daily, and hourly basis;
 - (g) A review of generation cost classification methodology options;
 - (h) Re-examine the current level of DSM programs and pricing strategies to encourage conservation, develop a program with more aggressive targets, and report to the Board; and
 - (i) Consider the use of wind power in remote diesel electric communities and file a report with the Board.
7. Hydro's proposed Cost of Service Study dated March 2002, which includes a number of methodology changes including allocating net export revenues to customer classes on the basis of total allocated costs BE AND IS HEREBY DENIED.
8. Hydro file an actual cost of service study for the year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the year ended March 31, 2004 by no later than September 30, 2003 which reflects the following:
- (a) The former Winnipeg Hydro revenues and costs are appropriately assigned to the various customer classes in the same fashion as current Hydro customers.
 - (b) Net export revenues are allocated on the basis of generation and transmission costs only in accordance with Order 51/96.
 - (c) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as is proposed for general service customers; and
 - (d) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.
 - (e) Transmission costs, including Dorsey are classified as 100% demand.
 - (f) Transmission and ancillary services costs are allocated on the basis of the 2 CP method.
 - (g) Generation demand costs are allocated on the basis of the 2 CP method.
 - (h) Energy related generation costs are allocated to customer classes based on their share of the overall annual energy requirements (Non-Coincident Peak).

- (i) HVDC costs (other than Dorsey) are functionalized as generation.
 - (j) Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function.
9. Hydro appropriately identify and specifically account for all export-related capital expenditures in their capital forecasts to ensure that export revenues are appropriately matched against the full costs of production.
 10. Hydro establish a more regular schedule for periodic rate reviews, not exceeding three years between hearings.
 11. Subject to other specific rate directives contained herein, Hydro's existing rate schedules **BE AND ARE HEREBY CONFIRMED**, to be in effect until March 31, 2006, or until otherwise amended by a further Order of the Board.
 12. Hydro file a General Rate Application for rates to be effective no later than April 1, 2006.

The Public Utilities Board

Chairman

Secretary

February 3, 2003
Board Order 7/03
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THE PUBLIC UTILITIES BOARD

"G. D. Forrest"
Chairman

"G. O. Barron"
Secretary

Certified a true copy of
Board Order 7/03 issued by
The Public Utilities Board

Secretary

Appendix A

Integrated Financial Forecast IFF MH 01-1

ELECTRIC OPERATIONS (MB01-1) WITH EXPOSURE MANAGEMENT AND SPECIAL PAYMENT
PROJECTED OPERATING STATEMENT
(x 1,000,000)

For year ending March 31:

REVENUES:

General Consumers Revenue

at approved rates

additional*

Winnipeg Hydro

Extraprovincial

Other

EXPENSES:

Finance Expense

Depreciation

Cost of Operations

Water Rentals

Tax Expense

Fuel & Power Purchased

Net Income

Special Payment

Contribution to Retained Earnings

*Additional General Consumers Revenue

Percentage Increase

Cumulative percentage Increase

Financial Ratios

Debt/Equity

Interest Coverage

Capital Coverage

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
General Consumers Revenue											
at approved rates	743	749	762	770	780	789	798	807	818	829	840
additional*	-	-	15	31	48	65	83	102	103	105	106
Winnipeg Hydro	48	48	50	51	52	53	55	56	57	58	58
Extraprovincial	628	553	528	467	454	448	430	425	404	425	427
Other	5	5	5	5	5	5	5	6	6	5	5
	1,424	1,355	1,360	1,324	1,339	1,360	1,371	1,396	1,388	1,422	1,436
EXPENSES:											
Finance Expense	496	504	507	493	497	490	484	478	475	492	491
Depreciation	237	256	269	280	286	296	303	312	317	322	332
Cost of Operations	254	262	266	268	273	278	284	290	295	301	307
Water Rentals	112	101	97	97	97	97	98	98	98	98	98
Tax Expense	40	41	41	42	42	42	42	42	42	42	42
Fuel & Power Purchased	65	81	89	86	75	80	84	90	94	96	102
	1,204	1,245	1,269	1,266	1,270	1,283	1,295	1,310	1,321	1,351	1,372
Net Income	220	110	91	58	69	77	76	86	67	71	64
Special Payment	150	75	63								
Contribution to Retained Earnings	70	35	28	58	69	77	76	86	67	71	64
*Additional General Consumers Revenue			15	31	48	65	83	102	103	105	106
Percentage Increase			2.0%	2.0%	3.0%	2.0%	2.0%	2.0%			
Cumulative percentage Increase			2.0%	4.0%	6.1%	8.2%	10.4%	12.6%	12.6%	12.6%	12.6%
Financial Ratios											
Debt/Equity	77:23	78:22	78:22	77:23	77:23	76:24	75:25	74:26	74:26	73:27	71:29
Interest Coverage	1.43	1.21	1.18	1.12	1.13	1.15	1.15	1.17	1.13	1.14	1.13
Capital Coverage	1.10	1.05	0.99	1.05	1.06	1.17	0.99	1.20	1.07	1.24	1.61

ELECTRIC OPERATIONS (MH01-1) WITH EXPOSURE MANAGEMENT AND SPECIAL PAYMENT
PROJECTED BALANCE SHEET
(x 1,000,000)

For year ending March 31:	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
ASSETS:											
Plant in Service	8,720	9,267	9,592	9,912	10,206	10,473	10,776	11,110	11,336	11,948	12,221
Accumulated Depreciation	(2,800)	(3,038)	(3,287)	(3,345)	(3,808)	(4,082)	(4,361)	(4,649)	(4,945)	(5,243)	(5,550)
Net Plant in Service	5,920	6,229	6,305	6,567	6,398	6,391	6,415	6,461	6,391	6,705	6,671
Construction in Progress	352	179	218	224	248	294	368	335	472	149	84
Current & Other Assets	2,502	2,456	2,372	2,300	2,272	2,263	2,258	2,267	2,279	2,309	2,363
	8,774	8,864	8,895	8,891	8,918	8,948	9,039	9,083	9,142	9,163	9,118
LIABILITIES:											
Long Term Debt (Net)	4,777	5,486	5,898	5,881	6,179	6,085	5,756	5,224	6,009	5,976	5,731
Current & Other Liabilities	2,577	1,927	1,521	1,479	1,143	1,193	1,542	2,035	1,245	1,231	1,366
Contributions in Aid of Construction	269	265	262	259	255	251	247	244	241	238	240
Retained Earnings	1,151	1,186	1,214	1,272	1,341	1,419	1,494	1,580	1,647	1,718	1,781
	8,774	8,864	8,895	8,891	8,918	8,948	9,039	9,083	9,142	9,163	9,118
Debt:Equity Ratio	77:23	78:22	78:22	77:23	77:23	76:24	75:25	74:26	74:26	73:27	71:29

ELECTRIC OPERATIONS (MH01-1) WITH EXPOSURE MANAGEMENT AND SPECIAL PAYMENT
PROJECTED FINANCING REQUIREMENTS STATEMENT

	(x 1,000,000)										
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
FUNDS FROM OPERATIONS											
Net Income	220	110	91	58	69	77	76	86	67	71	64
Provision for Depreciation	237	256	269	280	286	296	303	312	317	322	332
Other	9	19	13	16	(6)	(2)	(4)	(7)	(5)	(5)	(11)
	<u>466</u>	<u>385</u>	<u>373</u>	<u>354</u>	<u>349</u>	<u>371</u>	<u>375</u>	<u>391</u>	<u>379</u>	<u>388</u>	<u>385</u>
APPLICATION OF FUNDS											
Capital Expenditures	425	367	376	338	330	318	380	325	355	312	239
Refinancing of LTD	627	757	-	211	-	90	107	3	501	-	-
Sinking Fund Deposit	116	123	87	121	139	137	128	128	206	192	205
Other	80	39	36	19	18	20	20	21	20	31	22
	<u>-</u>	<u>225</u>	<u>63</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
	<u>1,248</u>	<u>1,511</u>	<u>562</u>	<u>689</u>	<u>487</u>	<u>565</u>	<u>635</u>	<u>477</u>	<u>1,082</u>	<u>525</u>	<u>466</u>
FINANCING REQUIREMENTS	<u>782</u>	<u>1,126</u>	<u>189</u>	<u>335</u>	<u>138</u>	<u>194</u>	<u>260</u>	<u>86</u>	<u>703</u>	<u>137</u>	<u>81</u>

Appendix B

Capital Expenditure Forecast CEF 01-01

MANITOBA HYDRO CAPITAL EXPENDITURE FORECAST (CEF01-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2001/02 TO 2011/12

Appendix B

Project	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	11 Year Total
Total												
POWER SUPPLY												
NEW GENERATION												
BRANDON COMBUSTION TURBINE	183	92	76									351
HVDC FACILITIES												
HVDC BIPOLE RELIABILITY ENHANCEMENTS	56	3										59
BIPOLE 1 MERCURY ARC VALVES STAGE 3	74	0	1	45	27							147
HVDC BIPOLE 2 THYRISTOR POLY PIPE REPLACEMENTS	5	1										6
CONVERTER TRANSFORMER BUSHING REPLACEMENT	7	1	1	2								11
DORSEY BIPOLE 1 SYNCH CONDENSER BREAKER REPLACEMENT	7	1	2									10
BIPOLE 1 & 2 DC FILTER CAPACITOR REPLACEMENT	5	2	1									8
BIPOLE 1 VALVE HALL WALL BUSHING REPLACEMENT	9	1	(0)									8
BIPOLE 1 & 2 ELECTRODE LINE MONITORING	1		1									2
HVDC SYSTEM SWITCHGEAR UPGRADE	3	1	1	1								6
HVDC AUXILIARY POWER SUPPLY	2	1	0	1								4
DORSEY SYNCHRONOUS CONDENSER REFURBISHMENT	8		1		1	1	1	1				13
HYDRAULIC REHABILITATION												
GREAT FALLS G.S. REHABILITATION	23	4	9	6	3	0						45
PINE FALLS G.S. REHABILITATION	20	2	2	6	3	1						34
LAURIE RIVER PLANT 1 AND 2 REHABILITATION	17		3	1	1	1						24
GRAND RAPIDS G.S. REHABILITATION	16	5										21
JENEPG G.S. UNIT OVERHAULS (UNITS 1-4)	19	0	4	4	0	4	4					35
POWER SUPPLY DAM SAFETY UPGRADES	15	1	2	2	2	2						24
WINNIPEG RIVER CONTROL SYSTEM	17	2	3	3								25
LIMESTONE OUTSTANDING WORK	17	0	1	4								22
WINNIPEG RIVER RIVERBANK PROTECTION PROGRAM	7	1	1	1	1	1	1					14
KETTLE G.S. IMPROVEMENTS & UPGRADES	69	1	1	1	0							72
KELSEY G.S. IMPROVEMENTS & UPGRADES	15		3	10	1							29
KUTTLE ANNUNCIATION SYSTEM RENEWAL	2	1										3
NELSON RIVER CONTROL	6		3	2	3							14
THERMAL REHABILITATION												
BRANDON G.S. UNIT 3 LIFE EXTENSION	23			2	1	0	1	3	7	3	1	38
SELKIRK G.S. FUEL SWITCHING PROJECT	32	19	13									64
SELKIRK G.S. LIFE EXTENSION	29		2	15	12	0						58
OTHER												
300MW ONTARIO HYDRO SALE - SYNC COND CONVERSION	9	0	1	1	2							13
SITE REMEDIATION OF CONTAMINATED CORPORATE FACILITIES	13	2	1	1	1	1	1	1	1	1	1	23
OIL CONTAINMENT	16	0	1	2	1	1	1	1	1	1	1	25
FIRE PROTECTION PROJECTS	6	1	3									10
GENERATION TOWNSITE INFRASTRUCTURE		2	3									5
PLANNING STUDY COSTS		41	12	8	5	4	3	3	2	10	20	68
DOMESTIC ITEMS - POWER SUPPLY		11	11	11	11	12	12	12	12	13	13	135
PROPOSED POWER SUPPLY		197	100	124	76	33	24	26	25	32	42	709

MANITOBA HYDRO CAPITAL EXPENDITURE FORECAST (CEF01-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2001/02 TO 2011/12

Appendix B

	Project Total	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	11 Year Total
TRANSMISSION AND DISTRIBUTION													
WUSKATIM TRANSMISSION													
HVDC CONVERSION BIPOLE MCONAWAPA TRANSMISSION													
TRANSMISSION FOR GENERATION													
RADISSON - RIEL ± 500kV HVDC LINE	332		1	5	13	14	12	60	76	64	44	-	352
RIEL 230/500kV STATION	98		2	3	6	8	23	31	32				99
INTERCONNECTIONS													
300MW ONTARIO HYDRO SALE - T/L UPGRADE	3	0	-	-	-	-	-	-	-	-	-	-	0
GLENBORO - RUGBY 230kV LINE	23	13	9	1	1	-	-	-	-	-	-	-	24
TRANSMISSION													
NORTHERN AC TRANSMISSION SYSTEM REQUIREMENTS	31	0	2	7	11	9							39
THOMPSON-HERBLET LAKE 230kV TRANSMISSION	53	-	1	1	1	9	22	18	-	-	-	-	53
NORTH CENTRAL MANITOBA PROJECT	18	0		-	-	-	-	-	-	-	-	-	0
FLIN FLON - CLIFF LAKE TRANSFORMER REPLACEMENT	6	0	(1)	-	-	-	-	-	-	-	-	-	(1)
HERBLET LAKE > THE PAS 230kV TRANSMISSION	46	-		0	0	1	1	1	7	20	16	-	46
DORSEY > NEEPAWA > CORNWALLIS 230kV LINE	50	0	(0)	-	-	-	-	-	-	-	-	-	(0)
WINNIPEG > BRANDON TRANSMISSION IMPROVEMENTS	37	-	1	3	3	6	10	8	4	-	-	-	37
FT GARRY - PERIMETER SOUTH BANK REPLACEMENT	5	-		0	3	3	-	-	-	-	-	-	5
RIDGEWAY TRANSFORMER ADDITION	9	-		0	1	1	4	1	-	-	-	-	7
ST. VITAL TRANSFORMER ADDITION	9	7	1	-	-	-	-	-	-	-	-	-	9
DORSEY-ROSSER 230kV TRANSMISSION IMPROVEMENTS	2	0	0	-	-	-	-	-	-	-	-	-	0
DORSEY > ST. VITAL 230kV AC TRANSMISSION	8	6	1	-	-	-	-	-	-	-	-	-	7
DORSEY > LAVERENDRYE > ST. VITAL 230kV TRANSMISSION	26	0	-	-	-	-	-	-	-	-	-	-	-
ROSSER > SILVER 230kV TRANSMISSION	30	-	0	3	7	14	-	-	-	-	-	-	34
NEEPAWA 230-66kV STN	18	-	-	0	0	8	8	-	-	-	-	-	18
ASSINIBOINE - WILKES AVE 115-24 kV BANK 1 ADDITION	13	1	(2)	-	-	-	-	-	-	-	-	-	(1)
ROSSER > MCPHILLIPS 115kV TRANSMISSION IMPROVEMENTS	3	-	0	1	2	-	-	-	-	-	-	-	3
RICHER SOUTH 230-66kV TRANSFORMER ADDITION	5	-	0	0	2	0	-	-	-	-	-	-	5
PINE FALLS > BLOODVEIN 115kV TRANSMISSION LINE	29	-	-	-	-	-	9	0	1	2	-	6	28
ST. VITAL > STEINBACH 230kV TRANSMISSION	23	-	-	-	0	0	1	3	4	14	-	-	22
RIDGEWAY > SELKIRK 230kV TRANSMISSION	26	-	1	3	4	5	7	0	-	-	-	-	30
SOURIS > PEMBINA VALLEY 230kV TRANSMISSION	33	-	-	-	-	-	1	1	1	2	(2)	16	33
WINNIPEG AREA TRANSMISSION REFLURISHMENT	8	7	2	1	-	-	-	-	-	-	-	-	9
DORSEY STATION 230kV BREAKER REPLACEMENT	19	0	9	-	-	-	-	-	-	-	-	-	9
DORSEY > US BORDER D602F 500kV AC T/L INSULATOR REPLACEMENT	8	1	1	-	-	-	-	-	-	-	-	-	2
BIPOLE 1 & 2 LINE SPACER DAMPERS REPLACEMENT	13	4	3	-	-	-	-	-	-	-	-	-	7
DORSEY 230kV BUS ENHANCEMENTS	16	3	4	4	4	3	-	-	-	-	-	-	16
FLIN FLON AREA TRANSMISSION IMPROVEMENTS	32	1	-	3	5	7	-	-	-	-	-	-	13
PINE FALLS-GREAT FALLS 115-66kV SUPPLY	10	2	4	4	9	-	-	-	-	-	-	-	19
SUBTRANSMISSION													
JENPED > NORWAY HOUSE 66 kV SUB TRANSMISSION LINE	12	5	6	-	-	-	-	-	-	-	-	-	11
RUTTAN > SOUTH INDIAN LAKE 66 kV LINE	16	0	9	0	2	8	-	-	-	-	-	-	9
PIKWITONEI & TIBCKET PORTAGE SITE REMEDIATION	6	2	1	-	-	-	-	-	-	-	-	-	2
BIRKLE SOUTH > ROSSBURN 66kV LINE	6	-	0	0	4	2	-	-	-	-	-	-	6
ST. BONIFACE PLESSIS Rd 115-25kV STATION	16	9	(3)	-	-	-	-	-	-	-	-	-	(1)
ROSSER - OAK POINT 115-24kV STATION	21	-	-	-	-	-	0	2	2	13	4	-	21

MANITOBA HYDRO CAPITAL EXPENDITURE FORECAST (CEF01-1)
(IN MILLIONS OF DOLLARS)
FOR THE YEARS 2001/02 TO 2011/12

Appendix B

	Project Total	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	11 Year Total
ROSSER - OAK POINT BANK 2 ADDITION	10	-	-	-	-	-	-	-	1	6	3	-	10
ST. BONIFACE PLESSIS Rd BANK 2 ADDITION	3	0	2	0	-	-	-	-	-	-	-	-	2
NEEPAWA 66KV SYSTEM	4	-	-	0	4	-	-	-	-	-	-	-	4
BESTON/GLENBORO CAPACITY INCREASE	6	3	1	-	-	-	-	-	-	-	-	-	4
ST. LEON 230-66KV TRANSFORMER ADDN AND IFL EXPANSION	6	4	0	0	-	-	-	-	-	-	-	-	5
BRANDON CROCUS PLAINS 115-24KV BANK ADDITION	8	1	-	-	-	4	1	1	1	-	-	-	8
BRERETON LAKE STATION AREA	7	1	1	2	0	0	1	-	-	-	-	-	7
	-	-	-	-	-	-	-	-	-	-	-	-	-
DISTRIBUTION													
VIRIDEN AREA DISTRIBUTION CHANGES	15	2	1	1	1	-	-	-	-	-	-	-	6
DEFECTIVE R/JN/ CABLE REPLACEMENT	8	1	2	2	2	1	-	-	-	-	-	-	7
PAINT LAKE FEEDER	2	2	-	-	-	-	-	-	-	-	-	-	2
	-	-	-	-	-	-	-	-	-	-	-	-	-
COMMUNICATIONS, CONTROLS AND INFO TECHNOLOGY													
MICROWAVE RADIO REPLACEMENTS	141	13	41	23	8	28	-	-	-	-	-	-	120
MAP/INFO IMPLEMENTATION	33	4	3	-	1	-	-	-	-	-	-	-	6
	-	-	-	-	-	-	-	-	-	-	-	-	-
OTHER													
SITE REMEDIATION	10	2	2	1	0	-	-	-	-	-	-	-	3
OIL CONTAINMENT	4	1	1	1	0	-	-	-	-	-	-	-	4
	-	-	-	-	-	-	-	-	-	-	-	-	-
DOMESTIC ITEMS - TRANSMISSION AND DISTRIBUTION		61	64	70	73	71	75	77	79	81	83	84	822
PROPOSED TRANSMISSION AND DISTRIBUTION		142	161	142	159	195	177	253	197	221	169	116	1,938
CUSTOMER SERVICE & MARKETING													
DEMAND SIDE MANAGEMENT CAPITAL COSTS		11	14	22	22	19	16	13	13	12	12	8	143
AUTOMATIC METER READING IMPLEMENTATION	31	2	3	1	1	3	1	1	6	2	0	-	31
DOMESTIC ITEMS - CUSTOMER SERVICE		44	45	48	49	50	51	52	54	55	56	57	540
	-	-	-	-	-	-	-	-	-	-	-	-	-
PROPOSED CUSTOMER SERVICE & MARKETING		57	62	73	74	72	71	68	72	69	69	64	752
FINANCE & ADMINISTRATION													
CORPORATE BUILDING PROGRAM		7	8	8	8	8	22	10	8	8	8	8	100
CUSTOMER INFORMATION SYSTEM	11	-	4	7	0	-	-	-	-	-	-	-	10
HUMAN RESOURCE MANAGEMENT SYSTEM	13	-	12	1	-	-	-	-	-	-	-	-	13
DOMESTIC ITEMS - FINANCE & ADMINISTRATION		22	23	21	22	22	33	24	26	25	29	25	253
	-	-	-	-	-	-	-	-	-	-	-	-	-
PROPOSED FINANCE & ADMINISTRATION		29	48	37	29	30	45	33	32	32	33	33	377
PROPOSED CAPITAL EXPENDITURES (ELECTRIC)		425	367	376	338	330	318	380	325	355	312	239	3,764

Appendix C

Revenue Cost Coverage Analysis – Schedule A-1

Manitoba Hydro
Retail Prospective Cost Of Service Study
March 31, 2002
Revenue Cost Coverage Analysis

Appendix C

S U M M A R Y

Class	Total Cost (\$000)	Class Revenue (\$000)	Contribution To Reserves (\$000)	Revenue Cost Coverage %	Net Export Revenue (\$000)	Total Revenue (\$000)	Contribution To Reserves (\$000)	RCC % - Current Rates
Residential	533,184.3	306,544.7	(226,639.5)	57.5%	207,789.6	514,334.4	(18,849.9)	96.5%
General Service - Small	207,096.3	141,827.1	(65,269.2)	68.5%	79,973.3	221,800.4	14,704.1	107.1%
General Service - Medium	117,575.1	77,393.3	(40,181.9)	65.8%	45,402.3	122,795.6	5,220.5	104.0%
General Service - Large	317,203.9	193,745.6	(123,458.2)	61.1%	123,352.9	317,098.5	(105.4)	100.0%
Interruptible	4,237.1	4,115.2	(121.9)	97.1%	-	4,115.2	(121.9)	97.1%
Area & Roadway Lighting	15,589.7	13,769.2	(1,820.5)	88.3%	2,113.4	15,882.6	292.9	101.9%
Total General Consumers	1,194,886.4	737,395.2	(457,491.2)	61.7%	458,631.5	1,196,026.6	(1,140.2)	100.1%
Winnipeg Hydro	-	-	-	0.0%	-	-	-	0.0%
Net Export Revenue	-	461,413.9	461,413.9	0.0%	(461,413.9)	-	-	0.0%
Total Central System	1,194,886.4	1,198,809.1	3,922.7	100.3%	(2,782.4)	1,196,026.6	(1,140.2)	100.1%
Disco	7,118.8	5,196.1	(3,922.7)	44.9%	2,782.4	5,978.6	(1,140.2)	84.0%
Total System	1,202,005.2	1,203,005.2	-	100.0%	-	1,202,005.2	-	100.0%

Appendix D

Revenue Cost Variance Analysis – Table D-1

Prospective Cost of Service Study for 2002
Detailed Variance Analysis
2002 PCOSS vs Final 2002 Alternate Scenario

Appendix D

	Residential	GSS	GSM	GSL	S/L	Wpg Hydro
<i>2002 Prospective Cost of Service (Previous Methodology)</i>	<i>88.4%</i>	<i>105.8%</i>	<i>107.3%</i>	<i>110.8%</i>	<i>97.6%</i>	<i>117.3%</i>
<u>Impact of Changes on RCCs due to the following variables*</u>						
(1) HVDC (excl Dorsey) as Generation & Ancillary Services	-0.1%	0.0%	0.1%	0.2%	0.1%	0.1%
(2) Transmission 100% Demand	-1.6%	-0.5%	1.0%	4.2%	1.4%	-2.4%
(3) Transmission - Avg 12 monthly Peaks	1.7%	0.0%	-1.4%	-3.3%	1.6%	-1.4%
(4) Gen reclassification & allocation on seasonal demand	-0.1%	1.2%	2.1%	0.8%	-1.5%	-9.6%
(5) Removal of Winnipeg Hydro as a customer class	0.8%	-0.2%	-0.1%	-0.5%	0.3%	-104.3%
(6) Allocation of export revenue	7.4%	0.8%	-4.6%	-12.2%	2.8%	0.0%
Total Impact on RCCs	-8.1%	1.3%	-2.9%	-10.8%	4.3%	+117.3%
<i>2002 Prospective Cost of Service Study - REVISED</i>	<i>96.5%</i>	<i>107.1%</i>	<i>104.4%</i>	<i>100.0%</i>	<i>101.9%</i>	<i>0.0%</i>

Appendix E

Interim Ex Parte Orders

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
09/09/98	120/98	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	Until confirmed or otherwise by a further Order of the Board following a public hearing
16/09/98	122/98	" " " "	" " " "	" "
23/09/98	124/98	" " " "	" " " "	" "
30/09/98	129/98	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
07/10/98	131/98	" " " "	" " " "	" "
14/10/98	133/98	" " " "	" " " "	" "
21/10/98	134/98	" " " "	" " " "	" "
28/10/98	135/98	" " " "	" " " "	" "
04/11/98	142/98	" " " "	" " " "	" "
10/11/98	146/98	" " " "	" " " "	" "
18/11/98	150/98	" " " "	" " " "	" "
25/11/98	151/98	" " " "	" " " "	" "
02/12/98	156/98	" " " "	" " " "	" "
09/12/98	157/98	" " " "	" " " "	" "
16/12/98	159/98	" " " "	" " " "	" "
23/12/98	164/98	" " " "	" " " "	" "
24/12/98	167/98	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 1998	" "
30/12/98	168/98	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
06/01/99	2/99	" " " "	" " " "	" "
08/01/99	3/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 1999	" "
13/01/99	5/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
20/01/99	10/99	" " " "	" " " "	" "
27/01/99	17/99	" " " "	" " " "	" "
03/02/99	19/99	" " " "	" " " "	" "
08/02/99	21/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 1999	" "
10/02/99	23/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
17/02/99	25/99	" " " "	" " " "	" "
24/02/99	26/99	" " " "	" " " "	" "
03/03/99	27/99	" " " "	" " " "	" "
10/03/99	28/99	" " " "	" " " "	" "
10/03/99	29/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of	" "

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
17/03/99	41/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Curtailable Service Program Reference Discount for March 1999 Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	-
24/03/99	54/99	-	-	-
31/03/99	56/99	-	-	-
07/04/99	57/99	-	-	-
12/04/99	60/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 1999	-
14/04/99	63/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	-
21/04/99	71/99	-	-	-
28/04/99	72/99	-	-	-
28/04/99	73/99	Hydro - Curtailable Rates Program	Interim Curtailable Service Program Order	???????????
05/05/99	83/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. I of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	-
10/05/99	85/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 1999	-
12/05/99	86/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	-
19/05/99	88/99	-	-	-
26/05/99	89/99	-	-	-
02/06/99	98/99	-	-	-
09/06/99	101/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 1999	-
09/06/99	102/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	-
16/06/99	111/99	-	-	-
23/06/99	114/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	-
30/06/99	119/99	-	-	-
07/07/99	122/99	-	-	-
14/07/99	138/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 1999	-
14/07/99	140/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	-
21/07/99	142/99	-	-	-
28/07/99	145/99	-	-	-
04/08/99	147/99	-	-	-
11/08/99	153/99	-	-	-
11/08/99	154/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of	-

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
18/08/99	155/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Curtailable Service Program Reference Discount for August 1999 Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
25/08/99	156/99	" " " "	" " " " " "	" "
01/09/99	157/99	" " " "	" " " " " "	" "
07/09/99	160/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 1999	" "
08/09/99	161/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
15/09/99	162/99	" " " "	" " " " " "	" "
22/09/99	164/99	" " " "	" " " " " "	" "
29/09/99	165/99	" " " "	" " " " " "	" "
06/10/99	166/99	" " " "	" " " " " "	" "
12/10/99	169/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 1999	" "
13/10/99	170/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
20/10/99	171/99	" " " "	" " " " " "	" "
27/10/99	172/99	" " " "	" " " " " "	" "
03/11/99	178/99	" " " "	" " " " " "	" "
08/11/99	184/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 1999	" "
10/11/99	185/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
17/11/99	196/99	" " " "	" " " " " "	" "
23/11/99	198/99	" " " "	" " " " " "	" "
01/12/99	201/99	" " " "	" " " " " "	" "
07/12/99	203/99	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 1999	" "
08/12/99	205/99	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	" "
15/12/99	209/99	" " " "	" " " " " "	" "
22/12/99	216/99	" " " "	" " " " " "	" "
29/12/99	217/99	" " " "	" " " " " "	" "
5/1/00	1/00	" " " "	" " " " " "	" "
7/1/00	2/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2000	" "
12/1/00	3/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement	" "

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
19/1/00	4/00		Energy Rate, Schedule B-2	
26/1/00	12/00			
2/2/00	15/00			
8/2/00	17/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 2000	
9/2/00	18/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
16/2/00	20/00			
23/2/00	23/00			
1/3/00	35/00			
6/3/00	37/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for March 2000	
8/3/00	38/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
15/3/00	40/00			
22/3/00	42/00			
29/3/00	50/00			
05/04/00	52/00			
10/04/00	53/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 2000	
12/04/00	54/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
19/04/00	60/00			
26/04/00	61/00			
03/05/00	63/00			
08/05/00	64/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 2000	
10/05/00	68/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. II of II	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
17/5/00	70/00			
24/5/00	75/00			
31/5/00	76/00			
2/6/00	77/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 2000	
7/6/00	78/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
14/6/00	79/00	Hydro - ISE, Spot Market Replacement Energy Rate, Schedule B-2 - Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
21/6/00	88/00			

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
28/6/00	89/00			
5/7/00	96/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
11/7/00	104/00	Hydro - Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 2000	
12/7/00	106/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
19/7/00	111/00			
26/7/00	113/00			
2/8/00	116/00			
8/8/00	117/00	Hydro – Monthly Reference Discount	An application by Manitoba Hydro for Interim Ex parte Approval of Curtailable Service Program Reference Discount for August 2000	
9/8/00	118/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
16/8/00	119/00			
23/8/00	121/00			
30/8/00	122/00			
5/9/00	124/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for September 2000	
6/9/00	125/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
13/9/00	126/00			
20/9/00	129/00			
27/9/00	131/00			
4/10/00	133/00			
10/10/00	134/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 2000	
11/10/00	135/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
18/10/00	136/00			
25/10/00	139/00			
1/11/00	144/00			
7/11/00	145/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for November 2000	

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
8/11/00	147/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
15/11/00	148/00			
22/11/00	149/00			
29/11/00	150/00		Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule SEP-1	
6/12/00	155/00			
6/12/00	156/00	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 2000	
13/12/00	159/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
20/12/00	163/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
27/12/00	164/00	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
3/1/01	1/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
9/1/01	3/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2001	
10/1/01	5/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
17/1/01	9/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Industrial Surplus Energy, Spot Market Replacement Energy Rate, Schedule B-2	
24/1/01	12/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	
31/1/01	16/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	
6/02/01	19/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for February 2001	
7/02/01	23/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	
14/02/01	29/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	
21/02/01	30/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	
28/02/01	31/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	
06/03/01	34/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for March 2001	

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
07/03/01	35/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- -
14/03/01	47/01	- - - -	- - - - - - - -	- - -
21/03/01	58/01	- - - - - - - -	- - - - - - - -	- - -
28/03/01	60/01	- - - - - - - -	- - - - - - - -	- - -
4/4/01	62/01	- - - - - - - -	- - - - - - - -	- - -
11/04/01	72/01	- - - - - - - -	- - - - - - - -	- - -
12/04/01	73/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for April 2001	- -
18/04/01	74/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. III of III	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- -
25/04/01	76/01	- - - - - - - -	- - - - - - - -	- - -
2/5/01	79/01	- - - - - - - -	- - - - - - - -	- - -
7/5/01	85/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for May 2001	- - -
9/5/01	86/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -
16/5/01	88/01	- - - - - - - -	- - - - - - - -	- - -
23/5/01	89/01	- - - - - - - -	- - - - - - - -	- - -
30/5/01	90/01	- - - - - - - -	- - - - - - - -	- - -
04/06/01	92/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for June 2001	- - -
06/06/01	93/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -
13/06/01	96/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -
20/06/01	102/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -
27/06/01	103/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -
4/7/01	105/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -
10/7/01	110/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for July 2001	- - -
11/7/01	111/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -
18/7/01	112/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -
25/7/01	115/01	- - - - - - - -	- - - - - - - -	- - -
1/8/01	120/01	- - - - - - - -	- - - - - - - -	- - -
8/8/01	121/01	- - - - - - - -	- - - - - - - -	- - -
8/8/01	122/01	Hydro – Monthly Reference Discount	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for August 2001	- - -
15/8/01	123/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -
22/8/01	128/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	- - -

DATE	BOARD ORDER NO.	FILE NAME	SUBJECT MATTER	TO BE BROUGHT FORWARD
29/8/01	131/01	Hydro – ISE, Spot Market Replacement Energy Rate, Schedule B-2 – Interim Ex Parte Orders Vol. IV of IV	Application by Manitoba Hydro for an Interim Ex Parte Order Approving Surplus Energy Program Rates, Schedule Sep-1	
5/9/01	133/01			
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7/10/02	177/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for October 2002	" " "
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10/12/02	213/02	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for December 2002	" " "
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8/1/03	2/03	Hydro – Monthly Reference Discount – Vol. II of II	An Application by Manitoba Hydro for Interim Ex Parte Approval of Curtailable Service Program Reference Discount for January 2003	" " "

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TAB 8

MANITOBA
THE PUBLIC UTILITIES BOARD ACT
THE MANITOBA HYDRO ACT
THE CROWN CORPORATIONS PUBLIC
REVIEW AND ACCOUNTABILITY ACT

Board Order 101/04

July 28, 2004

Before: G. Lane C.A., Chair
R. Mayer Q.C., Vice-Chair
L. Evans, Member

**AN ORDER IN RESPECT OF AN APPLICATION
BY MANITOBA HYDRO FOR INCREASED RATES
WITH FURTHER DIRECTIVES AND REASONS TO FOLLOW**

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1.0 Introduction

The increase in consumers' rates sought in the General Rate Application of Manitoba Hydro (MH or the Corporation) was influenced by the highest loss ever experienced by a Manitoba Crown Corporation. The loss arose as a result of a severe drought that reduced power generation and export potential. The financial effects of the drought were first felt in 2002/03 in reduced net income, and more fully realized in fiscal 2003/04 with MH incurring a loss in excess of \$400 million. The financial impact extended into fiscal 2004/05, with a reported loss of \$33 million in MH's first quarter.

The drought's impact on the Corporation's retained earnings, and a related and increased realization by The Public Utilities Board (the Board) of the financial and operating risks faced by MH, were the primary factors contributing to the Board's decision to grant MH rate increases, as outlined in this Order. As a result of the proceedings leading to this Order, the Board is more fully apprised of the importance of, and relationship among, water storage and flow levels, natural gas prices, and American wholesale electricity pricing to MH's financial situation and rates.

MH is Manitoba's largest and oldest provincial Crown Corporation. It is an integrated energy company, providing electricity and natural gas to approximately 500,000 and 250,000 electricity and gas customers, respectively.

In recent years, MH acquired Centra Gas Manitoba Inc. and Winnipeg Hydro, and integrated these operations with those of its pre-existing electric operations. The Corporation operates fourteen hydroelectric, two thermal and four remote diesel generating stations, and has plans for additional hydroelectric generation and transmission.

MH's consolidated annual revenues exceed \$1.75 billion, with the majority of its revenues coming from Manitoba's residential, commercial and industrial electricity customers. The Corporation is also involved in the export and import of power.

MH's assets approach \$10 billion at historical depreciated cost, and the Corporation is one of Manitoba's largest employers with a personnel complement forecast to approach 6,000 employees.

MH is administered through a Board of Directors appointed by the Lieutenant Governor-in-Council, and is funded not only by revenue from energy sales but also from borrowings guaranteed by the Province. These borrowings, which the Corporation services from operating income, enable the Corporation to develop generating, transmission and distribution capacity. This capacity is required to provide reliable service to the Corporation's Manitoba and export customers.

Because MH is a capital intensive utility, many of its costs are fixed for the medium to long term.

Consistent with the importance of MH to Manitoba, there is considerable oversight of its operations. MH is subject to the direction and/or oversight of the legislature, the Government of Manitoba, its Board of Directors, Crown Corporations Council, The Public Utilities Board and currently, the Clean Environment Commission. Two members of the Public Utilities Board sit on the Clean Environment Commission, in its hearing on the proposed Wuskwatim generating station and transmission project.

MHI's annual revenue requirement (the sum required to fund its operations and provide for its risks) and rates are subject to the approval of The Public Utilities Board. With respect to its electricity operations, MHI has a significant involvement in and reliance on export energy sales, with Manitoba consumers' rates benefiting from export profitability. The Corporation prices its electrical sales to Manitoba customers using a methodology based on cost, which is usually not representative of the market value for energy in North America.

2.0 Background

MHI last appeared before the Board seeking a rate increase in 1996; average increases in Consumers General Rates were approved of 1.5% effective April 1, 1996 and a further 1.3% effective April 1, 1997.

Six years passed before the Corporation returned to appear before the Board. In 2002, MHI provided the Board with an update of its situation, financial forecasts, costing methodologies, processes and other matters.

On February 3, 2003, the Board issued Order 7/03, arising out of the 2002 Status Update Filing. This Order, among other directives, required MHI to file a revised Schedule of Rates to be effective April 1, 2003. The Board directed rate decreases of 2.0% for the General Service Large Classes served at greater than 30 kV, and 1.0% for the General Service Small Class.

The rationale for the decreases was the then recent positive economic returns experienced by the Corporation and an indication that the classes for which rate decreases were granted had been levied rates that were higher than were justified by the Corporation's rate-setting methodology.

On March 19, 2003, concerned with financial loss development related to a drought that began subsequent to the 2002 Update hearing, the Corporation filed an Application pursuant to subsection 44(3) of *The Public Utilities Board Act*, asking the Board to rescind the rate decreases.

By Order 154/03 of October 31, 2003, in the absence of an amended rate setting methodology and with the developing financial losses having been realized after the 2002 hearing had occurred, the Board upheld its decisions regarding rate decreases. It also reduced the winter ratchet from 80% to 70%, and addressed other issues brought forward by Corporation. Board Order 01/04 of January 6, 2004 confirmed the direction, resulting in a reduction in Annual General Consumer Revenue of approximately \$6.5 million.

Since MH's 2002 Status Update filing, MH has faced a series of challenges. These included the integration of Winnipeg Hydro, negotiation of a coordination agreement with the Midwest Independent System Operator ("MISO"), related to the Corporation's export and import of power to and from the United States, and contract renewals with its five staff bargaining Units.

And, as indicated and more importantly for the purposes of this Order, the Corporation also suffered through a drought, an event resulting in an operating loss for the fiscal year ended March 31, 2004 in the range of \$400 to \$430 million.

3.0 Application

On January 29, 2004, MHI filed an application ("the Application") with the Board for an Order pursuant to *The Crown Corporations Public Review & Accountability Act and Manitoba Hydro Act*.

The Application sought:

- (a) Approval of electricity rate increases to be effective as of April 1, 2004 and 2005. The proposed rates were projected to result in an annual aggregate revenue increase of approximately \$28 million (3.0%) for the fiscal year April 1, 2004 to March 31, 2005, and an additional revenue increase of \$24 million or 2.5% for the fiscal year April 1, 2005 to March 31, 2006. MH also sought differentiated rate increases by customer class, and a further upward adjustment of those 2004/05 increases to raise the overall 3% revenue increase requested for the fiscal year over the remainder of the fiscal year. This was to compensate for the fact that the Board's Order was not expected until well into 2004/05.

MH opined that the 3.0% and 2.5% increases requested, an accumulated non-compounded average rate increase of 5.5% over two years, represented the minimum rate increases prudence required.
- (b) Final approval of interim approved ex parte Orders issued since January 15, 2003 relating to the Curtailable Rate Program, Surplus Energy Program and Order 153/03, which deals with various rate matters.
- (c) Extension of the Surplus Energy Program Terms and Conditions to March 31, 2007.

As indicated, the revenue increases applied for were differentiated by customer class, as follows:

Class	2004/05	2005/06
Residential	4.01%	3.51%
General Service Small Non-Demand	2.15%	1.52%
General Service Small Demand	2.09%	1.49%
General Service Medium	2.57%	2.11%
General Service Large < 30 kV	4.02%	3.50%
General Service Large 30-100 kV	2.71%	1.50%
General Service Large > 100 kV	1.95%	1.47%
Area and Roadway Lighting	2.03%	1.51%
Overall General Revenue Increase Average	3.00%	2.50%

And, as indicated, the rates sought for fiscal 2004/05 were to be adjusted upwards to compensate for the fact that the Board's Order was not expected until well into the fiscal year.

The hearing extended over thirteen days, and involved five active Intervenor's representing seven ratepayer constituencies, and three independent expert witnesses. The Board was assisted by Counsel from Fillmore Riley, professional accountants from PricewaterhouseCoopers and a professional engineer from Dillon Consulting.

4.0 Two-Stage Order

In recognition of the deterioration of the Corporation's fiscal situation arising out of the recent drought, the Board will issue its decisions arising out of the Corporation's General Rate Application in two parts.

By this approach, the Board reflects its desire to bring about a timely increase in MH's revenue:

Accordingly, this Order provides direction on the rates to be implemented August 1, 2004, and conditionally provides for two subsequent rate increases. It also indicates the Board's direction with respect to certain other significant matters.

The second Order will follow at a later date, and provide further rationale for the Board's directives regarding rates, as well as direction with respect to certain outstanding matters arising out of the Application.

Among the topics to be addressed in the second Order will be the issues related to Outstanding Board Directives, Revenue Requirement, Cost of Service Studies, Financial Targets, Demand Side Management, Rate Structures, the Surplus Energy Program, the Curtailable Rates Program, the positions taken by Intervenor and Presenters, and other matters examined during the hearing.

5.0 Key Information

5.1 Drought

Prior to this Application, MH had not sought a rate increase since 1997; favourable export revenues had more than offset increased operating costs. Net income levels had been very good, providing support for two important acquisitions and a special payment or dividend to the Province.

However, beginning in the fall of 2002, and particularly in the 2003/04 fiscal year, the Corporation sustained severe financial losses due to drought, making it unable to meet its future revenue requirements without rate increases.

The drought significantly increased MH's need to import power, reduced export sales, and drove its net income into a deficit position while depressing retained earnings.

Although the spring and summer of 2002 may have experienced sufficient rainfall in most parts of southern Manitoba for some purposes, there were insufficient amounts of water runoff to fill MH's storage reservoir system of lakes and rivers. Overall water supplies over large portions of the Churchill/Nelson River basin fell in the fall and winter of 2002/03 to lows that, on average, were expected by MH to occur only once in every 50 years. Going into the winter of 2003/04, reservoirs were at or near historic lows. While the entire watershed was not in a similar drought condition, the overall water storage situation was in a state experienced only once before in the last thirty years.

This reduced MH's generating capacity and, eventually impacted on its financial situation. The drought reversed the Corporation's progress towards achievement of its financial targets.

The Corporation's Integrated Financial Forecast projected that even with the increases sought through these proceedings, and further annual rate increases in the range of 2.5% through to and including fiscal 2013/14, the Corporation would not reach its targeted debt to equity ratio.

In summary, the financial effects of the drought were felt in 2002/03 through reduced net income, in 2003/04 with a net loss in excess of \$400 million, and continued into 2004/05 depressing MH's first quarter results.

Despite the advantages of MH's ability to sell export power, the experience of fiscal 2003/04 confirms the Corporation's vulnerability to the whims of nature, general economic circumstances, and, the fluctuations of the wholesale electricity market.

MHI has estimated that a repeat of the worst drought on record, would cost MHI at least \$2 billion. (The drought of 2002-2004 was the third worst on record.)

With minimal cash reserves, MHI would have to increase its borrowings to meet such a loss, and the additional financing charges would increase the cost of such a drought by a further \$200 million. Droughts of this severity are statistically predictable events.

Based solely on Lake Winnipeg inflow records, it would appear that comparable, or worse, droughts took place in 1929-1933, 1938-1941, 1961-1962, 1976-1978, 1980-1981 and 1987-1989.

The drought resulted in significantly increased imported power costs to meet domestic load and export commitments. Import prices rose as MH became an importer, with increased American demand and rising natural gas prices, further depressing net export income.

The 2002-2004 drought followed the lowering of water storage levels to seize profitable export sales opportunities in the fall of 2002, a decision that improved the Corporation's profitability in fiscal 2002/03 but, in hindsight and though understandable, proved expensive. Generating and selling storage water in 2002 meant MH has less water to meet 2003/04 domestic and export commitments from Manitoba generation, and had to import additional power to meet those commitments and ensure domestic reliability.

In 2003/04, the Corporation imported far more power than it has ever had to before. In one year, the Corporation spent more on imported power than it had in the previous ten. As a result of lower water storage levels in 2002, MH entered the winter of 2002/03 with well below optimal water levels and was unable to recover until very recently.

On a net basis, export/import operations moved from the substantial profits of recent years to a significant loss.

At the hearing, the Corporation displayed that it had learned from this experience, a time portrayed as "the perfect storm" (drought, high natural gas prices, high import prices, and low water storage). It is anticipated that some new insight was gained into the following:

- Low snowfall accumulation usually is a precursor to a drought
- Significant snowfall accumulation does not necessarily preclude a drought
- High energy prices can be a blessing if hydro generation is high
- High energy prices can be a curse if hydro generation is low
- Energy shortages may have high "on-peak" and high "off-peak" export price consequences
- Energy surpluses accompanied by high energy prices can be very profitable, while surpluses accompanied by low energy prices suggest caution in expanding export sales.

The Corporation acted to protect Manitoba ratepayers and its retained earnings once it fully apprehended the situation.

By its actions, it proved its commitment to domestic supply and reliability. It acted in the futures market to reduce its export delivery requirements, and, by so doing, prevented the 2003/04 loss from reaching \$1 billion. MH engaged in forward purchases of imported power and buybacks of contracted export sales.

By taking these and other steps, MH avoided having to pay ten cents a kilowatt hour and higher prices related to MH becoming a major importer of energy, rather than exporter. MH did not have to resort to its even higher priced thermal generation (gas) to satisfy domestic and firm export loads.

MH substantially curtailed its export sales to firm commitments in the second half of 2003/04, when off-peak on-peak trading ceased being economically advantageous. The Corporation has also increased its staffing for export trading operations, and engaged an independent expert to survey its approach to drought.

The criteria MH used for export sales, after it realized the extent of the drought and the export pricing situation, curbed unprofitable energy sales after August 2003. Its risk mitigation actions minimized unfavourable energy trading losses, and allowed the Corporation to retain in storage enough water to guard against the risk that the drought would continue into 2004/05. Through all of this, energy reliability to Manitobans and firm export commitments was maintained.

Notwithstanding the highly unfavourable experience of 2003/04, export sales over the longer term have been good for MH and its ratepayers. In fact, MH relies upon net export revenue to maintain below market rates for its domestic grid customers. Typically, only approximately 85% of MH's annual revenue requirement is met by domestic sales revenue (calculating net export revenue after an allocation of generation and transmission costs to export sales). Exports subsidize the rates of domestic grid customers.

With the loss experience of 2003/04, MH's retained earnings are expected to fall from \$1.17 billion as of March 31, 2003 to below \$750 million as of March 31, 2004. MH's peak retained earnings level was \$1.302 billion, reached as of March 31, 2002.

By the conclusion of this hearing, MH was able to indicate that it was reasonably confident that the recent drought is over, and forecast that, if the rate increases sought were granted, it would

meet its 2004/05 budgeted net income of \$40 million. However, there is no guarantee unfavourable circumstances can be avoided. Precipitation levels could decrease again, leading to additional financial problems.

While such a recovery from a loss of in excess of \$400 million would be welcome, a net income of \$40 million largely attributable to a rate increase is minimal for a Corporation with assets of approximately \$10 billion.

5.2 Revenue Requirement

MH's rate requests are based on forecast revenue requirements, and represent the Corporation's projections of how much additional revenue it requires from its customers to meet expenses and build sufficient reserves to provide for its operating risks.

Consumers' Association of Canada (Manitoba) Inc. and Manitoba Society of Seniors Inc. (CAC/MSOS), an Intervenor representing residential customers, challenged MH's contention that it required additional rate-related revenues of \$28 million for 2004/05.

CAC/MSOS submitted that an \$11 million arithmetical error was included in the 2003 Integrated Financial Forecast, and suggested that the error and an ongoing annual pension expense savings in the order of \$5 million had not been incorporated into the forecast. This Intervenor argued the 2004/05 revenue requirement and rate increase should be significantly reduced for 2004/05.

MH did not dispute the CAC/MSOS' contention, but indicated that only \$3.5 million of the savings would reduce the annual cost of operations.

As well, the Corporation suggested that any reduction to forecast revenue requirements related to the matters raised by CAC/MSOS would be offset by other cost pressures. In short, the Corporation stood by its submission that an additional \$28 million in rate-related revenue was required for fiscal 2004/05.

5.3 Financial Targets

In recent years, a number of major events changed the financial position of MH:

- a) Centra Gas Manitoba Inc. and Winnipeg Hydro were acquired during the 1999-2002 period, and both acquisitions were funded by debt;
- b) Similar to other jurisdictions with Crown owned utilities, a special payment or dividend was paid to the Province, after the Corporation had enjoyed a series of years of increasing net income results and export revenue gains, with no drought on the horizon;
- c) Interest in pursuing additional new generation and transmission developed; and
- d) A major drought deteriorated the retained earnings and debt:equity ratio.

While the acquisitions and plans improved MH's operational prospects, they also impacted on the Corporation's debt:equity ratio. The payment to the Province, though having justification given the good results of prior years, also had that effect.

In the two fiscal years before the dividend was announced, MH's export revenues and net income were the highest in the Corporation's history, and far above MH's average net income. In fiscal 2000/01 and 2001/02 MH reported net income of \$270 million and \$214 million respectively. By contrast MH's current forecast of net income anticipates annual net income

levels below \$100 million through to 2009/10, despite projected annual consumer rate increases through that period.

The 2002-2004 drought made it more difficult to achieve MH's debt:equity target of 75:25 within the ten-year forecast period. By itself, the loss associated with the drought pushed back the date of realizing a 75:25 debt:equity ratio by several years.

5.4 Cost of Service

The Cost of Service Study (COSS) is a tool used by the Corporation to assist in evaluating and setting rates for each customer class. The COSS analyzes the components of MH's revenues and costs, and makes allocations to the various customer classes. The intent of the COSS is to evaluate the relative fairness of rates between customer classes.

Revenue to Cost Coverage Ratios (RCC) are determined from the COSS, and indicate the proportion of costs recovered from the revenue arising from each customer class. A Zone of Reasonableness (ZOR) concept has been developed to assist in evaluating the RCC ratios.

Customer classes having RCC ratios that are between 95% and 105% of allocated costs are deemed to have average rates that are within the "zone of reasonableness." In short, as long as a particular customer class has a ZOR between 95 and 105, it is considered to be reasonably fairly assessed relative to the other classes.

The Corporation uses this methodology in developing its recommended rates. However, as the Corporation had not sought a rate increase for many years, seven for the residential class, twelve for the industrial classes, a fairly wide range of RCCs has developed, bringing into question the

fairness of customer class rates relative to other customer class rates. (The loss experienced in 2003/04 was very large, and if it were distributed to the various customer classes pursuant to the current Cost of Service methodology no customer class would have an adequate revenue to cost ratio.)

That being said, COSS involves a number of debatable allocation and forecasting procedures, and its value depends in large part on the all aspects of the COSS making sense, and being accepted by the Corporation, the customer classes and the Board.

MHI filed COSS data incorporating most of the Board Directives from Order 7/03. However, Winnipeg Hydro financial, customer and load data was not fully incorporated. The Corporation had some concerns with respect to the incorporation of Winnipeg Hydro data into its COSS model.

One of the concerns related to the application of load research results from the rest of the system to the former Winnipeg Hydro customer base, and another difficulty experienced related to the allocation of direct costs to the Area and Roadway Lighting customer class for the former Winnipeg Hydro's territory.

As well, the current COSS methodology does not include an Export Class, which was discussed in Board Order 7/03. With export sales and related imports representing a significant business area of operation, there is a strong argument for this business segment to be considered a customer class for COSS modelling purposes.

When the export class is established and the other amendments to the COSS model effected, the Board anticipates that the methodology will arrive at significantly different revenue to cost ratios

for the customer classes. Again, and in combination with the effects of the 2002-2004 drought, this supports an across-the-board increase for August 1, 2004, rather than rate increases differentiated by customer class.

With respect to export sales from existing generating and transmission assets, the Board recognizes that entering into short term export sales contracts on the basis of immediate incremental revenue potential represents the appropriate response. In short, the assessment of the value of an immediate export sale opportunity should take into account only incremental costs and revenues.

Included in the evidence in the GRA, MH filed a 2004 report by National Economic Research Associates (NERA) titled "Classification and Allocation Methods for Generation and Transmission in Cost of Service Studies" (the NERA Report). The report reviews alternative methodologies and provides recommendations for amendments to the COSS methodology.

MH did not revise its Application to reflect the recommendations of the NERA report, though it did provide some modelling of its effects. The Corporation and the Intervenor, in a view shared by the Board, agreed that the Cost of Service methodology is in a state of flux, and that NERA's recommendations require further consideration, analysis and review.

A comparison prepared by MH of the RCC's based on MH's proposed Cost of Service Study and the NERA Report follows:

Class	RCC – Existing Methodology March 31, 2004	RCC – Reflecting the NERA Report March 31, 2004
Residential	90.6%	93.8%
General Service – Small Non Demand	104.9%	108.1%
General Service – Small Demand	109.7%	110.2%
General Service Medium	104.8%	103.5%
General Service Large 0-30 kV	99.9%	96.6%
General Service Large 30-100 kV	109.3%	101.3%
General Service Large > 100kV	113.8%	106.8%
General Service Large > 100kV – Curtailed	114.6%	107.9%
Interruptible	94.2%	97.1%
Area and Roadway Lighting	108.9%	110.8%
Diesel	38.3%	54.9%

The above representation of NERA Report does not reflect the cost of uniform rates being made a first charge against net export revenue, nor the division of generation costs between low and high cost generation as suggested by the Intervenor. The Table does not reflect the formulation of net export revenues on a five year rolling average.

With respect to assessing the value of export sales, and utilizing the net benefit arising out of export and import activities in determining Manitoba-based customer class rates, the NERA model proposes an export class, with that class to be allocated export associated costs.

Costs associated with export activities include generation, transmission, operating, maintenance and administrative costs, water rentals and capital taxes.

Contrary to a position taken at the Status Update Hearing, MH indicated support for the concept of an export class, as did a number of the Intervenor. The Board is of the view that without an export class, and the assigning of appropriate revenues and costs to it, and in the absence of a

reasonable method of allocating the net income arising out of export activities, the COSS and its development of customer class RCCs is suspect.

Furthermore, there is the potential conflict between arithmetically driven decisions and public policy directives. CAC/MSOS contended that the existing COSS methodology, which assigns virtually the full \$14 million cost of the uniform rate policy, implemented through legislation, to residential customers, is inappropriate and was neither the intent of the Legislature nor the Government.

CAC/MSOS proposed that the cost associated with a uniform residential rate for grid customers throughout Manitoba be considered a first charge against net export income. In that way, all customer classes would bear a portion of the cost of this public policy initiative.

Other suggestions with respect to the COSS methodology were discussed at the hearing.

Time to Respect Earth's Ecosystems/Resource Conservation Manitoba (TREE/RCM) opined that the allocation of generation and transmission costs should be further governed by an accounting convention, one that would assign the higher cost of newer and more costly generation and transmission assets to the export class. TREE/RCM expressed the view that this would ensure that domestic ratepayers benefited from lower cost generation assets, and that the marginal costs associated with export sales generation would be more properly assigned to export activities.

5.5 Demand Side Management

Efforts to enhance the efficiency of the use of electricity in Manitoba, connoted as Demand Side Management ("DSM"), have proved reasonably successful to-date.

The reduced consumption of electricity arising out of DSM provides savings for residential and commercial customers, and frees up Manitoba energy generation for export sales, which are primarily to the United States.

While it was indicated at the hearing that the Corporation's current approach to DSM differs between its electricity-based and gas-based operations, MKO called for an integrated approach, one recognizing that customers avail themselves of various energy sources and that conservation and efficiency are useful objectives in all circumstances.

The Corporation indicated during the Application proceedings that it was in the process of preparing a new plan to guide its DSM activities, and suggested that this new plan would call for further investments in DSM.

Intervenors suggested that further review of and customer involvement in this plan was imperative, and the Corporation agreed.

As well, TREE/RCM proposed and other Intervenors generally agreed that changing the pricing approach for electricity sales would likely enhance DSM effectiveness, to the benefit of all. Currently, pricing schedules provide for reduced rates as volumes increase. An alternate approach would have rates increasing with increasing volumes. Such an approach may address the risk of inefficient usage associated with rates set below marginal cost.

It was recognized by all parties that an inverted rate schedule, whereby higher usage would bring higher rates and costs associated with that usage, required considerable study before being implemented. Though such an approach could be implemented on an overall revenue neutral

basis, implications could range from higher bills for some customers to impacts on commercial and industrial activities.

6.0 Board Findings

6.1 Revenue Requirement and General Rates

The Board accepts the CAC/MSOS comments with respect to arithmetical errors in MH's integrated financial forecast. Nonetheless, the Board accepts the overall forecast for net income for 2004/05 and 2005/06 provided by MH as being reasonable, having been based on macro assumptions. While the costs pointed out by CAC/MSOS may be over estimated, there may be offsetting items in the IFF. As well, the Board is of the view that there is a need for MH to rebuild retained earnings, particularly depressed as a result of the drought and required to meet on-going risks.

The Board has reasonable confidence in MH's efforts to project expenses. That being said, one of the goals of the hearing process is to best ensure that such confidence in the Corporation's forecasting is also shared by the Intervenors.

The Board finds that a more detailed examination of MH's cost experience and forecasts in future rate hearings would be in the public interest. The Corporation is engaged in a number of concurrent activities, projects and research initiatives, all requiring a substantial investment in personnel and consultants.

Cognizant of the necessity for the Corporation to meet its challenges effectively, managing the export activities being a prime example, the Board is reluctant, in fact unable on the record of

this proceeding, to provide critical judgement on the appropriateness of the current and projected departmental and functional personnel complement and cost levels.

The Board acknowledges that it is not alone in its oversight of the Corporation, and that its jurisdiction is limited. Accordingly, the Board finds it necessary and reasonable to rely upon the Corporation's Board, the Government, and Crown Corporations Council with respect to administrative oversight of MH's operating and capital expenditures.

Nonetheless, noting the ongoing and substantial increases in MH's operating, maintenance and administration expenses, and observing the continuing material negative differential between the costs per customer between MH and BC Hydro (as reported during the hearing), a more detailed examination of costs at future rate hearings represents a reasonable objective.

Rate Increases

On an overall basis, the Board finds the financial impact of the drought on MH to have been extremely significant, and, combining this with other factors results in the requested rate increases being insufficient.

Additional revenue is immediately required to begin the rebuilding of MH's retained earnings, towards the broadly accepted debt to equity ratio target of 75:25. The Board will expect MH to maintain vigilance over its costs, so that the additional revenues contribute as they are intended to move towards achieving the debt to equity target more quickly than suggested in MH's 2003 Integrated Financial Forecast.

Accordingly, and after careful reflection and realizing the additional burden that will be placed on the economy, the Board has determined to vary MH's rate increase requests.

The Board will direct MH to file a rate schedule reflecting annual revenue increases of 5% for all customer classes effective August 1, 2004.

The Board will also grant MH a conditional and interim rate increase of 2.25% for all customer classes, effective April 1, 2005, and a further conditional and interim increase of 2.25% for all customer classes effective October 1, 2005.

The April 1, 2005 conditional interim rate increase will be subject to MH filing a revised Integrated Financial Forecast and its second and third quarter fiscal 2004/05 financial statements with the Board by no later than January 31, 2005. An October 1, 2005 additional interim rate increase will be subject to MH filing its 2004/05 audited financial statements, an updated forecast for fiscal 2005/06 and its first quarter fiscal 2005/06 financial statements with the Board no later than July 31, 2005.

Recognizing the concerns of Intervenor and ratepayers, the Board will review the financial performance of MH at those times to determine whether the conditional rate increases should be adjusted downward. The Board's decision to confirm or vary the conditionally granted increases will be predicated upon its assessment of MH's financial condition, and its progress towards the 75:25 debt:equity ratio relative to the Board's understanding of MH's forecasts for future fiscal results.

The Board will not adjust the conditional rate increases upwards in the absence of a new rate application from the Corporation. The Board will invite written comments from registered Intervenor at the time it considers each conditional rate increase.

In making the last two increases conditional, the Board provides a level of protection for the long-term interests of ratepayers.

At the same time, these conditional increases provide reasonable assurance to MH that its revenue base will be strengthened if the need is present.

In particular, conditional increases recognize the uncertainties present with respect to forecasting export sales and net income. These uncertainties are related to water levels and storage issues, export demand, pricing and other related matters.

The Board accepts MH's contention that while current water levels and water storage levels are promising, weather conditions can quickly change, as can export demand and pricing.

The export sales potential, gross and net, for 2004/05 and 2005/06 is uncertain. Even more uncertain are the forecasts of results five and ten years out in time.

MH's projected rate increases for the years beyond 2006 are in the nature of "place marks", and more experience will be required before the need for such increases can be confirmed. The upwardly varied rate increases will reduce the risk that future rate increases will have to be higher, or have to occur as they are now forecast.

The Board had two concerns when dealing with MH's Applications, the interests of the utility's ratepayers and the financial health of the utility. Together, and in the broadest interpretation, these interests represent the general public interest.

In a sense, Manitoba and ratepayers are fortunate that the objective of avoiding rate shock plays a role in rate setting; in the case of other commodities (oil and gas), market price changes ignore the concept.

MHI provides electricity to Manitoba's residences and businesses at advantageous prices, and the advantage relative to other North American jurisdictions will continue even with the rate increases provided in this Order. Furthermore, the current rate schedules provide for lower energy charges as volumes increase, the last block being far below the average and marginal costs of production and sale. (In this Application, MHI proposed that the residential energy use blocks be consolidated in 2005, as a first step towards a possible future change to an inverted rate schedule after 2006.)

As indicated, MHI's previous residential grid rate increases were 1.5% and 1.3%, effective as of April 1, 1996, and 1997 respectively. A 2003 Board directed rate decrease of 2.0% and 1.0% for certain commercial and industrial customers came after the previous increase for industrial customers took place in 1992. So, as indicated above, MHI rates have been stable and low for many years.

The increases the Board will approve leave the average MHI rate well below the rates charged by utilities in most, if not all, other North American jurisdictions. The other two low cost utilities in Canada, BC Hydro and Hydro-Quebec, both requested rate increases in 2004. The BC Utilities Commission approved an interim rate increase of 7.23% effective April 1, 2004 for BC Hydro; and, BC Hydro also applied for a further increase of 2.0% effective April 1, 2005. Hydro-Quebec received and is pursuing across the board rate increases amount to approximately 6%.

Aggregate MHI rate increases since 1992, including those granted, firm and conditional, by this Order, are one-quarter to one-third of the accumulated increase in the Consumer Price index during the period. The MHI rate increases are dwarfed in comparison with commodity price

increases in other sectors: oil, natural gas, propane, coal and uranium; for example, since 1997 natural gas prices have tripled.

Provinces and American states served by other forms of generated electricity, such as coal and gas fired plants, have experienced far higher increases than those processed by the hydroelectric utilities of Canada, with Manitoba Hydro offering the lowest average rates among this group.

6.2 Customer Class Rates

During the hearing, persuasive evidence was presented that indicated the cost of service study (COSS) used to assess and recommend rates was in need of amendment.

Notwithstanding this, the rate differentiation sought by MH reflected the use of existing COSS methodology that does not segregate the revenues and costs associated with exports and imports, resulting in flawed results. As well, the current methodology does not meet the Board's interpretation of the intent of the uniform residential rate legislation.

Therefore, the Board agrees that the cost of service methodology requires further analysis and amendment. This further analysis should include a thorough consideration of the NERA recommendations, along with offsetting the financial impact of uniform rates by a first charge on net export revenues.

All Manitoba customer classes have benefited from export revenues, and all these customer classes require the support of a financially healthy utility.

Because the COSS methodology is in a current state of flux, and, in the Board's view incomplete, the Board is not prepared to adopt the current methodology in assessing the revenue to cost ratios of each customer class.

The process to address the fairness of the COSS and the appropriate revenue to cost ratios for the Manitoba customer classes is acknowledged to be lengthy. However, it is important that in the end the methodology be correct, appropriate, and supported.

As further hearings occur, there will be ample opportunity to further consider the ratios and the appropriate use of the ratios in rate setting, after the Board has accepted and confirmed the COSS methodology. Presumably this can be achieved by the time of consideration of the first conditional rate increase, as the Board prefers to begin the process of utilizing the COSS in rate setting at that time.

In the interest of fairness and recognizing the unusual severity of the effects of the recent drought, the Board has determined that the impacts of the drought should be borne by all the rate classes, and that sharing should be reflected in all customer classes receiving the same percentage rate increase on August 1, 2004.

As indicated, future rate increases may differentiate between classes.

In coming to a decision on the rate increases, firm and conditional, the Board considered the issue of rate shock, and opines that the rate increases for most customers will be within the thresholds put forth by the Intervenor (i.e. no more than 8-9% for any customers for the August 1, 2004 increase, and much less for most).

Compared to the price shocks experienced by oil and natural gas purchasers (Bank of Canada's Commodity Price Index for energy - natural gas, oil and coal - has increased by in excess of 100% since 1997), the rate increases, firm and conditional, provided in this Order are modest, particularly given the twelve and seven year rate freeze that industrial and residential customers, respectively, have enjoyed.

The Board shares the concerns of MH and Manitoba Keewatinowí Okimakanak Inc. (MKO), the Intervenor representing the interests of the diesel-served and other First Nations communities, regarding the rates charged to diesel communities. However, the Board is of the view that as the initial rate block for the diesel communities is provided at the same rate as enjoyed by MH customers connected to the electricity grid, diesel rates increases should correspond to the grid rate increase.

The Board is sympathetic to the situation faced by these communities, and is aware of discussions between the federal and provincial governments and MH. The Board expects a resolution for outstanding matters will be found quickly.

6.3 Rate Structure

The Board notes that the Intervenor were generally supportive of the rate structure changes, i.e. the distribution of rate increases between the demand and energy segments of invoices, proposed by MH.

The Board is of the view that MH's proposals regarding rate structures and the shift in the balance between demand and energy charges within the customer classes are reasonable,

promote conservation, and should be reflected in the revised rate schedules filed by MH. That being said, the Board will review the rate schedules to be filed by the Corporation arising out of this Order, and confirm or vary such schedules if and as deemed appropriate.

6.4 Financial Targets

A drought can occur in any year, and MH has projected that a five-year drought of the same proportions as the 2003/04 drought could risk the reduction of its retained earnings by in excess of \$2 billion.

It is instructive to note that the Corporation has reported that in the absence of the hedging transactions and other mitigating actions it carried out in response to the drought, as the Corporation realized its severity, its loss for 2003/04 would have approached \$1 billion. It is also noted that there have been worse droughts in history.

With a debt:equity ratio of 75:25 ratepayers would have increased assurance of future rate stability. Increased retained earnings would provide for a continuation of advantageous interest rates and finance costs. It would also provide increased confidence that a direct financial contribution to MH's capital would not be sought from the Province. Any calls on the Province would mean pressure on taxes, not that a call is expected. The ratepayers of MH are also the taxpayers of the Province; the fortunes and prospects of MH and the Province are, to some degree, co-mingled (in time, with continued repayment of the non-Hydro provincial debt, all of the Province's debt may be related to MH).

As of March 31, 2004, MHI's debt:equity ratio is forecast to rise to 86:14, far above the established target. At the hearing, MHI portrayed the current level of its retained earnings as being unacceptably low, and the Board concurs in this view. MH is not just another corporation, it is representative in some ways of Manitoba's future, and its stability needs to be better assured as it pursues expanded export opportunities.

Another critical financial indicator is the coverage of MH's interest payments by net income. Based on MH's projections, the interest coverage ratio will not reach reasonably safe levels for five years.

Along with the very real risk of another drought, there are other factors supporting the need for a major increase in retained earnings:

- (a) To some extent, particularly with respect to business interruption and insurance risk exclusions, MH self-insures. The corporation carries mainly property and general liability insurance; it has, understandably, no insurance against the financial and operating consequences of a drought;
- (b) Currently, MH has two HVDC transmission lines from the north. These lines are located in close proximity to each other, and transport 70% of MH's generating capacity to southern Manitoba. Until another line is constructed, particularly one geographically separated from the current lines, MH is subject to a substantial business and financial risk not covered by insurance;
- (c) The differential between on and off-peak wholesale electricity prices varies with market conditions, adequate financial margins available to MH from non-firm export sales are always at risk;
- (d) The conditions governing access to export markets are subject to the potential of future adverse or beneficial amendment. To the extent that such changes could disadvantage MH, (no such risk is currently evident) a material risk exists for a corporation dependent upon net export sales to restrain domestic pricing (rates);

- (e) Until new generation capacity comes on line, Manitoba electricity load increases will reduce export sales potential (average export prices have exceeded domestic rates);
- (f) Interest rates are at historic lows; some of MHI's debt carries rates of 3% or less. At some point rates will increase;
- (g) MH has a substantial portfolio of U.S. dollar debt, while this currently provides reduced interest costs and a hedge with respect to export sales, there remains a degree of foreign exchange risk;
- (h) MH reports substantial pressure on operating and maintenance expenditures, partly related to the myriad of responsibilities placed on the Corporation, and partly to aging plant. Upgrades and renovations to generating, transmission and distribution assets are much more expensive than in the past, with reliability and safety standards increasing; and
- (i) MH lacks material liquid assets to meet the risk of future losses; any such losses would require additional borrowings. (MH's balance sheet includes a significant aggregate amount of deferred costs and goodwill, representing historically determined value but illiquid.)

Achieving a debt:equity ratio of 75:25 would provide increased rate stability benefits, and hold down financial charges. The 75:25 benchmark represents a modest target, one comparable to the current debt:equity ratios of similar Crown hydroelectric utilities in other Canadian provinces (B.C. Hydro and Hydro Quebec). In summary, meeting this target within a reasonable period of time would reduce long-term pressure on domestic electricity rates, better assure bondholders and thus constrain financial charges and provide a hedge against a future drought (which is certain from a statistical probability perspective).

6.5 Cost of Service Study

As previously indicated, the Board heard persuasive evidence that the cost of service study (COSS) methodology presently employed by MH requires review and amendment, and now provides known distortions in cost allocation.

Therefore, the Board directs MH to file no later than January 30, 2005 three separate 2006 COSS, reflecting the following:

- (a) MH's existing methodology;
- (b) The implementation of the NERA recommendations;
- (c) The allocation of less expensive generation costs all to domestic customers, with higher cost generation being allocated between domestic and export customers on an in-service date basis as suggested by TREE/RCM; and
- (d) MH's preferred approach and methodology, including supporting rationale.

In preparing these studies, MH shall allocate a sufficient share of net export revenue to offset the cost of the implementation of residential uniform rates. Net export revenue shall be taken into account over a five year rolling average, given the wide fluctuations experienced to date.

6.6 Demand Side Management

The Board anticipates receiving MH's revised DSM plan by December 31, 2004, and that this plan will include a review of the option of integrating the approach to natural gas and other alternate fuels, and extending DSM to diesel communities.

Currently, the Corporation differentiates its DSM efforts between natural gas and electricity customers. However, with the convergence of natural gas and electricity space heating costs for grid customers, there is an increased risk that new construction customers will choose electricity.

If such a preference develops for electric space heat, increased domestic electrical load will reduce export potential.

These and other factors, including those of a public policy nature, suggest that MH's future DSM plan should take an integrated approach, and consider both electricity and natural gas. The cost to MH of extending DSM to natural gas may be offset by reduced future domestic electricity load, providing an increased export potential.

6.7 Future Study

In advance of a possible general rate application being filed or required in 2006, and in addition to the reports required related to the conditional rate increases and the COSS, the Board requests the following studies be filed with it by January 30, 2005:

- Consideration of the utilization the Zone of Reasonableness concept, to move all customer classes to "unity" (allocated revenue equals allocated expenses) within five to seven years (this proposal to utilize an amended COSS as outlined above);
- A study of MH's response to the 2002-2004 drought, with recommendations by an outside and independent expert;
- MH's revised risk management strategy, reflecting the quantification of risks both separate and in combination;

- A report on MH's insurance portfolio, its adequacy and options;
- A study of the implications of internally restricting retained earnings as a form of self-insurance reserve and rate stabilization fund, to restrict any future dividend payment until the 75:25 debt:equity ratio has been achieved;
- A report on the concept of the PUB reviewing any future proposed changes to water rental and capital tax rates (as an assist to the Province, MH and MH's customers);
- A report on the implications of returning the Interest Coverage financial indicator to a target of 1.2; and
- A report on the appropriateness of capitalizing all DSM expenditures, whether they represent projects that are implemented or achieve their targets, and consider whether the current amortization period of fifteen years for DSM and planning studies is reflective of prudent practice compared to the accounting policies of other hydroelectric utilities.

The Board will consider this information, and may call a limited hearing or paper review regarding these issues.

6.8 Surplus Energy and Curtailable Rates Programs

The Board will confirm all interim ex-parte Board Orders as contained in MH's Application, and extends the terms of MH's surplus energy program until March 31, 2007 with MH's suggested amendment.

6.9 Concluding Remarks

The Board found MH forthcoming, competent and helpful to these proceedings. The Board also found the contributions of the Intervenor, their witnesses and the presenters to be of value.

The appropriateness of the Board's decisions, now and in the future, are and will be directly related to the support and contributions of and by MH, the Intervenor and their witnesses, and presenters.

MH's operational considerations go beyond financial considerations, and its actions are, though supported by sophisticated computer modeling, determined based on human judgment supported by experience and knowledge. MH operates in a complex environment, where there are non-controllable as well as controllable factors at work.

Manitoba Hydro's operations are an important factor in the economic and social life of Manitoba. It is in the best interests of all parties that the Corporation be properly funded to support its present and future activities.

6.10 Other Findings

Additional Information, Board Findings and Directives will follow in a subsequent Order.

7.0 It Is Therefore Ordered That:

1. MH immediately file for final Board approval a revised schedule of rates to be effective August 1, 2004. The filing should include forecast revenue impacts reflecting a 5% increase for all customer classes;
2. MH file the following information by no later than January 31, 2005, for review by the Board with respect to a conditional rate increase for April 1, 2005:
 - (a) An update of its forecast for fiscal 2004/05 and 2005/06;
 - (b) Its second and third quarter financial statements for fiscal 2004/05;
3. MH file its audited financial statements for 2004/05, updated forecast for fiscal 2005/06 and subsequent years through to and including fiscal 2013/14, and its first quarter 2005/06 financial statements by July 31, 2005, for review by the Board with respect to a conditional rate increase for October 1, 2005;
4. MH file by no later than January 31, 2005, three separate COSS models to reflect:
 - (a) MH's existing methodology;
 - (b) The implementation of the NERA recommendations; and
 - (c) MH's preferred approach and methodology, including supporting rationale;
5. MH shall allocate the cost of uniform residential rates as a first charge on net export revenue; create an export class set out above, and file an analysis of the impact of allocating less expensive generation costs to domestic classes, with higher cost generation being allocated to domestic and export customers as suggested by TREE/RCM;

6. MH file the following studies by no later than January 31, 2005:

- A proposal to utilize the Zone of Reasonableness concept, based on an amended COSS, moving all customer classes to "unity" (allocated revenue equals allocated expenses) within five to seven years;
- A study of MH's response to the 2002-2004 drought, with recommendations by an outside and independent expert;
- MH's revised risk management strategy that reflects the quantification of risks both separate and in combination;
- A report on MH's insurance portfolio;
- A study of the implications of internally restricting retained earnings as a form of self-insurance reserve and rate stabilization fund, to restrict any future dividend payment until the 75:25 debt:equity ratio has been achieved and/or exceeded;
- A report on the concept of the PUB reviewing any future proposed changes to water rental and capital tax rates;
- A report on the implications of returning the Interest Coverage financial indicator to a target of 1.2; and
- A report on the appropriateness of capitalizing all DSM expenditures, whether they represent projects that are implemented and whether the projects achieve their targets, and consider whether an amortization period of fifteen years is optimal with respect to DSM and planning studies, with options;

7. The interim ex-parte Orders as included as Schedule A to this Order are approved; and

8. MH is to extend the Terms and Conditions of the Surplus Energy Program, as proposed and amended by MH, until March 31, 2007.

July 28, 2004
Board Order 101/04
Page 38

THE PUBLIC UTILITIES BOARD

"Graham F. J. Lane, C. A."

Chairman

"G. O. Barron"

Secretary

Certified a true copy of
Board Order 101/04 issued by
The Public Utilities Board

Secretary

SCHEDULE "A"

Ex Parte Orders Relating to the Surplus Energy Program

Order	S.O	Date	Order	S.O	Date	Order	Date
06/03	January 15, 2003		117/03	July 23, 2003		9/04	January 28, 2004
08/03	January 22, 2003		122/03	July 30, 2003		15/04	February 4, 2004
10/03	January 29, 2003		124/03	August 6, 2003		22/04	February 11, 2004
13/03	February 5, 2003		126/03	August 13, 2003		24/04	February 18, 2004
17/03	February 12, 2003		127/03	August 20, 2003		25/04	February 25, 2004
21/03	February 19, 2003		129/03	August 27, 2003		37/04	March 3, 2004
26/03	February 26, 2003		131/03	September 3, 2003		38/04	March 10, 2004
27/03	March 5, 2003		135/03	September 10, 2003		39/04	March 17, 2004
32/03	March 12, 2003		138/03	September 17, 2003		42/04	March 24, 2004
45/03	March 19, 2003		139/03	September 24, 2003		47/04	March 31, 2004
50/03	March 26, 2003		141/03	October 1, 2003		48/04	April 7, 2004
52/03	April 2, 2003		146/03	October 8, 2003		62/04	April 14, 2004
64/03	April 9, 2003		148/03	October 15, 2003		64/04	April 21, 2004
69/03	April 16, 2003		149/03	October 22, 2003		67/04	April 28, 2004
70/03	April 23, 2003		160/03	October 29, 2003		72/04	May 5, 2004
72/03	April 30, 2003		165/03	November 5, 2003		74/04	May 12, 2004
77/03	May 7, 2003		167/03	November 12, 2003		78/04	May 19, 2004
80/03	May 14, 2003		170/03	November 19, 2003		79/04	May 26, 2004
88/03	May 21, 2003		171/03	November 26, 2003		82/04	June 2, 2004
89/03	May 28, 2003		174/03	December 3, 2003		90/04	June 9, 2004
92/03	June 4, 2003		177/03	December 10, 2003		91/04	June 16, 2004
103/03	June 11, 2003		181/03	December 17, 2003		92/04	June 23, 2004
105/03	June 18, 2003		184/03	December 23, 2003		93/04	June 30, 2004
107/03	June 25, 2003		186/03	December 31, 2003		94/04	July 7, 2004
109/03	July 2, 2003		2/04	January 7, 2004		98/04	July 14, 2004
114/03	July 9, 2003		4/04	January 14, 2004			
116/03	July 16, 2003		6/04	January 21, 2004			

Ex Parte Orders Relating to the Curtailable Rate Program

Order	Date
16/03	February 10, 2003
28/03	March 11, 2003
70/04	April 30, 2004

Ex Parte Orders Relating to Various Other Rates

Order	Date
153/03	October 31, 2003
66/04	April 21, 2004

Appendix A

Appearances

R. Peters	Counsel for The Manitoba Public Utilities Board ("the Board")
O. Fernandes P. Ramage	Counsel for the Manitoba Hydro Electric Board ("Hydro")
J. Feldschmid	Counsel for Canadian Centre for Energy Policy Incorporated ("CCEP")
B. Williams	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc. ("CAC/MSOS")
T. McCaffrey	Counsel for Manitoba Industrial Power Users Group ("MIPUG")
M. Anderson	Representing Manitoba Keewatinowî Okimakanak Inc. ("MKO")
P. Miller	Counsel for Time to Respect Earth's Ecosystems/Resource Conservation Manitoba ("TREE/RCM")
G. Boyd	Representing International Brotherhood of Electrical Workers (Local 2034) ("IBEW")

Appendix B

Witnesses for Hydro

V. Warden	Chief Financial Officer, Vice President, Finance and Administration
C. Wmy	Treasurer and Division Manager, Business Analysis
H. Surminski	Section Head, Resource Planning and Market Analysis, Generation System Studies
R. Wiens	Manager, Rates and Regulatory Affairs
W. Derksen	Manager, Management Accounting and Budgeting
A. Cormie	Manager, Power Sales and Operations Division, Power Supply
C. Thomas	Cost of Service Supervisor, Rates and Policies Department
L. Kuczek	Manager, Consumer Marketing and Sales

Appendix C

Intervenors of Record

1. Canadian Centre for Energy Policy Incorporated ("CCEP")
2. Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors ("CAC/MSOS")
3. International Brotherhood of Electrical Workers ("IBEW")
4. Manitoba Industrial Power Users Group ("MIPUG")
5. Manitoba Keewatinowi Okimakanak Inc. ("MKO")
6. Time to Respect Earth's Ecosystems/Resource Conservation Manitoba ("TREE/RCM")

Note: Intervenors 1, 2, 4, 5 and 6 participated throughout the hearing and presented final comments. Intervenors 2, 4 and 6 presented witnesses.

Appendix D

Intervenor Witnesses

CAC/MSOS

B. Harper

Manager, Ecomalysis Consulting Services, Inc.

MIPUG

J. Osler

Principal Consultant and Manager, InterGroup Consultants Ltd.

P. Bowman

Consultant, InterGroup Consultants Ltd.

TREE/RCM

J. LAZER

Consulting Economist, Micro Design Northwest

Appendix E

Presenters

Mr. C. Cartwright

Citizen

Mr. A. Ciekiewicz

Citizen

Mr. T. Mathers

Citizen

Ms. M. Veno

Co-Chair Manitoba League of Persons with Disabilities

Ms. E. Ternette

Manitoba League of Persons with Disabilities

Mr. B. Turner

President, Manitoba Industrial Power Users Group

TAB 9

COALITION/MH I-106

Subject: Rate Stability

**Reference: Manitoba Hydro 2008/09 GRA, Tab 5, “Integrated Financial Forecast”,
page 4 of 20
Board Order 101/04, page 34**

Manitoba Hydro states:

“The dramatic swings in waterflows over the past few years have made it clear that regular stable rate increases are necessary for Manitoba Hydro to make measured progress towards its goal of meeting its financial targets while protecting consumers against future rate shock.”

- a) Given the risk of low water years and the potential adverse impact low water would have on domestic consumers, provide Manitoba Hydro’s understanding of all the pros and cons of establishing and maintaining a rate stabilization fund/drought protection fund for domestic consumers.**

ANSWER:

Manitoba Hydro’s debt/equity target is intended to protect against a number of negative contingencies, the largest being drought. By using a debt/equity target, provision can be made for more events than simply drought. In addition, this method allows for the equity level to rise as new facilities are added in order to provide for the increase in earnings variability as the system expands and increases its reliance on export revenues.

There are no pros of establishing and maintaining a separate rate stabilization fund/drought protection fund for domestic customers.

TAB 10



*Newfoundland
& Labrador*

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

**IN THE MATTER OF AN APPLICATION BY
NEWFOUNDLAND & LABRADOR HYDRO
FOR A
GENERAL RATE REVIEW**

**DECISION AND ORDER
OF THE BOARD**

**ORDER No. P.U. 7 (2002-2003)
JUNE 7, 2002**

BEFORE:

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

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

**Mr. Don Powell, C.A.
Commissioner**

**Mr. G. Fred Saunders
Commissioner**



NEWFOUNDLAND AND LABRADOR

AN ORDER OF THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

NO. **P.U. 7 (2002-2003)**

IN THE MATTER OF the Electrical Power Control Act, SN 1994, c. E-5.1 (“*EPCA*”) and the Public Utilities Act RSN, 1990, c. P-47 (“the *Act*”) and their subordinate regulations,

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro (NLH) for approval of: (1) Under Section 70 of the *Act*, changes in the rates to be charged for the supply of power and energy to its Retail Customer, Newfoundland Power, its Rural Customers and its Industrial Customers; (2) Under Section 71 of the *Act*, its Rules and Regulations applicable to the supply of electricity to its Rural Customers; (3) Under Section 71 of the *Act*, the contracts setting out the terms and conditions applicable to the supply of electricity to its Industrial Customers; and (4) Under Section 41 of the *Act*, its 2002 Capital Budget.

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

Darlene Whalen, P.Eng.
Vice-Chair

Don Powell, C.A.
Commissioner

G. Fred Saunders
Commissioner

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PART ONE. BACKGROUND

I. THE APPLICATION

1. Pre-Application Events

On November 19, 1999 NLH applied to the Board of Commissioners of Public Utilities (“the Board”) to reduce rates charged the Island industrial customers (Abitibi Consolidated Inc., Stephenville and Grand Falls Divisions; Corner Brook Pulp and Paper Company Ltd.; and North Atlantic Refinery Limited) to comply with changes in the *EPCA* which required that, as of December 31, 1999, the Island industrial customers no longer subsidize the rural deficit. As NLH had not completed a full Cost of Service (COS) study since 1994, the Board, in Order No. P.U. 23 (1999-2000), ordered NLH to, among other things, update this study so that the Board could assess the impact on other customers of the proposed changes in rates to the Island industrial customers.

On June 30, 2000 when NLH submitted its updated 1999 COS study, the Board decided there were several issues requiring a public hearing.

On September 13, 2000 the Board published notice of a pre-hearing conference to be held on October 11, 2000. The participants at the pre-hearing conference, including NLH, the Island Industrial Customers (IC), and Newfoundland Power Inc. (NP), agreed that the rates for the IC could not be set based solely on the updated COS study and that these rates could not be finalized in isolation of the rates charged to other customers of NLH.

During the pre-hearing conference, NLH advised the Board that it planned to submit an application for a general rate review in the spring of 2001. On October 27, 2000 the Board issued Order No. P.U. 25 (2000-2001) extending interim rates for the IC to December 31, 2001 and requiring NLH to file a general rate application by May 1, 2001. At the request of NLH, the Board subsequently extended the filing date for the Application to May 31, 2001.

2. NLH Application

Pursuant to the Order of the Board, on May 31, 2001 NLH filed this Application for a general rate review. As shown in Appendix A, the Application began the first comprehensive review of NLH since it became fully regulated in 1996. In the Application NLH is proposing the following:

- (1) *“that the rate charged NP be increased, as of January 1, 2002 to 48.0 mills/kWh;*
- (2) *that the existing policy be continued of allowing the Applicant, as NP changes its rates, to automatically adjust the rates which it charges its Island Rural Interconnected Customers, its customers served from the L’Anse au Loup System, and its Isolated Rural Customers, other than Government Departments and Agencies, for the first 700 kWh per month of consumption, so that such rates are the same as the rates charged by NP to its customers;*

- (3) *that the existing policy be continued of allowing the Applicant to change the rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural Customers, other than Government Departments and Agencies, by the average rate of change (i.e. increase or decrease) granted to NP from time to time;*
- (4) *that the “preferential rates” policies which traditionally have been made available to certain Rural Customers (fish plants and selected other organizations) be continued for the present;*
- (5) *that the rate classifications for Labrador Interconnected Customers be changed so that all customers served from that grid are subject to a common rate classification and that the rates charged as of January 1, 2002, to customers served from the Labrador Interconnected System be as set out in Schedule A, pp. 13-27...;*
- (6) *that the rates charged as of January 1, 2002 to Industrial Customers for firm service be a demand charge of \$7.01 per kW per month, an energy charge of 23.09 mills/kWh and the relevant annual specifically assigned charges;*
- (7) *that the purchase price of No. 6 Fuel oil used for the purposes of the RSP be changed from the current \$12.50 per barrel to \$20 per barrel, with effect from January 1, 2002;*
- (8) *that the RSP cap for NP be increased to \$100 million;*
- (9) *that the following financial targets based on current market conditions be set by the Board as appropriate;*
 - long term:*
 - Return on Equity (ROE) - 11% to 11.5%*
 - Debt/Equity Ratio - 60:40*
 - Return on Rate Base - 9.5%*
- (10) *that the estimated 2002 average rate base be \$1,370,471,000;*
- (11) *that the just and reasonable rate of return for the Applicant on the established average rate base for 2002 be 7.4%;*
- (12) *an accounting treatment for the net salvage value of assets and certain changes in the service lives of certain assets as described in the evidence filed in support of this Application;*
- (13) *amendments to its Rules and Regulations which govern the provision of service to its Rural Customers; and*
- (14) *to seek the approval of the Board for contracts with its Industrial Customers.*

Subsequent to filing the original Application, NLH filed three revisions. On October 3, 2001 and again on October 31, 2001, based on updated COS studies, NLH revised the Application amending previously proposed rates. On December 20, 2001 NLH filed revised IC contracts for the approval of the Board.

Effectively the rate increase sought by NLH in this Application, along with the 2002 RSP adjustments, will result in an overall rate increase to NP customers of 7.3% and to the IC of 16.1%, both effective January 1, 2002. NLH is also requesting that the Board continue the existing policy on rural rates which means that Rural Interconnected customers on the Island will pay the same rates as NP customers, and that Rural Isolated customers will pay those same rates for the first 700 kWh of energy consumed. NLH is also requesting that more uniform Labrador Interconnected system rates be set for the first time.

3. Further Applications

Because of the length of the hearing and the likelihood that a decision would not be finalized before January 1, 2002 NLH filed an application on November 20, 2001 seeking an Order approving certain 2002 capital projects as well as extending the interim rates charged to the IC until the final Order was issued. On December 20, 2001 the Board issued Order No. P.U. 30 (2001-2002) approving the capital projects that were not objected to by the parties and extending IC's interim rates as requested. (See Appendix G and Appendix H)

On December 28, 2001 NLH applied to the Board seeking approval of selected projects under \$50,000 and annual leases in excess of \$5,000. On January 14, 2002 the Board issued Order No. P.U. 31 (2001-2002) approving capital expenditures totalling \$731,000 involving projects under \$50,000 to which no party objected and the annual leases as requested. (See Appendix I and Appendix J)

II. THE HEARING

1. The Board

Members of the Board of Commissioners of Public Utilities who heard the Application were:

Chairperson Robert Noseworthy, (Chair and Chief Executive Officer);
Commissioner Darlene Whalen, (Vice-Chair);
Commissioner Don Powell; and
Commissioner Fred Saunders.

2. Pre-hearing Conference

Beginning June 18, 2001 notices of a pre-hearing conference were published in various newspapers throughout the Province to establish the process and timing of the hearing. The pre-hearing conference was held on July 5, 2001. On July 11, 2001 the Board issued Procedural Order No. P.U. 7 (2001-2002) (See Appendix B) which identified registered intervenors, set procedural rules for the conduct of the hearing and set the schedule for the filing and service of documents, the motions days and the actual hearing. The location and dates were also set for public participation days which afforded interested individuals and organizations the opportunity to express their views on the Application.

NLH was represented throughout the hearing by Ms. Maureen Greene, Q.C., and Mr. Geoffrey P. Young, LL.B.

The registered intervenors for the hearing were:

Represented by:

Newfoundland Power Inc. (NP)	Ms. Gillian Butler, Q.C. and Mr. Peter Alteen LL.B.

Industrial Customers (IC) (Abitibi Consolidated Inc., Stephenville and Grand Falls Divisions; Corner Brook Pulp and Paper Company Ltd.; and North Atlantic Refinery Limited)	Ms. Janet M. Henley Andrews, Q.C. and Mr. Joseph S. Hutchings, Q.C.

Government Appointed Consumer Advocate, Mr. Dennis Browne, Q.C., (CA)	Mr. Stephen Fitzgerald, LL.B.

The Towns of Labrador
City and Wabush (LC/W)

Mr. Edward M. Hearn, Q.C.

The Town of Happy Valley-
Goose Bay

Mr. Dennis Peck,
Director of Economic Development

The hearing was scheduled to begin at 9:30 a.m. on Monday, September 24, 2001 in the Board's Hearing Room located at Prince Charles Building, 120 Torbay Road in St. John's.

On December 17, 2001 Mr. Martin Lockyer, LL.B., counsel for CFB Goose Bay (5 Wing) applied to the Board for intervenor status. Following agreement by other parties the Board recognized CFB Goose Bay (5 Wing) as a registered intervenor and gave leave for them to make a presentation during final submissions.

The Board was assisted by:

Mr. Mark Kennedy, LL.B., Counsel for the Board
Ms. G. Cheryl Blundon, Board Secretary
Ms. Barbara Thistle, Assistant Board Secretary

3. Motions

On July 18, 2001 the Board held its first motions day where outstanding issues were addressed, including the hearing procedures and schedule, the role of Board staff, and the naming of expert witnesses. As part of its Notice of Intervention, pursuant to Section 90 (1) of the *Act*, the IC applied for an Order of the Board setting out in advance of the hearing that they were entitled to their taxed costs. On July 20, 2001 the Board issued Procedural Order No. P.U. 8 (2001-2002) ordering that the issue of costs for the IC and other intervenors will be considered by the Board at the conclusion of the hearing. (See Appendix C)

The second motions day was held on August 29, 2001. The Board issued Procedural Order No. P.U.18 (2001-2002) on September 7, 2001 amending the earlier Procedural Order and setting a final schedule regarding public participation days. (See Appendix D)

Further motions were filed with the Board on September 17, 2001 and September 24, 2001. As a result of these motions, the Board issued Procedural Order No. P.U. 22 (2001-2002), and Procedural Order No. P.U. 23 (2001-2002). These Orders were intended to further clarify the hearing process and resulted in minor amendments to Procedural Orders No. P.U. 7 (2001-2002) and P.U. 18 (2001-2002). (See Appendix E and Appendix F)

4. Information Management

This Application represented a challenge for the Board in terms of information management. The quantity of evidence and related documentation made it imperative that an effective system be implemented to manage the information. With the agreement of the parties,

the Board ordered that all hearing generated documentation be filed in an electronic format, with one paper copy filed as the official Board record.

Once the documents were made available in electronic format, the Board was able to provide public access to this information through the Board's website (www.pub.nf.ca). The website was updated daily with transcripts and additional evidence filed during each day's proceedings posted to the website in advance of the commencement of the hearing the following day. Having the information in electronic format also allowed the Board and parties to view the documents simultaneously on monitors located in the hearing room. The use of this technology was groundbreaking for the Board and resulted in substantial savings of both time and paper. The Board is grateful to Mr. Terry O'Reilly of NLH and Mr. Mike McNiven of the Board for their technical support throughout the hearing and to all the parties for their co-operation in the use of this technology.

5. Notice of Hearing

Beginning September 4, 2001 public notice of the hearing scheduled for September 24, 2001 was published in newspapers throughout the Province. This notice also invited interested persons and organizations to express their views on the Application, either during public participation days which were scheduled at various locations throughout the Province or by submitting a Letter of Comment.

6. Evidence

Pre-filed Evidence

Prior to the start of the hearing NLH and the intervenors were required to file their evidence with the Board. This pre-filed evidence was circulated and posted on the Board's website in advance of the hearing.

As part of its Application NLH filed proposed Rate Schedules, Rules and Regulations, Industrial Contracts and details of its 2002 Capital Budget. On July 12, 2001 NLH submitted the pre-filed testimony of its witnesses, which was updated and revised throughout the hearing. On August 15, 2001 the intervenors filed their evidence and questions arising from this evidence were filed on August 27, 2001.

After receipt and distribution of pre-filed evidence, the parties exchanged information requests in accordance with the regulations under the *Act*. The information requests and responses were filed with the Board and formed a part of the evidence in the hearing. More than 1000 Information Requests and responses were filed throughout the hearing process. These information requests and the responses to them are referenced in this decision in numerical order based on the party who made the request. For example the first information request from NP is referenced as NP-1.

Evidence During the Hearing

The hearing began as scheduled on September 24, 2001 and continued over a nineteen week period, for 61 hearing days. During the hearing there were 21 witnesses called by the parties along with additional filings consisting of 50 exhibits, 13 consent-exhibits, 24 information items and 42 undertakings. During public participation days there were 34 public presentations in 6 communities. The proceeding produced in total 1425 electronically filed documents, 20,000 pages of evidence and approximately 2,200 pages of daily transcripts.

Each of the parties was represented and called witnesses throughout the hearing, with the exception of the Town of Happy Valley-Goose Bay who made a presentation at the time the Board visited the town to hear public presentations. Witnesses were sworn, and after adopting their pre-filed testimony and speaking to amendments, each was subject to cross-examination by the other parties.

Witnesses called by NLH:

Mr. William Wells	President, NLH
Mr. Dave Reeves	Vice-President, Transmission Rural Operations, NLH
Mr. Robert Henderson	Manager, Systems & Operations, NLH
Mr. Hubert Budgell	Director of System Planning, NLH
Mr. John C. Roberts	Corporate Controller, NLH
Mr. Derek Osmond	Vice-President and Chief Financial Officer, NLH
Ms. Kathleen McShane	Senior Consultant & VP, Foster Associates, Bethesda, Maryland
Mr. Douglas Hall	Managing Director, Global Banking, RBC Dominion Securities
Mr. John A. Brickhill	President & CEO, Foster Associates, Bethesda, Maryland

Witnesses called by NP:

Mr. John T. Browne	John T Browne Consulting, Toronto, Ontario
Mr. Larry B. Brockman	Managing Consultant, PA Consulting Group, Cambridge, Massachusetts

Witnesses called by the IC:

Mr. Michael J. Vilbert	Principal, The Brattle Group, Cambridge, Massachusetts
Mr. Cameron F. Osler	Inter-Group Consultants Ltd., Winnipeg, Manitoba
Mr. Mel Dean	Coordinator, Strategic Services, Abitibi-Consolidated Inc. Stephenville, NF
Mr. Jay Backus	General Manager, Abitibi-Consolidated Inc. Stephenville, NF
Mr. Glenn Mifflin	VP & Chief Financial Officer, North Atlantic Refinery Ltd., Come-by-Chance, NF

Witnesses called by the CA:

Dr. Basil Kalymon	Professor of Finance, Richard Ivey School of Business, University of Western Ontario
Mr. Douglas C. Bowman	Manager, Performance Assessment & Strategy Services, EMA Consulting, Fairfax Virginia

Witness called by LC/W:

Mr. Mark Drazen	Consultant, Drazen Consulting Group, Calgary, Alberta

Witnesses called by Counsel to the Board:

Dr. John W. Wilson	President, Wilson & Associates, Arlington, Virginia
Mr. William R. Brushett, C.A.	Partner, Grant Thornton LLP, (GT) St. John's, NF (Board's Financial Consultant)

Public participation days were held in St. Anthony, Labrador West, Happy Valley-Goose Bay, Stephenville, Grand Falls-Windsor and St. John's. During this phase of the hearing interested persons and organizations were offered the opportunity to present to the Board, NLH and the intervenors their views on issues arising from the Application. These comments were provided under oath and formed part of the evidentiary record of the hearing.

The Board heard from the following persons:

St. Anthony, on October 15, 2001:

Mr. Trevor Taylor, MHA, District of the Straights-White Bay North
Mr. Ernest Simms, Mayor, Town of St. Anthony
Mr. Dean Coates, Plant Manager, St. Anthony Seafoods

Labrador West, on October 16, 2001:

Mr. Jim Farrell, Mayor, Town of Wabush
Mr. Graham Letto, Mayor, Town of Labrador City
Mr. George Kean, President, Steelworkers Union, Iron Ore Company of Canada
Mr. Randy Collins, MHA, District of Labrador West
Mr. Ern Condon, Private Citizen, Town of Labrador City
Mr. Ron McClatchie, President, Labrador West, Chamber of Commerce

Happy Valley-Goose Bay, on October 18, 2001:

Mr. Wally Anderson, MHA, District of Torngat Mountains
 Mr. Stanley Oliver, Executive Assistant to Hon. Ernest McLean, MHA,
 District of Lake Melville
 Mr. Dennis Peck, Director of Economic Development,
 Town of Happy Valley-Goose Bay
 Mr. Richard Rich, Mayor, Town of Rigolet
 Mr. Glen Sheppard, Mayor, Town of Postville
 Mr. Shawn Boland, Councillor, Town of Hopedale
 Mrs. Ruth Flowers, Councillor, Town of Makkovik
 Mr. Henry Broomfield, Deputy Mayor, Town of Nain

Happy Valley-Goose Bay, on October 19, 2001:

Colonel Paul McCabe, Commander of CFB Goose Bay (5 Wing)
 Mrs. Yvonne Jones, MHA, District of Cartwright-L'Anse au Clair
 Mrs. Betty Samson, Town Clerk, Town of Port Hope Simpson
 Mr. Nat Moores, Mayor, Town of L'Anse au Clair, and Treasurer,
 Coastal Communities and Combined Councils of Labrador
 Mrs. Annie Rumbolt, Mayor, Town of St. Lewis
 Mrs. Melita Paul, Town Manager, Town of Charlottown
 Mr. Ford Rumbolt, Deputy Mayor, Town of Mary's Harbour
 Ms. Roxanne Notley, Strategic Opportunities Officer,
 Southeastern Aurora Development Corporation

Stephenville, on October 22, 2001:

Mr. Gerry Murphy, Vice-President, Bay St. George Chamber of Commerce
 Mr. Mel Moores, Local 1093-Communications,
 Energy and Paper Workers Union of Canada
 Mr. Cecil Stein, Mayor, Town of Stephenville
 Mr. Tom Hutchings, Executive Director,
 Long Range Regional Economic Development Board

Grand Falls-Windsor, on October 23, 2001:

Mr. Walwin Blackmore, Mayor, Town of Grand Falls-Windsor
 Mr. Dave Barker, Private Citizen, Grand Falls

St. John's, on October 26, 2001:

Mr. Bruce Pearce, Climate Change Action Coordinator, Conservation Corps
of Newfoundland and Labrador
Ms. Sara Peckford, Eco-team Program Director, Conservation Corps
of Newfoundland and Labrador
Ms. Barbara Mullaly-Pauly, Chief of Housing Programs, Office of Energy Efficiency,
Natural Resources Canada

The Board appreciates the efforts of people who took the time to appear and present their views on the Application. The presentations and the comments were candid and very helpful in providing the Board with both personal and community perspectives on the Application. Copies of the transcripts for the public participation days are available on the Board's website (www.pub.nf.ca) or from the Board office.

During the hearing, interested persons and organizations were afforded the opportunity to submit a Letter of Comment, which also formed part of the record before the Board. Letters of Comment were submitted by:

Rev. Clarence R. Sellars, Executive Secretary, The United Church of Canada
Newfoundland and Labrador Conference, St. John's, NF
Mr. Andy Wells, Mayor, City of St. John's
Mr. Ron Smith, Mayor, Town of Conception Bay South
Mr. Dave Porter, Vice President Human Resources,
Iron Ore Company of Canada, Labrador City
Mr. John F. Peddle, Executive Director,
Newfoundland and Labrador Health Boards Association
Mr. Lawrence O'Brien, M.P., Labrador
Mr. Bob Clarke, Business Manager, I.B.E.W., Local 1615

The Board also extends its appreciation to those persons and organizations submitting Letters of Comment.

7. Final Submissions

Written argument was submitted by NLH and the registered intervenors (NP, IC, CA, LC/W) on January 21, 2002. Final oral submissions were presented on January 28 and 29, 2002. In addition, CFB Goose Bay (5 Wing) made a presentation during final oral submissions.

III. PRELIMINARY MATTERS

1. Perspective

To ensure a sound understanding of the context in which this decision was written the Board sets out the following perspective. The first section addresses the historical context and sets out the development of NLH and its regulation by the Board. The second part describes the current industry structure.

i) Historical

EARLY HISTORY

Limited Electrification - Pre-Confederation

Newfoundland and Labrador is a sparsely populated, resource rich province, the Island portion of which is isolated from the North American electrical power grid. From the first supply of power in 1895, electricity has been supplied by the independent action of separate utilities established relatively close to the load centers they were serving. Although the Government of the day supplied some financial assistance to enable the provision of electricity to rural areas, for the most part investment in electrification was left in the hands of private investors. Extensions to existing systems were made only as these investments became attractive. There were no major interconnections between systems, the transmission lines were relatively short and service standards varied. The large number of independently operating utilities resulted in little coordinated planning or standardization of rates or services.

Public Utilities Commission – 1929

In 1929, the Government created a Public Utilities Commission which was intended to assist with establishing consistency of electrical rates and services. The Commission did not have full authority to set rates or direct services as it was limited to investigating matters referred to it by the Government of the day. In 1933 the Commission was granted authority to set rates to be charged by a utility following a referral from Government.

Public Utilities Board - 1949

One of the first acts of the Government as a province of Canada was to establish, in 1949, a Board of Commissioners of Public Utilities, which had full authority to regulate public utilities in the province. Unlike the earlier Commission, the Board had general authority to supervise utilities in the province. Utilities were required to apply to the Board for approval of rates, except in areas where electricity service was highly subsidized by Government. In this latter case, Government reserved the right to establish rates. The regulatory structure established in 1949 was not unlike that which exists today. The Newfoundland Court of Appeal, in 1983 succinctly set out the purpose of the Board in T.A.S. Communication Systems Ltd. V. Newfoundland Telephone Co. (1983). Mr. Justice Gushue, said at para 44, NFLD. & P.E.I. R. 114.

“The PUA, as with similar statutes in all other Canadian jurisdictions, was enacted for the purpose of controlling and regulating companies providing essential services such as electrical power, water supply and sewage disposal and communication facilities in order to ensure that those services are properly and fairly provided to the public, and that the charges for such services are fair and reasonable. Services of this nature are normally supplied by one company only in any given geographical area and the Act, while guaranteeing the utility company a “just and reasonable return” on its investment (Section 77), also provides a control procedure to ensure that the rates charged are always fair and equitable and that, in effect, the utility company’s profits are not more than just and reasonable. The Act is administered by the Board.”

PROVINCIAL GOVERNMENT INVOLVEMENT - 1954 to 1964

Newfoundland Power Commission - 1954

The first entry of the Government of Newfoundland and Labrador into an active role in planning the province's electric power system came with the creation of the Newfoundland Power Commission (NPC). Its mandate was to investigate existing and potential capacity for the generation of electricity, make recommendations to the Lieutenant-Governor in Council, and, where directed, participate in the supply of electricity. While its charge was broad, NPC was directed to focus on a rural electrification program to be financed by the provincial Government. As such the Board did not regulate the NPC.

In its formative years the NPC worked closely with the existing regulated utilities in financially supporting the expansion of their facilities to reach nearby rural customers. Initially, Government financed and owned new rural distribution lines including replacements and additions. The utilities supplying power agreed to operate and maintain these distribution lines. In cooperation with the Department of Municipal Affairs, the NPC also constructed diesel generating plants and distribution lines to other rural communities, municipalities generally operated these diesel installations, while Government paid the costs in excess of revenues. Government involvement helped but it soon became apparent that substantial progress in rural electrification would require the infusion of much larger amounts of capital. Studies of the Island's individual power systems indicated looming generation shortages and a need to interconnect these systems with a high voltage transmission network.

Power Distribution Districts - 1963

In June 1963, the Government introduced the concept of Power Distribution Districts (PDD), which would manage the supply of electricity to rural areas not serviced previously. PDDs were given the power to borrow the funds necessary for the construction and supervision of electric systems. The stated objective of the Government was to ensure that every community in the province with fifteen or more families would have reasonable access to electricity. As the PDDs were policy instruments, not involved in selling electricity directly or indirectly to the public, the Board exercised no regulatory control.

MAJOR ELECTRIFICATION PROGRAMS - 1965 to 1975

By the mid-1960s the lack of generation capacity and the absence of an Island transmission grid were stagnating economic expansion and limiting the standard of living in the Province. To address this issue the Government decided to proceed with two major electrification programs which had been identified by the NPC. These programs involved both an accelerated, province-wide, rural electrification and also a major expansion of the Island's generation and transmission capacity. The financing of these two programs would come from a mixture of federal, provincial and private sources, and required a major redefinition of the NPC. To satisfy the conditions of financing, the Government would have to separate the uneconomical rural supply from the rest of the system.

Rural Electricity Authority - 1965

In April 1965, the Government established the Newfoundland and Labrador Rural Electricity Authority (REA), which was charged with designing, constructing and operating diesel generating plants and line extensions that would not be economically feasible for private industry to undertake. Similar to the original NPC, the REA's principal role was to make recommendations to the Government as to the improvement and expansion of the supply of power to rural areas. Under that mandate the REA accelerated the rural electrification plan first initiated by NPC. All assets and liabilities of NPC were transferred to REA, which then both owned and operated the PDD systems. It was recognized that the resulting operation would have to be heavily subsidized by the Government and, as a consequence, rural electricity rates would continue to be set without regulation of the Board.

For the next decade a clear distinction existed between the rural electrification program under the REA's mandate and the Island power development project. By the early 1970s the program of electrifying all communities with 15 families or more was complete and efforts became more focused on operations rather than capital expansion. The REA initiated a program to transfer the PDD assets to existing utilities. In order to reduce administrative overhead, more than fifty PDD's operating in the province were consolidated by the end of 1971 into a single PDD.

Newfoundland and Labrador Power Commission - 1965

At the same time the REA was created, the Government, to address the growing need in the province for additional electrical energy, reconstituted the NPC as a corporation to be known as the Newfoundland and Labrador Power Commission (NLPC). It had authority to "*establish, construct, maintain and operate works in any part of the province for the development and generation of power and may transmit and sell anywhere in the province all power generated thereat*". As was the case with the NPC, the legislation confirmed that the NLPC was not subject to regulation by the Board.

The NLPC immediately busied itself with the negotiation of power contracts to support the financing and construction of on Island hydro-electric and thermal generating stations, a high voltage transmission grid and the conversion of the power system to the North American

frequency standard of 60 Hertz. In 1965 the NLPC purchased the water rights on the south coast of the Island to begin developing the Bay d’Espoir reservoir area. Construction of this major hydroelectric station and high voltage transmission network was completed within three years. It was followed by the construction of the Holyrood thermal generating station and the development of several other hydroelectric sites. During the same time negotiations were being finalized to develop the potential of the Churchill River in Labrador. By 1972 the first energy from that large scale undertaking was flowing into the North American market.

The development of these projects, which resulted in energy being provided to retailers at uniform rates, encouraged the consolidation of the retailers and uniformity of rates to consumers. In 1966, several of the island utilities were amalgamated under the name of Newfoundland Light and Power Co. Ltd (a predecessor to NP which, for convenience is also referred to as NP). At the time of amalgamation there were 77 different rates charged in the areas that they served. By 1968 NP had introduced a uniform schedule of rates, becoming the first electrical utility in Canada to do so. This new schedule ensured that all customers in the company’s service area receiving the same type of service paid the same rate.

In the next few years the Government established several policies which discouraged rate differentials throughout the province. In 1974 the Government declared that rates for service to fish plants served by PDD were to be continued at current levels. This was followed in 1975 with an order that rates charged by PDD for its connected domestic customers would be adjusted to conform to those rates approved for NP. At the same time Government established the “*lifeline block*” which required that PDD domestic customers supplied from isolated diesel powered plants be charged the same rate as was charged to NP customers for the first 500 kWh consumed per month. The lifeline block was increased in April 1987 to 600 kWh per month, and in July 1989 to 700 kWh per month.

Newfoundland and Labrador Power Corporation - 1974

In the mid 1970s, with both the Labrador and Island projects completed and on stream, the Government turned its attention to a much larger project - developing the Gull Island and Muskrat Falls sites on the Lower Churchill River in Labrador and linking the Labrador and Island transmission networks. To prepare for this the Government gave NLPC much broader powers than it previously held and renamed the NLPC as the Newfoundland and Labrador Power Corporation (NLPCorp).

GOVERNMENT MOVES AWAY FROM PARTICIPATING IN SUPPLY - 1975

By 1975 the Government had, through the REA and NLPC, substantially accomplished its goal of electrifying the province and ensuring supply to meet its growing power needs. Government next decided it was time to consolidate these interests in one corporation. Over time legislation was passed which gradually reduced and eventually phased out the REA and the PDD.

Newfoundland and Labrador Hydro-Electric Corporation - 1975

In 1975 NLPCorp was renamed the Newfoundland and Labrador Hydro Electric Corporation (NLH). The Government transferred to NLH all of the assets and obligations of NLPCorp., and REA. This transfer brought all of Government's interests in the supply of power under the umbrella of one corporation, the shares of which were owned by Government. The authority of NLH was expanded to include the efficient supply of power both inside and outside the province.

Even after the creation of NLH, the REA and PDD continued to exist as separate entities. NLH operated supply to retail customers, PDD continued to operate rural supply and the REA was the mechanism by which funds were transferred from the Consolidated Revenue Fund to PDD in order to provide grants for capital construction and operating subsidies. By 1978 the Government decided that funding could be provided directly to the PDD, and the REA was abolished. The PDD and the REA had facilitated the consolidation of virtually all the isolated rural systems, many of which would not have been developed in the first instance without this structure and Government financial support.

While NLH was not subject by statute to the regulation of the Board, the Government began to believe that some oversight might be advisable. When NLH proposed a rate increase to NP in 1976, the Government directed NLH to appear before the Board to defend the proposed rate increase. In support of this direction, the Government enacted legislation to establish a regulatory framework for NLH.

Regulatory Framework for NLH - 1977

In June 1977 the Government introduced legislation known as the *Electric Power Control Act*, S.N. 1977, c. 92 (*EPCA*, 1977), which required that the rates charged by NLH to retail customers be reviewed by the Board. Rates charged to industrial customers continued to be determined by contracts entered into and approved by NLH's Board of Directors without review by the Board. The *EPCA*, 1977 set out the power policy of the province as ensuring that rates were fair to consumers while providing an adequate return to suppliers.

With the enactment of the *EPCA*, 1977 the Board began to review some aspects of the business of NLH. While the Board reviewed the retail rates set by NLH, the Government maintained the right to set the rates after considering the recommendations of the Board. The recommendations of the Board in the first six reviews of NLH's rates were accepted by Government without alteration.

As part of its movement away from involvement in supplying power, the Government made several legislative amendments in the late 1980's. In 1989 the Government eliminated the PDD and vested all of its assets and liabilities in NLH. At the time the Government was paying an annual subsidy of about thirty million dollars for the PDD to operate the rural system. The payment of the rural subsidy by Government was gradually phased out so that, by 1992, the entire subsidy was passed on directly to all consumers of electricity in the province. At the same

time, Government introduced an annual guarantee fee of one percent on the total outstanding long-term debt which was guaranteed by Government.

In 1992 NLH filed an application with the Board dealing with proposed electricity rates to rural customers. Hearings on the application were held and the Board submitted recommendations which, among others, included the gradual reduction of the rural subsidy and the elimination of preferential rural rates. Government declined to implement these recommendations and directed the Board to investigate issues surrounding the supply of electricity in isolated rural areas and report to the Minister of Natural Resources. This inquiry was conducted in 1995.

Upon submission of the Board's Report, the Minister questioned why recommendations did not recognize traditional Government policy respecting a uniform electricity rate throughout the Province, at least for some minimum level of consumption. The Minister also observed the Report did not acknowledge Government's policy of having rural rates cross-subsidized by all NLH ratepayers, as explicitly provided for in the *EPCA*, 1977. Finally, the Minister felt the Report did not reflect Government's intended policy to eliminate industry contribution toward the rural deficit as set out in the then unproclaimed *EPCA*. As a result, the Board was directed to reconsider the issues covered by the Report. In mid-1996, a revised Report was submitted to the Minister. Government has not acted upon this Report and has provided no further communication to the Board on its contents.

As well, in early 1996, Government referred to the Board the issue of appropriate rates for rural customers located from L'Anse au Claire to Red Bay. This referral was pursuant to a contract between Hydro-Quebec and NLH to construct a transmission line connecting this area with the Lac Robertson hydro-electric project. The Board held a public hearing and presented a Report to Government. Government accepted the recommendations and directed NLH to set rates equivalent to those charged by NP and eliminate preferential rates in the area.

Also, in 1996, the St. Anthony/Roddickton Isolated system was interconnected to the Island grid. Subsequently, in 1999, both the Roddickton woodchip fired plant and the diesel generating plant were decommissioned.

Changes to the Regulatory Framework - 1996

By the mid 1990s Government had decided that it would make further legislative changes that would decrease its role in the supervision of the rates of NLH. In January 1996 the *EPCA* was proclaimed, which placed NLH under the full regulation of the Board. NLH would now be subject to the review and approval of the Board in setting its rates for both retail and industrial customers. The rates were to be set so as to allow NLH a just and reasonable return comparable to other utilities.

Shortly after NLH became fully regulated, there were two amendments to the *EPCA* which gave Government the right to control both rates and other matters that for public convenience or general policy are in the best interest of the province. These amendments allow the Government to direct the Board with respect to policies or procedures in relation to the

determination of rate structures and to exempt a public utility from the application of the *Act*. While Government has not generally directed the Board pursuant to these amendments, there were four exemptions, all in 2000, which include the Granite Canal Project, the Labrador Hydro Project, the Corner Brook Pulp and Paper Limited's Cogeneration Project and the Refurbishment of Hydroelectric Facilities at Abitibi Consolidated.

After the mid 1990s, interaction between NLH and the Board generally involved routine applications relating to capital budgets or financing. While there was no general rate proposal filed by NLH, there were several hearings addressing issues of limited scope, including annual capital budget approvals.

ii) Current Industry Structure

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 with a relatively small amount of distribution. NP operates solely on the Island portion of the Province and is principally a distribution company with some generating capacity.

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.

The generation capacity on the Island is as follows:

Generation Capacity		
Producer	MW	%
NLH Island Hydro	887.4	48.27
NLH Island Thermal	598.2	32.54
NLH Isolated Island	7.9	0.43
NP	147	8.00
Deer Lake Power	121	6.58
Abitibi Consolidated	58	3.15
Non Utility	19	1.03
Total	1838.5	100%

(Source: Extract from R. J. Henderson, Presentation; D. W. Reeves, Schedule III)

On the Island NLH has approximately 1500 MW of installed capacity consisting of 887.4 MW of hydro-electric generation from Bay d'Espoir, Upper Salmon, Cat Arm and Hynes Lake, 598.2 MW of thermal generation from Holyrood and 7.9 MW of isolated diesel generation. NLH also owns 3,380 km of high voltage transmission lines, and 2,458 km of distribution lines.

NP's generating capacity is 147 MW from its various hydro-electric generating sites. NP purchases approximately 90% (4,434 GWh in 2001) of its energy requirements from NLH.

Energy generated by Deer Lake Power and Abitibi Consolidated 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 two Non Utility Generators, the Star Lake Hydro Partnership (15MW) and Algonquin Power (4MW). For peaking purposes, NLH can also purchase power from Abitibi Consolidated (Stephenville) under an interruptible load contract where the customer will interrupt up to 46 MW of load on request by NLH.

On the Island system, NP operates transmission and distribution lines in the majority of areas excluding the South Coast, Harbour Deep, Little Bay Islands and St. Brendan's. In these areas service is supplied by NLH using nine isolated diesel generation and distribution systems. Service is supplied to the Great Northern Peninsula (except Harbour Deep) by NLH through the Island Interconnected system.

In Labrador NLH provides service to all customers. Power is purchased (1780 GWh in 2001) from Churchill Falls to supply the Labrador Interconnected system consisting of Labrador City, Wabush, and the Happy Valley-Goose Bay area. In the isolated coastal areas NLH operates 16 diesel generation facilities with a combined capacity of 20.9 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, energy requirements in 2001 were largely met by 46.42 GWh of diesel operation and 14.17 GWh of power purchased from Hydro Quebec.

Together NLH and NP supply, transmit and distribute electricity to 252,000 domestic and general service customers as well as to six large industrial customers. NP's operations on the Island service 216,879 customers or 86% of all general service and domestic customers. NLH services the remaining 14% or 35,107 customers with 26,200 of these classified as rural customers.

The following two pages attach maps outlining the Provincial Transmission Grid and the Isolated Systems (Diesel). (Pre-filed Evidence, D. W. Reeves, Schedules I & II)

LEGEND

Schedule I
D.W. Reeves

—	230 kV		FREQ. CONVERTOR
- - -	PROPOSED 230 kV		ABITIBI CONSOLIDATED
—	138 kV		DEER LAKE POWER
—	69 kV		
- - -	745 kV OWNED BY OTHERS		
- - -	230 kV OWNED BY OTHERS		
- - -	138 kV OWNED BY OTHERS		
- - -	69 kV OWNED BY OTHERS		
	TERMINAL STATION		



Provincial Transmission Grid



Provincial Isolated Systems (Diesel)

2. Strategic Considerations

Challenges

This Application, representing NLH's first general rate review in ten years and its first as a fully regulated utility, presented a host of challenges for the Board.

The Application produced a massive body of evidence and a complex web of regulatory, public policy, economic, social and legal issues impacting a broad range of stakeholders. These stakeholders include residential, commercial and industrial electricity consumers living in both urban and rural areas of the Province as well as Government. In this initial application, newly applied legislative amendments governing the regulation of NLH combined with a lengthy chronology of regulatory reviews and referrals demanded detailed examination of existing policies and precedents. Certain key issues have degenerated over time making corrective measures more difficult to implement. For example, Government's Energy Policy Review¹ remained outstanding at the close of this hearing and raised questions regarding important public policy matters. It also became clear early in the hearing that one of the goals of NLH in its proposals contained in this Application was to avoid "*rate shock*" to customers. Throughout the proceeding NLH placed the Board on notice that financial targets and other measures contained in the Application are temporary and will be fully addressed in its next application scheduled for 2003.

For these reasons, the Board acknowledges it will take time to implement changes which will allow NLH to move forward in the context of full regulation. The Board points to the need to develop an effective strategy which will govern the regulation of NLH into the future. Mr. Wells in his opening statement indicates "*it will be necessary to achieve the ultimate objective (regulatory) through a period of adjustment*". (Pre-filed Evidence, W.E. Wells, pg. 5) Mr. Kennedy, Board Counsel, in his final remarks offered this advice: "*Accordingly, the Board must decide not only what to order on the specific issues raised in the general rate application but keep an eye looking forward to one year out, two years out, five years out, and perhaps even ten years into the future and set with that in mind a broad policy for the future regulation of Hydro.*" (Transcript, Jan. 29, 2002, pg. 18/33-39)

Strategy

The Board recognizes that its decisions must reflect fairly and responsively in relation to this Application and set the groundwork for the regulation of NLH into the future. The Board identified a number of strategic considerations, therefore, which should assist the Board in achieving its regulatory objectives, both for this Application and looking ahead. These are:

¹ While a consultation paper on the Electricity Policy Review has since been released, this paper was not available as evidence in this hearing and, therefore, was not considered by the Board.

i) Regulatory Framework

In this Application, NLH's first as a "*fully regulated utility*", it was necessary for the Board to set out an appropriate framework for regulating NLH. This regulatory framework is outlined beginning on pg. 23 of this decision and is consistent with the framework applied by the Board to NP.

ii) Public Policy Considerations

Public policy established by Government through previous Orders in Council and implemented through NLH has played a fundamental role in setting rural electricity rates. Except for the IC, ratepayers either receive the benefit of subsidized rural rates or contribute toward the subsidy. Now that NLH is a fully regulated utility, the jurisdiction of the Board and the impact of its decisions on these public policies present an important question for both consumers and NLH alike. These issues are addressed by the Board beginning on pg. 120 of this decision.

iii) Pace of Regulation

Given the time and resources consumed with this Application, the Board focused in the short term on making as many firm decisions as the Application would allow. The Board noted there was a significant array of financial and other issues that NLH deferred to be fully addressed at its next rate application scheduled for 2003. Since NLH became a fully regulated utility in 1996, the Board expresses concern with the pace of regulation and has been quite specific in outlining its future regulatory requirements in this decision, including the timing of NLH's next application.

iv) Decision Criteria

In striving to optimize short term decisions required in this Application with long term regulatory objectives, the Board felt it was important, to the extent possible, for its decision-making criteria to reflect both goals. In addition, the Board's decisions are meant to convey a clear and consistent message to the various stakeholders. In striking an equitable balance between the utility and the consumer, the Board has opted in favour of implementing policy based on rational decision-making and phasing in the resulting impact as opposed to manipulating policy over time to achieve the desired result. The former option is deemed preferable in moving toward a supportive and stable regulatory environment. Examples of this approach are reflected in decisions of the Board on the Rate Stabilization Plan (RSP) and the Labrador Interconnected system.

v) Focus for the Future

The Board believes that the early establishment of an appropriate regulatory environment is in the interests of all stakeholders. In the case of NLH, this objective has been abetted by the on-going reporting/compliance which clearly exists. Beyond this Application, the Board will continue to focus on balancing business risks with implementing desired regulatory objectives. To accomplish this balance the Board will emphasize policies and procedures over detailed review and controls.

These strategic considerations are either dealt with explicitly as outlined in this document or incorporated within the methodology and decision making of the Board in considering this Application.

3. Regulatory Framework

The Board is an independent, quasi-judicial agency 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 electricity 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 PROCEDURES govern the presentation of the evidentiary record on matters before the Board.
- iii) REGULATORY PRINCIPLES which are commonly accepted in guiding sound utility regulation.
- iv) THE RATE SETTING PROCESS is founded in accounting, engineering and economic methodologies which are applied in combination with 1), 2) and 3) and weighed by the Board in making decisions affecting rates.
- v) REPORTING/COMPLIANCE provides appropriate regulatory monitoring of the utility's ongoing activities and enforcement of Board Orders.

i) Board Authority

The authority of both NLH and the Board is based in legislation. Both were created by statute, and as such are governed by the provisions of the *Hydro Corporation Act, R.S.N. 1990, c. H-16*, as amended, and the *Act*. In addition, the *EPCA* sets out the power policy of the province and roles of the stakeholders in the supply of power.

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.

Mandate

In addition to the Board's mandate under the Act, 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.”

Accordingly, Section 3 of the *EPCA* states:

“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...”*

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 be 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. Alternative forms of regulation include Return on Equity (ROE) and/or an emerging trend toward Performance Based Regulation (PBR). Return on rate base regulation is more fully described in relation to the Rate Setting Process.

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.”

The Board notes that Section 5.1 was introduced as an amendment to the *EPCA* in 1996 coincident with NLH becoming a fully regulated utility. To date, the Board has received no direction under this provision from the Lieutenant-Governor in Council. As noted previously, in 2000, pursuant to Section 5.2 the Lieutenant-Governor in Council exempted four projects, namely, the Granite Canal Hydroelectric Project, the Labrador Hydro Project, the Corner Brook Pulp and Paper Limited’s Cogeneration Project and the Refurbishment of Hydroelectric Facilities at Abitibi-Consolidated Incorporated.

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 the public;
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 the rates as long as it observes the legislation and sound utility practice.

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 public'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 paragraph 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 management of a utility. Mr. Justice Green suggested that the Board should observe a presumption of managerial good faith.

ii) Board Procedures

The Board's procedures are governed by the relevant legislation and, as a quasi-judicial body, the principals 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. Complete 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. Documentary evidence is entered and the Board maintains a full and complete record of all the evidence.

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

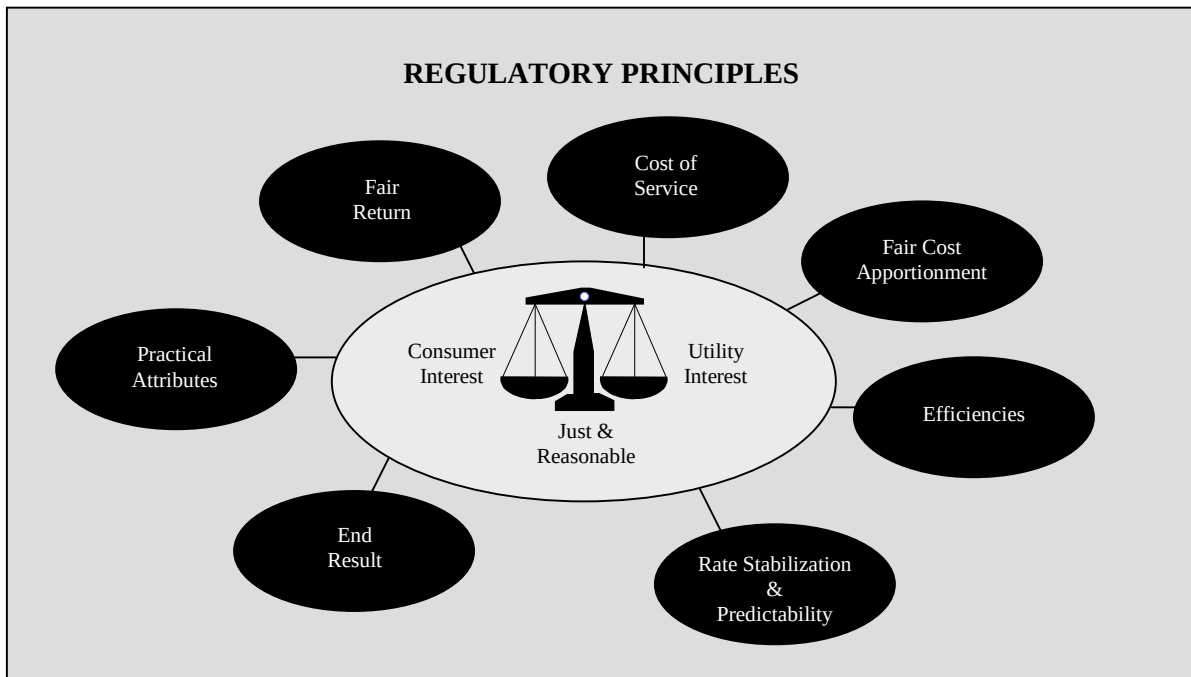
After full consideration of all of the evidence the Board will issue a reasoned decision, usually in writing. Together with the decision an order of the Board will be issued and, as noted previously, can only be appealed to the Court of Appeal.

iii) Regulatory Principles

Sound regulatory practices encompass fundamental principles which are used by regulators as a guide or roadmap to rational decision making. As stated in the Bonbright J. C., /Danielsen A.L, Kamerscen D.R., Principles of Public Utility Rates (Arlington: Public Utilities Reports, Inc., 1988): "*We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.*" These are commonly referred to as Bonbright's principles and are specifically outlined on pages 383-384 of his book.

Section 4 of the *EPCA* directs the Board to apply tests that are consistent with generally accepted sound public utility practice. Also Mr. Wells, NLH's CEO, in his Opening Statement during the hearing remarked: "*It is important that we adhere to sound and proven regulatory principles and practices.*" While there was a difference of opinion among expert witnesses as to the application of these regulatory principles which will be dealt with by the Board in its examination of the evidence, there was consensus as to the general principles.

The Board sets out the following principles for purposes of its regulatory framework:



1. Fair Return

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

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

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

2. Cost of Service

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

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

3. Fair Cost Apportionment

Fairness of specific rates in the apportionment of total costs of service among the different ratepayers 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 employed 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

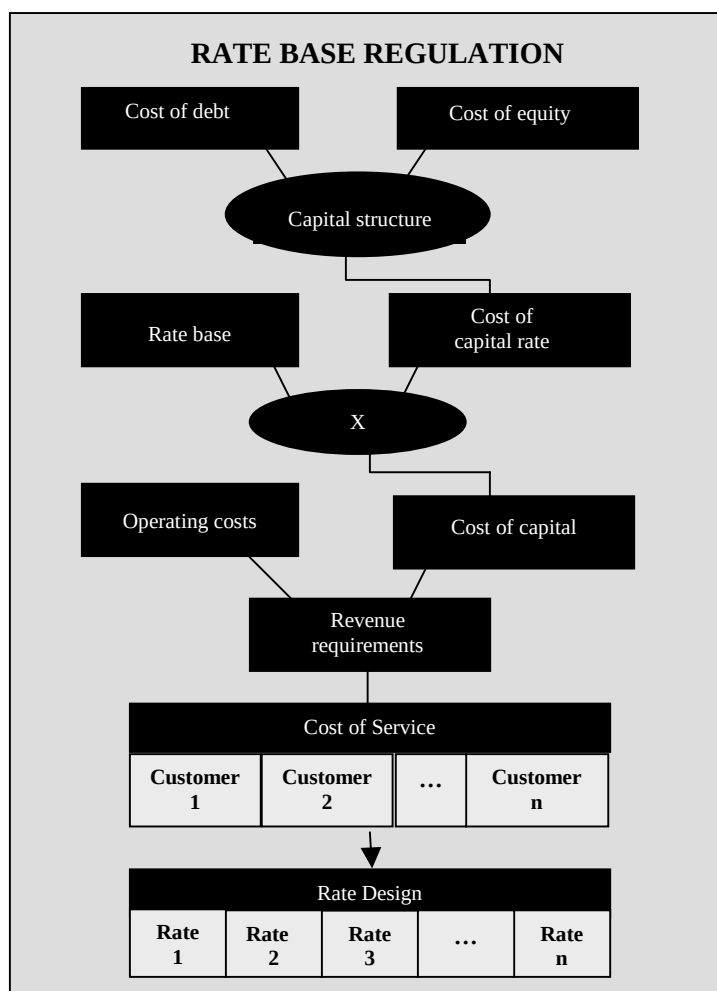
legislative mandate, is to balance oftentimes competing objectives within the regulatory environment to ensure a set of sound and reasoned decisions serving the interests of both consumer and utility alike.

iv) 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.

Rate Base Regulation

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



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

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

An appropriate capital structure is normally established by a company's management through an examination of the costs and risks involved with each source of funds, both debt and equity. Management must strive to choose an efficient capital structure which will provide access to needed capital at lowest cost.

Revenue Requirement

Revenue requirement is the amount of revenue required by a utility to cover the sum of operating costs including debt service, taxes (not applicable to NLH), 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:

$$\text{Revenue Requirement} = \text{Operating Costs} + (\text{Rate Base} \times \text{Rate of Return})$$

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 requirements are allocated to each class of customer served. The utility normally submits a study of the costs incurred in 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.

v) 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 Mr. Justice Green’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.

vi) Summary

The regulatory framework of the Board has been in place in one form or another since the Public Utilities Board was established in 1949. This framework has evolved to date through a series of legislative amendments and case law. The regulatory framework of the Board is comprised of five distinct elements:

- i) Board Authority
- ii) Board Procedures
- iii) Regulatory Principles
- iv) Rate Setting Process
- v) Reporting/Compliance.

This regulatory framework has been used by the Board to regulate NP. The Board believes a consistent and equitable regulatory framework would be in the interests of both the utility and consumers. For this reason, the existing regulatory framework described above will be used as the standard in assessing NLH’s first general rate application as a fully regulated utility.

PART TWO. BOARD DECISIONS

I. CAPITAL STRUCTURE

1. NLH Proposals

NLH proposes under Section 14(9) of the Application that the following long-term financial targets based on current market conditions be set by the Board as appropriate:

Return on Equity (ROE) - 11% to 11.5%

Debt/Equity (D/E) Ratio - 60:40.

For the interim, NLH proposes that the Board allow a ROE of 3%.

In final argument (pg. 35-36) NLH submits:

“Hydro proposes that its long term debt/equity ratio target be 60/40, and further stated in its Application that, if it had been requesting a “normal” rate of return in the Application, it would have been in the range of 11% to 11.5% ROE. However, Hydro did not propose that these financial targets be attained in the test year. Messrs. Wells and Osmond on behalf of Hydro explained that the magnitude of the rate increase and its impact on Hydro’s customers moderated Hydro’s position with respect to the time period over which these financial targets should be achieved. (pre-filed evidence, W.E. Wells, p. 14, pre-filed evidence, D.W. Osmond, p. 5) If a return on equity of 11.25% had been used in the original filing, the proposed rates to NP would be approximately 6% higher than the base rate increase requested. (Pre-filed Evidence, D.W. Osmond, pg. 6/7-9)

Because the provincial guarantee of Hydro’s debt permits Hydro to operate with a lower capital structure than otherwise, Hydro proposes that the following targets be adopted in the short term:

- 1. a debt/equity ratio of 80/20 with the 2002 debt/equity ratio being 83/17;*
- 2. a ROE of 3% for 2002 as a means of assisting in reducing the rate increases required for customers; and*
- 3. a return on rate base of \$98,319,000 (Schedule VII A, J. C. Roberts, pre-filed evidence October 31, 2001) or 7.2%.*

However, in view of Hydro’s request for these low financial targets in the test year, it was emphasized by Hydro witnesses that it was essential that the financial markets be advised, through the decision of the Board, that the targets established were short-term in nature, with the principle being adopted that Hydro is entitled to earn a return normally approved by the Board for a commercial entity, whether it be investor-owned or Crown owned.” (Pre-filed Evidence, W.E. Wells, pg. 13/27-31)

NLH believes the Board should endorse the long term target of a 60/40 debt equity ratio. (NLH, Final Argument, pg. 39/15-17)

2. Introduction

NLH's long-term debt consists of promissory notes, debentures and long-term loans which are unsecured but unconditionally guaranteed by the Province. The Province charges NLH a guarantee fee of 1% annually on the total debt (net of sinking funds) guaranteed. The Province is NLH's sole shareholder and equity has accumulated in NLH over the years in the form of retained earnings. NLH's "*regulated*" average capital structure for 2000 is outlined in Exhibit 1 of GT's 2001 General Rate Hearing Report as \$1,106,400,000 Debt (D) and \$278,800,000 Equity (E) for a D/E ratio of 80/20 (est)².

Beginning in 1995, Government, as shareholder, required NLH to pay dividends. As shown in NP-72 these dividends have varied over the years both in absolute terms (\$1,309,000 - 1999 to \$14,500,000 - 1995) and as a percent of net regulated operating income (10% - 1999 to 172% - 2000). Government has served notice on NLH that it may be seeking a dividend, forecast at \$70,147,000 or 730% of projected net regulated operating income for 2002.

In NLH's situation, the risks and costs associated with its capital structure are closely linked to issues of Provincial ownership, Provincial guarantee of debt and the resulting regulatory treatment of NLH. The Board felt these issues constituted a sound place to start its assessment of NLH's capital structure and return on rate base proposals.

3. Government Guarantee

The Provincial Government provides a guarantee in relation to NLH's debt. The Province receives compensation for this guarantee in the form of an annual fee paid by NLH equivalent to 1% of the previous year's debt. NP-77 notes this fee in the 2002 test year will amount to \$12,336,000. This amount includes adjustments to the guarantee fee based on the notional increase in promissory notes resulting from recall revenue cash flow. (NP-253; Transcript, Jan. 9, 2002, pg. 6/71-81)

It was clear from the evidence that the ability of NLH to maintain a sound credit rating in the financial markets of the world is currently dependent on this Government guarantee. NLH acknowledges this in their final argument in reference to Ms. McShane's pre-filed evidence. (NLH, Final Argument, pg. 22/5-9) Ms. McShane indicated the Provincial guarantee allows NLH to access funds from the capital markets at more attractive rates than it could achieve on its own, in virtually all market conditions. (Pre-filed Evidence, K. McShane, pg. 20/27-28 & pg. 21/1-4) Dr. Kalymon concluded the capital structure of NLH would not be financially viable in the absence of the Provincial guarantee. (Pre-filed Evidence, Dr. B. Kalymon, pg. 12/8-9) Mr. Hall observed the Provincial guarantee provides a number of advantages to NLH; among them, access to debt markets, attractive financing rates and the ability to operate at excessive debt

² Estimated only .0.8% due to Employee Future Benefits.

levels. (Pre-filed Evidence, D. Hall, pg. 5-6/8-3) The witnesses did not dispute the financial benefits of the Provincial guarantee to NLH.

IC-61 stated insofar as NLH is aware at this time there will be a continuation of the guarantee of NLH's debt and the payment by NLH of a 1% guarantee fee to the Province. Outside of NLH's assurance, the Board heard no direct evidence concerning Government's disposition on the Provincial guarantee. Clearly in light of the financial implications of any precipitous change in policy regarding the Provincial guarantee, the Board is left to conclude that its withdrawal is unlikely under current circumstances

The Board acknowledges the fundamental importance of the provincial guarantee to NLH's financial status. The Board recognizes the need to maintain the Provincial guarantee until such time as NLH is in a position to achieve and maintain a sound credit rating in the financial markets of the world on a stand-alone basis.

In considering the appropriateness of the amount of the fee, NLH quotes Ms. McShane as follows:

"The test for whether the guarantee fee is a legitimate component of the cost of debt is whether the cost inclusive of the guarantee fee is less than or equal to the cost at which the utility could raise debt on the strength of its own financial parameters. At the forecast utility capital structure the cost of debt to NLH absent the Provincial guarantee, would be more than 100 basis points higher than the debt cost calculated with the guarantee fee". (NLH, Final Argument, pg. 22/15-21)

While both Ms. McShane and Dr. Kalymon used somewhat different methodologies in approaching this issue, Dr. Kalymon concluded the guarantee fee of the Province is not excessive given the equity investment which the guarantee implies. Dr. Kalymon notes, however, that the guarantee fee would need to be reduced should NLH's equity increase to stand-alone proportions. (Pre-filed Evidence, Dr. B. Kalymon, pg. 14/10-16). Mr. Hall observes the guarantee fee paid to the Province is an expense to the utility for value received and is quite clearly an appropriate component of its cost of debt. (Pre-filed Evidence, D. Hall, pg. 6/14-16) In final argument (pg. 97) the IC observes NLH (and ultimately the ratepayers) pays a generally appropriate guarantee fee. No parties presented evidence disputing the level of compensation paid by NLH to the Province in return for its guarantee.

The Board accepts that the Government guarantee plays an essential role in NLH's ability to maintain a sound credit rating in the financial markets of the world. The Board concurs that the guarantee fee of \$12,336,000 in the 2002 test year is appropriate.

4. Dividends

As sole shareholder of NLH, Government advised in the 1995/96 Provincial budget that it would be seeking an annual dividend from NLH as a return on the public investment in the electrical industry. (NP-168) In addition to dividends on the regulated earnings of NLH and the

Provincial guarantee fee, the Province also receives dividends from CF(L)Co as well as revenue on Hydro-Quebec recall power. (PUB-57)

NP-72 outlined the dividends paid by NLH to Government since 1995 in relation to net regulated operating income as follows:

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
1995	14,500	22,829	64%
1996	9,688	20,693	47%
1997	12,357	31,351	39%
1998	10,489	24,847	42%
1999	1,309	13,015	10%
2000	10,026	5,829	172%
2001	11,976	13,727	87%
2002 (F)	<u>70,147</u>	<u>9,610</u>	730%
Total	<u>140,492</u>	<u>141,901</u>	

F-forecast

The forecast dividend for 2002 is in excess of \$70,000,000 representing an estimated 730% of the net regulated operating income. Should this amount of dividend be paid, it is projected the impact on revenue requirement for the 2002 test year will be \$1,700,000 (NP-72) and \$2,400,000 for 2003 (NP-205). With the \$70,000,000 payout, the dividends paid since 1995 approximate the Net Regulated Operating Income (NROI) earned by NLH over the same period (Dividend - \$140,492,000 versus NROI - \$141,901,000).

NLH's regulated capital structure as outlined in GT's 2001 General Rate Hearing Report is as follows: (pg. 11)

	1998 %	1999 %	2000 %	2001(F) %	2002(F) %
Debt	79.3	79.0	79.2	80.0	83.1
Employee Future Benefits	0.0	0.0	0.8	1.6	1.6
Equity	<u>20.7</u>	<u>21.0</u>	<u>20.0</u>	<u>18.4</u>	<u>15.3</u>
Total	<u>100.0</u>	<u>100.0</u>	<u>100.0</u>	<u>100.0</u>	<u>100.0</u>

F- forecast

GT's report further notes that the primary reason for the decrease in equity in the 2002 test year is the forecast dividend payout of \$70,000,000. IC-66 (Rev) shows that, without the payment of any dividends since 1995, NLH's debt to equity ratio for the 2002 test year would be approximately 75/25 versus 83/17 as projected.

In May 2000 NLH's Board of Directors changed its dividend policy originally introduced in November 1995 as follows (IC- 276):

<u>1995</u>	<u>2000</u>
The Corporation shall pay each year to its sole shareholder, the Government of Newfoundland and Labrador, dividends of up to 75% of the Corporation's net operating income for that year provided that such payment shall not cause a deterioration in the existing debt/equity ratio of the Corporation, with such dividends to be paid on a quarterly basis.	The Corporation shall pay each year to its sole shareholder, the Government of Newfoundland & Labrador, dividends of up to 75% of the Corporation's net operating income before net recall revenue for that year plus 100% of net recall revenues received, 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 the Corporation.

The 1995 dividend policy was developed at that time based on advice from Scotia McLeod, NLH's Financial Advisors. (NP-169)

Witnesses expressed differing views regarding the impact of the dividend paid in the test year. Ms. McShane noted a supportive dividend policy which is predictable is in the best interests of shareholders, management and ratepayers and recommends the Province, as shareholder, implement and maintain its dividend policy as approved by the Board of Directors. (Pre-filed Evidence, K. McShane, pg. 24/24-28; Transcript, Oct. 29, 2001, pg. 9/7-8) Dr. Kalymon suggested money paid out in dividends is effectively replaced by debt with the liability remaining with the Province through its guarantee. (Transcript, Nov. 13, 2001, pg. 32/23-26)

Mr. J.T. Browne commented where dividend payments result in higher revenue requirements, one option is to deem a capital structure as if the dividends had not been paid. (Pre-filed Evidence, J. T. Browne, pg. 22/20-21) In principle, he had no objection to the payment of the dividend as long as the guarantee remained in place. (Transcript, Nov. 2, 2001, pg. 16/1-9)

NLH's position outlined in its final argument (pg. 46) contends the shareholder is entitled to a return and that there was nothing so unusual about the proposed payment of dividends that it would require an adjustment to ROE.

NP in its final argument (pg. 35-38), while not disputing the shareholder's right to request such a dividend, submits the \$70,000,000 proposal in the test year is excessive from a rate making perspective. NP argues that a payout of 75% in line with NLH's policy would reduce the proposed revenue requirement by an estimated \$1,500,000 and concludes this reduction should be accurately determined and an adjustment made accordingly.

The IC agree with NP's position on the \$1,500,000 adjustment to revenue requirement. (Transcript, Jan. 28, 2002, pg. 31/3-7) In final argument (pg. 97-100) the IC submit that Government as "*shareholder*" made no initial investment in NLH. Over the years, the accumulation in "*retained earnings*" which form part of NLH's regulated operations constitute "*ratepayer equity*" in NLH which the IC conclude must be isolated in a separate account from "*shareholder equity*", the only source from which dividends may be paid to Government.

The Board concurs with the prevailing view expressed during the hearing that dividend policy is a matter between NLH and its shareholder and is an issue over which the Board has no direct control. The Board acknowledges the right of the shareholder to receive an appropriate dividend. The declaration of dividends in a normal business environment results from decisions made by the company's Board of Directors in concert with management based on an assessment of risks. Both Dr. Kalymon and Mr. J. T. Browne's testimony took no issue with the dividend insofar as Government provides a guarantee. The Board notes the proposed \$70,000,000 dividend runs contrary to NLH's own dividend policy and produces impacts that are inconsistent with the long term financial objectives NLH is seeking to establish in its first Application as a fully regulated utility.

Mr. Wells indicated that while no firm decision had yet been made by Government on the test year dividend, NLH would move forward over time towards its targeted objectives. (Transcript, Sept. 24, 2001, pg. 38/74-92)

The Board makes no further comment on NLH's dividend policy but suggests greater consultation regarding future dividends between NLH and its shareholder may prove in the interests of all parties. The Board notes that, while IC-49 reveals no discussions with the shareholder have been held to date, NP-73 reflects NLH's intentions to meet with the shareholder on a stable dividend policy following direction from the Board. The Board encourages this consultation.

The IC argument concerning the Province's entitlement to dividends from only the "*unregulated*" entity CF(L)Co, based on its share structure, was not supported or commented on by any other Intervenor. The Board points to the ownership of NLH as a Crown Corporation, with the Province being its sole shareholder, and notes financial risk is borne by the shareholder.

The Board agrees a supportive dividend policy which produces a predictable and stable outcome on rates is preferable. Rate stability and predictability is one of the principles contained in the Board's regulatory framework and serves the interests of customers.

The Board concludes the \$70,000,000 dividend is an extraordinary event for the test year, which, if declared, will have a significant adverse impact on the revenue requirement, and hence rates. A fair and reasonable dividend should be permitted and appropriate interest allowed in the test year. The Board has no basis for determining this interest adjustment other than linking it to the established dividend policy of NLH which provides for a payout of up to 75% of net operating income at the discretion of NLH's Board of Directors.

The Board sees little merit in Mr. J. T. Browne's suggestion that it deem a capital structure as if the extraordinary dividend were not paid. This approach is not seen as necessary in light of the 3% ROE and the Board adjusting revenue requirement consistent with NLH's adopted dividend policy.

The declaration of dividends is a matter between NLH and its shareholder, Government. The Board does recommend improved coordination and consultation between NLH and Government on establishing a mutually appropriate and predictable dividend arrangement on a go forward basis.

The Board feels the proposed dividend payment of \$70,000,000 in the 2002 test year places an excessive burden on consumers when it is included in revenue requirement. The Board finds that the interest expense and return on equity in the 2002 test year revenue requirement should be based on NLH's dividend policy providing for dividends of up to 75% of its net operating income. The interest cost for the 2002 test year will be required to be reduced using the embedded cost of debt to reflect the cost of financing the dividend in excess of NLH's dividend policy. A corresponding increase in return on equity or net earnings reflecting the requested 3% return on the notional increase in equity will partially offset the interest reduction.

5. NLH's Request To Be Treated As An Investor Owned Utility

Before deciding on NLH's interim and long term proposals for its capital structure and return on rate base, a fundamental determination is how NLH should be treated within the context of the *Board's* regulatory framework.

Mr. Wells, NLH's CEO, stated the legislative amendments indicate that, as a matter of public policy, NLH is intended to operate as a fully regulated utility, more similar to that of an investor owned utility than has previously been the case. (Pre-filed Evidence, W.E. Wells, pg. 6/20-22) As earlier quoted in NLH's final argument (pg. 36) it is NLH's position that it is essential the financial markets be advised, through the decision of the Board, that the targets established are short term in nature, with the principle being adopted that NLH is entitled to earn a return normally approved by the Board for a commercial entity, whether it be investor owned or crown owned.

A consensus existed among cost of capital witnesses that NLH should be treated as an investor owned utility. Ms. McShane indicated, pursuant to the legislation, NLH's rates are to be determined on the basis of a rate base/rate of return model similar to that which governs the regulation of the preponderance of investor owned utilities in North America, and specifically, similar to that used to set rates for NP. (Pre-filed Evidence, K. McShane, pg. 2/29-32) Mr. Hall concurs that, to the greatest extent possible, in coming up with appropriate returns and capital structures, NLH should be treated as an investor owned utility. (Transcript, Oct. 31, pg. 36/60-68) Mr. J.T. Browne agreed it is appropriate for a public sector utility to use normal commercial targets respecting rate base subject to a separation of the role of government as an investor and its normal role given to social and public policy objectives. (Pre-filed Evidence, J.T. Browne, pg. 15/15-18; pg. 16/11-12) Dr. Kalymon and Mr. Hall both concurred with this explicit separation

of social policy objectives. (Transcript, Nov. 14, 2001, pg. 7/20-101 Transcript, Nov. 1, 2001, pg. 31/3-5) Dr. Kalymon further felt investor owned regulation is implicit in the legislation in that “*just and reasonable return*” is the same wording applied to privately owned utilities and also in that the legislation refers to NLH achieving a sound credit rating. (Transcript, Nov. 14, 2001, pg. 4/82-92)

The IC submitted that there is no investor owned utility that could come before a Board in current circumstances and look for a 3% return on equity. The IC further argue NLH has no stand-alone equity base and it doesn’t have any plans to get one. The only reason that all these things can happen is because government guarantees the debt of NLH. The IC concluded that the notion of a commercial entity³, to the extent that it costs ratepayers money, is neither mandated nor justified by the legislation that governs the Board in its considerations. (Transcript, Jan. 28, 2002, pg. 25/15-20,45-48)

While not addressing the investor owned concept, NP suggests in its final argument (pg. E-6) that it is only appropriate to deal with the requested ROE of 3% at this time and the longer-term D/E target of 60/40 should not be endorsed in the absence of a concrete plan to reach this objective.

The CA did not comment in final argument on NLH being regulated as an investor owned utility.

NP-75 provides a number of legislative excerpts in support of NLH’s case that, as a matter of public policy, it is intended to operate as an investor owned utility. NLH’s position on this issue, however, is developed primarily as a consequence of the evidence and its interpretation of *EPCA*, Section 3(a)(iii) wherein it is the policy of the province ... to enable NLH “*to earn a just and reasonable rate of return as constituted 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.*”

The Board notes NLH’s credit rating, as attested to earlier, is dependent on the standing provincial policy which currently guarantees NLH’s debt. While it is true witnesses presented evidence in support of NLH being treated as an investor owned utility, none of these witnesses recommended the elimination of the provincial guarantee. Ms. McShane stated there is no reason to withdraw the guarantee as long as the appropriate compensation for the risks that are being taken is represented in the return to debt and the return to equity. (Transcript, Oct. 29, 2001, pg. 12/10-13). Mr. Hall remarks, in the transition period, there are significant advantages to the utility in the guarantee, and hence, as long as the Province makes it available at reasonable cost, electricity consumers are better served by the utility using it. (Pre-filed Evidence, D. Hall, pg. 6/25-28) Dr. Kalymon indicated “*nowhere in my testimony do I say that the provincial guarantee is to be removed or assume that it is being removed*”. (Transcript, Nov. 14, 2001, pg. 6/15-16) Finally, Mr. J.T. Browne concedes, if government guarantees the debt and charges the utility, which then gets passed on to customers, the lower equity ratio should be considered. (Transcript, Nov. 2, 2001, pg. 15/19-22)

³ Commercial entity and investor owned utility, while having slightly variant definitions in their usage by intervenors/witnesses, are for purposes of this report indistinguishable.

The Board further evaluated NP-75 and NP-76 outlining both the similarities and differences respectively in the way NLH currently operates and how it would operate as a fully regulated utility, more similar to an investor owned utility. NLH views these similarities as follows (NP-75, pg. 5-6/28-2):

- Operate in an efficient and least cost basis
- Achieve appropriate return on rate base
- Provide an appropriate return on equity
- Achieve appropriate debt/equity ratios
- Provide an appropriate dividend payout.

The Board is of the view that the comparisons NLH has set for itself in this RFI do not currently exist. Efficiency and productivity standards have yet to be determined. Through NLH's own admission, return on rate base, return on equity and debt/equity ratio reflected in this Application is not in keeping with stand-alone investor owned utilities. As outlined previously, the issue of future dividend payout and its impact on rates remains uncertain.

The main differences between the way NLH is intended to operate and an investor owned utility are, as follows (NP-76, pg. 1/8-18):

- As a Crown Corporation, NLH may receive directions from its shareholder, the Government of Newfoundland and Labrador, which reflects social or public policy considerations, not in conflict with legislation, which NLH will implement;
- NLH's ability to borrow and its borrowing program is influenced by the fact its debt is guaranteed by the Province, NLH is able to borrow at the lower cost, which results in lesser cost to customers.
- As a Crown Corporation, NLH is not subject to corporate income taxes.

There has been no evidence to suggest that these differences will be eliminated in the short term.

As shown in CA-113, the Board also notes a capital structure reflecting greater equity and an increased ROE will result in higher revenue requirements, and hence higher rates for consumers. NLH has not presented a plan on how its investor owned financial objectives will be achieved or what the impact of these objectives will be on rates. IC-49 indicates NLH will be outlining its recommendations to the Board for achieving reasonable medium and long term financial targets at each future rate application.

In summary, for the most part, final arguments did not address the concept of regulating NLH as an investor owned utility. NLH is able to sustain its borrowing capacity in the financial markets of the world because of the Provincial guarantee and there was no evidence to indicate this should or will change. The Board concludes there is no statutory or evidentiary foundation for regulating NLH similar to an investor owned utility and points to the fact that NLH as a fully

regulated utility is subject to the Board's existing regulatory framework. As outlined previously, this framework is currently used to regulate NP, an investor-owned utility, and is capable of regulating NLH in a similar manner, when and if this designation is warranted. The Board notes NLH has presented no concrete plans as to how it will achieve its stated goals in operating similar to an investor owned utility (See NP-75) and what the impact of implementing these plans will be on electrical rates for consumers, business and industry in the Province.

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.

6. Debt/Equity

NLH's forecast average "*regulated*" capital structure for 2002 is contained in the evidence of Ms. McShane and Mr. Roberts. [Pre-filed Evidence, K. McShane, pg. 15/Table2; (Supplementary Evidence, J.C. Roberts, Schedule VIIIA) NLH's regulated capital structure beginning in 1998 with projections for 2001 and 2002 is set out on pg. 43 of this decision.

The 2002 test year forecast debt/equity ratio is 83/17 based on the assumption of a \$70,000,000 dividend paid to the shareholder. NLH is proposing that the Board adopt debt/equity targets in the short term of 80/20 with approval in principle to move to 60/40 debt/equity in the longer term. (NLH, Final Argument, pgs. 35-36)

In final argument (pg. 39) NLH points to the conclusions reached by Ms. McShane, Dr. Kalymon and Mr. Hall indicating the appropriate capital structure should be consistent with the business risk NLH faces and should permit NLH, on a stand-alone basis, to achieve an investment grade rating of BBB or better. This debt/equity, NLH concluded, is 60/40 based on Ms. McShane's evidence. NLH continues, in light of the fact that the parties have agreed that the debt/equity of 83/17 in the test year can be supported in the short term, the Board may ask whether it needs to comment on a longer term financial structure for NLH. NLH believes it is essential for the credit rating agencies and the financial markets of the world to be aware that the acceptance of both a capital structure of 83/17 and a 3% ROE are temporary measures only. These measures are intended to mitigate current circumstances and are not reflective of the Board's position on the appropriate returns that NLH should earn in normal circumstances. (NLH, Final Argument, pg. 39-40/25-2)

NP's final argument notes the five-year financial plan in IC-98 shows NLH achieving an 82/18 debt/equity ratio by the year 2005. NP is of the view that the target 80/20 debt/equity ratio as provided for by this Board in its 1992 report is sufficient as long as NLH remains a Crown Corporation with its debt guaranteed by the Province. (NP, Final Argument, pg. E-3) NP further contends the Board should refrain from endorsing NLH's longer term debt/equity targets of

60/40 in the absence of a concrete plan. Finally, NP states there is no evidence that this target would be in the best interest of electricity consumers. (NP, Final Argument, pg. E-4)

The IC state in final argument that NLH has a sound credit rating now based on the government guarantee of its debt. The common and sensible decision is to continue to pay the fee rather than attempt to move to a stand-alone situation which could only be viable with a much different debt/equity structure. In summary the IC argued there is no pressing need to increase the equity in NLH at ratepayer's expense, and the least cost option consistent with the *EPCA* does not require the Board to address capital structure at this point. (IC, Final Argument, pgs. 93-94)

The Board notes that the longer term 60/40 capital structure proposed in the Application is pursuant to the principle of regulating NLH similar to an investor owned utility. For reasons already explained, the Board is not persuaded by the evidence to endorse this concept at this time. Neither, therefore, is the Board prepared to accept NLH's related proposal to move to a 60/40 capital structure. The evidence supports 60/40 as an appropriate target if NLH is to be operated on a stand-alone basis without a Government guarantee. As pointed out earlier, none of the witnesses are advocating the withdrawal of the Provincial guarantee. While a 60/40 capital structure appears to be an extension of NLH's argument to be treated as an investor-owned utility, there is no accompanying plan as to how or when this will be achieved or the impact a doubling of the equity base will have on customers. The Board points to a notable inconsistency in this area when IC-98 shows NLH's financial plan in 2005 projecting a capital structure of 82/18. The Board earlier concluded the build up of equity is dependent on NLH's ability to exercise control over its dividend stream into the future. This issue remains unresolved and is subject to further discussions between the shareholder and NLH.

The intervenors did not object to NLH's targets for a capital structure of 83/17 in the 2002 test year and a move toward 80/20 in the short term. This latter target (80/20) is in keeping with the recommendation of the Board's 1992 report.

The Board accepts NLH's proposals for a debt/equity ratio in the 2002 test year of 83/17 and a target short term debt/equity ratio of 80/20. The Board concludes the evidence does not support the principle of NLH moving to a capital structure of 60/40 at the present time. If NLH is committed to move in this direction, it must formulate an appropriate long term financial plan to present to the Board.

7. Return on Equity

NLH's return on equity forecast for the test year 2002 is contained in Mr. Roberts' evidence. (Supplementary Evidence, J.C. Roberts, Schedule 1A) Adjusting for non-regulated earnings, NLH's regulated return on common equity is shown in GT's 2001 General Rate Hearing Report (pg. 12) as follows:

	1998	1999	2000	2001(F)	2002(F)
Regulated Return on Common Equity (%)	8.76	4.34	2.10	5.11	3.00

F – forecast

NLH explained that the proposal of a 3% ROE in the 2002 Test year is a means of assisting in reducing the rate increases required for customers. (NLH, Final Argument, pg. 36/4-5).

Several witnesses submitted evidence concerning NLH's long-term ROE. In final argument, however, NLH withdrew its long-term proposal for a return on equity (ROE) of 11-11.5%. (NLH, Final Argument, pg. 35/19-23)

NLH in its final argument comments that the decision on a fair and reasonable return need not be determined in this proceeding, given NLH's request for only a 3% ROE. That decision can be made at the time of NLH's request for a full return on rate base in light of economic and capital market conditions prevailing at the time. (NLH, Final Argument, pg. 38/1-7) Similar to its proposal on capital structure, NLH feels it is essential that the Board's decision convey to the financial markets that the acceptance of 3% ROE is a temporary measure, short term in nature, to reflect current circumstances. (Transcript, Jan. 28, 2002, pg. 6/67-71)

NP states that, while the otherwise acceptable ROE for NLH at this time would be higher, NLH has chosen to seek only 3% and indicates this fact alone in the Board's Order should be sufficient to address Mr. Wells' concern of sending an appropriate message to the financial markets. (NP, Final Argument, pg. E-3)

The IC state that, given the Board has more than enough real contested issues, it need do nothing more at this point than state it is satisfied with the 3%. Furthermore, the Board can indicate it has not been requested to determine a just and reasonable rate for 2002 and will not do so until such time as an application requests approval of a market rate. (IC, Final Argument, pg. 96)

The CA submits NLH's Application requesting a 3% ROE is flawed from a number of perspectives. Section 80. (1) of the *Act* makes reference to return on rate base but does not refer to return on common equity. The Stated Case⁴ points to the rate of return on rate base being a reasonable range as opposed to a fixed number. The absence of a cap exercises no limitation on NLH realizing excess earnings on ROE above a reasonable rate of return. Based on these conclusions, the CA feels the Board should allow NLH to earn an ROE in the range of 2.5-3.0% in the test year, while recognizing that, theoretically, but for NLH's request for a 3% ROE, NLH would be entitled to 8.5-9.0% for the test year (CA, Final Argument, pgs. 4,7, 52).

The Board does acknowledge a 3% ROE is well below market and recognizes NLH's entitlement to earn a just and reasonable ROE in concert with the legislation. As suggested by NLH, a determination on full return on rate base can be made based on a future request and in light of economic and capital market conditions prevailing at the time. This position was generally accepted by all parties.

⁴ Stated Case refers to Newfoundland (Board of Commissioners of Public Utilities) 164 Nfld. and P.E.I.R. 60 (NF CA)

The Board is not persuaded by the arguments of the CA and feels a 3% ROE is sufficiently limiting to prevent excess earnings. Consideration of ROE simply sets the equity dimension of the cost of capital and does not compromise the ability of the Board to determine a just and reasonable return on rate base as set out in the legislation. Finally, setting a reasonable range of return would serve to either undercut the acknowledged conservative ROE requested by NLH or increase the ROE above that requested. Either scenario is not deemed prudent by the Board.

The Board accepts NLH's request for a 3% ROE in the 2002 test year. The Board acknowledges this level of ROE is below normal market returns because of NLH's position taken in this Application to lessen the rate impact on its customers. Consideration of a more normal return will be subject to a future request by NLH.

II. FORECASTING: PRODUCTION AND FUEL COSTS

1. Introduction

Forecasting

Accurate forecasting plays a key role in setting the revenue requirement and resulting electricity rates. Forecasts of hydraulic versus thermal production, the fuel efficiency factor used at Holyrood and the price of fuels contributes significantly to the costs of power generation.

Hydraulic/Thermal Production

As outlined in describing the Current Industry Structure (See pg. 17 of this decision), the bulk of NLH's generation capacity is supplied from hydro electric developments located at Bay D'Espoir, Cat Arm, Upper Salmon and Hinds Lake as well as thermal generation at Holyrood. The amount of hydro electric (hydraulic) power which can be generated is dependent on precipitation and water inflows into the reservoirs (hydrology). Estimates of water inflows are based on historic records of hydrology data. Wetter years than average provide NLH with the ability to produce more hydraulic power thereby requiring less thermal production at Holyrood. Of course, the opposite is true in the drier years.

The proportion of hydraulic versus thermal production affects the resulting cost of electricity. Hydraulic power is substantially cheaper to generate than thermal power and less hydraulic production in a given year leads to higher electricity costs. Determination of hydraulic and thermal production forecasts are important factors in setting the revenue requirements of NLH in the test year and hence affect electricity rates. Depending on actual hydraulic production, any variation from the test year forecasts requiring more or less thermal production at Holyrood is reflected in increases or decreases in thermal costs and is accordingly debited or credited to the Rate Stabilization Plan (RSP) whose balances are recovered from consumers. (See pg. 79 of this decision)

Fuel Efficiency Factor

The fuel efficiency factor is a measure of the thermal output in kWh from burning a barrel of fuel at Holyrood and is a reflection of the performance and reliability of the generating plant. Test year forecasts are established using trend analysis and consideration of recent or planned upgrades and/or outages in plant and equipment. A higher fuel efficiency factor compared to the test year will yield lower fuel consumption and hence lower electricity costs. The reverse is also true.

Fuel Costs

The actual price of No. 6 fuel versus the test year forecast has a direct impact on the cost of thermal production at Holyrood. Higher fuel costs contribute to higher electricity rates and vice versa. The actual costs of No. 6 fuel above or below the forecast costs used for the test year

base rate are accordingly reflected in the RSP to be recovered from consumers over a three year period.

The cost of diesel fuel directly impacts the cost of electricity generated by Isolated diesel systems.

2. Production

i) Test Year Hydraulic Production Forecast

NLH uses the simple average of all the available years of hydrology records with adjustments for fisheries release and spills to determine the forecast hydraulic generation. Using this methodology NLH forecasts the hydraulic production for the 2002 test year to be 4,285 GWh, representing an “*average water year*”. NLH notes that the methodology used for forecasting hydraulic production is the same as used in previous rate referrals.

NP raised the following specific concerns about NLH’s hydraulic forecasting methodology:

1. Appropriate length of hydraulic record - Since NLH uses the entire available hydraulic record old data never gets dropped from the data set. It was suggested by NP that this reduces the effect of any trending in inflow and that the 30 year average for each year for the period 1988-2000 shows an increasing trend in historical inflows. (1st Supplementary Evidence, L. B. Brockman, pg. 2/7-8)
2. Reliability of pre-plant vs post-plant data - NLH treats the data series for both pre-plant and post-plant inflow data as a continuous series. It was acknowledged by NLH that the method used to determine inflows for the pre-plant data is different than that used to collect post-plant data (Transcript, Oct. 9, 2001 pg. 14/77-80). It was also confirmed by Mr. Henderson that NLH had not conducted a review to determine if the data sets are comparable or whether there are any concerns with the reliability of the pre-plant data. (Transcript, Oct. 10, 2001, pg. 37/58-65)
3. Inclusion of spills in the calculation - Since NLH would not expect to spill water at Bay d’Espoir during an average water year, which is forecast for the test year, NP suggests that these spills should not be included in the calculation of the test year spill estimate. (NP, Final Argument, pg. C-13)

NP proposes using a 30 year moving average as the basis for determining the test year hydraulic forecast. Use of this data set would increase the average hydraulic production forecast and consequently reduce the forecast thermal generation for 2002. It was suggested by Mr. Brockman that a 30 year moving average would better reflect technological improvements in data collection and more accurately represent recent historical flows. As well Mr. Brockman stated that a 30 year moving average “*is long enough to minimize volatility in the average but recent enough to reflect changes in inflow patterns.*” (1st Supplementary Evidence, L. B. Brockman, pg. 2/13-21) NP submitted Exhibit LBB-4 pointing to an increasing trend in inflows, which may be due to climate change or may relate to measurement problems with the older data.

A variance of 100 GWh in forecast hydraulic production would result in a difference of approximately \$3.3 million in revenue requirement for the test year. (NP-141) NP suggests using the 4,425 GWh proposed by Mr. Brockman as compared to NLH's revised forecast of 4,285 GWh. This lower forecast in hydraulic production would result in a reduction in revenue requirement of approximately \$4,600,000. (NP, Final Argument, pg. C-14)

NLH points out in final argument (pg.15) that any difference between the actual production and the forecast production goes into the RSP to be recovered over time so NLH is indifferent from a financial perspective. The use of a higher hydraulic forecast could, however, affect the RSP balances as projected in PUB-81. The real question is which forecast should be used in setting base rates.

The questions raised by NP regarding forecasted hydraulic production are valid and the Board sees merit in NP's position. No other direct evidence was entered to support the proposal to use a 30 year moving average other than the evidence brought forward through NP's cost of service witness, Mr. Brockman. The most compelling information for the Board is the information provided in U-Hydro # 17 which compares forecast and actual hydraulic energy production using both a 30 year moving average and the full historical average for the period 1950-2000. This evidence suggests to the Board that there may be an increasing trend in hydrology for the last 10 years which may not be captured using a 50 year average. The Board notes, however, that either method (NLH's long-term average or NP's 30 year moving average) would have underestimated the actual inflows for the period 1993-2000. (U-Hydro # 17, Figure 7) No other intervenor expressed a strong position on this issue during the hearing. In final argument the CA recommended the use of the 30 year moving average. The IC stated they did not object to the use of a 30 year moving average.

The Board accepts NP's concern that NLH has not conducted a review of the pre-plant and post-plant data to assess whether the full data set of inflows constitutes a continuous time series for the purposes of data analysis. (NP, Final Argument, pg. C-11) The Board also concurs with NP that technological improvements in data collection may justify using a more recent data set. It is the Board's opinion that a 30 year moving average will accurately represent recent historical flows for the purpose of forecasting the average annual hydraulic production. NLH has calculated the 30 year average annual hydraulic production, including 2000 data, as 4,425 GWh. (Supplementary Evidence, R. J. Henderson, pg. 2/17-18)

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.

ii) Test Year Thermal Production Forecast

NLH has forecast a total required energy supply for the 2002 test year of 6,625.60 GWh, comprised of:

NLH Revised Forecast	
Hydraulic production	4,271.67 GWh
Thermal generation	2,207.43 GWh
Energy purchased	146.50 GWh
Total energy supply	6,625.60 GWh

(2nd Supplementary Evidence, Oct. 31, 2001, H. G. Budgell, Schedule A)

NLH subsequently updated the forecast for hydraulic production to 4,285 GWh to reflect the year 2000 results.

As indicated previously, the Board will require NLH to use a 30 year moving average of 4,425 GWh as the forecast for hydraulic production for the test year. The energy forecast to be supplied from thermal generation will decrease, resulting in lower forecast No. 6 fuel costs for the 2002 test year. This will result in the following energy supply breakdown for the test year:

Hydraulic production	4,425.00 GWh
Thermal generation	2,054.10 GWh
Energy purchased	146.50 GWh
Total energy supply	6,625.60 GWh

The 2002 test year forecast of thermal generation will be adjusted to reflect a forecast hydraulic production of 4,425 GWh.

iii) Holyrood Fuel Efficiency Factor

The fuel efficiency factor is the expected kWh output from burning a barrel of oil (kWh/bbl) and, when applied to the forecast thermal generation, gives the expected number of barrels of oil required at Holyrood for the test year. A higher fuel efficiency factor will result in lower forecast fuel, and hence lower costs.

The fuel efficiency factor for Holyrood was last set in 1989 when the Board recommended that NLH use 605 kWh/bbl in forecasting revenue requirement. NLH had proposed using 600 kWh/bbl to be consistent with long term averages. The Board increased the efficiency factor at that time to recognize anticipated efficiencies resulting from NLH's efforts to modernize the units in Holyrood. The efficiency factor of 605 kWh/bbl has been used by NLH since then. NP-51 shows the average efficiency factor for 1992-2000 as 605.7 kWh/bbl, with a low of 579.3 kWh/bbl in 1994 and a high of 629.5 kWh/bbl in 1997.

For the 2002 test year NLH is proposing a fuel efficiency factor of 610 kWh/bbl and is forecasting thermal production at Holyrood to be 2,207 GWh which results in a forecast consumption of approximately 3.6 million barrels of No. 6 fuel.

The calculation of a fuel efficiency factor of 610 kWh/bbl is based on the average of the actual efficiency achieved at Holyrood for the period 1996-2000, as shown below: (NP-45; NP-51)

Year	kWh/bbl	Thermal production
1996	611.0	1,406.49
1997	629.5	1,530.85
1998	618.8	1,262.59
1999	577.1	919.15
2000	609.6	968.30
Average	609.1	Not Applicable

NLH states that the increase from 605 kWh/bbl to 610 kWh/bbl is intended to reflect efficiency improvements experienced at the Holyrood plant since an on-line efficiency monitoring system was placed in operation in 1995. (NLH Final Argument, Pg. 16/21-24) NLH outlined the changes implemented at the Holyrood generation facility undertaken to improve reliability, efficiency and environmental performance. (Pre-filed Evidence, R. Henderson, pg. 3-4/28-8)

NP submits that the test year fuel efficiency factor is too low and results in a fuel forecast and corresponding fuel costs for 2002 that are too high. (NP, Final Argument, pg. C-21) The fuel efficiency factor is calculated for a time period when hydrology was significantly above normal. Higher hydraulic production results in lower thermal production, and in turn a lower fuel efficiency factor at Holyrood. NP points to the fact that the highest actual efficiency factor for the 1996-2000 time period was 629.5 kWh/bbl in 1997, which was also the year of highest thermal production, at 1,531 GWh. The forecast thermal production for 2002 is 2,162 GWh (later revised to 2,207 GWh), approximately 40% higher than the highest thermal production achieved in 1997.

Mr. Brushett of GT suggested that the forecast 2001 thermal production may be more representative of an average hydrology year. Using the actual thermal production and achieved conversion rates for fuel to October 2001 GT estimated the efficiency factor for 2001 at 633 kWh/bbl. Since the forecast thermal production of 2,207 GWh for 2002 is for an average water year, and the thermal production forecast for 2001 is 2,184 GWh, Mr. Brushett suggested that 633 kWh/bbl may be a better proxy for the forecast efficiency at Holyrood. (Supplementary Evidence, GT, pg. 3/17-19)

In final argument NLH submits that the proposed fuel efficiency factor of 610 kWh/bbl best represents NLH's experience since 1996 when the efficiency improvements were put in place and that it is a reasonable factor to use on a go forward basis (NLH, Final Argument, pg. 17/24-27). They also point out that a fuel efficiency factor of 633 kWh/bbl does not address the potential variability in the efficiency factor and the resultant impact on NLH's net income. In cross-examination Mr. Brushett of GT acknowledged that if the actual results in 2002 are similar to 1999 NLH's net income could be reduced by \$6,600,000.

While the thermal production forecast by NLH for 2001 is comparable to that forecast for 2002 it is clear that 2001 was not an average water year. Mr. Henderson confirmed that the summer of 2001 was the third driest on record and resulted in NLH having to use more thermal generation to keep reservoir levels at minimum storage targets. (Transcript, Oct. 9, 2001, pg. 34/8-18) The Board does not feel that the 633 kWh/bbl would be a reasonable efficiency factor to use for a forecast average water year in 2002.

The period 1996-2000 used for calculating the fuel efficiency factor proposed by NLH does not cover "*average water years*" and includes some of the wettest years in NLH's hydraulic plant operation. This affects the operation of Holyrood since lower thermal production results in lower efficiencies, as shown for 1999. Similarly, drier years will result in higher thermal production and higher efficiencies, as happened in 2001. However it does not appear from the evidence that this relationship can always hold true either. Operating results for 2000, a relatively wet year, show a low thermal production of 968 GWh but an efficiency factor of 609.6 kWh/bbl. This is the same as the forecast efficiency factor of 610 kWh/bbl for 2002, even though the 2002 thermal generation is forecast to be 128% higher than 2000.

It also appears that an increase in the amount of energy purchased since 1998 has resulted in lower thermal production and lower fuel efficiency factors. NP-45 shows an increase in energy supply from power purchases of 193.98 GWh in 1998 from 1997. The hydraulic production in 1998 was 4262 GWh, close to that predicted for the 2002 "*average water year*" and the thermal production was 1263 GWh, with an efficiency factor of 618.8 kWh/bbl. Presumably the efficiency factor would have been higher had NLH generated the additional 194 GWh at Holyrood. This would also be true for 1999.

The Board does see an inconsistency in accepting forecast costs associated with average hydraulic conditions and then approving fuel costs based on an efficiency factor derived from experience under above average water conditions, as is the case for the last five years. Accordingly the Board is of the opinion that the forecast efficiency factor of 610 kWh/bbl is too conservative for the expected 2002 operating conditions and may result in higher forecast fuel costs for the test year than circumstances warrant. The Board also agrees that the efficiency factor for Holyrood should be adjusted upward to reflect increased operating efficiencies. This adjustment will result in some of the benefits of the investment in efficiency improvements being passed on to consumers in the form of lower fuel costs.

The challenge for the Board is to set an efficiency factor that will provide a fair approximation of fuel costs to be recovered from consumers for 2002 onwards (until the next rate hearing) while at the same time recognizing that NLH does not have control of the actual

hydrology conditions under which it will be operating. The Board is also cognizant of the impact on NLH's margin of any variability in the efficiency factor between that embedded in rates and actually realized.

The Board finds that a fuel efficiency factor in the range of 615-620 kWh/bbl is warranted. To mitigate potential impacts on NLH's margin which, at 3%, is already below a normal market rate the Board will order an efficiency factor of 615 kWh/bbl. This efficiency factor will also be used for calculating hydraulic variation in the RSP.

3. Fuel Costs

i) Price Forecasts

NLH retains the services of the PIRA Energy Group of New York to provide forecasts of fuel prices. PIRA is an internationally recognized company specializing in petroleum product market analysis and price forecasting.

At the time of this Application the forecast average price (Cdn) of No. 6 fuel was \$28.38/bbl which was later revised to \$25.91/bbl and confirmed by NLH in early January 2002. NLH's projection of the 2002 weighted average No. 6 fuel price of \$25.91 Cdn/bbl based on the PIRA forecast dated November 30, 2001 and NLH's most recent exchange rate forecast is shown below:

Holyrood No. 6 Fuel Price Forecast (\$Cdn/bbl)	
December 2001	22.70
2002	
January	24.30
February	25.20
March	25.20
April	25.70
May	25.80
June	25.50
July	25.70
August	26.50
September	26.60
October	26.80
November	26.60
December	27.10
2002 Weighted Annual Average	25.91
2003	26.55
2004	26.50
2005	27.50

(2nd Supplementary Evidence, R. J. Henderson, pg. 1)

NLH's projection for No. 2 diesel fuel prices for each of NLH's interconnected system standby plants is shown below. These prices are also based on the November 30, 2001 forecast of the PIRA Energy Group.

No. 2 Fuel Price Forecast (\$/litre, Cdn)					
	December 2001	2002	2003	2004	2005
Holyrood & St. John's	0.288	0.337	0.349	0.354	0.370
Stephenville	0.299	0.348	0.360	0.365	0.381
Happy Valley GT	0.390	0.398	0.410	0.415	0.433
Roddickton & Hawkes Bay	0.372	0.386	0.398	0.403	0.421
St. Anthony	0.352	0.366	0.378	0.383	0.401

(2nd Supplementary Evidence, R. J. Henderson, pg. 2)

NP-219 indicates the average diesel fuel cost per litre for the Rural Isolated systems for 1992-2000 and the forecast for 2001-2005, as shown below:

Diesel Fuel Unit Price Rural Isolated Systems	
Year	Avg. Fuel Cost per Litre (\$)
1992	0.23
1993	0.23
1994	0.22
1995	0.23
1996	0.26
1997	0.28
1998	0.24
1999	0.26
2000	0.42

Forecast Diesel Fuel Unit Price Rural Isolated Systems	
Year	Forecast Avg. Purchase Cost per Litre (\$)
2001	0.44
2002	0.42
2003	0.41
2004	0.40
2005	0.42

These forecast diesel fuel prices are also based on PIRA's market forecast.

The forecast energy supply costs for NLH's Isolated Rural systems were revised to \$7,100,000 based on the November 30, 2001 forecast by PIRA. (2nd Supplementary Evidence, R. J. Henderson, pg. 3) This forecast cost includes the cost of purchased power and diesel fuel, with diesel fuel accounting for 90% of the total cost. (2nd Supplementary Evidence, H. Budgell, pg. 4) The forecast costs for Isolated diesel fuel expenses for 2002 reflects the fuel already purchased and stored for the winter season at plants that do not receive deliveries of fuel until the spring of 2002. (2nd Supplementary Evidence, R. J. Henderson, pg. 3)

Although the updated fuel forecast filed by NLH did not specifically identify the Isolated diesel system unit fuel prices, U-Hydro # 28 indicated a revised forecast unit price as of October 1, 2001, based on information concerning diesel fuel available up to the end of August 2001, of \$0.455/litre. NLH also indicates in U-Hydro # 28 that the actual comparable price for November 2001 was \$0.40-\$0.41/litre. The Board was not presented with any evidence to suggest that the pricing forecasts for No. 6 fuel and No. 2 fuel (diesel fuel) were not reasonable

The Board accepts the 2002 test year forecasts for fuel prices as filed.

ii) Purchasing

NLH currently has a volume only contract for 10 million barrels of No. 6 fuel oil shipped to the Holyrood facility. This contract has been in place since 1997 and was awarded based on competitive bids. The price NLH pays for No. 6 fuel under this contract is based on the average New York Harbour price in the month a delivery is received. (Pre-Filed Evidence, R. J. Henderson, pg. 14/10-17). Under the contract NLH is required to provide firm shipment dates and delivery requirements one month in advance of the fuel shipment with estimates for future shipments. The estimates take into consideration the need to balance oil deliveries with current rainfall, storage capacity and best estimates of future oil price movement. (Transcript, Oct. 10, 2001, pg. 24/24-99) NLH confirmed that, as of June 2001, it had received 6.1 million barrels of No. 6 fuel under this contract, with further shipments received since. (Transcript, Nov. 20, 2001, pg. 35/43-45)

Other factors that NLH has to consider in planning fuel oil deliveries are the capacities of the various storage tanks located at Holyrood and at its diesel generating sites, as well as the impact on shipping schedules caused by ice blockages. Holyrood has a storage capacity of 840,000 barrels and receives deliveries in quantities between 250,000 and 300,000 barrels. According to IC-24 (Rev), Holyrood consumes between 1.3 and 3 million barrels of No. 6 fuel per year. Depending on rainfall and demand, the amount of storage is crucial especially during the period November to March.

In purchasing No. 6 fuel, NLH does not attempt to take advantage of market price swings. Under cross-examination by the IC Mr. Osmond agreed that no detailed analysis has been carried out on *"the cost of storage and the carrying costs of inventory against the potential benefits of purchasing in advance, from a price point of view."* (Transcript, Nov. 20, 2001, pg. 30/17-22) The arrangement NLH has with its supplier is that the price is determined using an average for the month in which it takes delivery. Only on rare occasions can NLH arrange for the purchase of fuel to take advantage of low prices.

The IC argued that there was little strategic purchasing or attention by NLH in obtaining the best price for its No. 6 fuel requirements. The IC submitted that the lack of a coordinated approach by management to minimize fuel costs may indicate that NLH is not receiving the best price for its fuel purchases. Consequently the IC recommend that the Board direct NLH to develop an integrated, strategic approach to fuel purchases, pointing out that a 1% reduction in forecast No. 6 fuel costs will result in savings of \$1,000,000 per year.

The CA stated that NLH had not developed a clear oil purchasing strategy aimed at reducing its substantial annual fuel costs. The CA observed as well that there remains some uncertainty as to which department at NLH is ultimately responsible for the strategic purchasing of fuel to ensure that the lowest possible price is obtained. Furthermore, in commenting on NLH's storage capacity for No. 6 fuel at Holyrood, the CA argued that the Board should require NLH to demonstrate that its oil storage capacity is adequate.

Fuel represents one-third of all NLH's costs of operation. As was pointed out by the intervenors NLH should acknowledge and implement appropriate controls and policies with respect to fuel purchasing and clearly assign and document management accountability throughout each step of the purchasing procedures.

With respect to diesel fuel, NLH is currently involved in the early years of a five year contract that is public tendered. (Transcript Oct. 5, 2001, pg. 27/30-32). No additional information was offered into evidence by NLH on purchasing practices for diesel fuel and no intervenors commented specifically on this issue.

Oil Price Hedging

During the past couple of years NLH operated a "*phantom hedging program*" in an effort to determine the impact of such a program. The research indicated that hedging generally costs between 5¢ and 10¢/barrel (US) and that the value of hedging has to be measured from a stability or insurance perspective. NLH stated that: "*The goals of any oil hedging program would be to protect Hydro's customers from adverse, unexpected and random price fluctuations, that are short-term in nature and provide a degree of price certainty.*" (Pre-filed Evidence, D.W. Osmond, pg. 17/23-25)

NLH concluded that, since its customers are already afforded a degree of stability by virtue of the rate stabilization plan, it would not implement a hedging program at this time. NLH does state however that: "*there is some merit in a continued monitoring of an 'active' approach to oil price hedging to assess whether the additional risks are worth the benefits to consumers in terms of protection from market volatility.*" NLH expects that a final determination on the appropriateness of an oil hedging program could be reached in advance of its next rate application. (U-Hydro # 31, pg. 3)

The CA argued that there was sufficient evidence in the form of positive results from NLH's oil hedging experiment to require NLH to either implement such a program or to provide a detailed explanation as to why such a program cannot be justified.

Dr. Wilson observed that, despite the importance of No. 6 fuel oil prices, the Board has received little information concerning the forecasts adopted by NLH and the conditions under which NLH might adopt a hedging strategy. He further observed that, although NLH has rejected the implementation of a hedging program at this time, both the nature of its analysis and the conditions under which such strategy would be adopted remain unexplained. (Pre-filed Evidence, Dr. J. W. Wilson, pg. 34)

The Board will require NLH to file by December 31, 2002 a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing. The statement should address managerial accountability for fuel purchasing along with consideration of such issues as an oil hedging program and the adequacy of existing storage capacity.

III. REVENUE REQUIREMENT

1. Introduction

NLH requested approval of a revenue requirement of \$323,261,000 for the 2002 test year, modified by Supplementary Evidence and final argument as shown in Table 1 below. The Board considered these revenue requirement items and will deal with each separately. Some smaller uncontested costs have been grouped as explained later.

Table 1 Newfoundland and Labrador Hydro Revenue Requirement – Test Year 2002			
	As Filed \$(000)'s	Revised October 31, 2001⁽¹⁾ \$(000)'s	Subsequent Revisions \$(000)'s
Depreciation	31,790	31,665	31,665
Fuel			
No. 6 Fuel	100,585	104,175	92,146⁽²⁾
Rate Stabilization Plan	(25,490)	(26,819)	(14,790)⁽²⁾
Other fuels	7,193	7,679	7,379⁽³⁾
	82,288	85,035	84,735
Power purchased	15,266	15,100	15,100
Other costs			
Salaries	61,773	62,426	62,426
System equip.maint.	16,763	16,763	16,763
Insurance	848	977	977
Transportation	1,923	1,923	1,923
Office supplies	1,939	1,939	1,939
Bldg. Rentals & maint.	626	626	626
Professional services	4,340	5,340	4,340⁽⁴⁾
Travel	2,375	2,375	2,375
Equipment rentals	1,558	1,558	1,558
Miscellaneous	4,458	4,458	4,398⁽⁵⁾
Loss on disposal	791	890	890
	97,394	99,275	98,215
Allocations			
Capitalized expenses	(5,722)	(5,722)	(5,722)
C.F.(L) Co.	(1,910)	(1,910)	(1,910)
	(7,632)	(7,632)	(7,632)
Interest	93,584	91,821	91,821
Return on Equity	9,610	7,997	7,997
Revenue requirement	322,300	323,261	321,901

⁽¹⁾ Schedule IA, J. C. Roberts, October 31, 2001

⁽²⁾ Estimated No. 6 fuel based on R. J. Henderson's testimony of revised fuel forecasts (2nd Supplementary Evidence, R. J. Henderson; Transcript, Jan 9, 2002, pg. 15/41-56)

⁽³⁾ Reduced by \$300,000 in R. J. Henderson's testimony of revised fuel forecast (2nd Supplementary Evidence, R. J. Henderson, pg. 3; Transcript, Jan. 9, 2002, pg. 16/51-56)

⁽⁴⁾ Reduced by \$1,000,000 by NLH during final submissions to reflect NLH's decision to not defer hearing costs to the test year. (Transcript, Jan. 28, 2002, pg. 7-8/99-30)

⁽⁵⁾ Reduced by \$60,000 by NLH to reflect decision to remove Bay D'Espoir street lighting from revenue requirement. (Transcript, Jan. 28, 2002, pg. 8/31-48)

2. Depreciation

Depreciation is the portion of previously capitalized costs that are included in revenue requirement. The amount of depreciation is based on a detailed analysis of each asset's capital cost and estimated useful life. NLH is proposing a depreciation cost of \$31,665,000 be included in the test year revenue requirement.

In December of 1986 KPMG completed a Depreciation Policy Study for NLH which formed part of the 1988 rate referral and was accepted by the Board. The study was updated in October 1998 by KPMG. NLH has filed the updated study with this Application for approval.

This latest study recommends a number of changes including estimating and accounting for the net salvage value of assets, changing the service life of assets and the need for condition surveys of various assets. These recommendations have been accepted by NLH and incorporated into its financial records. Mr. Brushett of GT agreed that the depreciation allowances included in the revenue requirement are reasonable and that NLH had adhered to the recommendations in the study. (Transcript, Jan. 9, 2002, pg. 8/62-66)

NLH also undertook condition surveys of the transmission lines affected by the Avalon upgrade to determine the potential impact on their original estimated service lives. These condition surveys recommended that these transmission lines have revised service lives of 50 years once the upgrade is complete. (NLH, Final Argument, pg. 10) NLH has requested, as part of this Application, that the Board approve the extended service lives for these transmission lines as of 2002. This issue was not contested by the intervenors.

NP recommended that the depreciation allowance be adjusted to reflect any reduction in the 2002 forecast capital expenditures. (NP, Final Argument, pg. C-52) No other intervenors raised any issues about the depreciation study or the methods used by NLH to account for depreciation.

The Board accepts the depreciation study and approves the changes in depreciation policies as filed by NLH. The depreciation expense proposed by NLH will be required to be adjusted to reflect the Board's decisions on NLH's 2002 capital budget. NLH will be required to submit its next depreciation study in 2005.

The Board will approve the extension of the service lives for the transmission lines affected by the Avalon upgrade program as proposed by NLH.

3. Test Year Fuel Costs

NLH's proposed a revenue requirement for the 2002 test year fuel costs of \$85,035,000, as shown below. This revenue requirement was later revised in Supplementary Evidence to reflect updated forecasts of fuel costs.

NLH REVENUE REQUIREMENT – FUEL TEST YEAR 2002 \$(000)'s			
	As Filed	October 31, 2001	R. J. Henderson December 12, 2001
No. 6 Fuel	100,585	104,175	92,146 ⁽¹⁾
Diesel fuel	6,323	6,808	6,508
Other fuel costs	870	871	871
Total fuel costs	107,778	111,854	99,525
Rate Stabilization Plan (RSP)	(25,490)	(26,819)	(14,790) ⁽¹⁾
Revenue Requirement	82,288	85,035	84,735⁽¹⁾

⁽¹⁾ Estimated based on R. J. Henderson's testimony of revised fuel forecasts
(Transcript, Jan. 9, 2002, pg. 16)

i) No. 6 Fuel

As can be seen the cost of No. 6 fuel to be burned at the Holyrood generating station accounts for over 92% of the total forecast fuel costs for 2002. NLH is proposing to recover No. 6 fuel costs in the test year based on \$20 Cdn/bbl with the difference accounted for in the RSP as described below. The actual calculation of fuel costs in revenue requirement is directly related to the forecast thermal production to be supplied by Holyrood in 2002. The forecast thermal production depends on NLH's forecast of hydraulic production, the fuel efficiency factor of the Holyrood plant (to estimate the amount of fuel needed), and the price used to calculate the cost of No. 6 fuel. The Board has previously addressed the issues of hydraulic and thermal production forecasts and the fuel efficiency factor at Holyrood. The following Section deals with the price of No. 6 fuel to be used in calculating fuel costs contained in the revenue requirement.

NLH is proposing that the cost of No. 6 fuel to be included in rates be set at \$20 Cdn/bbl and not at the average forecast price of \$25.91 Cdn/bbl set out in Forecasting: Production and Fuel Costs. NLH proposes to book the difference between the actual price and the embedded price of \$20 Cdn/bbl in the RSP to be recovered at a later time. NLH is proposing this approach because of the magnitude of rate increase that would be required with a higher fuel price. Table 2 compares the rate impacts of using test year No. 6 fuel costs of \$20 Cdn/bbl and \$28 Cdn/bbl.

Table 2			
Impact of Test Year Fuel Price on Rates for 2002			
	May 31, 2001 Original Application		October 31, 2001 Revision
	Rate Increase ⁽¹⁾ (\$20/bbl) %	Rate Increase ⁽²⁾ (\$28/bbl) %	Rate Increase ⁽³⁾ (\$20/bbl) %
NP base rate	6.7	16.0	6.4
Consumer base rate	3.7	9.0	3.5
NP RSP mill rate	5.9	5.9	6.7
Consumer RSP mill rate	3.4	3.4	3.8
Industrial base rate	10.4	23.0	10.0
Industrial RSP mill rate	7.4	7.4	6.1
Total NP increase	12.6	21.9	13.1
Total Consumer increase	7.1	12.4	7.3
Total Industrial increase	17.8	30.4	16.1

⁽¹⁾ Pre-filed Evidence, D. W. Osmond, pg. 3/9-16

⁽²⁾ Pre-filed Evidence, D. W. Osmond, pg. 2-3/28-3

⁽³⁾ 2nd Supplementary Evidence, D. W. Osmond, pg. 1, Schedule A

Using \$28/bbl versus the \$20/bbl proposed by NLH (October 31, 2001, Revised) would mean an additional rate increase of 8.8% to NP, 5.1% to consumers and 14.3% to IC on top of that already proposed by NLH in this Application.

In final argument (pg. 12) NLH again reiterated its position that, in light of the impact it had on base rate changes, \$20 Cdn/bbl was still an appropriate number to use in determining No. 6 fuel costs, with the difference between the \$20 and actual prices paid accounted for through the RSP. NLH agreed that this remained a matter of judgment and deferred to the Board the issue of whether the price used in base rates should be higher than \$20 Cdn/bbl. No intervenor suggested the price should be lower than \$20 Cdn/bbl.

While the Board is cognizant of the impact of using the forecast fuel prices in setting rates, it is not convinced that the proposal by NLH to use a lower price than forecast is the best approach in the current circumstances. The Board is required to set rates based on forecast costs for a test period and believes that the most prudent course of action is to set the fuel price at or near the price forecasted for the test year. The Board believes that this is the only way to avoid the current situation of having an ever increasing balance in the RSP with no short term hope of recovery. This approach is also consistent with the generally accepted regulatory principle of matching costs and revenues. The Board also believes it is important to maintain the relationship between the price of fuel and electricity rates so that correct price signals are reflected in rates to consumers.

The forecast price for No. 6 fuel, as set out by NLH in Table 1 on page 1 of R. J. Henderson's 2nd Supplementary Evidence, which shows a 2002 weighted annual average price of No. 6 fuel of \$25.91 Cdn/bbl, will be used in the 2002 test year costs for No. 6 fuel.

The Board recognizes that this decision will result in a significant increase in NLH's revenue requirement for fuel costs and hence impact electricity rates accordingly. The Board has already ordered that the 2002 thermal production forecast be reduced which will result in a lower forecast quantity of No. 6 fuel to be burned at Holyrood. In addition the Board has ordered the fuel efficiency factor for the Holyrood plant be increased from 610 kWh/bbl as proposed by NLH to 615 kWh/bbl, which will also result in a calculation of lower fuel consumption for the test year.

Based on the evidence and information before it, the Board has attempted to assess the net impact on revenue requirement of the decisions outlined above and has calculated the following estimated impacts on fuel costs:

Estimated Impact on Revenue Requirement	
Increase in No. 6 fuel costs at forecast price	\$13,674,000
Decrease in thermal production	(5,212,000)
Increase in efficiency factor	(586,000)
Total	<u>\$7,876,000</u>

The impact that fuel costs would have on the revenue requirement would result in higher increases in rates than proposed by NLH. The estimated increases in 2002 rates (including RSP mill rate adjustments) for NP and IC as a result of the Board's decision above as compared to the rate increases proposed by NLH are as follows:

Customer	Rate Impacts NLH Application October 31, 2001 (%)	Estimated Rate Impacts of Board's Decision on Fuel Costs (%)
NP	13.1	15.9
Consumer	7.3	8.9
IC	16.1	19.8

The Board will have to assess the impact of these decisions on rates to NLH's customers and to consumers in general, together with other decisions relating to the overall revenue requirement. The Board would prefer to address the rate impact of using forecast fuel costs in the test year revenue requirement directly rather than defer a portion of these forecast fuel costs for the 2002 test year through the RSP as proposed by NLH.

ii) Diesel Fuels

The second largest component of NLH's fuel expense category is diesel fuel. The forecast 2002 test year cost is forecast to be \$6,808,000. (1st Supplementary Evidence, J. C. Roberts, Schedule 1A) In the revised fuel forecasts filed by NLH in December 2001 Mr. Henderson advised that the test year forecast costs could be reduced by \$300,000 as a result of the updated forecast. (Transcript, Jan. 9, 2002, pg. 16/51-58)

No issues with respect to the diesel fuel price were raised by the intervenors and the Board accepts the test year costs as reasonable.

The Board accepts the diesel fuel costs of \$6,508,000 for the 2002 test year.

iii) Other Fuel Costs

A total of \$871,000 is included for other fuel costs in the test year fuel costs as outlined below:

Additives and Indirects	\$178,000
Environmental Fee	\$124,000
Ignition Fuel	\$123,000
Gas Turbine Fuel	<u>\$446,000</u>
Total	<u>\$871,000</u>

The Board accepts the Other Fuel Costs of \$871,000 for the 2002 test year.

4. Power Purchased

NLH's purchased power expense for the test year is \$15,100,000. (Pre-filed Evidence, J. C. Roberts, Schedule 1A, pg. 1 of 4) This amount represents approximately 5% of NLH's total costs for the test year and represents a slight decrease from 2000-2001. Also included in purchased power is an amount of \$1,300,000 which is paid to Abitibi Consolidated in Stephenville under a contract giving NLH the right to interrupt a portion of Abitibi Consolidated's power supply should NLH need the power to meet its own demand.

Neither NLH's nor NP's systems are connected to the North American Power Grid. As stated by NLH in response to NP-164, this limits options as they relate to purchased power in the event of abnormal load requirements.

In addition to its own generation, in order to meet its supply requirements, NLH has long standing arrangements to purchase energy from Corner Brook Pulp and Paper Limited and Abitibi Consolidated at Grand Falls when it is available and cost effective.

Since the fall of 1998 NLH has been purchasing energy on the island from two Non-Utility Generators (NUGS) operating at Star Lake and Rattle Brook. NLH also has an interruptible load contract with Abitibi Consolidated at Stephenville and can call upon NP to

operate its stand-by gas turbines and diesel units to meet peak loads. Long-term contracts are in place with all of these suppliers whose output is used to meet peak demand or emergency requirements.

In Labrador a purchase agreement with CF(L)Co allows NLH to meet the major portion of power and energy requirements for the Labrador Interconnected system.

Also included in the category of purchased power is the cost associated with the purchase of secondary energy for the L'anse au Loup system from the Hydro-Quebec Lac Robertson plant.

NLH's forecast purchased power costs were not challenged by the intervenors.

The Board accepts purchased power costs in the amount of \$15,100,000 for the 2002 test year.

5. Other Costs

i) Certain Other Costs Consolidated

The major cost items under revenue requirement were explored extensively by the Board and will be examined and decided separately. Certain other cost items listed below received little or no attention by intervenors and are being dealt with as a group.

Insurance	\$977,000
Transportation	1,923,000
Office supplies	1,939,000
Building rentals & maintenance	626,000
Equipment rentals	1,558,000
Loss on disposal	<u>890,000</u>
Total	<u>\$7,913,000</u>

The Board has insufficient evidence on which to order a specific adjustment on these costs and is of the view that they can be appropriately considered within the context of a general productivity allowance.

Certain other costs (insurance, transportation, office supplies, building rentals and maintenance, equipment rentals and loss on disposal) as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

ii) Salaries and Fringe Benefits

NLH is requesting approval for an expenditure of \$62,426,311 for salaries and fringe benefits in the revenue requirement for the 2002 test year as shown below:

Salaries Permanent	\$44,876,638
Salaries Temporary	5,293,516
Overtime	2,615,424
Directors Fees	62,000
Fringe Benefits	6,359,483
Labrador Travel Benefits	106,180
Group Insurance	1,680,500
Employee Future Benefits	2,432,570
Less Vacancy Credit	<u>(1,000,000)</u>
Total Salary Cost	<u>\$62,426,311</u>

(NP-4; 2nd Supplementary Evidence, J.C. Roberts, Schedule 1A)

Salary costs represent approximately 63% of NLH's total other costs. The issues raised during the hearing included the level of permanent salaries and the use of a vacancy credit, the change in accounting for employee future benefits, and accounting for overtime. The treatment of salaries included in capitalized expenses is dealt with on pg. 75 of this decision. The remaining issues are considered following.

Table 3 shows a comparison of total salary costs, kWh of energy produced and cost per kWh from 1997 to the 2002 test year.

Table 3 Comparison of KWH Produced to Gross Salaries 1997 to 2002						
Year	Salaries⁽¹⁾ \$	Increase over 1997 %	KWH Produced⁽²⁾	Increase over 1997 %	Cost Per KWH \$	Increase over 1997 %
1997	51,863		6,197,000		0.00837	
1998	54,904	5.9	5,556,000	-10.3	0.00988	18.0
1999	57,069	10.0	5,756,000	-7.1	0.00991	18.5
2000	61,267	18.1	6,025,000	-2.8	0.01017	21.5
2001E*	61,941	19.4	6,172,990	-0.4	0.01003	19.9
2002F*	62,426	20.4	6,479,100	4.6	0.00963	15.1

(*E-estimated; F-forecast)

⁽¹⁾ NP-8 (a); Pre-filed Evidence, J. C. Roberts, Schedule 1A, pg. 1

⁽²⁾ CA-101, 2002 Annual Report, pg. 40; Supplementary Evidence, H. Budgell, Schedule A

The figures reflect an increase in the salary cost per kWh in each year when compared to 1997. Increases in 1998 through 2000 have occurred despite reductions in kWh produced over 1997. The Board notes the decreased trend estimated for 2001 and forecast for the 2002 test year. The Board, however, is concerned with the observed inconsistencies in the above analysis.

Salaries (Permanent)

Table 4 shows a reduction of 61 permanent filled positions from 1997 to 2002. The total salaries to be paid are projected to increase by 14.1% with the average employee salary increasing by 22.6% during this period.

Table 4 Average Permanent Salary 1997 to 2002					
Year	Total Salaries Paid⁽¹⁾ \$	Increase over 1997 %	Filled Permanent Positions⁽²⁾	Average Salary \$	Increase over 1997 %
1997	38,440,452	-	887	43,338	-
1998	39,330,387	2.3	868	45,312	4.6
1999	40,444,741	5.2	859	47,084	8.6
2000	41,061,053	6.8	853	48,137	11.1
2001	42,620,061	10.9	826	51,598	19.1
2002	43,876,638	14.1	826	53,119	22.6

⁽¹⁾ NP-8(a)

⁽²⁾ GT 2001 General Rate Hearing Report, Exhibit 3

In response to questioning by Chair Noseworthy Mr. Wells stated:

“...to those things that we do control and for which we are accountable for our actions, we should be subject to scrutiny, because we don’t have any competition in that sense, and that’s why I mentioned the three pillars Hydro works on.....Those items that we can control, all that’s subject to scrutiny and we will have to stand on our record and prove to you that we’re really not employing any more than we should, or that our costs are reasonable in those items over which we have control.....” (Transcript, Sept. 28, 2001, pg. 27/84-88; 95-100)

The Board notes the difficulty in measuring the performance and efficiency of NLH salary expenditures. The Board acknowledges NLH’s implementation of the full time equivalent (FTE) method of accounting for the number of employees and recognizes that this will provide a useful tool for measuring performance regarding future staffing levels. At the present time, however, the Board also notes the apparent upward trend in salary costs despite the declining number of permanent staff and slow energy growth.

The Board finds that any reduction in salary costs to be incorporated in the 2002 test year is best managed by NLH within the scope of the vacancy credit adjustment and in the application of the productivity allowance set by the Board.

Vacancy Credit

The use of a vacancy credit by NLH is due to the prior method used to equate salaries with the number of employees. The Board again acknowledges the use of the FTE method and notes for this reason the vacancy credit will not be necessary in future years.

For the test year NLH budgeted its permanent salaries on the basis of its permanent staff complement. In such a large organization there are always permanent positions that become vacant throughout the year. This results in salary savings because of the period of time which elapses between the date of vacancy and the date of hiring the replacement. For the test year NLH estimates that 2½% (approximately \$1,000,000) of total permanent salaries is a reasonable estimate of the allowance for vacancies.

Over the period 1997 to 2000 NLH has over budgeted salaries by an average of 4%. (GT 2001 General Rate Hearing Report, pg. 25) NP in final argument (pg. C-34) proposed that a 4% vacancy allowance should therefore be used in the test year.

NLH has not convinced the Board that a 2½% vacancy allowance is adequate and reflects recent experience. The Board finds in the circumstances that a vacancy credit in the amount of \$1,500,000 should be used in the test year 2002. This is \$500,000 more than proposed by NLH.

The Board will order NLH to reduce salaries and fringe benefit expenses for the 2002 test year by an additional \$500,000 to reflect a higher vacancy credit.

Executive Incentive Plan

During the hearing NLH provided information on an executive incentive plan being piloted for Executives and Senior Management. NLH provided details of the plan in U-Hydro # 12, pg. 1:

“During 2000, the Compensation Committee of the Board of Directors of Newfoundland and Labrador Hydro considered the introduction of a performance based incentive plan for members of the Executive and Senior Management. Hay Management Consultants, a human resources consulting group, was retained to assist with the development of an incentive plan similar in concept to those in place at other Atlantic Canada electric utilities. In December 2000, the Board of Directors, on the recommendation of the Compensation Committee, approved the implementation in 2001 of a pilot project for the five members of the Executive and twelve Directors (heads of departments). The plan is composed of both corporate performance objectives and individual or departmental performance objectives.”

The areas of responsibility selected for the 2001 pilot project were financial performance, improved system reliability and strategic planning. (U-Hydro # 12, pg. 2/4-5)

Depending on the experience with this type of plan, it may be modified or extended to other members of management in future years. As it is a pilot project the cost of the incentive plan is not included as a regulated expense in the 2002 cost of service. (U-Hydro # 12, pg. 1/26-29)

The Board recognizes the importance of NLH connecting Executive compensation to a performance based incentive plan.

Employee Future Benefits

Employee future benefits represent a liability for a retiring allowance to qualifying employees and the cost of health, dental and life insurance for retired employees. Generally Accepted Accounting Principles (GAAP) as articulated by the Canadian Institute of Chartered Accountants (CICA) recommend that, effective January 1, 2000, employee future benefits should be accounted for on an accrual basis in a company's financial statements. Prior to this change NLH accounted for the cost of employee future benefits on a "*pay as you go*" or cash basis, which requires the financial statements to reflect the actual funds disbursed on behalf of employee future benefits. The accrual method requires the financial statements to reflect the estimated cost incurred during the financial reporting period.

NLH has requested permission to change its method of accounting for employee future benefits from a cash to an accrual method effective January 1, 2000. The actuarial accrued balance of employee future benefits as of December 31, 1999 is estimated at \$21,200,000. (Pre-filed Evidence, K. McShane, pg. 13/29) NLH is proposing to write-off this balance against prior period earnings and will not attempt to recover this amount from ratepayers. On a go forward basis NLH will make a charge against earnings for the annual actuarial cost of employee future benefits. In the 2002 revenue requirement this is included in salaries and fringe benefits at a cost of \$2,244,000. This was further revised to \$2,433,000 based on an additional \$189,000. (J. C. Roberts, Schedule 1A, pg. 3, Note 23; NP-4, pg. 2) The actual cash disbursements during the period will be charged against the estimated liability. The liability for employee future benefits is treated as no-cost capital in the calculation of the weighted average cost of capital. (Pre-filed Evidence, K. McShane, pg. 13/16-21)

Mr. J. T. Browne testified that a utility could conform to GAAP and adopt the accrual method of recording employee future benefits for financial reporting purposes but use the cash method for ratemaking purposes. (Transcript, Nov. 1 2001, pg. 36/82-91) NP presently uses the cash method for ratemaking purposes and recommends that the Board adopt a similar method for NLH. NP estimates that the use of the accrual method will result in an additional cost in the test year of \$1,000,000. (Transcript, Nov. 15, 2001, pg. 8/16-18; NP, Final Argument, pg. C-26)

The Board agrees with NLH's position of changing the accounting for employee future benefits to agree with GAAP by charging against regulated earnings the actuarial cost in the year incurred. The Board also supports NLH's initiative of absorbing prior period costs in retained earnings and not recovering this cost from ratepayers.

The Board accepts NLH's proposals for the treatment of employee future benefits and accepts the 2002 test year costs.

iii) System Equipment Maintenance

System equipment maintenance costs consist primarily of the costs associated with the Holyrood thermal plant, diesel generation plant operations and property maintenance. The revised revenue requirement for system equipment maintenance for 2002 is \$16,763,000.

GT's 2001 General Rate Hearing Report (pg. 29) noted that the Holyrood thermal plant costs are often subject to a high degree of variability and in some cases are discretionary regarding timing of projects. NLH entered into maintenance contracts with the manufacturers of the Holyrood plant equipment in 1995, with the expectation of cost savings. NLH's experience to date shows very little evidence of the maintenance contracts having had the anticipated impact on costs. (GT 2001 General Rate Hearing Report, Exhibit 4-2)

The Holyrood thermal plant, because of its age, will probably require more maintenance in future in order to maintain the efficiencies required to support the system. Under cross-examination by NLH, Mr. Brushett of GT stated that he had some concerns with that portion of the system equipment maintenance expense related to Holyrood because the fluctuations over a number of years makes it very difficult to assess what an appropriate normalized level of expenditure would be. Because of these fluctuations and the difficulty in normalizing costs GT was not able to achieve the comfort level that would allow them to conclude that the costs associated with Holyrood were reasonable and prudent. (Transcript, Jan. 8, 2002, pg. 5/45-48)

NLH noted that the Holyrood thermal plant is an aging plant requiring more maintenance than earlier in its service life. (NLH, Final Argument, pg. 27) The Board believes that this is all the more reason for NLH to investigate the yearly fluctuations in costs as pointed out by GT with a view to establishing normalized level of expenditures.

No intervenors commented on the remaining diesel system and property maintenance costs under system equipment maintenance.

System equipment maintenance costs as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

NLH will be required to submit to the Board by December 31, 2002 a detailed plan of projected maintenance expenditures over the next ten years for the Holyrood Generating Station.

iv) Professional Services

Professional service costs in the test year total \$4,340,000 and consist primarily of consulting fees involving legal, audit, software technology and maintenance as well as annual Board assessments. This amount was later revised to \$5,340,000 to reflect a decision by NLH to defer a portion of the hearing related costs into the test year. During final submissions NLH informed the Board that, in order to keep the revenue requirement for 2002 as low as possible, it was changing its position on the issue of deferral of rate hearing costs and would now be absorbing an amount of \$1,000,000 in 2001 to cover NLH's incremental internal costs, the estimated costs of the Board and the costs of the CA. (Transcript, Jan. 28, 2002, pg. 8/9-15) This reduces the proposed test year cost for professional services to \$4,340,000.

In its 2001 General Rate Hearing Report (pg. 34) GT determined that the professional services expense in the test year represents an increase of 65% from 1997 to 2002 and suggested that additional information be obtained. Under cross-examination Mr. Henderson testified that the increase in professional services expense was as a result of more use of professional services by the information systems department, the partnering agreements in place at the Holyrood thermal station and costs related to a study into equal billing and other pay methods carried out in the finance department. (Transcript, Oct. 11, 2001, pg. 31-32/79-86; pg. 32/13-17)

Mr. Roberts stated under cross-examination that he was satisfied that there are sufficient controls in place to ensure that all items going forward in the budget for professional services are given an adequate screening by the various management levels at NLH and its management committee. However, when questioned by Board Counsel he was unable to be very specific about the controls in place by his department to screen budget expense proposals. (Transcript, Nov. 16, 2002, pg. 16-17) Mr. Roberts stated:

"Well, I may be raising it in a different vein. I may be raising it from the point of, to management saying, for your information, included in this year's cost is this project that you should be aware of, and I may express my own opinion to management committee, which I will do, as to whether or not, you know, if I have an opinion on it whether or not I think, in my mind, there may be an option or an alternative to delay or whatever." (Transcript, Nov. 16, 2001, pg. 17/8-15)

The intervenors did not offer any evidence to challenge the costs of professional services as incurred by NLH or as forecast in the test year. NLH also did not provide any evidence that the professional services expenses are justified in the way of demonstrative results or improved efficiencies. For example, a comparison of the costs at Holyrood Thermal Station using partnering agreements with the equipment manufacturers compared with the previous maintenance practices would have proved helpful to the Board. Similarly, the benefits of the increased professional services expense in the information services department was not confirmed by any evidence of cost saving or efficiency improvements.

The Board recognizes the increasing trend in professional services costs leading into the test year but has insufficient evidence to order a specific reduction in the costs. The Board will request its financial consultants to seek additional justification of these costs as part of its next

financial review. The Board is of the view that any reduction in professional services expense is best achieved within the context of a general productivity allowance.

Professional services costs as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

v) Travel

Travel expenses generally were not challenged by the intervenors except insofar as the amount included for spousal travel. Spousal travel is an item that gets raised at most general rate hearings.

GT, in its 2000 review of NLH, stated that, in its opinion, it was not prudent to include expenditures of this nature in the revenue requirement. Under questioning by Board Counsel, Mr. Brushett of GT offered the qualification that spousal travel *“to CEA conferences and conferences such as that”* was really what he was referring to in his report. (Transcript, Jan. 9, 2002, pg. 6/32 – 33) Mr. Roberts, when questioned as to why GT’s comments on spousal travel in recent annual review reports have gone unheeded by NLH, responded by saying that *“ we haven’t made an effort to identify those costs and eliminate them”* (Transcript, Nov. 16, 2001, pg. 20/20-22)

The Board has not been presented with any policy by NLH indicating what the procedure is for obtaining approval of expenses such as spousal travel. The Board is also not aware of policies and procedures adopted by NLH to cover matters such as this. The Board does not accept spousal travel as a regulated expense.

Travel costs as proposed by NLH for the 2002 test year are accepted subject to an reduction by NLH resulting from the productivity allowance set by the Board. NLH will be directed to exclude spousal travel costs from regulated expenses. NLH will also be required to file its policies and procedures for employee travel with the Board.

vi) Miscellaneous Costs

Miscellaneous costs for the 2002 test year are summarized as follows (GT 2001 General Rate Hearing Report, pg. 32):

Staff Training	\$841,000
Donations/Corporate Promotion	193,000
Sundry costs	84,000
Diesel fuel Hydro	94,000
Demand side management	45,000
Employee expenses	340,000
Collection fees	25,000
Bad debt expense	300,000
Inventory gain/loss	594,000
Municipal and payroll tax	<u>2,075,000</u>
	4,591,000
Less: Non-regulated donations and corporate promotion	<u>(133,000)</u>
Total	<u>\$4,458,000</u>

Municipal and payroll taxes account for 47% and staff training and employee expenses account for 26% of miscellaneous expenses. Except for inventory gain/loss, which is dealt with below, the Board has no specific evidence on which to base a decision on cost reductions in other categories and is of the view that such savings can be appropriately addressed by NLH within the context of a general productivity allowance.

Included in the Donations/Corporate Promotion amount above is a donation to the Town of Bay D'Espoir in the amount of \$60,000 for street lighting. (GT, 2001 General Rate Hearing Report, pg. 32) The Board had accepted this expense as a regulated expense several years ago. During final submissions NLH informed the Board that it was proposing to exclude the \$60,000 for the Bay D'Espoir street lighting costs from the 2002 revenue requirement. (Transcript, Jan. 28, 2002, pg. 8/32-35)

The Board approves NLH's proposal to discontinue treatment of Bay d'Espoir street lighting costs as a regulated expense and will order its removal from the 2002 test year revenue requirement.

Inventory Gain/Loss

NLH maintains an inventory of parts and materials in its various depots throughout the Province. These inventory items are used to support the routine maintenance and operation of the system. The total value of the supplies inventory has ranged from \$17,630,000 in 1992 to \$21,095,000 in 2000 after adjusting for the Roddickton wood chips plant. (NP-145, pg. 3) This represents an increase of approximately 19.65% in the value of the inventory.

In 1997 NLH adopted a number of strategies expected to result in reduced costs relating to inventory overhead. One of these strategies was the awarding of long term blanket contracts for goods and services. These contracts account for the majority of NLH's regular maintenance materials and service requirements. (GT 1999 Annual Financial Review, pg. 31-32)

During the hearing attention focused on proposed miscellaneous gains and losses to be written off in the test year. The test year revenue requirement includes an allowance for supply inventory losses of \$594,000. (GT 2001 General Rate Hearing Report, pg. 32) The inventory losses for 2001 were budgeted at \$606,000 with an additional charge of \$688,000 for write off of obsolete items in Bishop Falls. (Supplementary Evidence, J. C. Roberts, Schedule IA, pg.3/11-12) The additional charge increases the total adjustment to supplies inventory in the 2001 year to \$1,294,000. NP expressed the opinion that the supplies inventory for the test year should be reduced to reflect the higher losses experienced in 2001 year. (Transcript, Nov. 15, 2001, pg. 2/34-41)

In NP-145 (pg. 1/17-25) NLH described the changes that have been implemented since 1993 in its inventory control system, including moving from a manual system of hard copy inventory control forms and annual physical inventory counts to an on-line computer based system. The JD Edwards system will provide on-line inventory, quantities and cost transactions on a real time basis.

The IC in their final argument (pg. 119) asked the Board to reduce the 2002 supplies inventory by \$600,000.

The implementation of the JD Edwards System should provide NLH with the flexibility and opportunity to improve the tracking of purchasing and allocation of supplies and materials. The Board is of the view that in future the losses/gains for supplies inventory should reflect the new inventory management and purchasing policies of NLH. The Board is of the opinion that any resulting reduction in the revenue requirement is best achieved within the context of a general productivity allowance.

Miscellaneous costs as proposed by NLH for the 2002 test year, including inventory gain/loss, are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.

6. Productivity Allowance

As indicated in the foregoing assessment of "*other costs*" outlined in Table 1 considerable attention was devoted throughout the hearing to the level of controllable expenses and the degree to which these expenses reflected efficiencies in NLH.

In its Supplementary Evidence GT noted that one approach to address efficiencies in forecast controllable expenses is to provide for a "*productivity allowance*" to adjust test year revenue requirement. GT points out that this approach provides management with the latitude to determine where further cost savings or efficiencies can be best achieved. Attempting to reduce individual expense categories may impede the ability of NLH management to make decisions on

how and where efficiency improvements are best implemented. (Supplementary Evidence, GT, Dec. 13, 2001, pg.4/11-19) The concept of applying a productivity allowance to the test year revenue requirement is not new to the Board and was used in the 1996 general rate hearing for NP.

Intervenors for the most part were unanimous in their support for a productivity allowance. In their final argument (pg. C-34) NP identified specific reductions in revenue requirement totalling \$4,135,000 and submitted that, in order to provide an incentive for efficiency, the Board should order a productivity allowance of 1.5% of the adjusted “*other*” operating costs in the revenue requirement of \$99,275,000, or \$1,500,000. The CA pointed to GT’s evidence which suggested that a fair way to deal with these expenses is in a “*macro*” sense and to employ a productivity allowance for NLH in reference to total controllable operating and maintenance costs. The CA continued that, while GT suggested a productivity allowance in the range of 1-1.5%, Mr. Brushett of GT agreed a 2% productivity allowance could be appropriate, depending upon the Board’s view of the matter. (CA, Final Argument, pg. 41) The IC in their final argument (pg. 19) submitted that the Board should direct NLH to give increased focus to cost reduction projects and they would support the type of productivity allowance suggested by Mr. Brushett.

NLH, in its final argument (pg. 29), concluded that the use of the productivity allowance factor as suggested by GT is totally inappropriate in the absence of any evidence that any of the expenditures are unreasonable, unnecessary or imprudent. NLH submits it has demonstrated that it has been fiscally responsible and prudent with respect to the control of its costs from 1992 to 2002, and that such a productivity allowance factor should not be ordered by the Board.

The Board believes the onus is on NLH to bring forward performance 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. Under these circumstances 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. The Board, in considering its findings of “*other costs*” as previously outlined, believes a productivity allowance for the test year of \$2,000,000 on NLH’s “*other costs*” is reasonable. In looking ahead the Board is of the opinion that without adequate performance standards to reduce the operating efficiency of NLH the effectiveness of its regulation will be marginalized. This is not acceptable and the Board will be asking GT to review NLH’s operations and, following consultation with NLH, make recommendations on suitable regulatory performance standards that can be implemented in a practical and cost effective manner as part of NLH’s normal reporting process.

In addition to the other adjustments to the 2002 test year revenue requirement, the Board will require a reduction of \$2,000,000 on NLH's "other costs" for the 2002 test year to reflect a productivity allowance.

The Board will request its financial consultants to work with NLH to recommend suitable regulatory performance standards which will be used to measure operating efficiencies at NLH and these will be incorporated as part of NLH's ongoing reporting to the Board.

7. Non-regulated Expenses

At various times throughout the hearing references were made to the identification and treatment of non-regulated expenses. Non-regulated expenses represent expenditures incurred by a utility which are not approved by the Board for recovery from ratepayers. Included in this category are such expenses as donations, promotion and certain other costs that, in the Board's opinion, do not provide any benefit to ratepayers. For regulatory purposes total non-regulated expenses are eliminated, or added back to net income, for the purposes of calculating rate of return on rate base or rate of return on equity.

In this Application, NLH has eliminated \$133,000 of non-regulated expenses from the revenue requirement. (GT 2001 General Rate Hearing Report, pg. 32) In addition, during final submission NLH proposed that \$60,000 relating to street lighting costs for the Town of Bay D'Espoir also be excluded from revenue requirement. (Transcript, Jan. 28, 2002, pg 8/32-35) As noted in the section on Miscellaneous Costs, the Board approves NLH's proposal on this item. Another item which has attracted attention during the hearing is spousal travel, which was addressed on pg. 70 of this decision.

The only other regulated expense that was questioned during the hearing was the inclusion of an expense of \$75,000 for "*Communications Plan*" advertising. In response to NP-188 NLH explains that the issue of external and internal communications is currently being dealt with by NLH's Management as part of its strategic planning process. Under cross-examination by NP, Mr. Osmond confirmed that the expense does not include costs for advertising on safety or conservation issues (Transcript, Nov. 19, 2001, pg. 23/11-26)

NP-286 asked GT whether, in its opinion, the communications plan advertising expense of \$75,000 should be a regulated cost, or whether the nature of the plan is one of corporate promotion and should therefore be chargeable to non-regulated accounts. GT's response was that its understanding of the purpose of the plan is to strengthen NLH's corporate image with their external and internal stakeholders, effectively communicate internally and externally, enhance employee effectiveness and build closer relationships with communities and its customers. In the opinion of GT the nature of the plan is one of corporate promotion and should be considered a non-regulated expense.

In final argument (pg. C-31) NP points out that in Order No, P.U. 7(1996-1997) the Board ordered that NP's regulated expenses for advertising be limited to matters relating to

conservation, safety and consumer information. NP suggests that it is questionable whether the corporate communications plan included in the revenue requirement would meet this test.

NLH does not agree with GT's position on the corporate communications plan. In final argument (pg. 26/13-19) NLH states that *"The purpose of the costs referred to are to improve communications, primarily with employees and with stakeholders. The costs are not for a promotional type of advertising to enhance Hydro's corporate image in the community."* NLH submits that the communication cost referred to in NP-286 is an appropriate regulated expense.

Based on the evidence, in particular that of Mr. Osmond and Mr. Brushett of GT, the Board is of the view that the \$75,000 advertising expense is aimed at corporate promotion of NLH as opposed to an expense which would directly benefit customers in areas of either conservation, safety or consumer information. The Board concludes that, while this type of advertising may serve to enhance NLH's corporate image within the general community, this is insufficient justification for it to be treated as a regulated expense supported by ratepayers of NLH. This is also consistent with the Board's treatment of similar expenses for NP.

The Board will not accept the \$75,000 for "Communication Plan" advertising as a regulated expense for the 2002 test year.

Subject to adjustments for Bay D'Espoir street lighting, spousal travel and "Communication Plan" advertising, the Board concludes that non-regulated expenses are properly excluded from NLH's 2002 test year costs.

8. Capitalized Expenses

Capitalized expenses include salaries and benefits of NLH employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead which is considered necessary to support those capital projects.

NLH proposes to reduce its revenue requirement in the test year by \$5,722,000 to reallocate operating costs that are deemed attributable, either directly or indirectly, to the capital program. (Supplementary Evidence, J. C. Roberts, Schedule 1A) The majority of test year capitalized expenses are salaries in the amount of \$4,046,950 which are directly attributable to forecast capital projects. [NP-8(b)] NLH's forecast capitalized expenses as a percentage of budgeted capital expenditures in 2002 is approximately 13.3%. (Exhibit No. NP-7) This figure compares to an average percentage of capitalized expenses from 1992 to 2000 of 24.8%. NLH does not budget for overtime in capital expenditures and as a result both capitalized expenses and salaries are budgeted lower with one cost affecting the other. (Transcript, Nov. 14, 2001, pg. 38/65-71) NP-237 explains that \$1,377,000 of capitalized expenses in 2000 are related to:

Labrador River Project	\$650,000
Salary overtime	<u>727,000</u>
Total	<u>\$1,377,000</u>

Adjusting the 2000 capitalized expenses to reflect the above items will reduce the percentage of capitalized expenses in 2000 to 15.2% which brings the 2000 percentage in line with the estimated percentage of 2002 capitalized expenses to the revised 2002 capital budget.

On cross-examination by NP Mr. Roberts explained that the impact of underestimating capitalized expenses would result in more margin for NLH. Mr. Roberts detailed NLH's method of allocating capitalized expenses and acknowledged there could be more than one method used to track capitalized expenses. He further acknowledged that NLH's policy of allocating capitalized expenses has not been submitted to the Board for approval. (Transcript, Nov. 14, 2001 pg. 37/19-23)

Mr. Brushett of GT agreed that NLH's capitalized expenses for the test year are conservatively estimated. He also acknowledged that NP's method for allocating capitalized expenses was subject to a full review by the Board and, as a result, NP was ordered to use the incremental approach in calculating capitalized expenses. Mr. Brushett suggested that the Board would have to do a review to assess the impact and appropriateness of NLH using the incremental approach of accounting for capitalized expenses. (Transcript, Jan. 8, 2002, pg. 28/19-25)

The Board feels that a review of the methodology and approach used by NLH to determine capitalized expenses would be appropriate at some point in the future. Such a review or study would need to be fairly comprehensive to address its impact on ratepayers and on NLH. Considering the magnitude of this particular item and the many other regulatory issues to be dealt with in the near term, the Board is not prepared to order that such a study be undertaken at this time.

The Board notes that NLH's 2002 test year capitalized expenses of \$5,722,000 are lower as a percentage of total capital expenditures as compared to prior years. However, the Board has no basis to order an adjustment to capitalized expenses for 2002.

The Board accepts the capitalized expenses in the amount of \$5,722,000 as proposed by NLH for the 2002 test year.

9. CF(L)Co Allocation

The CF(L)Co allocation represents inter-company charges from NLH to CF(L)Co for the provision of services in accordance with a Services Agreement. Essentially this Agreement provides for cost recovery of salary and certain overhead expenses which can be attributed to CF(L)Co, a non-regulated entity. It is important that appropriate procedures and methodology be in place to ensure all inter-company services are properly costed and recorded. If this were not the case, ratepayers may end up bearing certain costs which are attributable to non-regulated activities.

NLH recently updated its methodology for determining and allocating inter-company costs. Information with respect to the approach and methodology employed by NLH was provided to all parties by way of response to NP-11 (b). GT reviewed the inter-company charges and new methodology used by NLH and in its report concluded that the new methodology is reasonable and appropriate.(GT, 2001 General Rate Hearing Report, pg. 37)

The Board accepts the CF(L)Co allocation in the amount of \$1,910,000 as proposed by NLH's for the 2002 test year.

10. Interest

Interest is primarily the cost of the long term and short term debt of NLH. The interest calculation also includes costs associated with the amortization of the foreign exchange losses, the Government guarantee fee, long term leases and the notional interest on recall power less credits for RSP, sinking fund assets and non-regulated debt.

As shown in Table 1, NLH's interest calculation included in 2002 test year revenue requirement is \$91,821,000.

The primary discussions on interest during the hearing covered four distinct topics:

1. Guarantee fee
2. Dividend paid
3. Notional interest calculation
4. Interest on overdue accounts

The issues of the guarantee fee (See pg. 34) and dividend paid (See pg. 35) have been addressed by the Board as referenced. Notional interest calculation and interest on overdue accounts are dealt with following.

Notional Interest on Dividend from Churchill Falls Recall Power

NLH sells recall power to Hydro Quebec under the terms of an unregulated contract. The funds are received by NLH on a monthly basis and are paid to Government in the form of a dividend. The payments are 100% of the profits received from the sale of recall power. NLH contends that there is a benefit to the ratepayers of understated interest expense. This benefit, or notional interest, is calculated based on the premise that the funds deposited in NLH's bank account during the year are utilized and as a result its short term promissory notes are reduced and its interest cost is understated.

The main issue with respect to notional interest was the opinion that there is no obligation by NLH to pay the interest and the Board had not given prior approval for the inclusion of such calculations in the revenue requirement. (NP, Final Argument, pg. C-36; IC, Final Argument, pg. 116-117) Under cross-examination Mr. Brushett of GT agreed with the concept of notional interest and checked the basis of the calculation, but acknowledged that the Board has not reviewed the methodology used to calculate the adjustment. (Transcript, Jan. 8, 2002, pg. 24/51-54)

The Board acknowledges the benefit to ratepayers of the flow through income from recall power in that it reduces NLH's borrowing costs during the year and accepts NLH's calculation of the notional interest in the 2002 test year revenue requirement.

The Board will require NLH to file prior to June 30, 2003 details of the methodology used for calculation of notional interest.

Interest on Overdue Accounts

NLH has not included in the revenue requirement for 2002 any provision for interest to be collected from customers for late payment of invoices for services rendered. Prior to the implementation of the new JD Edwards accounting system NLH did not have the tools to charge customers interest on overdue accounts. (Transcript, Nov. 19, 2001, pg. 46/17-26). Effective January 1, 2002 NLH proposes to charge interest on overdue accounts but because of past practice of not charging interest, it does not have any basis for estimating an amount for 2002. (Transcript, Nov. 19, 2001, pg. 46/88-95)

In final argument NP expressed the view that NLH's position of not estimating an amount for interest income on overdue accounts in the test year is unreasonable in light of its ability to calculate notional interest on non-regulated recall sales. (NP, Final Argument, pg. C-37) In final argument NLH states that there is no need to include an interest component for the rural customers because it did not forecast any lag in receiving payments from these customers in the cash working capital allowance calculation. (Transcript, Jan. 28, 2002, pg. 6/41-44) Under cross-examination Mr. Hamilton stated that the collection policy of NLH is to include a late payment charge after 30 days. (Transcript, Nov. 29, 2001, pg. 28/72-79) The revenue lag shows a collection lag of 39.47 weighted average days. (Supplementary Evidence, J. C. Roberts, Schedule IVA)

The evidence presented to the Board indicates that NLH has anticipated receiving interest on overdue accounts. The revenue lag analysis uses a 39.47 day collection period and the stated policy of NLH respecting accounts over 30 days will attract overdue charges. The calculation of a reliable estimate for anticipated interest should not be an insurmountable problem if the lag analysis and policy are integrated.

The Board will require NLH to include in the 2002 test year revenue requirement an appropriate credit for interest collected on overdue accounts.

NLH will be required to revise the calculation of the interest expense for the 2002 test year to incorporate the decisions of the Board.

11. Return on Equity

Return on equity (ROE) is dealt with on pg. 43 of this decision.

12. Total Revenue Requirement

The total revenue requirement will be recalculated by NLH to reflect the decisions contained in this decision.

IV. RATE STABILIZATION PLAN

1. Introduction

Prior to 1986 NLH maintained two separate accounts to adjust for annual variations in hydraulic and thermal production as compared to test year forecasts allowed in NLH's rates.

A water equalization provision recorded the fluctuations in water availability and the resulting changes in thermal generation costs needed to meet load requirements. NLH charged or credited fuel expense in its annual income statements with a corresponding adjustment in the water equalization account equivalent to actual increased or decreased generation costs relative to hydraulic production based on an average yearly water condition. For example, a drier year than average would generally result in less hydraulic production, more thermal generation and hence higher fuel costs; whereas a wetter than average year would have the opposite impact. The water equalization account had a maximum provision of \$36,000,000 which was considered sufficient to absorb the adverse affects of a reoccurrence of the three consecutive driest years on record.

NLH's second account involved an adjustment formula to recover generation costs attributable to fuel prices in excess of those allowed in test year rates. These fuel adjustment charges were recovered in the month following which the costs were incurred. This method of recovery resulted in significant volatility in rates to customers, particularly during winter months when consumption was highest.

In the early 1980s rising fuel prices and higher fuel consumption from increased thermal generation at Holyrood raised consumer concerns regarding monthly rate fluctuations and high electricity rates. In 1985, as a means of providing greater rate stability to customers, NLH proposed the Rate Stabilization Plan (RSP). The RSP contemplated consolidating both the hydraulic and the fuel adjustment charge (FAC) accounts into a single plan. The positive balance at the time in the water equalization provision would be refunded to NP and the Island IC over three years. The proposed RSP was accepted by the Board subject to various conditions. NLH later clarified the operating characteristics and mechanics in a letter to the Board. [IC-284(e)]

The existing RSP provides for adjustments to smooth variations between forecasted test year costs used to set rates and actual costs attributable to differences in the price of No 6. fuel, hydraulic production and load forecast. The plan also includes an adjustment to account for any variation in NLH's rural revenues which may arise as NLH's rural rates are changed, in accordance with Government policy, to reflect NP's rates. This provision was incorporated into the RSP as part of the 1993 generic COS hearing.

The variables used in the RSP are based on the cost of service study filed with the Board in November 1991 which is based on forecast test year costs and operating conditions for the 1992 test year. These include a normal annual hydraulic production of 4,205.32 GWh, a cost of service oil price of \$12.50 Cdn/bbl and a fuel efficiency factor for Holyrood of 605 kWh per barrel.

NLH tracks the various components of the plan monthly, comparing actual results with the cost of service and crediting or charging the plan with the difference. The annual balances in the plan are recovered from NP using a declining balance over a three-year period and from IC through an automatic adjustment in rates. In the case of NP, one-third of the amount as of December 31 is either recovered or paid over the 12 month period commencing the following July 1 through an adjustment in the energy rate charged to NP. NP passes this adjustment on to its retail and general service customers. In the case of the IC one third of the plan balance as of September 30 is either recovered or paid over the 12 month period commencing the following January 1 through an adjustment in their firm energy rate.

2. Current Status of the RSP

The actual balances in the RSP for the period 1992-2000 and the forecast balances for 2001 and 2002, are shown below:

Rate Stabilization Plan (\$ millions)			
Year	Total Balance	Retail (NP)	Industrial
1992	4.1	0.6	3.5
1993	9.4	3.8	5.6
1994	(4.0)	(5.6)	1.6
1995	12.9	6.9	6.0
1996	30.2	21.0	9.2
1997	41.3	27.6	13.7
1998	48.8	33.0	15.8
1999	34.5	21.5	13.0
2000	35.6	22.7	12.9
2001 forecast – as filed	87.4	61.3	26.1
2001 forecast – revised (PUB-81)	83.6	60.4	23.2
2002 forecast – as filed	97.8	72.0	25.8
2002 forecast – revised (PUB-81)	86.3	65.0	21.3

(Supplementary Evidence, J. C. Roberts, Schedule XIV)

In final argument (pg. 53) NLH states that the increases in the balances in the RSP from 1992 to 2001 were caused by the dramatic increase in the price of No. 6 fuel from the time that base rates were set in 1992 using \$12.50 Cdn/bbl for No. 6 fuel. The increase forecast RSP balance for 2002 relates primarily to the difference in the forecast average price for No. 6 fuel and the price NLH is proposing to use for the RSP of \$20 Cdn/bbl.

PUB-81 indicates the mill rate adjustments required for NP and the IC to recover the outstanding balances. The IC RSP mill rate for 2001 was set in January 2002, based on the September 30, 2001 balance, at 5.14 mills/kWh. An RSP mill rate of 4.84 mills/kWh is forecast for January 2003 based on the forecast September 2002 balance. For NP, the RSP mill rate based on the December 2001 balance is forecast to be 4.52 mills/kWh in July 2002, with a

forecast mill rate of 4.83 mills/kWh in July 2003 based on the projected December 2002 balance in the retail plan. These mill rate adjustments are in addition to base rate increases requested in this Application.

3. NLH's Proposals

NLH outlined proposed changes to the RSP in IC-120. These changes include:

1. Hydraulic Production Variation
 - An addition of mini-hydro plants to the calculation of hydraulic production variation.
 - A change in the Holyrood conversion factor from 605 to 610 kWh/bbl
2. Load Variation
 - No longer include interruptible energy in the plan. Barrels relating to this energy will also be excluded from the fuel price variation calculation (along with the existing exclusion for barrels relating to emergency sales).
3. Customer Splits
 - No longer base the RSP split on test year Cost of Service Study (COS); instead use 12 month-to-date invoiced/bulk transmission energy, as well as test year Rural deficit allocation.
4. Rate Calculation
 - Establish energy rates on the same basis as split, ie. 12 month-to-date invoiced/bulk transmission energy.
5. Other
 - Change finance charge from NLH's embedded cost of debt to NLH's WACC.
 - Increase the RSP cap for NP of \$50,000,000 to \$100,000,000.

The current "*cost of service*" price of fuel in the RSP is \$12.50 Cdn/bbl set by the Board in 1992. NLH is projecting that the weighted average annual purchase price for No. 6 fuel in 2002 will be approximately \$25.91 Cdn/bbl. (2nd Supplementary Evidence, R. Henderson, pg. 1) In this Application, NLH is proposing a test year fuel price of \$20 Cdn/bbl in calculating the revenue requirement for base rates. The difference resulting from the \$20 Cdn/bbl and the actual price will be included in the RSP.

4. Issues Raised at the Hearing

There was considerable discussion surrounding the RSP. Some of the issues raised by the intervenors included the complexity of the plan, the amount of the outstanding balance, the recovery of this balance and the future of the plan.

Mr. Bowman expressed his concerns about the existing RSP: (Pre-filed Evidence, C. D. Bowman, pg. 6):

- i. *“It causes cross-subsidization in that past consumers are being subsidized by current consumers, and it appears that current consumers will be subsidized by future consumers;*
- ii. *It removes any incentive that Hydro might have to better manage its fuel supply costs and improve its forecasting techniques; and*
- iii. *It is difficult for consumers to understand.”*

Mr. Bowman also submitted that the RSP in its present form distorts price signals and should be eliminated, or, at the very least, the Board should direct NLH to file a revised RSP that addresses the above concerns. (Pre-filed Evidence, C. D. Bowman, pg. 5-6/21-12)

Mr. Brockman agrees with the continuation of the RSP but not with the proposed increase of the cap to \$100,000,000. The *“increase cap is excessive and gives Hydro little or no incentive to operate efficiently”*. (Pre-filed Evidence, L.B. Brockman, pg. 9) Mr. Brockman suggests that the Board allow NLH to book amounts in excess of the present cap of \$100,000,000. NLH can decide to either absorb the difference or apply to the Board for a hearing to justify the difference. (Pre-filed Evidence, L. B. Brockman, pg. 9) Mr. Brockman disagreed with the CA’s position on eliminating the RSP and stated:

“I do not advocate the elimination of the RSP. The RSP helps reduce the volatility associated with dramatic changes in both fuel costs and hydraulic conditions. It was implemented because customers did not want to be exposed to excessive price volatility. In that respect, it has served its purpose well”. (Supplementary Evidence, L. B. Brockman, pg. 5)

The IC do not object to the concept of a RSP as a mechanism to protect both ratepayers and NLH from variations in uncontrollable variables such as hydrology and fuel prices. Mr. Osler, in his pre-filed and supplementary testimony, had a number of observations, in particular, with respect to the load variation component and the allocations of the plan balances between NP and the IC. When commenting on the load variation component Mr. Osler stated (2nd Supplementary Evidence, C. F. Osler, pg. 4/81):

“„the load variation component provides substantial protection to Hydro from errors in its load forecasting and changes in all factors influencing energy sales, including weather, economy, changing consumer fuel mix requirements, etc. The load variation component has provided Hydro with substantial additional income in 8 of the past 9 years, as much as \$5,300,000 in 1999 which has clearly played a marked role in Hydro being able to avoid regulatory review by the Board over this period.”

Mr. Osler also comments that, based on the evidence filed by NLH on the RSP *“it is concluded that Hydro’s process results in substantial balances in the fund being improperly allocated to NP, IC and Rural Interconnected customers based on reallocation of cost-of-service*

amounts that are not properly part of the RSP.” (2nd Supplementary Evidence, C. F. Osler, pg. 3/17-19)

Mr. Osler states that, in relation to the intended operation of the RSP, there are two areas where the operation of the current RSP differs from the 1985 Board Order (2nd Supplementary Evidence, C. F. Osler, pg. 7/21/28):

- “1. *The RSP was intended only to adjust for load variation to the extent that it caused an earnings variation for Hydro.*
2. *The RSP was intended to be simple for the utility to administer and for customers to understand.*

Neither of these principles have been applied in the current RSP: the operation of the plan is clearly complex to a degree that is unnecessary, and the plan adjusts and reallocates substantial costs between customers that are in no way related to variations in Hydro’s earnings.”

In final argument (pg. 64) the IC submitted that:

“It should not be forgotten that, while the RSP is clearly a ‘rate’, it serves a different purpose than the base rate. It is intended to fluctuate, to accommodate variations both positive and negative over time arising from particular causes. It is not intended to represent an amount which forms a part of the charge for electricity to consumers over the long term. Long run changes in price levels of inputs, such as fuel, should be incorporated in base rates; it is the failure to do so in this case, i.e. that continued attachment to the unrealistic \$12.50/bbl fuel, that has created something of a crisis.”

The IC propose that the Board should direct NLH to establish separate rate elements to track fuel price changes and water inflow changes. They also suggested that the fuel price adjustment should be shorter term (1 year) while the water inflow provision is more suited to a longer term adjustment since forecasts are based on long term averages. (IC, Final Argument, pg. 64)

Dr. Wilson questioned whether the social gain of deferring recovery of NLH’s fuel cost, by setting a base below market, justifies the pricing inefficiency and equity issues inherent in shifting costs between generations. He stated *“The apparent philosophy behind Hydro’s RSP is somewhat different than the reasons offered by most utilities for fuel cost adjustment clauses in their rates.”* (Pre-filed Evidence, Dr. J. W. Wilson, pg. 34)

The Board’s decisions on the issues raised by the intervenors are dealt with below.

5. Continuation of RSP

The Board agrees with NP and NLH that the RSP provides rate stability to customers and also provides a mechanism to eliminate volatility in NLH’s revenue requirement due to events beyond NLH’s control. This was the original intent of the RSP and remains so today. Ratepayers benefit from the smoothing of the impact of changing fuel prices on rates and thus

eliminating the rate spikes experienced by customers under the previous fuel adjustment charge. The Board believes that the regulatory principle of rate stability and predictability is still important to customers.

The Board is not convinced that the interests of the consumers or NLH would be served through the elimination of the RSP and, other than the specific adjustments and changes described in this decision, will not make any other change in the RSP or its operation at this time.

The Board does however note the concerns and issues surrounding the RSP raised by the intervenors, especially the CA and the IC, in particular concerns about the complexity of the plan and the interactions of the various components of the plan, especially the inclusion of the load variation provision. The Board also agrees that the existing RSP and its operation is difficult to understand.

The Board is convinced, based on the evidence and issues raised at the hearing, that the design and elements of the existing plan should be reviewed. To that end the Board will commission a study of the RSP, which will include a review of the plan since its implementation, together with the operational issues raised by the intervenors at the hearing. The Board will decide based on the results of that study what action should be taken.

6. Price of Fuel in RSP

The primary concern of the Board at this time is not the intent or principle of the RSP but rather its operation over the last five years which has seen the plan balances increase significantly. The Board acknowledges that the primary reason for this is the price of No. 6 fuel in the RSP of \$12.50 Cdn/bbl, when actual fuel prices in recent times have exceeded \$40 Cdn/bbl.

The Board agrees with NLH that the issue of *rate shock* to consumers is an important one. The Board is convinced, however, that incorporating the forecast price of fuel into base rates is the fairest and most prudent course of action which will avoid ever increasing balances in the RSP and also protect future consumers from having to pay even higher rates because of the deferral of a portion of fuel costs. As indicated when considering revenue requirement, the Board believes it is important to maintain the relationship between the price of fuel and electricity rates and that the correct price signals are reflected in rates to consumers. The Board will monitor the actual price of fuel, the RSP operation and the plan balances through NLH's quarterly reporting to the Board.

The COS price for No. 6 fuel to be used in the RSP for calculating the fuel price adjustment will be based on the monthly 2002 forecast fuel prices as filed in Table 1 of R. J. Henderson's, 2nd Supplementary Evidence. This table indicates that the weighted average fuel price for the test year will be \$25.91 Cdn/bbl. In addition, NLH will be required to file updated 12-month fuel forecasts as part of its quarterly report to the Board.

7. Increase in Retail Cap

The existing retail portion of the plan has a cap of \$50,000,000 (positive or negative) and was established in the Board's 1985 report recommending approval of the RSP. The cap was set to trigger a review by the Board as outlined in the 1985 report (pg 42):

"...if the net balance of provisions created by the Rate Stabilization Plan, to the extent that they are applicable to retailers, reaches \$50 million (either positive or negative). At that appearance, Hydro would either propose alternative rates or present facts relevant to examining the need for an alteration of rates in light of the circumstances at that time."

NLH has requested in this Application that the current cap on the retail portion of the plan be increased from its current level of \$50,000,000 to \$100,000,000. The reasons for the proposed increase in the cap relate to the increasing plan balance and the fact that NLH is proposing that the price of fuel to be used in base rates for 2002 be \$20 Cdn/bbl, which is significantly less than the forecast price. NLH also acknowledges that the original request for a \$100,000,000 cap was based on a forecast RSP total balance of \$97.8 million. (NLH, Final Argument, pg. 54/4-5)

In supplementary evidence GT recommended that the Board approve a temporary or interim increase in the retail cap and that the cap should be set in relation to the forecast retail plan balance over the 2002 and 2003 time period. (Supplementary Evidence, GT, pg. 8) NLH did not oppose GT's recommendation but suggested that the cap be set at \$85,000,000 to allow for forecasting uncertainties and the fact that the RSP balance will also be increased by the date of implementation of new rates for 2002. (NLH, Final Argument, pg. 54/19-29)

In final argument NP did not object to an increase in the RSP cap stating that *"An increase of the Retail RSP cap to \$60-65 million, the forecast year end 2001 balance, is in Newfoundland Power's view, practically inevitable given that the year end 2001 balance represents fuel costs already incurred by Hydro."* (NP, Final Argument, pg. D-4)

The reason for implementing a cap on the retail plan was to ensure that the plan balance did not become excessively large. It is clear to the Board that the mere existence of a cap has not prevented this from happening. However, the Board is now faced with the dilemma of a large plan balance, which needs to be recovered from customers, coupled with a significant increase in base rates to these same customers due to higher fuel costs.

Any mechanism that is put in place to trigger a review of the RSP must be considered with a view to the original intent of the plan. On pg. 87 of the Board's 1985 report the Board states:

"The elimination of FAC will mean that fuel costs will be reflected in higher base rates and will not vary from month to month between adjustments made for the Rate Stabilization Plan and will protect the consumer from the large increase in the FAC that occurred during the winter of 1984-1985."

This indicates that the Board at the time was concerned about rate stability and felt that this goal was best achieved by recovering fuel costs in base rates. The Board believes that this is still the best method to deal with fuel costs and that the goal should be to minimize deviations between current fuel costs and current electricity rates. The RSP should be used only to capture the uncertainties in forecasting. The Board maintains this principle in its decision to order NLH to use the forecast average fuel price in calculating its 2002 test year costs for No. 6 fuel.

In light of the other decisions taken at this time, including the commissioning of a review of the RSP, it is the Board's opinion that a cap on the retail plan balance is no longer necessary. The Board believes that setting the price of No. 6 fuel at forecast prices and recovering those costs in base rates instead of deferring a portion of the costs in the RSP will address the significant issues with respect to the cap. As well, the Board will undertake increased monitoring of the plan and will track the spread between the price of No. 6 fuel used in the plan, the actual price NLH is paying and the forecast long term price. The Board will exercise its authority to investigate or make changes to the RSP when it determines, based on the information before it, that action is necessary.

The Board does not accept NLH's proposal to increase the cap on the retail portion of the RSP to \$100,000,000. The Board will remove the existing cap of \$50,000,000 on the retail portion of the RSP.

8. Recovery of Balance in the RSP

The balance in the plan is currently recovered from customers over a three-year period using a declining balance method. As indicated previously, this recovery method has been in place since 1985 and means that residential customers are assessed as of July 1 each year for one third of the balance in the plan as of December 31 of the previous year. Similarly, the RSP adjustment for the IC occurs on January 1 each year based on a plan balance for the IC as of September 30 of the previous year.

While this recovery method has been working well according to NLH, there were questions raised during the hearing as to whether a shorter time frame for recovery should be considered in light of the increasing balances in the plan. GT proposed two alternatives for the Board to consider (Supplementary Evidence, GT, pg. 9):

1. Freeze the balance as of December 31, 2001 and continue to recover this balance using the current three year declining balance method, and recover any accumulation in the plan in subsequent years using a straight line basis over a two year period.
2. Freeze the balance as of December 31, 2001 and recover over a three year period using a straight line balance, and recover any accumulation in the plan in subsequent years using a straight-line basis over a two year period.

Either of these options will be faster than the existing method in recovering plan balances over the long term. Both will, however, result in higher mill rate adjustments in 2003 than would

occur under the current recovery mechanism because of the two year recovery period. (Supplementary Evidence, GT, Exhibit IV)

In final argument (pg. 56) NLH submitted that it is not opposed to a shorter period for the recovery of the RSP balance as proposed by GT but requested that the Board recognize the impact on consumers of using an accelerated recovery method. NLH stated that either of the alternatives suggested by GT is acceptable.

In considering this issue, the Board has to take into account the effect on rates of recovering some of the existing plan balance in the test year combined with its decision to rebase fuel at forecast prices. While lower RSP balances should accumulate as a result of recovering more of the fuel price in the actual base rate, the increase in base rates will be higher than that originally proposed by NLH. Recovering the RSP balance as proposed by NLH will mean even higher rates for both retail and industrial customers.

In addition to considering the impact of all costs on electricity rates to consumers, the Board has to balance the issue of trying to match recovery of costs with the period in which these costs were incurred, sometimes referred to as an inter-generational equity issue. This issue was raised by several of the expert witnesses, in particular Mr. Bowman and Dr. Wilson. Although costs should normally be recovered over the period in which they are incurred, the Board also has to balance this goal with the impact on ratepayers of this kind of matching recovery.

Because of the magnitude of the anticipated rate increases which will result from the Board's decision to use the forecast average fuel price in base rates, the Board will not allow any additional recovery of the existing RSP balance until 2003. The Board believes that deferral of the RSP mill rate adjustments together with an extended recovery period mitigates the impact of moving to true "cost based" rates incorporating the forecast price of No. 6 fuel.

With respect to the recovery of the balance in the RSP the Board will order the following:

- **The existing balances in the RSP are to be fixed as of the end of the month prior to the effective date of rate implementation based on the current methodology.**
- **The RSP mill rate for the IC will be reset as of the effective date of rate implementation for the remainder of 2002 to 2.80 mills/kWh, which was the rate effective January 1, 2001.**
- **The RSP mill rate for 2002 for NP will remain at 1.77 mills/kWh, which was the rate effective as of July 1, 2001.**
- **Recovery of the fixed balance outstanding will be spread over a five year period commencing in 2003 using a straight line recovery method. The method for calculating the mill rate adjustments and the date of the adjustments for both the IC and NP will remain the same. The amounts recovered will be credited against the outstanding balance of the plan. Interest will be accumulated and maintained on the balance using the WACC.**

- **Recovery or credits of balances that accumulate in the plan after the effective date of rate implementation will be calculated using a straight-line method over a two year period, to be effective January 1, 2004 for the IC and July 1, 2004 for NP.**

9. Allocation of Rate Stabilization Plan Balances

The IC raised the issue of the allocation of balances in the RSP between the retail customers and the IC. Mr. Osler submits that there were “*significant inconsistencies and improper operation of the RSP since the Board last reviewed Hydro in 1992*”. (2nd Supplementary Evidence, C. F. Osler, pg. 8/19-29) Their concern is summarized in the IC’s final argument (pg. 73):

“One point on which the 1985 report is clear and consistent is that the RSP generally and the load elements in particular were intended to be applied to circumstances which gave rise to an actual change in NLH’s revenues or costs. At page 90 of the Report, the Board states, repeating in part its words on p. 88 in item (vi) where it enumerated the changes from Hydro’s proposed RSP:

The Board recommends that any earnings variation because of a difference between the estimated load and the actual load be included in the Rate Stabilization Plan so that Hydro’s earnings will not vary. (Emphasis added)

The concern was clearly to ensure that Hydro was made whole in respect of additional costs and refunded amounts which represented income not expected to be received on the basis of its forecasts. There was never a suggestion that the RSP was intended to re-distribute cost responsibility among Hydro’s customers. If Hydro’s income was not affected, there was no need for the RSP to effect a rate change in response to any experienced result, whether or not that result varied from the forecast.”

The main issue is with the monthly re-calculation of Average and Excess Demand factors which were used under the former cost of service methodology to assign costs to customer classes. The IC submit that the demand elements they should pay in the RSP were set by the Board in 1992 and that this recalculation is actually an alteration in the Board approved cost allocations. The fact that NLH has recalculated the demand elements each month since the Board implemented the 1992 report means that neither NP nor the IC have paid the “approved” allocated amounts. Mr. Osler, on behalf of the IC, submitted that in 2000 alone an amount in the order of \$1,500,000 in cost were transferred from NP to the IC as a result of the RSP calculations. (2nd Supplementary Evidence, C. F. Osler, pg. 9/1-2) The IC recommend that the Board recalculate and restate the RSP to calculate the proper balance in the industrial RSP since 1995. (IC, Final Argument, pg. 78)

The IC also objected to the continued use of Albright and Wilson and Royal Oak Mines load in determining the load variation for the IC after both these customers ceased operation. The IC submit that the RSP charges to the industrial portion of the plan arising from this load variation calculation be reversed from the dates on which those operations ceased in Newfoundland (IC, Final Argument, pg. 78).

NLH submits that the way in which NLH split the RSP balance between the Island IC and NP was understood and communicated to the IC and has been reviewed by the Board and its financial consultants a number of times since 1986. NLH argues it is difficult to accept the IC position that the RSP has not been implemented properly or that these customers were unaware of the implications or the manner in which the balance was split between retail and industrial customers. NP agrees with NLH's position on this issue.

The Board agrees with NP and NLH that there is no basis upon which to reallocate past RSP balances between the retail customers and the IC. It is the Board's view that both NP and the IC, as the two major stakeholders in the operation of the RSP, have had sufficient opportunity to question any aspect of the RSP directly, either with NLH or through a query to the Board since 1992. The IC were present at the December 1999 hearing dealing with the phase out of their portion of the rural subsidy and at the subsequent pre-hearing conference, which set the date and scope of the present hearing. No such questions were raised on either occasion concerning the NP/IC split in the RSP plan.

It is also apparent that there was communication between NLH and the IC regarding aspects of the RSP, as evident from correspondence filed in IC-284 and IC-286. The Board is not in a position to comment on whether the IC understood the correspondence and its implications or the manner in which the balance was split between NP and the IC. The Board can only assume that if there was a concern it would have been raised at the time. It is the view of the Board that NLH has consistently applied the rules as they were intended by the Board in 1986, and as communicated to the Board by NLH at that time. The Board does not agree with the IC that NLH has implemented the RSP improperly.

NLH has proposed that in future the allocation of the RSP balance be based on the customers' 12 months-to-date inventory/bulk transmission energy for the year in question. This change to the operation of the RSP will address the concern of the IC regarding the allocation of balances in the plan.

The Board will not make any adjustments to the RSP prior period balances as requested by the IC.

10. Other Changes to RSP Proposed by NLH

In addition to the issues addressed above NLH has proposed a number of other changes to the RSP as previously outlined. These other changes are restated below:

1. Hydraulic Production Variation
 - An addition of mini-hydro plants to the calculation of hydraulic production variation.
2. Load Variation
 - No longer include interruptible energy in the plan. Barrels relating to this energy will also be excluded from the fuel price variation calculation (along with the existing exclusion for barrels relating to emergency sales).

3. Customer Splits
 - No longer base the RSP split on test year Cost of Service Study (COS); instead use 12 month-to-date invoiced/bulk transmission energy, as well as test year Rural deficit allocation.
4. Rate Calculation
 - Establish energy rates on the same basis as split, i.e. 12 month-to-date invoiced/bulk transmission energy.
5. Other
 - Change finance charge from NLH's embedded cost of debt to NLH's WACC.

None of the intervenors took issue with these proposals and the Board finds them reasonable.

The Board accepts the changes in the RSP as proposed by NLH with the exception of the price of No. 6 fuel, the Holyrood efficiency factor, the test year hydraulic production and the increase in RSP cap, which are dealt with elsewhere in this decision.

V. CAPITAL BUDGET

1. Introduction

Section 41 (1) of the *Act* states that “A public utility shall submit an annual capital budget of proposed improvements or additions to its property to the board for its approval not later than December 15 in each year for the next calendar year,...

NLH’s 2002 capital budget was submitted for approval as part of this Application and proposed capital expenditures totalling \$48,037,000. During the hearing NLH revised this amount to \$40,946,000. The revisions included the following (NLH 2002 Capital Budget, Revised Oct. 31, 2001, pg. A-1; NLH 2002 Capital Budget, Revised Nov. 30, 2001, pg. A-1):

1. Removal of a feasibility study into the generation of electric power through the harnessing of wind energy.	(\$200,000)
2. Removal of AS400 computers from the capital budget.	(\$2,109,000)
3. Spreading over 2 years the replacement of the VHF Mobile Radio.	(\$5,292,000)
4. Purchase of the existing leased AS400 computers and additional disc space.	\$143,000
5. Completion of the upgrade to TL262 (69 kV – Daniels Harbour to Peter’s Barren) which was delayed from 2001 due to environmental considerations.	<u>\$367,000</u> <u>(\$7,091,000)</u>

On November 20, 2001 NLH filed an application requesting (i) approval of certain projects contained in the proposed 2002 capital budget filed as part of the General Rate Application and (ii) an order extending the interim rates charged the IC pursuant to Order Nos. P.U. 23 (1999-2000) and P.U. 25 (2000-2001). Upon filing the application, NLH explained that projects objected to by the parties had been withdrawn from the list for which NLH was seeking approval.

On December 20, 2002 the Board issued Order No. P.U. 30 (2001-2002) approving certain capital projects without prejudice to the parties’ rights to address argument on:

- (i) the sufficiency of the documents supplied to support capital projects generally or the principle and procedures applied in the capital budget process; and
- (ii) an adjustment to the 2002 capital budget to reflect NLH’s past capital spending practice.

On January 14, 2002 the Board issued Order No. P.U. 31 (2001-2002). This Order was in response to NLH’s application dated December 28, 2001 for approval of capital expenditure projects under \$50,000 and leases in excess of \$5,000. Order No. P.U. 31 (2001-2002) approved all projects contained in the application.

In final argument (pg. 94) NLH advised the Board that it was deferring three projects to which objection had been raised by one or more intervenors. These projects are (NLH, Final Argument, Schedule B, pg. 9/5-13; pg. 12/1-3):

Project	Description	Amount
B-23	Replace Two Air Compressors - Buchans	\$65,000
B-46	Replace 136 kW Diesel Unit No. 284 – Harbour Deep	282,000
B-57	Upgrade Diesel Plant – Harbour Deep	<u>515,000</u>
		<u>\$862,000</u>

NLH stated that the deferral of the Harbour Deep projects related to the continued uncertainty of the status of the community (NLH, Final Argument, pg. 94/27-29). The replacement of the air compressors at Buchans was deferred based on the condition of the compressors. (NLH, Final Argument, Schedule “B”, pg. 9/5-13)

NLH also advised in final argument that it was proposing to defer B-47, Replace 75 kW Diesel Unit No. 252, Petites (\$238,000) which was approved by the Board in Order No. P. U. 30 (2001-2002). (NLH, Final Argument, pg. 94/4-5) NLH stated the reason for deferring this project is the declining load in the community, and that the existing units should be able to meet this load. NLH also requested that Order No. P. U. 30 (2001-2002) be amended to cancel approval of this project. (NLH, Final Argument, pg. 95/9-10)

These deferrals result in a revised 2002 proposed capital budget of \$39,846,000.

2. Issues Raised During the Hearing

Intervenors raised several issues with respect to the NLH’s proposed 2002 capital budget. These issues included the capital budget process, the standards for justification of capital expenditures, the adequacy of documentation provided, historical capital expenditures, and concerns about specific projects. These issues are dealt with below.

i) Standards for Justification and Adequacy of Documentation for Proposed Capital Expenditures

NP-179 (pg. 3/13-20) indicates that the capital budget process at NLH involves the input of supervisory personnel with budgetary responsibility through to each level of management reporting to the Management Committee until it is eventually approved by NLH’s Board of Directors before being presented to this Board for approval. The process spans approximately nine (9) months from start to finish and involves the review and evaluation of each capital budget project for approval to move on to the next level of responsibility. After capital requirements are identified, projects are assessed based on the following criteria:

- (i) To protect human life;
- (ii) To prevent imminent interruption of service to customers;
- (iii) To protect Hydro’s assets against loss or damage;
- (iv) To maintain power system reliability and availability;

- (v) To comply with pertinent regulations, standards, etc. and environmental standards;
- (vi) To meet projected customer load demand; and
- (vii) To reduce costs and improve efficiency.

Mr. Roberts testified that to determine the cash available for its capital program, NLH uses as a guideline its net regulated income plus depreciation, recognizing that there may be years in which the guideline may be exceeded as a result of various capital requirements. (Transcript, Nov. 15, 2001, pg. 27/57-68)

In presenting its capital budget NLH states that *“the majority of the projects included in Hydro’s 2002 capital budget have no formal cost benefit studies supporting the decisions to proceed.”* (Revised Capital Budget, October 31, 2001, pg. B-6) Mr. Reeves testified that the dollar values used in the capital budget *“are done on primarily engineers’ estimates”*. (Transcript, Oct. 3, 2001, pg. 19/76 & 77) Most of the NLH witnesses were questioned extensively on this matter and it appears from the evidence that cost benefit studies were carried out in respect of only two projects. (Transcript, Nov. 5, 2001, pg. 32/37-43)

For example, in NP-117 (pg 1/22-23;25-27) NLH stated that a cost benefit analysis was not carried out at the time the VHF mobile radio system was purchased in 1989. Furthermore, the deferral of the replacement of the VHF system could jeopardize NLH’s ability to provide VHF mobile radio service to ensure the safety of personnel and efficient operation of the power system. In NP-117 NLH states that there are several equipment replacement options and briefly explains what these options are but, despite the existence of *“options”*, NLH waives the cost benefit study approach and prioritizes the project on the basis of safety and reliability. (Transcript, Oct. 3, 2001, pg. 21/61-79) During cross-examination of both Mr. Reeves and Mr. Budgell there were several examples discussed wherein projects were approved for inclusion in the capital budget using safety and reliability of service as the main criteria.

In commenting on the question of whether or not cost benefit studies should be put forward in support of some or all of the capital budget projects Mr. Reeves stated: *“...if the Board is feeling uncomfortable with what we’re providing, well then it might be more appropriate for the Board to give us an indication where they might need some extra information.”* (Transcript, Oct. 5, 2001, pg. 24/67-70)

Mr. Budgell, responding to questions from the IC, stated that not all of the decisions with respect to individual capital projects are supported by formal cost benefit studies. (Transcript, Nov. 6, 2001, pg. 28/10-31) He explained that when the level of safety or reliability of service to customers would be clearly jeopardized if a project did not proceed, a formal cost benefit study would not be done.

The IC submitted that NLH’s approach to its capital budget process is unacceptable since the exemptions that NLH imposes on itself to remove the requirements for cost benefit studies are so broad that virtually no projects require one. The IC further argued that NLH should more thoroughly investigate its capital budget proposals and prepare detailed analysis of the expected costs of the proposals before submitting them to the Board for approval. (IC, Final Argument,

pg. 85) The IC concluded that NLH's capital budget should not exceed its forecast depreciation cost for the year in question; that all projects not involving serious environmental or safety risks should require a cost benefit analysis; that projects involving serious environmental or safety risks should be supported by evidence describing the nature and the level of the risk; and, that generally NLH should provide the Board with more adequate justification in support of its capital budget proposals. (IC, Final Argument, pg. 93-94)

NP argues that while a utility's legal obligation to serve its customers may justify a capital expenditure where there are no reasonable alternatives, there are available options for many capital expenditure requirements. Where these options exist, NP submits that the obligation to provide electrical service at the least cost requires that they be subject to cost analysis. (NP, Final Argument, pg. C-40) NP further submits that NLH's six assessment factors are "*too broad to provide, in and of themselves, reasonable satisfaction of the regulatory least cost imperative*". (NP, Final Argument, pg. C-42) NP recommended that all material capital expenditures proposed by NLH should be subjected to cost benefit analysis, except where there are no reasonable alternatives to the proposed expenditures. NP also submitted that capital project justification should also include a discussion of the qualitative factors contributing to the decision to proceed with a project. (NP, Final Argument, pg. C-49)

The CA urged the Board to be cognizant of the possibility of duplication that may exist between the two utilities and suggested that the Board develop a test to determine if duplication exists prior to approving NP's or NLH's capital budget. (CA, Final Argument, pg. 39-40)

The *EPCA* mandates the Board to implement the power policy of the province and to apply tests which are consistent with generally accepted sound public utility practice. Furthermore, Section 3 (b) (iii) requires that utilities manage their facilities in a manner that enables power to be delivered to consumers at the least cost. The Board, while mindful of the overriding importance of safety and reliability of service, believes that cost benefit studies should be carried out wherever possible.

The Board has dealt with the issue of duplication under Other Issues beginning on **page ?** of this decision. The issue of duplication addressed by the CA in final argument in respect of the capital budget process is one which the Board believes can be addressed with both utilities during the annual capital budget approval process. Since this is NLH's first rate Application as a fully regulated utility the Board believes, as it has stated elsewhere in this decision, that regulatory practices and procedure respecting NLH's future activities which are subject to the Board's approval should commence with this Order. The Board also agrees with NLH's position outlined in its final argument (pg. 92/26-29) that "*if any additional justification or documentation is required, it should be determined by the Board and communicated to Hydro in advance of Hydro's submission of its next capital budget (2003) so that Hydro will have adequate time to respond*". To that end, the Board believes it is necessary to set forth the procedures to be adopted by NLH in presenting future capital budget applications.

The Board will require NLH, commencing with its 2003 capital budget application, to use a net present value methodology together with supporting justification to evaluate projects of a material amount. Where a project is not evaluated against other acceptable alternatives and/or, if the project does not produce a positive net present value, sufficient rationale must be provided to justify implementation. The Board has set out guidelines to be used by NLH in future capital budget applications in Schedule 3, attached to this decision.

ii) Historical Capital Expenditures

GT conducted a review of the actual versus estimated capital expenditures and determined that, from 1996-2000 inclusive, the total capital expenditures of NLH were lower than budget by an average of 15% after accounting for events that would be considered exceptional. (GT 2001 General Rate Hearing Report, pg. 14) GT further stated that, based on discussions with NLH officials, NLH is probably under spending by approximately 5% and that the remaining 10% variance must be due to delays and carryovers. (GT 2001 General Rate Hearing Report, pg. 15)

Under cross-examination by the IC, Mr. Brushett of GT confirmed the 15% variance and stated that, if NLH's projected capital budget for 2002 is 15% too high, the revenue requirement for the test year 2002 is overstated by \$424,000. (Transcript, Jan 8, 2002, pg 44/59-61; pg. 45/7-17). Mr. Brushett also pointed out that the real issue on this topic is not the approval of the capital expenditure but whether it would be appropriate to adjust the rate base projected for 2002 to reflect an allowance for under spending. (Transcript, Jan. 8, 2002, pg. 44/57-75)

In final argument (pg. C-50) NP submitted that the Board should reduce NLH's 2002 revenue requirement to reflect NLH's historical experience in over budgeting annual capital expenditures by 15%. The IC also support this reduction. (IC, Final Argument, pg. 95)

NLH outlined in its final argument (pg. 95-96/30-3) some of the action that it has taken to address the issue of under spending, including enhanced coordination between engineering and operations staff, more critical attention to completing projects in the year in which they are budgeted, focus on total project cost, and the use of new software tools to monitor and control project costs. NLH submitted that, if the Board was to consider an adjustment for under spending, that it should be no more than 4%, which was the adjustment applied to NP in Order No. P. U. 36 (1998-1999). (NLH, Final Argument, pg. 96/15-28)

The Board acknowledges the actions taken by NLH to address the issue of historical under spending. The Board also notes that the total variance percentage of actual expenditures to budget as shown on pg. 14 of GT's 2001 General Rate Hearing Report has been decreasing since 1998. Because of this the Board does not feel that a 15% downward adjustment would be fair or is necessary. However, the Board does believe that some downward adjustment should be applied and feels that a 7½% reduction is warranted.

The Board will order that, for the purposes of establishing the revenue requirement, NLH reduce its approved capital budget by 7½%. This downward adjustment will reduce depreciation and interest expense as well as the forecast rate base for the 2002 test year.

iii) Contingency Fund

In previous capital budget applications NLH has requested approval, and the Board has ordered the inclusion, of a contingency fund in the amount of \$1,000,000. The Board's intention for the contingency fund was to allow NLH to deal with emergency funding requirements of a capital nature. The Board notes that NP has a similar provision in place called "*Allowance for Unforeseen Items*". For consistency the Board will refer to NLH's fund in the same manner.

The Board believes that it is necessary to implement certain conditions regarding the type of project expenditures that should be made from the contingency fund, which will now be referred to as "*Allowance for Unforeseen Items*". These conditions are outlined below:

- i. The cost of the project must be greater than \$50,000.
- ii. The project must be seen, both by NLH and subsequently by the Board, to be urgent. Circumstances must require that immediate action be taken, and it must be evident that any delay resulting from the time taken to file an application with the Board could have serious negative consequences for the company, its customers, or the public. These consequences may be financial, or for reasons of safety or reliability.
- iii. A report must be filed with the Board detailing the circumstances of the need, the alternatives that have been considered, the financial effects of each of the alternatives, and reasons for the choice. Any reliability or safety issues should be reported in detail at this time. Also included must be a time line that indicates the date of the requirement for emergency action, the date of the decision of the company, the date upon which the action was begun, and the expected date of completion of the projects.
- iv. The reports on expenditures from the "*Allowance for Unforeseen Events*" for the year must be entered as part of the Application for Approval of the Capital Budget for the following year.
- v. The "*Allowance for Unforeseen Events*" will be considered by the Board annually at the time it considers the NLH capital budget and may be varied from year to year. Unused balances in the account will not carry forward.

The Board will approve an "*Allowance for Unforeseen Events*" of \$1,000,000 as part of the 2002 capital budget but will impose conditions on its use.

iv) 2002 Test Year Capital Budget

Pursuant to Section 41 (1) of the *Act*, as indicated previously NLH is requesting approval of a total capital budget of \$39,846,000. While there were questions asked of NLH witnesses regarding several of the projects proposed, only three projects were raised as significant concerns. These projects were B-66 (VHF Mobile Radio system) and two projects relating to Harbour Deep (B-46 and B-57). As NLH has deferred the Harbour Deep projects no further comment will be made on those projects at this time.

The VHF Mobile Radio system as proposed by NLH is part of NLH's broader Telecommunications Plan. This plan was presented to the Board in 1997 and an updated schedule was filed at the request of the Board as part of NLH's 2001 Capital Budget application. The original plan proposed replacement of certain portions of the VHF Mobile Radio system. This proposal requests approval to replace the entire VHF Mobile Radio system at a total cost of \$8,700,000. NLH proposes spending \$3,081,000 as part of the 2002 Capital Budget with the remainder to be spent in 2003.

NP, in final argument, (pg. C-42 to C-44) detailed the history of this project as part of the Telecommunications Plan and submits that the fact that NLH has maintained that no formal cost benefit analysis of the Telecommunications Plan is necessary "*defies any notions of least cost management of electrical system investment that no cost justification was attempted by Hydro for the original plan nor the materially more expensive current version*". (NP, Final Argument, pg. C-43) NP's position is that justification of an expenditure such as the proposed VHF Mobile Radio system clearly warrants cost analysis of the viable alternatives. (NP, Final Argument, pg. C-44)

The CA noted in final argument (pg.40) the absence of a formal cost benefit study for this project. The CA submitted that there were indications that both utilities should be sharing in one VHF Mobile Radio system and that, until this issue is resolved, no money should be provided to NLH for a VHF Mobile Radio system.

NLH provided additional justification on this project as part of its final argument. (NLH, Final Argument, Schedule "B", pg. 17-22). NLH submits that "*the evidence is clear that the VHF Radio System is a critical system required by Hydro to complete its maintenance and to provide communications link between field personnel and the Energy Control Center, as well as communications within a line crew and between crews. The evidence is equally clear that the existing system is obsolete and no longer is supported by the original manufacturer. It is not possible to get replacement parts nor does Hydro have enough spare parts in inventory to adequately support this system.*" (NLH, Final Argument, Schedule "B", pg. 20/19-25)

The Board has noted the submissions of the intervenors with respect to this project. The additional justification provided by NLH in its final argument was helpful to the Board in understanding the scope of the project and the technical and safety issues involved but the Board believes that further justification of this project is required.

The Board agrees that further justification should be completed of NLH's proposal to replace its VHF Mobile Radio system, including a cost benefit analysis of alternatives. The Board will also require NLH to prepare and file an updated version of its Telecommunications Plan with the Board.

The Board will approve the remaining capital budget projects not approved in P.U. 30 (2001-2002) with the exception of B-66 (VHF Mobile Radio system).

The Board will approve a 2002 test year capital budget of \$36,765,000, adjusted to remove the VHF Mobile Radio system project.

VI. RATE BASE

1. NLH Proposals

NLH proposes under Section 14 (9) of the Application that the long term return on rate base be set based on current market conditions at 9.5%.

NLH further proposes under Section 14 (10) that the estimated 2002 average rate base be \$1,370,471,000; and under Section 14 (11) that, interim for this Application, the return for NLH in 2002 on that rate base be 7.4% given a return on equity (ROE) sought by NLH of 3%. (Pre-filed Evidence, J. C. Roberts, Schedule II, pg. 1; K. C. McShane, pg. 5/54-55) In final argument (pg. 35,36/31-8) NLH submits:

“Because the provincial guarantee of Hydro’s debt permits Hydro to operate with a lower capital structure than otherwise, Hydro proposes that the following targets be adopted in the short term: ...3. a return on rate base of \$98,319,000 (Schedule VIIA, J.C. Roberts, pre-filed evidence) or 7.2%.”

2. Background

Section 80 (1) of the Act states:

“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”

NLH is requesting the following assets be included in the rate base for the 2002 test year:

- Average capital assets
- Cash working capital allowance
- Fuel Inventory
- Supplies Inventory
- Deferred realized foreign exchange losses.

Cash working capital allowance and deferred realized foreign exchange losses are somewhat contentious or unusual items which require separate consideration and comment as noted below.

3. Cash Working Capital Allowance

Cash working capital allowance (CWCA) reflects the average amount of capital provided by investors above and beyond investments in plant and other separately identified rate base items that bridge the gap between the time expenditures are made to provide service and the time payment is received for the service. (Pre-filed Evidence, K. McShane, pg. 6/7-12) Schedules III, IV, V and VI of Mr. Roberts pre-filed testimony detail the calculation and analysis of the CWCA.

With the exception of the witness for LC/W, Mr. Drazen, there were no substantial comments or changes suggested to disagree with the approach taken by NLH. Mr. Drazen expressed the view that the calculation should recognize the timing difference between the payment of semi-annual long-term bond interest and the receipt of the funds for their payment. (Pre-filed Evidence, Mr. Drazen, pg. 3-6) The intervenors questioned Mr. Drazen as to why this method is not used in other jurisdictions.

Mr. Brushett of GT agreed in principal with Mr. Drazen's proposal stating: "*conceptually I would agree that it's reasonable but I haven't done a detailed review of his calculations and what all the impacts are*". (Transcript, Jan. 8, 2002, pg 43/22-48)

The IC accepted Mr. Drazen's recommendation to take into account the lag related to interest expense on bonds payable semi-annually in the calculation of the CWCA. (IC, Final Argument, pg. 116)

NLH submitted in final argument (pg. 49) there is insufficient evidence before the Board to support Mr. Drazen's recommendation.

The Board agrees in principle with Mr. Drazen's proposal and acknowledges that there appears to be a benefit to NLH from the timing of funds received and the payment of interest on long-term bonds. The Board also recognizes the comments of Mr. Brushett of GT, who stated that a detailed review of Mr. Drazen's calculations or an analysis of the full impact of any benefits or costs has not been prepared.

At the present time the Board will not act to adjust the CWCA to reflect the timing difference between the payment of semi-annual long term bond interest and the receipt of the funds for their payment. The Board feels this issue warrants further consideration and will require NLH to submit to the Board, prior to the next rate application, an analysis of this issue.

4. Foreign Exchange Losses

The realized foreign exchange losses relate to the issuance of Swiss franc and Japanese yen denominated debt. The first loan was issued in 1979 and the repayments were completed in 1997. Prior to the 1985 rate referral NLH only recognized foreign exchange losses when they were realized. At the 1985 referral and the subsequent 1992 referral NLH requested a change in policy to recognize estimated losses and amortize them over a period of five years. The Board recommended that NLH commence recording an amortization of \$1,000,000 per year related to the probability of an exchange loss on the Swiss franc loan. As of January 1, 2002 this amortization provision amounted to \$10,000,000. The total unamortized realized foreign exchange losses after the repayment of the loans in 1997 were \$96,278,000.

Subsections 17(3)(b) and (e) of the *Hydro Corporation Act*, as amended in 1996, stipulate that all foreign exchange losses be amortized over a 40 year period commencing in the year when NLH's rates are first altered by the Board.

NLH is proposing that the \$10,000,000 accumulated provision be netted against the total realized foreign exchange losses of \$96,278,000 and the balance be included in revenue requirement at a rate of \$2,157,000 per year. NLH is requesting that the unamortized portion of the realized foreign loss be included in the rate base because NLH must continue to finance this balance until it is fully recovered.

The methodology, calculation and regulatory requirements related to NLH's proposed treatment of foreign exchange losses were reviewed by GT as part of its 2001 General Rate Hearing Report (pg. 7-8) None of the intervenors took issue with NLH's proposal.

The Board accepts NLH's proposed treatment of amortizing the foreign exchange loss at the rate of \$2,157,000 per year and its inclusion in the 2002 test year revenue requirement with the average balance of \$85,200,000 forming part of the rate base.

5. Rate Base

The total revised rate base for the test year is \$1,367,557,000. (Supplementary Evidence, J.C. Roberts, Schedule IIA, pg. 1) This amount compares to the "*as filed*" rate base of \$1,370,471,000.

Net capital assets of \$1,243,290,000 for 2002 represent NLH's actual capital asset balances as of December 31, 2000 which have been adjusted for the impact of the Board approved 2001 capital budget and the projected capital budget for 2002, reduced by the accumulated depreciation allowances, contributions in aid of construction and the Muskrat Falls assets in each year. The average of the net capital assets for 2001 and 2002 is included in the 2002 rate base. NLH's 2002 capital budget was revised by the Board and is dealt with beginning on **pg. ?** of this decision.

Fuel inventories are calculated on a thirteen-month average and supplies inventories are estimated based on December 2000 balances. No intervenors took exception to inclusion of these items in rate base or to the manner in which they were determined.

The "*as filed*" rate base was reviewed by GT as part of its 2001 General Rate Hearing Report (pg. 7) and GT concluded there were no discrepancies in the calculation and that the items, excepting deferred foreign exchange losses, are reasonable and appropriate in reference to legislative guidance and normal regulatory practice. Following further analysis, GT concluded that utilizing other mechanisms to recover financing costs would undoubtedly add complexity to the regulatory process and the proposal by NLH of including these deferred losses in rate base is reasonable. (GT 2001 General Rate Hearing Report, pg. 8)

NLH recited conclusions in GT's report regarding rate base in support of its final argument. (NLH, Final Argument, pg. 48/9-22)

In final argument the IC indicated that, once the Granite Canal project has been placed in service and NLH has completed the required study, consideration should be given to whether the GNP generation continues to be useful overall (and for the non-GNP customers) and whether it

should be removed from rate base or assigned to rural customers. (IC, Final Argument, pg. 37) This issue has been considered by the Board on pg. 110 of this decision.

The Board approves the approach and methodology used by NLH in determining the 2002 test year rate base.

6. Return on Rate Base

The return on rate base is the just and reasonable return as per Section 80.(1) of the *Act* that fairly compensates a utility for the use and risks inherent in its investment. The first step in determining the rate to be applied to the rate base is to establish the type and amount of capital used to finance the utility. Mr. Roberts details the three types of capital used to finance NLH rate base. (Supplementary Evidence, J. C. Roberts, Schedule VIIIA) The three types are long and short-term debt, liability for employee future benefits and retained earnings. The average of 2001 and 2002 forecast is as follows:

<u>Capital</u>	<u>%</u>
Long and short term debt	83.38
Employee future benefits	1.55
Retained earnings	<u>15.07</u>
Total	<u>100.00</u>

Each component of capital is allowed a specific rate of return.

NLH is allowed to recover the costs of financing its long and short term debt. NLH's total debt is \$1,314,468,000 with a cost of \$106,923,000. The cost expressed as a percentage of long and short-term debt is 8.134%. (Supplementary Evidence, J. C. Roberts, Schedule IXA)

Employee future benefits are deemed no cost capital since they are provided by the ratepayers rather than the investors. (Pre-filed Evidence, K. McShane, pg. 13/16-21). Effectively, the cost of this source of capital is included in the annual expense recorded for employee future benefits which is calculated actuarially.

The rate of return on equity is normally determined by a number of factors, such as risk, national rating standards for similar utilities, actual capital structure ratios and various other guidelines used by debt rating agencies. For the test year these factors are not considered because NLH is requesting an ROE of 3%, which the Board acknowledges is well below market. (See pg. 44 of this decision)

The calculated rate of return allowed for each component of capital is expressed as a percentage of its portion of capital. Mr. Roberts details the calculation to arrive at a weighted average cost of capital of 7.234% as shown in Table 6. (Supplementary Evidence, J. C. Roberts, Schedule VIIIA)

Table 6 Weighted Average Cost of Capital Proposed for the 2002 Test Year \$(000)'s						
Types of Capital	2001 \$	2002 \$	Average \$	Percent	Cost %	Weighted Average %
Long & Short-term Debt	1,234,963	1,393,973	1,314,468	83.38	8.134	6.782
Employees Future Benefits	23,832	25,075	24,454	1.55	0.000	0.000
Retained Earnings	<u>267,256</u>	<u>208,170</u>	<u>237,713</u>	<u>15.07</u>	3.000	<u>0.4520</u>
Total Capital	<u>1,526,051</u>	<u>1,627,218</u>	<u>1,576,635</u>	<u>100.00</u>		<u>7.234</u>

NLH's return on rate base is adjusted to exclude the rural interconnected and isolated assets from equity for the purposes of determining return. As a result NLH is only allowed an average cost of debt return on these assets. The return on rate base as calculated by NLH for the 2002 test year is \$98,319,000 as shown in Table 7. (Supplementary Evidence, J. C. Roberts, Schedule V11A)

Table 7 Return On Rate Base Proposed for the 2002 Test Year \$(000)'s				
Component Base	2002 \$	Weighted Average Cost of Debt %	Weighted Average Cost of Capital %	Return on Rate Base \$
Rural Interconnected & Isolated Assets	134,978	6.782		9,154
Other Rate Base Assets	<u>1,232,579</u>		7.234	<u>89,165</u>
Average Rate Base	<u>1,367,557</u>			<u>98,319</u>

With a view to the long term return on rate base of 9.5% proposed in this Application, NLH points out in its final argument that a full return on rate base can be decided by the Board when NLH requests same and in light of economic and capital market conditions prevailing at the time. The specific approach (i.e. the specific tests) for a fair return on rate base can also be left to the time when NLH asks for approval of a commercial return. (NLH, Final Argument, pg. 38/5-10)

The Board notes other decisions affecting return on rate base are contained under Capital Structure beginning on pg. 33 of this decision. An example of this is the decision of the Board to reduce interest costs in NLH's 2002 revenue requirement to reflect the cost of dividends in excess of NLH's dividend policy. This decision will have the estimated effect of reducing return on rate base to 7.134% as follows:

Return on Rate Base Following Dividend Adjustment⁵ \$(000)'s						
Types of Capital	2001 \$	2002 \$	Average \$	Percent	Cost %	Weighted Average %
Long & Short-term Debt	1,234,963	1,332,891	1,283,927	81.43	8.134	6.624
Employee Future Benefits	23,832	25,075	24,454	1.55	0.000	0.000
Retained Earnings	<u>267,256</u>	<u>269,252</u>	<u>268,254</u>	<u>17.01</u>	3.000	<u>0.510</u>
Total Capital	<u>1,526,051</u>	<u>1,627,218</u>	<u>1,576,635</u>	<u>100.00</u>		<u>7.134</u>

This reduction and other appropriate adjustments will have to be made to NLH's regulated return on rate base of 7.234%.

NLH will be required to file a revised rate base and revised calculation of return on rate base which reflects the decisions of the Board.

⁵ Remove \$61,084,000 of dividends [67,082,000 - 5,998,000 (7,997,000 x 75%)] Ref: Supplementary Evidence, Oct. 31, 2002, J.C. Roberts, Schedule VIIIA and Schedule X11A

VII. COST OF SERVICE

1. Introduction

The Cost of Service (COS) methodology used by NLH in this hearing was the subject of a special generic hearing before the Board in 1992. In 1993 the Board issued a report⁶ to the Minister of Mines and Energy dealing with cost of service issues for NLH. The report included 23 specific recommendations on COS methodology and recommended that NLH use the generic methodology at its next rate referral. The report was filed as evidence in this hearing in LC-1. This hearing is the first rate hearing since the COS methodology was approved.

The Board's 1993 generic COS report contained the following interim recommendations:

1. Recommendation 8: that a 1 CP⁷ allocator be approved for interim use in the island interconnected system and that NLH present to the Board at the time of its next rate hearing an analysis of the relationship between load factor⁸ and system reserve requirement⁹, together with a recommendation regarding the number of peaks on which the CP allocator for generation demand costs should be based.
2. Recommendation 14: that NLH examine the practicality of attributing system energy losses to rate classes on a time differentiated basis and report its conclusions as to both practicability and impact on allocated costs at the time of its next rate referral.
3. Recommendation 19: that NLH's proposed classification of distribution cost be accepted for interim use and that NLH prepare a revised study of distribution cost for presentation to the Board at the time of its next rate referral.
4. Recommendation 21: that subject to the provisions of recommendation 19, NLH's proposed methodology be approved for the Labrador interconnected and rural isolated systems.

As recommended in the 1993 generic COS report the methodology used by NLH in this hearing is an embedded cost of service study which allocates the costs of the utility for existing plant and operating expenses. NLH submits that its current filing complies with all recommendations of the 1993 report and that, while judgment must be exercised with respect to certain cost of service methodology issues, it has made its proposals based on what it perceives to be the most fair and equitable for all customer classes.

⁶ "Report of the Board of Commissioners of Public Utilities to the Honourable Minister of Mines and Energy, Government of Newfoundland and Labrador on a Referral by Newfoundland and Labrador Hydro for the Proposed Cost of Service Methodology and a Proposed Method for Adjusting its Rate Stabilization Plan to Take into Account the Variations in the Rates set by the Board to be Charged by Newfoundland Light and Power Co. Limited to its Customers", February 1993 (hereafter referred to as the 1993 generic COS report)

⁷ Coincident peak (CP) is the sum of two or more peaks that occur in the same time interval. CP is the demand of each customer or customer class at the time of system peak demand. CP demand is often used to allocate costs when setting rates for service since the costs of providing service is higher at that time.

⁸ Load factor is the ratio of average load to peak during a specific period of time, expressed as a percentage. The load factor indicates to what degree energy has been consumed compared to maximum demand, or the utilization of units compared to the total system capacity.

⁹ System reserve requirement is equipment and capacity that is available and is in excess of that required for load.

The Board agrees that most of the COS issues were dealt with in the 1993 generic COS hearing and should not be reconsidered here. As well, in Order P.U. 25 (2000-2001), NLH was ordered to prepare its rate filing based on the 1993 generic COS methodology. Accordingly the Board will only comment on those issues raised with respect to the COS methodology and the interim recommendations noted above or those issues that represent a change from that intended by the Board's 1993 generic COS report.

2. Allocation of Generation Demand Costs

In the 1993 generic COS hearing the Board found that a CP allocator would be preferable for allocating generation demand costs, however, the Board was unable to decide whether cost causation would be best measured by a single or multiple CP allocator. The Board did state that a 1 CP allocator appears to correlate best with a major part of the costs but also recognized that a multiple peak allocator would assign some costs to those class demands not necessarily coincident with the system annual peak. The 1993 generic COS report recommended that a 1 CP allocator be approved for interim use for the Island Interconnected system. (Recommendation # 8, 1993 generic COS report) NLH was also requested to complete an analysis of the relationship between load factor and system reserve requirement and make a recommendation regarding the number of peaks on which the CP allocator should be based for generation demand costs at the time of its next rate hearing (1993 generic COS report, pg. 23-24).

In response to NP-135 NLH filed a study entitled "*An Analysis to Determine the Relationship Between Load Factor and System Reserve Requirement*", prepared by NLH's System Planning Department in April 2001. Loss of load hours (LOLH) refers to the number of hours in a year that system capacity is unable to meet system load requirements. The LOLH study is a guide to the use of CP allocators and shows those times when NLH might be at risk of losing load, of not being able to provide sufficient power for firm customers.

The study concludes that the greatest LOLH contributions are made in the peak month of February (65% contribution at 60% annual load factor), followed by January (21% contribution at 60% annual load factor). As the annual load factor increases the portion of the LOLH contributions for January and February combined increases occur from 71% at a 50% annual load factor to 96% at a 70% annual load factor. The contribution from the remaining months is a relatively minor portion of the annual LOLH. The study recommended that the allocation of generation demand costs should be based on the CPs of the two peak months (i.e. a 2 CP cost allocator). NLH accepted these study results and used a 2 CP allocator in this Application. Mr. Brickhill reviewed the loss of load hours study as part of his evidence and concluded a "*greater risk of loss of load hours largely in two winter months*" with the probability increasing as the load factor increases. (Pre-filed Evidence, J. A. Brickhill, pg. 8-9)

The only party who took significant issue with the study results was NP, who argued that the study time frame of 1990-1994 was limiting. NP argued that by not updating the analysis to reflect the years 1995-2000, NLH excluded years in which peaks occurred primarily in December or March. Mr. Brockman, on behalf of NP, recommended the use of a 4 CP allocator for the following reasons (NP, Final Argument, pg. G-3;G-4):

- 1) the system peak can occur in any one of the four winter months and NLH is unable to predict which month the peak will occur;
- 2) a single peak is not what determines the timing of generation additions under NLH's LOLH planning criteria; and
- 3) use of only two months in cost allocation is unstable because the choice of peak months in the test year can affect the cost sharing among customer classes. NLH does not know in which two of the four months the peaks will occur.

NP also states in its final argument (pg. G-2) that the Board expressed a preference for a multiple peak allocator in their 1993 generic COS report.

Mr. Bowman recommends a 1 CP allocator from a cost causality perspective and because NLH uses 1 CP for allocating costs for its other systems. Mr. Bowman acknowledged that a 1 CP allocator is more volatile and recommends that, if the Board does prefer a multiple CP allocator in order to avoid volatility, a 4 CP allocator be approved because it reflects the fact that four winter months all contribute to LOLH. (Pre-filed Evidence, C. D. Bowman, pg. 8)

Mr. Osler recommended a 1 CP allocator because the peak month contributes more to the LOLH than the other three months combined. He also recognizes that a 1 CP approach may create concern over stability to the extent that variability in the month when the system coincident peak occurs is associated with materially different 1 CP allocators for the rate classes. (Supplementary Evidence, C. Osler, Pg. 16/31-34) This issue was not raised by any of the other parties.

NLH stated in its final argument (pg. 62) that, while the study supports the use of a 2 CP allocator, the use of a 1 CP allocator is also appropriate.

The choice of the CP allocator for the test year does affect the proportion of costs each customer class will pay. It is relatively more advantageous to the IC to utilize 1 CP and relatively more advantageous to NP to use multiple CPs. IC-244 shows the impact on NP's costs of using 3 CP and 4 CP allocators. The use of a 4 CP allocator reduces NP's costs by \$365,000 in the test year. (NP, Final Argument, pg. G-5)

The Board has already ordered that the coincident peak demand method be used for the allocation of generation demand costs. Variations in peak demand methods for cost allocation (such as the use of a single CP versus a multiple CP) are generally around the number of system peak hours analyzed, which in turn depends on the utility's annual load shape and on system planning considerations.

It appears from the evidence that system planning is done on the basis of the peak occurring sometime in the winter period starting in December. (Transcript, Nov. 5, 2001, pg.40/37-44) Mr. Budgell confirmed, under cross-examination by the IC, that the forecast peak for each year as shown in Schedule X of his evidence is derived from econometric modeling and is based on a combination of weather conditions and customer loads. (Transcript, Nov. 5, 2001, pg. 40/48-55) Only one peak is modeled and NLH does not care when it occurs, but only that it occurs. The fact that this system peak does not occur in February (as indicated in the LOLH

study) but in some other month is not relevant to the allocation of costs attributed to the various customer classes contributing to the system peak. NLH does not concern itself with trying to predict the second or higher coincident peaks nor does it have to for system planning purposes.

The Board is not convinced that the LOLH study provides sufficient evidence to justify using a 2 CP allocator for generation demand costs. Furthermore, the Board is not persuaded that the use of any other multiple allocator is correct in this situation. The Board finds that the evidence supports the use of a 1 CP allocator and the Board will order that NLH use a 1 CP allocator for allocation of generation demand costs.

3. Classification and Allocation of Distribution Costs

There are two methods normally used to split certain distribution costs between the customer and the demand component, namely the zero intercept method¹⁰ and the minimum system method¹¹. At the 1993 generic COS hearing NLH proposed that distribution costs be classified in accordance with the zero intercept method. The Board agreed with NLH's opinion that the choice of method had little impact on cost sharing between classes and accepted NLH's proposal at that time. However the Board had concerns with the method proposed to be used by NLH to obtain the zero intercept cost of poles. As a result the Board accepted NLH's proposed classification of distribution costs but required NLH to prepare a revised study of distribution costs for presentation to the Board at the time of its next rate referral (Recommendation #19, 1993 generic COS report). The Board also accepted NLH's proposal to allocate the distribution demand costs using a 1 CP allocator (Recommendation #20, 1993 generic COS report).

Mr. Brickhill outlined NLH's response to this recommendation in his pre-filed testimony stating that the requested study was first prepared in 1996, updated in 1998, and further updated in 2000 for the purposes of this filing. (Pre-filed Evidence, J. A. Brickhill, pg. 2) The 1998 study recommended the use of the zero intercept method because it avoids the classification of small components of total cost to demand, as is inherent in the minimum system study. Mr. Brickhill states that the current zero intercept results of the updated study are consistent with the similar analysis used in the 1992 rate hearing. (Pre-filed Evidence, J. A. Brickhill, pg. 4) He also stated that limitations in data availability still impair the preparation of a minimum system study. Copies of the 1996, 1998 and 2000 studies on the distribution system cost classification were filed in response to NP-123.

This issue did not receive much debate or examination at this hearing. The only COS witness who raised the issue was Dr. Wilson. He does not agree with the use of the zero intercept method to divide the distribution system costs between the customer and demand classifications. Dr. Wilson's position is that a "*zero load size methodology*" ignores the basic fact that the costs associated with investments in distribution lines and related equipment are part

¹⁰ Zero intercept method is the method which seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. It separates demand-related costs from customer-related costs by use of a regression equation.

¹¹ Minimum system method is the method of classifying distribution plant which assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. This is then valued at the average book cost and classified as customer related costs. The demand related costs for each account are the difference between the total investment in the account and the customer-related costs.

of an integrated power delivery network and have been sized to meet the expected loads placed upon them. They are not customer specific facilities that are causally attributable on the basis of customer counts. (Pre-filed Evidence, Dr. J. W. Wilson, pg. 28) Dr. Wilson states that:

“The consequence of the failure of the minimum-size or zero intercept methodology to provide a reliable basis for classifying customer-related costs is that the customer-related component of distribution facilities should largely be limited to clearly identifiable, directly assigned costs like accounting and billing, meters, and service line drops.”(Pre-filed Evidence, Dr. J. W. Wilson, pg. 30).

NLH confirmed in PUB-69 that most integrated utilities in North America rely on the minimum system method rather than the zero system method. NLH also clarified that the data limitations that preclude NLH preparing a minimum system study relate primarily to the way in which NLH’s system developed. NLH’s rural systems were acquired at various times from various entities, sometimes for a nominal fee, meaning that detailed records regarding the age and quantity of much of the distribution plant are not available.

It was not clear from the evidence in this hearing what cost impacts result for customers from the use of the zero intercept approach versus the minimum system approach. It is noted that in the 1993 generic COS report the Board accepted NLH’s opinion at the time *“that the methodology used does not have a great impact on cost sharing between classes”* (1993 generic COS report, pg. 47). Mr. Brickhill does acknowledge that the result of using the zero intercept methodology is a somewhat lower proportionate classification to the customer component than generally used by Canadian utilities. (Pre-filed Evidence, J. A. Brickhill, pg. 5) Although Dr. Wilson does not agree with the methodology, no other party contested NLH’s position and there is not sufficient evidence on the record to support or require further consideration by the Board at this time.

The Board finds that the use of the zero intercept method for classification of distribution system costs as proposed by NLH is an acceptable method for dividing distribution costs into demand and customer related components.

Both Dr. Wilson and Mr. Bowman also questioned NLH’s proposal to allocate all non-customer distribution system costs on the basis of coincident peak. They suggest that it is the local loads, and not the system coincident peak, that determine cost levels on the distribution system. Both propose that a non-coincident peak (NCP)¹² demand allocator for distribution capacity is generally thought to be more reasonable for cost allocation (Pre-filed Evidence, Dr. J. W. Wilson, pg. 17; Pre-filed Evidence, C. D. Bowman, pg. 8-9).

As pointed out by Mr. Brickhill, since there are no distribution costs allocated to NP and IC, this issue only affects NLH’s Island Interconnected Rural customers (whose rates are not determined by the COS), Isolated Rural customers, and Labrador Interconnected customers. Distribution load requirements on the rural isolated systems are not sized based on local loads but rather the anticipated peak, supporting the use of 1 CP allocator. On the Labrador Interconnected system the distribution network is sized based on a cold weather driven peak, also

¹² Non-coincident peak (NCP) is a customer’s maximum energy demand during any stated period.

supporting the use of a 1 CP method which, according to Mr. Brickhill, links cost causation and costs better than the NCP method in this circumstance. The use of the 1 CP allocator for distribution demand costs was not challenged by NP or the IC.

The Board accepts the use of a 1 CP allocator for distribution demand costs, as approved by the 1993 generic COS methodology.

4. Assignment of the Great Northern Peninsula Plant

The Great Northern Peninsula (GNP) interconnection involved an extension of the existing 138 kV line through to the St. Anthony/Roddickton area as well as interconnection of approximately 20 MW of generation to the grid. The GNP interconnection was completed in 1996 at a cost of \$31,418,995. NLH received \$5,000,000 from a Canada/Newfoundland Infrastructure grant resulting in a net cost of \$26,418,995. The estimated annualized net cost of the GNP Interconnection is \$2,290,000 (CA-35).

The following customer classes changed as a result of the interconnection: Rate 1.2 Domestic Diesel; Rate 1.23 Churches, Schools and Community Halls; and Rate 2.5 General Service Diesel. NLH confirms that all these classes benefited from the interconnection. (IC-125) As a result of the interconnection revenue decreased across these customer classes by approximately \$2,750,000 for 2000. (Actual revenue of \$1,400,000 at interconnected rates versus \$4,150,000 at diesel rates prior to interconnection.)

The Board examined the following issues surrounding NLH's proposed treatment of the costs of the GNP interconnection in the 1995 Study on Rural Electrical Service: 1) the prudence of the interconnection; 2) cost assignment; and 3) cost classification. In its final report to the Government the Board did not deal with the issue of prudence, stating clearly that, since the project had not come before the Board for review before the decision was made by NLH to proceed, the Board was not able to deal with this issue. The Board did, however, consider and make recommendations on NLH's proposals for the cost assignment.

The 1993 generic COS report includes a number of recommendations related to the treatment of costs for the GNP interconnection. These were outlined in the Board's 1995 Rural Electrical Service Report (pg. 39) as:

Assignment of Costs

- The cost of transmission dedicated to serve one customer should be specifically assigned¹³, and costs of (plant and equipment of) substantial benefit to more than one customer should be apportioned among all customers.

¹³ Specifically assigned costs are costs associated with services or products that are of benefit to a single customer or class of customers. This implies that the facilities can be considered entirely apart from the integrated system. Costs associated with services or products that are of joint benefit to all customers or classes of customers are referred to as common costs.

- Transmission lines dedicated to the service of Newfoundland and Labrador Hydro rural rate classes be included in a sub-transmission function, which means that the costs attributed thereto should be allocated exclusively to such classes.

Classification of Costs

- That the transmission lines and substations of the Island Interconnected system used solely or dominantly for the purpose of connecting remotely located generation to the main transmission system be classified in the same manner as the generation stations they serve.
- That all plant costs relating to gas turbine and diesel generation in the Island interconnected system be classified as demand related.
- That the cost of gas turbine and diesel fuel in the Island Interconnected system be classified to demand and that variable operating costs and all other fuel costs be classified as energy.

The issue of assignment of costs (common versus specifically assigned) was considered at the 1995 hearing on Rural Electrical Service. The Board's report outlines the position of NLH and NP at pg. 6/42-43. NLH argued at the time that the interconnection is of benefit in three ways: (1) it provides additional generation reliability to all customers; (2) the plant provides emergency back-up and energy to the GNP area; and (3) the capacity of the plant defers future peaking capacity additions. For this reason NLH proposed treating the generation assets as common. NP disagreed, stating NP's requirements did not cause the St. Anthony/Roddickton system to be interconnected, nor do NP's customers receive any benefit from the interconnection. NLH proposed in 1995 to treat the generation plant as common and to treat the related transmission line as specifically assigned to rural interconnected. It was noted that more than one customer will be served by the transmission line extension to the GNP. (1995 Rural Electrical Service Report, pg. 43)

In the 1995 Rural Electrical Service Report (pg. 43) the Board stated that it did not feel it had sufficient evidence before it to make a final determination on the issue. The Board was also concerned with the inconsistency in treatment between the generation and transmission assets. As a result the Board made an interim cost treatment decision until further information was presented at a future hearing as stated below:

"The Board concludes that the treatment of the Great Northern Peninsula interconnection by Newfoundland and Labrador Hydro in its cost of service study requires modification. Until such time as a more detailed study of proper assignment for the rural interconnected system can be concluded, the following recommendations are proposed: both the 138 kV transmission line and generation assets should be treated as common in the assignment of costs; and transmission assets, related to transmission lines of lesser voltage, should continue to be treated as specifically assigned, through a sub-transmission function. This treatment is of an interim nature until the Board re-examines the cost assignment rules at a future hearing."

This recommendation was also carried forward to the Board's 1996 Report on Rural Electrical Service.

Clearly the Board felt that, at the time of the 1995 hearing, it did not have sufficient information or evidence before it to make a final decision on cost assignment for the GNP. The question at present is whether the Board now has the evidence to make a final determination on the issue. NLH did not submit further studies or evidence in the present Application to support the interim recommendation of the Board. NLH merely stated that it concurred with the recommendation of the Board and that it had prepared its Application based on that recommendation. The evidence that the Board now has before it to consider this issue as set out in the pre-filed testimony of Mr. Budgell, information requests and cross examination of NLH witnesses.

NLH has proposed in this Application that generation and associated transmission assets on the GNP be assigned as common consistent with the Board's 1996 recommendation. IC-215 describes the guidelines that NLH has proposed in order to apply the Board's 1996 recommendation consistently across the Island Interconnected system. In its guidelines NLH is proposing that, in situations where transmission and terminal station equipment connect a single customer and remote generation to the grid, that the transmission and terminal equipment would be assigned common if, under any normal operating scenario, the output of the remote generation can be delivered to the 230 kV grid. (IC-215, pg. 3)

NLH further defined the guideline by putting forward a test that, if under light load conditions the combined generation on the radial line exceeds the radial load, the assets would be assigned common. This test was applied to radial systems on the Island and, in addition to the assignment of GNP assets to common, resulted in reassignment of the Doyle's-Port aux Basques system from NP specifically assigned to common, and confirmed the existing assignment of the Burin Peninsula to common.

The IC argue that the generation plant on the GNP is not of benefit to the grid but accept that it could be assigned common until Granite Canal is in service. The IC submit that GNP transmission assets should be specifically assigned to NLH's rural customers. The IC do not agree that inconsistency in treatment between the generation and transmission assets is a problem (Osler, pg. 49). In final argument the IC submit that the Board should not approve the proposed changes in assignment of plant unless NLH or some other intervenor can satisfy the Board that these assets provide substantial benefit to more than two customers of NLH.

IC-180 (Rev. 1) shows the cost implications of the change in assignment of 138 kV and 66 kV transmission lines and associated terminal station equipment connecting Hawke's Bay, St. Anthony and Roddickton generation from NLH rural to common. It shows the allocated costs to NP will decrease by \$10,000 and allocated costs to the IC will increase by \$1,458,000.

The Board has insufficient evidence to accept NLH's proposed change in assignment of GNP assets to common. While the GNP generation can exceed the radial load under specific low load conditions, it is not clear that this scenario would actually provide any benefit to the Island Interconnected customers since this is not when the generation would be needed by the

system. IC-128 shows that the annual generation from GNP assets has constituted on average less than 3% of the GNP annual radial load since interconnection with the St. Anthony and Roddickton diesel units operating only for planned and forced outages.

It is clear that during the 1995 inquiry on Rural Electrical Service the Board contemplated further detailed study of the assignment of transmission assets on the GNP before making a final determination. NLH has, in this Application, accepted the Board's interim recommendation of the 1996 report on plant assignment, but has not provided sufficient evidence in the form of a detailed study to justify the assignment.

Based on the evidence before it at 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 Doyle-Port aux Basques assets from NP specifically assigned to common is also not accepted. The Board will reconsider this issue at NLH's next rate hearing. 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 Doyle-Port aux Basques and the Burin Peninsula systems to the grid.

5. Assignment of Frequency Converters

The rationale for installing the frequency converters at the time of development of Bay D'Espoir and the construction of the Island Interconnected grid is explained in IC-55 and IC-56. It is clear the development of the single frequency system as we know it today would not have occurred had the frequency converters not been installed. The economics and technical merits of proceeding with the Bay D'Espoir development and interconnecting the 50 and 60 cycle systems was dependent on the installation of the frequency converters. The Newfoundland and Labrador Power Commission received a grant from the Atlantic Development Board to cover the cost of purchasing and installing the frequency converters in Grand Falls and Corner Brook. Both converters are owned and maintained by NLH.

In the initial years of the Island Interconnected system the frequency converters provided the mechanism that allowed the 50 Hz and 60 Hz systems to be interconnected and function as a single system and for this reason they were treated as a common cost. It is also clear that it was intended that the Island Interconnected system was to develop as a 60 Hz system and that conversion of existing 50 Hz systems was to take place over time.

In response to IC-55 NLH states that there is very little 50 Hz load remaining on the system today and the operation of the frequency converters has little impact on the 230 kV system voltage levels and hence the operation of the interconnected system. (IC-59, pg. 1/13-15) The role of the frequency converters has been reduced to providing local voltage control for the paper mill power systems and transferring power from 50 Hz to 60 Hz for use within the individual paper mills. NLH proposes that, since these assets are of benefit to only these

industrial customers, the costs associated with the frequency converters should be specifically assigned to these customers.

The IC submit that the frequency converters should continue to be assigned as a common cost to recognize the role that industrial customers have played in the development of the interconnected system on the Island, including absorbing significant conversion costs. In final argument (pg. 41-42) the IC describe the historical basis and understandings that existed between the industrial customers and NLH in respect of the continued support that NLH would provide in respect of the frequency converters.

During the hearing Abitibi Consolidated in Grand Falls confirmed that the frequency converter at that location would be decommissioned in the spring of 2002. (NLH-16) The converter at Corner Brook is still required to convert 50 cycle generation from Deer Lake Power to 60 cycle for use in the mill. It was also suggested by the IC, and acknowledged by Mr. Budgell, that the frequency converter at Corner Brook could be used to supply emergency power to the grid. (Transcript, Nov. 8, 2001, pg. 4/40-91) Mr. Budgell was uncertain however as to the conditions under which NLH would require this power.

In final argument (pg. 71) NLH states *“The issue before the Board is whether the frequency converters should continue to be treated as common, because of the benefit to the grid they provided at the time of construction and for a period of time thereafter, when, at this particular point in time, they are of benefit only to the two industrial customers being served.”* NLH submits that based on the normal tests that are applied for assignment of plant, the frequency converters should be specifically assigned and that the historical usage is no longer relevant.

IC-134 (Rev.1) indicates that the cost impact of the change in assignment as proposed by NLH of the frequency converters from common to specifically assigned is a decrease of \$140,000 for NP and an increase of \$141,000 in costs assigned to the IC.

The Board agrees with NLH that the frequency converters should be specifically assigned to the industrial customers as they are of benefit to only those customers. The suggestion that a previous assignment of plant would not be able to be changed if the circumstances for the original assignment changed is neither acceptable nor reasonable.

The Board accepts NLH’s proposal that the frequency converters be specifically assigned to the IC in the COS.

6. Treatment of Non-Firm Load/Demand Credit

NLH has the ability to access peaking capacity for the system from both the IC and NP. In the case of the IC, NLH has a contract with Abitibi Consolidated in Stephenville which gives it the right to interrupt its load under certain defined conditions. For this right to interrupt Abitibi Consolidated is compensated on an annual basis in the amount of approximately \$1,300,000 plus an additional payment when interruption occurs (Interruptible “B” credit). In the case of NP, NLH has the option of requesting that NP use its generating plant to supply power to the system.

Compensation to NP for this right is provided through a generation credit in the COS study. The calculation of the credit is based on NP's installed capacity, with the capacity credit calculated as shown in NP-126. The net generation credit removes the contribution from hydraulic sources and is calculated as 77.8 MW. (Supplementary Evidence, C. F. Osler, pg. D-1/24-32) The peak demands for NP in the COS study are reduced by this amount of the net generation credit.

The IC raised an issue of apparent inconsistency in approach by NLH in compensation treatment of non-firm loads for NP and the IC. Mr. Osler states overall “ *Hydro has not presented a consistent approach to addressing non-firm loads (including industrial non-firm energy, industrial Interruptible ‘B’ and NP interruptible demand via self-generation) in the COS modelling*”. (Supplementary Evidence, C. F. Osler, Sept. 12, 2001, pg.20/19-21).

In final submissions the IC summarized its position on this issue:

“One of the problems that we have with the generation credit is that it treats NP’s generation as if it’s serving the system all of the time, and it’s not, so NP’s peak is treated as if it is generating it’s own energy all of the time and it only generates that energy on their circumstances. This shifts costs to the industrial customers for every single hour of generation and we don’t think that that’s fair...” (Transcript, Jan. 28, 2002, pg. 34/48-55)

The IC’s position is that the compensation that NP receives for generation credit is out of proportion to what it should be. (Transcript, Jan. 28, 2002, pg. 34/71-78)

Both Mr. Brockman and Mr. Brickhill agree that NLH’s approach of treating the IC and NP differently through the generation credit and the Interruptible ‘B’ credit is fair to each party (Transcript, Dec. 4, 2001, pg. 35/40-43; Transcript, Nov. 26, 2001 pg. 37/55-66). Mr. Brockman testified that treatment of the generation credit in the same way as the Interruptible ‘B’ credit in the cost of service study would result in the vast majority of the cost being charged to NP. Mr. Brockman argued that this approach would be unfair as it amounts to NP paying NLH for its own generation. NLH also stated that, if NP’s generation capacity was not recognized, NP could opt to run its own generation in order to reduce its purchased power costs. This option may result in higher costs on the system.

The Board is not convinced that there is any inherent unfairness in the methods in which NLH treats the non-firm load and demand credit for the IC and NP. While the end result of the Interruptible ‘B’ credit and the generation credit is the same i.e. additional energy is available to the system when needed, the mechanisms are different and hence it would be expected that the method for compensation would be different.

The Board accepts NLH’s treatment of the generation credit for NP and the Interruptible ‘B’ credit for the IC.

7. Classification of Hydraulic Plant

In the 1993 generic COS report (Recommendation # 9) the Board concluded the classification of hydraulic and thermal plant in the cost of service should be done on the basis of operating parameters and recommended:

“That portion of hydraulic plant costs in the Island Interconnected System equal to the annual system coincident load factor be classified as energy-related and the balance be classified as demand-related.” (1993 generic COS report, pg. 38)

The IC have raised the issue of how NLH calculates the annual system coincident load factor, suggesting that NLH has made a mistake in this calculation. This argument is similar to the IC’s concern about NLH’s treatment of the NP generation credit as a reduction in NP’s coincident peak for allocating generation demand costs. The generation credit is also used to reduce NP’s coincident peak for the purposes of calculating the Island Interconnected system load factor. (IC, Final Argument, pg. 44-45/17-14)

Under cross examination by the IC, Mr. Brickhill agreed that this “*adjusted*” coincident peak reduces NP’s net system coincident peak contribution, resulting in the cost of service not capturing NP’s actual relative contribution to system peak. (Transcript, Nov. 27, 2001, pg. 20/86-93; pg. 21/1-3) The IC argue that this results in more costs being assigned to the IC. In final argument (pg. 48) the IC submitted that NLH’s use of an “*adjusted*” load factor is contrary to the methodology directed by the Board in the 1993 generic COS report for classification of hydraulic plant.

In its final submission NLH states that its treatment of NP’s capacity, which can be supplied at system peak, is consistent. If there were no demand credit given to NP, then NP would forecast its own generation at the time of peak, reducing its demand required from NLH. NLH submits that “*this reduced demand is used for both costing to NP as well as for the system load factor, since, if NP used its own generation at peak, the adjusted demand is all that would be required to be produced on Hydro’s system.*” (Transcript, Jan. 28, 2002, pg. 13/5-10)

The Board has already addressed the issue of the generation credit for NP and has accepted NLH’s treatment of both the generation credit for NP and the Interruptible “B” credit for IC. The Board does not agree with the IC that NLH’s calculation of the system load factor for the cost of service is contrary to the 1993 generic COS methodology. Adjusting NP’s coincident peak with the generation credit recognizes NP’s contribution to the system peak through their own generation sources.

The Board accepts NLH’s treatment for classification of hydraulic plant as being in accordance with the 1993 generic COS methodology.

8. Transformer Losses

NLH delivers power to all customers except Corner Brook Pulp and Paper Ltd. and its rural customers at transmission level voltages. Because metering is at a lower level, voltage losses occur from the delivery point to the metering point. In the past, these losses have been paid for by all customers as no adjustment was made to metered quantities to account for the losses.

NLH is proposing that the rates for NP and IC be based on transmission supplied to the line side terminals of customer owned or specifically assigned transformers. This proposal will result in losses associated with the customer owned or specifically assigned transformer being assigned to that particular customer or customer class. NLH submits that this treatment of the losses is fairer and more equitable and is in accordance with proper cost recovery.

IC-227 shows the customer impact of this proposed change in treatment of transformer losses. The net effect is a decrease in assigned costs to NP of \$5,276 and a net increase to the IC of \$6,600. The impacts on specific industrial customers is shown below:

Abitibi Consolidated – Stephenville	\$ 29,531
Abitibi Consolidated – Grand Falls	10,447
Corner Brook Pulp and Paper Ltd.	(41,405)
North Atlantic Refining	<u>8,027</u>
Net difference	<u>\$ 6,600</u>

The IC submit that the Board should reject NLH's proposal to change its treatment of transformer losses on the basis that NLH's proposal is unfair to customers and will not result in consistent treatment of transformer losses among customers. The IC propose that NLH should absorb transformer losses from 230 kV to 66 kV and that the losses from 66 kV to usage voltages should be absorbed by the customers. (IC, Final Argument, pg. 57)

The Board agrees with NLH that the proposed treatment of transformer losses is fairer and is in accordance with proper cost recovery principles.

NLH's proposal for treatment of transformer losses is accepted.

9. Labrador Interconnected System

i) Cost of Service

Customers in the Happy Valley/Goose Bay area, Labrador City and Wabush are supplied with electrical energy from Churchill Falls. NLH has an agreement with CF(L)Co to purchase recall power and energy up to a maximum of 300 MW and 2,352 GWh annually.

On the Labrador Interconnected system, 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 13 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 326 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 27 MW gas turbine and a 11.7 MW diesel plant in Happy Valley/Goose Bay to meet system emergencies. The gas turbine is remotely operated by NLH's Energy Control Centre. Approximately 8,700 customers are served on the Labrador Interconnected system.

In this hearing LC/W have objected to a single cost of service for the Labrador Interconnected system. Their position is that *"the Labrador Interconnected system consists of two discrete systems, one in the Happy Valley/Goose Bay area and the other in the Labrador West area, with respective systems having different histories, dealing in different economies and different cost bases"*. (LC/W, Final Argument, pg. 10) While acknowledging that there are common generation costs in that energy for each system is generated by CF(L)Co at Churchill Falls, LC/W submits that the system consists of separate transmission and distribution systems for the Labrador West and Happy Valley/Goose Bay areas and that there are no common costs.

It is NLH's position that all of the customers on the Labrador Interconnected system are served by the same source of power, and that normal policy is that if customers are served from the same system or grid, each should pay the same rates. (NLH, Final Argument, pg. 79)

No other intervenors took a position on this issue.

The issue of the COS methodology for the Labrador Interconnected system was examined in the 1993 hearing on the generic COS at which the Towns of Labrador City and Wabush appeared as intervenors. On Pg. 10 of the 1993 COS methodology report the Board found that:

"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. 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."

NLH was also directed to use the 1993 generic methodology at their next rate application and, as a result, NLH filed a single COS for the Labrador Interconnected system in this Application. No evidence was submitted in the present hearing to convince the Board that costs in Labrador Interconnected system are not properly allocated by the approved generic COS methodology.

The Board has already ruled in the 1993 generic COS methodology that there be a single cost of service study for the Labrador Interconnected system and is not persuaded that there is sufficient evidence to reconsider the matter at this time.

ii) Generation Demand Allocator

NLH is proposing in this Application a change in the allocator for generation demand costs on the Labrador Interconnected system.

The Board approved, as proposed by NLH at the time, the use of an Average and Excess Demand (AED) allocator for generation demand cost for Labrador Interconnected and Rural Isolated systems at the 1992 Cost of Service Hearing. NLH is now proposing a 1 CP allocator for allocation of generation demand costs to be consistent with the Board's determination in the 1993 generic COS report that a CP allocator was appropriate for the Island Interconnected system (instead of an AED allocator as proposed). Mr. Brickhill states that the seasonal peak, based largely on heating load, supports the use of a single CP allocator for the Labrador Interconnected system (Pre-filed Evidence, J. A. Brickhill, pg. 12). Additionally there is little probability of a loss of firm load on the Labrador Interconnected system. The use of a CP allocator is also beneficial for allocating the rural deficit between systems (NP-136). No other party opposed or took a position on this issue.

The Board accepts NLH's proposal and reasons to use a 1 CP allocator for generation demand costs for the Labrador Interconnected system.

VIII. RURAL SYSTEMS

1. NLH Proposals

NLH proposes under Section 14 of the Application the following:

- (1) that the rate charged NP be increased, as of January 1, 2002 to 48.0 mills/kWh (This was revised as of Oct. 31, 2001 to 47.84 mills/kWh);
- (2) that the existing policy be continued of allowing NLH, as NP changes its rates, to automatically adjust the rates which it charges its Island Rural Interconnected Customers, its customers serviced from the L'Anse au Loup System, and its Isolated Rural Customers, other than Government departments and agencies, for the first 700 kWh per month of consumption, so that such rates are the same as the rates charged by NP to its customers;
- (3) that the existing policy be continued of allowing NLH to charge rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural Customers other than Government departments and agencies, by the average rate of change (i.e. increase or decrease) granted to NP from time to time;
- (4) that the “*preferential rates*” policies which traditionally have been made available to certain Rural Customers (fish plants and selected other organizations) be continued for the present.

In its final argument (pg. 44) NLH confirms:

“Hydro is proposing the continuation of the existing policy that will set rates for all customers served on Hydro’s Island Interconnected System to be the same as rates charged by NP to its customers. Hydro is also proposing to continue the policy that the rates for the first 700 kWh of consumption a month in the isolated rural areas be the same as that charged by NP to its customers. Hydro submits that the continuation of these long standing policies for rate design be continued and... that it is not appropriate to adjust the return on equity because of the rural subsidy arising from the implementation of these rate policies. Like any other element in the cost of service, the Board must deal with the costs associated with serving Rural Customers through the issues of revenue requirement and through rate design. Should the Board wish to change these policies, then it must direct a change in rate design on the basis that the rate policies for Rural Customers are no longer acceptable.”

2. Public Policy Considerations

The term “*rural customers*” encompasses NLH’s isolated and interconnected rural Island customers, a total of 26,200. At the time of this application, the Island Interconnected system served 21,800 rural customers residing in 181 communities. There are also 25 isolated diesel systems serving 4,400 rural customers in some 45 communities. Sixteen isolated diesel systems are located along coastal Labrador and have an installed capacity of 20,896 kW. Nine isolated

diesel systems are on the Island with an installed capacity of 7,858 kW. All isolated rural systems are serviced by NLH generation, with two exceptions. At Mary's Harbour, in addition to diesel generation, NLH purchases energy from a small privately-owned hydro plant. On the L'Anse au Loup system, NLH purchases secondary energy from the Lac Robertson hydro plant. When this is not available, NLH uses its diesel generation at L'Anse au Loup.

In 2002 the net deficit for all of NLH's rural interconnected and isolated systems is projected at \$31,700,000. Of this amount, \$21,600,000 is attributable to the operation of the isolated systems.

The Board acknowledges that rural rates and the treatment of the rural deficit are some of the more prominent and controversial issues arising from this hearing. Decisions on these issues now and into the future will have far reaching economic and social consequences for the people of Newfoundland and Labrador. The Board cautions there are no easy solutions to these issues and likely no solutions that will satisfy all expectations. During the hearing, those subsidizing the deficit disapproved of substantial cross-subsidization, those who were to begin subsidizing the deficit were opposed to it, and subsidized rural customers wanted lower overall rates leading to greater cross-subsidization.

As set out in the historical perspective (See pg. 11 of this decision), existing rural electrification policies have evolved from specific decisions of Government and have been in place for a number of years. CA-2 contains the Board's 1995 report and its 1996 revision. These reports resulted from a referral by Government requesting the Board to investigate rural electricity services in the Province. The recommendations contained in these reports proposed significant changes to existing rural rate policies. Government did not act on these recommendations and the Board received no follow-up communication. Outside of excluding the IC from sharing in the rural deficit and the interconnection of certain isolated diesel systems, no policies influencing rural systems have changed in more than a decade.

In NP-214 NLH describes public (social) policy objectives of Government affecting NLH's actions or the nature of its services, and which are included in the 2002 test year revenue requirements. These items result from direction of NLH's shareholder and in terms of rural rates policy include:

- Customers served on the Rural Interconnected system would be charged the same rates as NP's customers.
- Life line rate block for Isolated Rural customers of 700 kWh per month;
- Preferential rates for certain rural customers;
- Payment of the rural deficit by NP and Labrador Interconnected customers.

Mr. Wells confirmed that the subsidization of the rural deficit by other customers is a matter of social policy. (Transcript, Sept. 24, 2001, pg. 31/34-39)

Before embarking upon its decision regarding rural rates, the Board must determine how established Government policies are to be treated from a regulatory perspective.

Section 4 of the *EPCA* states:

“In carrying out its duties and exercising its powers under the 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 the first instance, the Board is clearly bound by Government policy contained in its governing legislation. The Board notes none of the rural rates policies outlined by NLH are specifically contained in Section 3 of the *EPCA*.

Following statutory authority, the second source of binding Government policy is the Lieutenant-Governor in Council. Section 5.1 of the *EPCA* , declares:

“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.”

No Orders in Council affecting rural rates have been issued under this authority. The Board notes that each of the rural rates policies identified in NP-214 have resulted from Orders in Council issued prior to the granting of this authority. From a regulatory perspective, the primary issue for the Board is how to treat existing public policy established at the time when NLH was not regulated by the Board.

Ms. Greene stated NLH’s position on this issue, as follows: (Transcript, Sept. 27, 2001, pg. 5/33-47)

“Our position is that Hydro is a fully-regulated utility under The Public Utilities Act. If direction is to be given by Government on such issues, it will be given to the Board under Section 5.1 of The Electrical Power Control Act. Part of the historical problem is that in approaching this hearing we had historic rates which may have been based on previous orders-in-council and the issue for the Board is how to deal with our historical context. Originally it was set by order-in-council which would be viewed by this Board and accepted by this Board as a means of how rates were designed for rural customers, but on a go-forward basis, if Government were to issue direction, it would have to be to the Board under Section 5.1 of The Electrical Power Control Act and that’s Hydro’s position for this hearing.”

The Board found little other evidence to guide its decisions in this area. Intervenors, for the most part, did not articulate a firm position but generally imbued the Board with discretion regarding existing rural rates policies.

The Board concurs with the position of NLH and concludes it has discretion. If direction is to be given by Government on rural rate policies in future, it must be given to the Board under Section 5.1 of the *EPCA*. While not bound by previous Orders in Council, the Board will give regard to established social policies of Government. The Board will examine each rural rate policy on an individual basis and will assign appropriate weight to the evidence including the longevity and clarity of the policy.

3. Rural Deficit

The rural deficit arises from the fact that rural customers are paying rates that are lower than the costs of providing them with electrical service. In essence, NLH is experiencing losses on its rural systems. As reviewed in the history of rural electrification, Government subsidized these losses until 1989 when NLH was directed to begin recovering the rural deficit from all its customers. The only change in this policy was the amendment in the *EPCA* eliminating the IC from sharing in the rural deficit as of December 31, 1999.

The rural deficit for the 2002 test year is contained in Mr. Brickhill's revised cost of service as follows:

Rate Class	Rural Deficit	Revenue to Cost Ratio
	(\$)	(%)
Island Interconnected	8,672,891	78
Island Isolated	7,368,299	15
Labrador Isolated	14,252,129	23
L'Anse au Loup	<u>1,399,780</u>	<u>45</u>
Total	<u>\$31,693,099</u>	<u>55% (Avg.)</u>

(3rd Supplementary, J.A. Brickhill, Schedule 1.2, pg. 3)

In 2002, the projected deficit for all of NLH's systems is \$31,693,099 with \$21,620,428 of this amount attributable to the operation of the isolated systems. Average cost recovery on the rural system is 55% ranging from 15% on the Island isolated system to 78% on the Island interconnected system.

This Application also represents the first occasion NLH is implementing Government's 1989 directive to recover the rural deficit from all NLH customers, hence the inclusion of the Labrador Interconnected system. As evidenced below, in accordance with the 1993 generic COS methodology, 87.1% of the rural deficit will be allocated to NP's customers and 12.7% to NLH's Labrador Interconnected customers.

Rate Class	Rural Deficit Allocation	
	\$	(%)
Newfoundland Power	27,616,380	87.1
CFB Goose Bay Secondary	64,408	0.2
Labrador Interconnected	<u>4,012,311</u>	<u>12.7</u>
Total	<u>\$31,693,099</u>	<u>100.0</u>

As per the 1996 *EPCA* amendment, the 2002 test year for the first time reassigns the IC's share of the rural deficit following the expiry of its contribution in December 1999. CA-151 indicates the amount of the IC deficit absorbed by NLH over the past two years, i.e. 2000 (Actual) - \$4,760,666 and 2001 (Forecast) - \$5,037,347.

Witnesses are varied in their comments on the rural deficit. While most acknowledged cross-subsidization among ratepayers is a common practice in regulated industries, some commented on the relatively large subsidy contributed by ratepayers in this situation.

NLH in its final argument quotes Ms. McShane, Mr. Hall and Dr. Kalymon as supporting its position that no adjustment to return on equity is warranted and this is consistent with practices demonstrated elsewhere where social policy is incorporated into the utility's rate design. (NLH, Final Argument, pgs. 41-44) NLH continues its argument by remarking that Mr. J. T. Browne is the only witness to suggest an adjustment to NLH's rate of return to account for social policy objectives. (NLH, Final Argument, pg.40) Indeed Mr. J.T. Browne indicates, in considering a commercial rate of return for NLH, the Board may assess whether to effectively direct part of the rural deficit as a return to the owner. (Transcript, Nov. 1, 2001, pg. 35/9-23)

The Board also notes positions taken by other witnesses. Mr. Brockman stipulates that, if NLH expects to earn returns commensurate with investor-owned utilities, there must be recognition of the financial impact of these "*shareholder decisions*". (Pre-filed Evidence, L.B. Brockman, pg. 6/22-23, pg. 7/1-3) Mr. Brockman further observed there is no economically justifiable reason for having a long term goal of serving any class of customer at 20%-50% of its cost of service and recommends that NLH be required to implement a plan with the Board to begin eliminating these subsidies within the next five years. (Pre-filed Evidence, L.B. Brockman, pg. 27/1-4).

Mr. Bowman contends if the Government wants to apply its social policy through reduced electricity rates for consumers in isolated areas, then Government should pay for it. The Government provides a more efficient vehicle for collecting what amounts to a tax involving the rural rate subsidy. (Pre-filed Evidence, D. Bowman, pg. 23/4-7) Mr. Bowman concludes the energy policy review might be a good way to address this issue. (Transcript, Dec. 6, 2001, pg. 26/89-90)

Dr. Wilson recommends the Board consider developing an evidentiary record regarding the extent to which the rural deficit should be reduced and the extent to which universal service should be subsidized. He states NLH should continue to cover the rural deficit based on equity considerations that the Board deems appropriate. (Pre-filed Evidence, Dr. J.W. Wilson, pg. 8/18-20; pg. 9/1-5)

In final argument NLH proposes the continuation of the existing policy that will set rates for all customers served on NLH's Island Interconnected system to be the same as rates charged by NP to its customers. NLH is also proposing to continue the policy that the rates for the first 700 kWh of consumption a month in the Isolated rural areas be the same as that charged by NP to its customers. NLH submits that the continuation of these long standing policies for rate design be continued. Like any other element in the cost of service, the Board must deal with the costs associated with serving Rural customers through the issues of revenue requirement and through rate design. Should the Board wish to change these policies, then it must direct a change in rate design on the basis that the rate policies for Rural customers are no longer acceptable. (NLH, Final Argument, pg. 44/1-14)

NP's final argument submits that the current levels of cross-subsidization which result in NLH's Labrador Interconnected customers and NP's customers paying a forecast total of \$31,700,000 in subsidies in the test year has significant discriminatory aspects. Future direction of this issue is a matter of regulatory policy which the Board must address in considering NLH's Application. (NP, final argument, pg. B-3; B-4) In its final argument, NP also recites Mr. Brockman's and Dr. Wilson's evidence and submits that NLH be required to report annually to the Board on its progress in the management of the rural deficit. This reporting will develop an evidentiary record regarding the extent to which the deficit can and should be reduced. (NP, Final Argument, pg. F-7)

LC/W in its final argument refers to legislation, particularly the Canadian Constitution Act, legal articles and case law in concluding the proposed allocation of the rural deficit is discriminatory and inappropriate and ought to be collected as a tax on the entire electrical production base of the Province, including electrical production exported from Churchill Falls. LC/W submits that the Board would be in serious dereliction of its statutory obligations to electrical consumers if it imposed the rural rate subsidy as requested by NLH. LC/W further submits the Board should instead recommend legislation to encompass as a base all electrical production, including exports, on which to impose the burden of such a subsidy. (LC/W, Final Argument, pgs.18-22)

Neither the IC nor the CA made specific comment on the rural deficit in their final arguments.

In this hearing the Board heard little evidence directed toward this kind of substantive change proposed in the 1995 and 1996 reports. Apart from LC/W, no Intervenors advocated dramatic change in the current treatment of the rural deficit.

The Board concurs that a measured approach to addressing this important issue is in the interest of all parties. The Board agrees that an evidentiary record should be developed to

determine the extent to which electrical service in the Province should be subsidized and who should pay for any subsidy. NLH should avail of this opportunity to apprise its shareholder, Government, on the impact of these existing policies and encourage Government to appropriately evaluate its future social policy options. On the heels of these findings, the recently initiated Electricity Policy Review affords a timely opportunity for Government and NLH to examine and co-ordinate its review of historic rural rates policies in a strategic context. This approach would respect both the public policy role of Government and the regulatory role of the Board.

In compiling this evidentiary record some comments by the Board on the rural deficit may prove useful to NLH.

1. Magnitude of Subsidy

The 2002 total deficit for all rural customers is \$31,700,000 with \$21.6 or 68% attributable to isolated rural customers. The average subsidy, as calculated by the Board, for each isolated rural customer is \$5,232 per year (up from \$3,082 in 1995) while for interconnected customers the annual subsidy per customer is \$398 per year (down from \$475¹⁴ in 1995). On the isolated systems an estimated 20 cents for each dollar spent is recovered from customers whereas on the interconnected system in excess of 70 cents on the dollar is recovered. Between 10-13% (average) of the revenue collected from an unsubsidized customer goes toward the rural deficit. Sales to customers covered by the rural deficit represent roughly 10% of NLH total electricity sales.

While cross-subsidization among ratepayers is a common practice, witnesses noted the magnitude of the subsidy is of fundamental importance. The Board acknowledges the burden the rural deficit places on subsidizing ratepayers and is concerned with the potential for increasing levels of subsidization. The Board notes that rising costs, and hence higher subsidies, may place an even greater burden on ratepayers who have no ability to control these costs but are responsible for paying them.

2. Future Options

The Board refers to its statutory obligations in implementing rates that are in accordance with the provincial power policy. Section 3.3 (a) (i) of the *EPCA* states “*the rates to be charged ... should be reasonable and not unjustly discriminatory*”. Depending on the level of subsidy paid by one customer to support equitable rates for another customer, rates may be judged unreasonable and discriminatory to the subsidizing customer. The alternative, commensurate with reducing this subsidy, would be to change rate design to shift additional costs to rural customers. This reallocation, it could be argued, may not provide reasonable or non-discriminatory rates to rural customers. Under these circumstances, the only effective means of implementing the provincial power policy is to transfer some or all the rural deficit to NLH or its shareholder, Government. The question of who should share in this continuing liability, either rural customers, other customers, NLH and/or Government, may become a central

¹⁴ This reduction is attributable to the GNP Interconnection and the elimination of these costs from the rural deficit.

issue for the Board in future. The Board notes that a number of witnesses supported social policies being reflected as a cost to Government with the proposed options varying from adjusting shareholder return to recovering this cost through appropriate taxation. The Board is not inclined to adjust NLH's regulated 3% ROE in this Application and is of the view that taxation is a prerogative of Government beyond the control of this Board. The Board feels strongly, however, that discussions involving NLH and Government around future funding options for the rural deficit should constitute part of the evidentiary record.

In summary, the Board has identified a number of concerns involving the rural deficit. The Board sees little in this Application by way of specific initiatives presented by NLH to address these concerns and better manage this deficit. The only notable step is the proposed 20% increase in rates to Provincial and Federal Government departments which will decrease the deficit by \$136,119 or less than half of one percent in the test year. (2nd Supplementary Evidence, P. R. Hamilton, pg. 9, Table 2) The Board finds the lack of progress by NLH in addressing and reducing the rural deficit unacceptable and concludes an evidentiary record should be developed by NLH on this important issue. The evidentiary record should contain a comprehensive assessment incorporating the magnitude of existing subsidies and comparative practices elsewhere along with an evaluation of future funding options relative to the rural deficit. The Electricity Policy Review may present a timely opportunity to address the rural deficit in a strategic context. Without this evidentiary record, the Board is not confident the rural deficit can be addressed in an appropriate and effective way at a future rate hearing.

The Board will direct 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.

4. Rural Rates

Rural rates, which have been established as a matter of public policy by Government since 1975, have been set based on NP rates and have fluctuated up or down depending on respective adjustments.

The Board heard no specific evidence on changing this policy as a means of reducing the rural deficit. This policy is subject to the same evidentiary considerations described by the Board beginning on pg. 120 of this decision. Depending on the options selected, clearly a change in the existing relationship between NLH rural rates and NP rates may produce dramatic results impacting the rural deficit. The Board notes the status quo was not objected to by any Intervenor and concludes this policy should be reviewed along with others as part of the evidentiary record on the rural deficit ordered by the Board.

The Board will order that the existing policy be continued of allowing NLH, as NP changes its rates, to automatically adjust the rates it charges its Island Rural Interconnected customers, its customers serviced from the L'Anse au Loup system and its Isolated Rural customers for the first 700 kWh per month of consumption, other than Government departments and agencies, so that rates are the same as the rates charged by NP to its customers, and to automatically change the rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural customers, other than Government departments and agencies, by the average rate of change granted to NP.

5. Preferential Rates

A variety of general service customers including the Provincial and Federal Governments benefit from preferential rates. Apart from Governments themselves, the treatment of these preferential customers has evolved over the years resulting from public policy as directed through Orders in Council.

Since the beginning of rural electrification, Provincial and Federal departments and agencies have been the recipients of preferential electrical rates in communities served by diesel generation. For the most part, Government owned and funded these first diesel installations and in return received preferential rates. These preferential rates for government departments and agencies continue to the present day.

In 1996 the Board recommended that *“a new rate be designed for federal and provincial departments and agencies, and these rates, phased in over five years, should recover full costs.”* (CA-2; Report on Rural Electrical Service, July 1996, pg. 32). *“Government departments and agencies”* includes provincial and federal government departments, agencies, boards, commissions and crown corporations and includes schools and hospitals.

In this Application, NLH has accepted this recommendation. In order to move to full cost recovery for government departments and agencies, rates would have to increase by approximately 280% (Pre-filed Evidence, D. W. Osmond, pg. 12/11). NLH has proposed that these customers receive an overall initial 20% increase in rates, including the general rate increase, effective January 1, 2002. As part of its next rate application, NLH further proposes it will submit a rate plan outlining rate alterations over a five-year period to achieve full cost recovery. (NLH, Final Argument, pg. 76/28-31) A 20% increase in rates for government departments and agencies on the rural system will result in an additional \$136,119 in revenue (2nd Supplementary Evidence, P. R. Hamilton, pg. 9, Table 2). Once the phase in period is completed, NLH will receive approximately \$2,000,000 in additional revenue. (Transcript, Sept. 25, 2001, pg. 24/42-44)

The only issue raised by the parties with respect to the phase out of government preferential rates on rural systems was that NLH was not moving quickly enough. In its final argument, NP proposed that the Board could expedite cost recovery through annual adjustments to government rates instead of waiting until the next rate application from NLH to implement a five year rate plan. NP continues, the Board should order that the rural deficit be reduced by \$2 million for ratemaking purposes to reflect full cost recovery from NLH's government customers.

(NP, Final Argument, pg. F-7) The CA proposes all preferential rates provided to the Federal Government should be discontinued immediately while those affecting the Provincial Government, schools and churches should be phased out with notice. (CA, Final Argument, pg. 43)

In 1975 Government introduced preferential rates for fish plants connected to isolated diesel systems. Preferential rates were further extended in 1978 to include churches, schools and other community based facilities. Fish plants with demands exceeding 30 kW have been given access to electrical service from diesel plants at interconnected general service rates. These rates are substantially lower than those charged to customers paying the general service diesel rate (Rate Category GS 2.5) in the same community. Churches, schools and community halls have also been given preferential rates (Domestic Diesel rate), and a special rate is in place for the Burgeo School and Library (Rate category Special 1.3).

In the 1996 Report on Rural Electrical Service, the Board agreed with NLH that preferential rates should be phased out over a five-year period. (CA-2); Report...concerning Rural Electrical Service, pg. 32) In this Application, NLH has not proposed starting the phase out of these preferential rates to fish plants, churches, schools and community halls because the magnitude of rate increases would be significant. Once again, as part of its next rate application, NLH indicates it will submit a rate plan outlining alterations in rates over a maximum of five years that will address the recommendations in the 1996 Report, including the phase out of preferential rates. (NP-150) NP-152 indicates that NLH would receive an additional \$600,000 in revenue once the phase out of non-governmental preferential rates is completed. As a result of the current Application, these customers would receive an increase of approximately 3.7%, which is the estimated overall increase expected for NP as a result of this Application (IC-121). NP submits that the Board require NLH to file a proposal on the phase out of preferential rates. (NP, Final Argument, pg. F-6) No other Intervenor commented on preferential rates to non-government customers.

In final argument NLH explains that, because of the increase proposed for customers, it did not recommend an additional increase (except for Government departments and agencies) to reflect either the phase out of the preferential rates or the full implementation of cost recovery for Government departments and agencies. NLH submits this issue is now before the Board and, while it believes this is a reasonable approach in the current context, there is more than one reasonable approach. NLH leaves this matter for the Board's consideration and decision. (NLH, Final Argument, pg. 77/8-16)

No parties, including NLH, supported the premise of ratepayers subsidizing taxpayers in paying for electrical service used by the Federal and Provincial Governments. Mr. Wells remarked in his testimony there is no apparent reason why Government rates, Federal or Provincial, should be subsidized. (Transcript, Sept. 25, 2001, pg. 8/81-84) The Board notes preferential government rates are unique to this Province. Other jurisdictions provide either full cost recovery on Government rates or charge Government an additional surtax in order to reduce the deficit arising from serving rural communities. (e.g. NWT, Yukon, Manitoba, Saskatchewan and Ontario) (Transcript, Nov. 19, 2001, pg. 39/10-21)

The Board acknowledges NLH's proposals but feels the five-year timeframe to eliminate preferential rates to Government will serve to perpetuate this historical inequity for ratepayers. The Board believes that coincident with the application of the rates approved by this decision that NLH should move to implement rates for both the Federal and Provincial Government reflecting full cost recovery on rural systems. The Board is sensitive to the impact this decision may have on hospitals and other organizations not directly funded by either the Federal or Provincial Governments. Such institutions and public organizations will be treated similar to schools and continue to benefit from preferential rates for the time being.

In the longer term, however, the Board finds no regulatory foundation for preferential rates. As outlined when considering the rural deficit, it can be argued cross-subsidization to effect equal rates among similar classes of customers is an accepted regulatory principle depending on the magnitude of the subsidy. No similar regulatory argument can be made for offering one customer a substantially better rate than another comparable customer for the identical service. Some customers who are entitled to preferential rates pay on average an estimated 12% of the cost of their service and pay roughly one-half the rate of general service customers on the same system. Preferential rates are inequitable to the non-recipient consumer and based on the Board's statutory obligations are deemed discriminatory. In making the decision to eliminate preferential rates, the Board is cognizant of the regulatory principle where the end result of the new rate on fish plants, institutional and community based facilities will be unfair and unreasonable unless implemented over time. For this reason the Board concurs with NLH's proposal regarding the presentation of a plan at its next rate application for phasing out over a five-year period the remaining categories of preferential rates.

The Board finds preferential rates are discriminatory and will order that NLH increase rates to the Federal and Provincial Governments effective with the implementation of other rate changes arising from this decision to recover the full costs of providing this service in rural areas. Preferential rates will continue to apply to hospitals, fish plants, churches, schools, community halls, municipal buildings and like facilities currently benefiting from preferential rates. NLH's proposal is accepted to present to the Board at its next rate application a plan to phase out preferential rural rates.

6. Lifeline Block

For isolated rural 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 concept of a lifeline block was established by government and has been in place since 1975 when the block was set at 500 kWh per month. At the same time, Government also established a policy that NLH's rural customers are charged the same rate as NP's domestic customers, currently 6.579 cents/kWh for the lifeline block, significantly lower than the cost of service. This block was increased to 600 kWh per month in 1987 and to the current level of 700 kWh per month in 1989. The second block is for usage between 701 kWh and 1,000 kWh per month, with a rate of 9.606 cents per kWh. For usage exceeding 1,000 kWh per month the

current rate is 13.022 cents per kWh (called the “run-off rate”). Rural customers also pay a basic monthly customer charge of \$16.71, which is the same as that charged by NP to all other domestic customers.

General service customers also have access to a lifeline block as ordered by Government in 1989. The result is that general service customers have access to energy at a rate of 8.624 cents per kWh for the first 700 kWh and 19.540 cents per kWh for energy use beyond 700 kWh. The basic monthly charge for general service customers on rural systems is \$19.02.

The Board dealt with the concept of the lifeline block during the Rural Electrical Service inquiry in 1995. At that time the Board did not recommend any change in the lifeline block of 700 kWh per month for rural domestic customers (CA-2; 1996 report, pg. 31). The Board did recommend, however, that the special general service lifeline rate be eliminated in order to achieve greater cost recovery on isolated systems from general service customers.

In response to CA-58 (revised) NLH addressed its position on the Board’s 1996 recommendations dealing with the lifeline block, stating that it concurs with the recommendation to eliminate the special general service rate for the first 700 kWh per month and that it will address this issue at its next rate application as part of its five year rate implementation plan. NLH also agrees with the Board’s recommendation that the lifeline block for domestic customers remain unchanged at 700 kWh per month.

The CA raised the issue of the adequacy of the lifeline block:

“The Consumer Advocate believes that 700 kWh per month falls short of typical consumption levels of Domestic consumers on Isolated Systems. This causes significant financial hardship for domestic customers in Isolated Systems who are least able to afford it. In this regard, the Consumer Advocate recommends that the Board address this issue now but direct Hydro to undertake a study to determine an appropriate lifeline block size, and report back on the results at the next rate hearing scheduled for 2003.” (CA, Final Argument, pg. 51)

As an interim measure, it was proposed by the CA that the lifeline block be increased to at least 900 kWh. (CA, Final Argument, pg. 53)

NLH’s position is that the lifeline block should not be changed and that increasing the lifeline block would increase the amount of the subsidy associated with serving rural customers. No evidence was brought forward which would quantify the impact on the rural deficit of increasing the lifeline block to 900 kWh per month. (Transcript, Jan. 28, 2002, pg. 14/36-50)

The Board notes the existing lifeline block of 700 kWh has been in place since 1989. At the public participation days in Labrador, several presenters stated that the existing lifeline block was inadequate and electrical requirements have changed since that time. Hot water boilers were noted as particularly high users of electricity. The Board has a statutory obligation to ensure that all consumers should have access to sufficient electricity to meet their basic needs at equitable rates. The Board cautions that the “lifeline block” needs to be established at a precise level to

ensure equitable access while minimizing the rural deficit. The Board was presented with insufficient evidence to make this determination. The Board believes the “*lifeline block*” is a critical component of an effective rural rates policy and concurs with the CA that a review into the appropriateness of the “*lifeline block*” is timely.

The Board points to its decision contained on pg. 133, requiring NLH to take steps to introduce at its next rate application a demand energy rate structure for general service customers on isolated systems. Bearing this in mind, a plan should be devised to coordinate the implementation of this initiative with the elimination of the 700 kWh lifeline block for these same general service customers. This latter finding, as recommended in the Board’s 1996 report was agreed to by NLH, who are now proposing to address the issue at its next rate application. Coordinated implementation of these measures will provide equitable and comprehensive rate setting for this class of general service customers.

The Board will approve the existing “*lifeline block*” of 700 kWh for both domestic and general service customers. NLH will be required to undertake a review of the existing “*lifeline block*” for domestic customers to assess its adequacy and prior to December 31st, 2002 file a report with the Board.

The Board accepts NLH’s proposal to address at its next rate application the elimination of the “*lifeline block*” for general service customers on isolated systems. This proposal is to be appropriately coordinated with the Board’s decision to implement a demand energy rate structure for this same class of customers.

7. Demand Charge for General Service Customers on Isolated Systems

In its July 1996 report “*Referral by the Lieutenant-Governor in Council Concerning Rural Electrical Service*” the Board recommended “*that Hydro be directed to provide a cost benefit analysis of a rate structure for general service customers which provides for a demand charge. The energy and demand charge in such a rate structure should recover long run marginal costs*”. (pg. 32)

NLH filed a report “*Cost Benefit Analysis of Implementing Demand Charges in the General Service Rate Structure in Isolated Areas*” in NP-184 (b). This report concludes that the cost of implementing demand charges in general service rates in isolated areas is not significant. Incremental costs relate primarily to costs of demand meters versus energy only meters, additional billing costs and additional costs of enquiries from customers. The benefits of such a rate structure are related to:

- sound rate design principles where rates reflect the costs associated with the level of service provided;
- consistency with Interconnected Systems rate structures; and
- improved customer load factors.

The report recommended that NLH proceed with implementing demand charges in the general service rates charged in isolated areas, with the actual timing of the implementation reflecting the other rate issues to be addressed in isolated areas. The report also recommended that demand meters be installed on all appropriate customers in preparation for implementation of this rate structure.

In cross-examination by NP, Mr. Hamilton advised that NLH has been proceeding with implementing demand meters on general service customers in isolated systems but was unable to confirm whether all necessary demand meters have been installed. Mr. Hamilton also confirmed that NLH proposes to address this rate structure option at their next rate hearing. (Transcript, Nov. 28, 2001, pg. 26/3-49)

The Board agrees that implementation of a demand charge for general service customers on isolated systems should proceed. It is recognized that this may result in lower load factor customers receiving increases in rates while customers with higher load factors will receive decreases, assuming the rate is designed to recover the same revenue. However, this rate structure will better reflect the respective costs of serving specific general service customers and provide those customers the opportunity to reduce their bills through managing the level of demand they place on the system.

NLH will be required to take the necessary steps required to prepare for implementation of a demand energy rate structure for general service customers on isolated systems and to file at its next rate application a proposal for such a rate structure. The implementation of this decision is to be coordinated with the elimination of the “lifeline block” for general service customers to be addressed by NLH at its next rate application.

8. Phase-out of IC Contribution to Rural Subsidy

Before the enactment of the amended *EPCA* in 1996, all customers of NLH were required to share in subsidizing the rural deficit. The 1996 amendments relieved the IC of responsibility for sharing in subsidizing the rural deficit. Subsection 3(a) (iv) of the *EPCA* declares that:

- After December 31, 1999 the rates charged to the IC should not include any amount for the rural deficit; and
- The portion of the subsidy paid by the IC should be gradually reduced over the period January 1, 1996 to December 31, 1999.

While NLH did apply to the Board in November 1999 to reduce the IC rates to eliminate their share of the rural deficit, it did not apply to the Board for a gradual reduction of rates to phase out the subsidy. The rates remained constant throughout the period 1996 to 1999. In response to the November application of NLH, the Board issued its first Order in P.U. 23 (1999-2000) dated December 14, 1999 whereby it approved interim rates for the IC excluding any contribution to the rural deficit. This Order effected a single rate adjustment, as of January 1, 2000.

The IC argue that subsection 3(a) (iv) of the *EPCA* required that the subsidy be reduced in 1996 and gradually decreased each year thereafter until total elimination was achieved at the end of 1999. The IC suggest that NLH breached the *EPCA* by failing to gradually reduce the rates during this period. They estimate, based on an annual reduction of twenty percent, that this failure resulted in NLH overcharging the IC an estimated \$9,140,317 for which they are now requesting a refund (See IC-8)

NLH argues that while the *EPCA* states that the IC portion of the rural subsidy was to be “*gradually reduced*”, it did not require that the subsidy be reduced by equal annual amounts as suggested by the IC. NLH explains, in IC-9, that it did not make application to gradually reduce the rates as government had advised that it was reconsidering the policy of eliminating the IC contribution to the rural subsidy. NLH submitted in evidence, a copy of a letter from the Minister of Mines and Energy which on October 14, 1999 directed NLH to proceed with the application to reduce rates as government “*has considered alternates respecting the implementation of Section 3 (a) (iv) of the Electrical Power Control Act, 1994*”. NLH points to subsection 17(5) of the *Hydro Corporation Act*, which NLH interprets as saying “*that no ruling by the Board in this hearing is to have a retroactive effect on the rates including providing for refunds or credits*”. (Transcript, Jan. 28, 2002, pg.13/2-9).

No other parties addressed this issue, either during the presentation of evidence or in final argument.

The Board agrees that, while the term “*gradually reduced*” in Section 3(a) (iv) of the *EPCA* may not require equal annual adjustments as suggested by the IC, it does imply more than the elimination of the subsidy in one step. NLH did not apply to the Board at any time to gradually reduce the subsidy paid by the IC. Instead it applied in 1999 to totally eliminate the IC portion of the subsidy. It is the Board’s view that this has contributed unnecessarily to the complexity of this hearing and that the issue should have been addressed several years ago. While NLH has offered the explanation that government was considering changing the provision at the time, the Board is concerned that such a significant issue was left to the informal direction of government, when the power policy of the Province was clearly set out in the legislation.

The Board notes that under the provisions of the *Act* the IC also could have brought this issue to the Board at any time after the enactment of the *EPCA* in 1996. The IC could have made a complaint or could have asked the Board to exercise its discretion to investigate the rates. Instead the IC took no steps to ensure that the subsidy was gradually reduced, and no evidence was submitted to explain this lack of action. While the Board may wonder whether the IC knew that the government was reconsidering the rural subsidy allocation, there is no evidence to form any conclusion on that point. The failure of the IC to raise this issue with the Board at the time has led them to seek at this hearing a retroactive rate adjustment of \$9,140,317.

This request for a retroactive rate adjustment runs contrary to one of the basic principles of rate regulation and generally accepted sound public utility practice, whereby rates are set prospectively. The *EPCA* codifies this principle in subsection 3(a) (ii), whereby it says that the rates set by the Board are to be based upon forecast costs. In addition, subsection 17(5) of the *Hydro Corporation Act* prohibits the Board from retroactively amending the rates. While the

Board agrees with the IC that the portion of the rural deficit subsidized by the IC was not gradually reduced, the Board will not now retroactively adjust the rates for the period 1996 to 1999. The proposed adjustment would be contrary to sound regulatory principles as well as the relevant legislation, especially in light of the failure of the IC to pursue this issue previously.

The Board will not direct NLH to provide a refund to reflect a gradual reduction of the IC portion of the rural subsidy over the period 1996-1999.

IX. RATE ISSUES/RATE DESIGN

1. Rate Approvals Requested by NLH

As part of its Application NLH requested, pursuant to Section 70 of the *Act*, approval of rates for NP and the IC, as well as rates for street and area lighting in Rural Isolated and Rural Interconnected systems, and rates for Labrador Interconnected system customers.

During the hearing revisions to several of these proposed rates were filed as a result of updated COS studies. The Board notes that NLH will have to file revised rate schedules for approval incorporating the decisions of the Board, especially those relating to the COS and the test year revenue requirement. Although the Board is not in a position at this time to approve final rates as proposed by NLH there are several rate issues that need to be addressed. These include:

- Labrador Interconnected system proposed Rate Structure and Secondary Energy Rate
- Wabush Surplus
- Industrial Contracts
- Wheeling Rate
- Rate Design Issues

These issues are dealt with below. The Board also gives direction to NLH on **page ?** of this decision on the steps it will have to take in advance of filing rates for 2002 to be approved by the Board.

2. Labrador Interconnected System – Rate Structure

Currently there are three sets of rates, rules and regulations for the Labrador Interconnected system that have evolved over time as NLH acquired the systems:

1. Rates in Happy Valley-Goose Bay were frozen in 1981 at the Island Interconnected rates which remain in effect today. The same Rates, Rules and Regulations as on the Island Interconnected system apply in Happy Valley-Goose Bay.
2. In 1985 NLH acquired from Wabush Mines the distribution assets associated with serving the Town of Wabush and the Board subsequently recommended the Rates, Rules and Regulations that would be applied.
3. In 1992 NLH acquired from the Iron Ore Company of Canada the distribution assets associated with serving the Town of Labrador City and the Board subsequently recommended the Rates, Rules and Regulations that would be applied.

At the present time average rates are approximately 2.0¢/kWh in Wabush, 1.5¢/kWh in Labrador City and 3.8¢/kWh in the Happy Valley-Goose Bay area. (Pre-filed Evidence, D. W. Osmond, pg. 13)

i) NLH's Proposed Rate Structure

In this Application NLH is proposing 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. NLH is proposing to consolidate the 24 different rate classes presently in effect in the Labrador Interconnected system into 6 classes and is also proposing one set of Rules and Regulations that will apply to all of NLH's rural customers. The new rate classes are the same as those for the Island Interconnected system with rates reflecting the costs of the Labrador Interconnected system. Customers on the Labrador Interconnected system will be placed into the appropriate rate class based on their load characteristics. NLH notes that it will not receive any additional revenue from the consolidation of these rate classes but customers will receive increases or decreases depending on their load characteristics. (Pre-filed Evidence, D. W. Osmond, pg. 14).

NLH is also proposing that, effective January 1, 2002 customers in Labrador City and Wabush will pay the same rates. On average, domestic customers in Labrador West will have an increase of approximately 17.1%, with 95% of these customers seeing increases of less than \$150 annually. Rates for general service customers in Labrador West are proposed to decrease on average by 5.4% with certain small general service customers having relatively small increases. However most customers in the general service rate class will see significant decreases. (Pre-filed Evidence, D. W. Osmond, pg. 15)

It is also noted that NLH sees this proposal as a first step in implementing a Labrador Interconnected rate structure. A rate plan outlining alterations in rates over a maximum period of five years will be filed as part of their next rate application. In the long term NLH is proposing the following cost recovery targets for the Labrador Interconnected system, which are the same as those accepted by the Board for NP (Pre-filed Evidence, P. R. Hamilton, pg. 5):

Domestic	95%
General Service	105-115%
Street Lighting	100%

The LC/W have objected to NLH's proposal for uniform interconnected rates in Labrador. They argue that NLH has not presented sufficient evidence to show that a rate increase in Labrador West is warranted and that rates in Labrador West should not be altered at this time.

NLH submits in final argument (pg. 79) that: *"its proposal to have one Labrador Interconnected System is consistent with the recommendation of the Board in its 1993 report and that it is consistent with normal utility practice that customers served from the same system (where there are common costs) pay the same rates."* NLH has also proposed a phasing in of the rate changes because of the impacts on certain customers on the system.

The Board agrees with NLH that its proposed approach to rate changes in the Labrador Interconnected system is consistent with the Board's recommendation in the 1993 generic COS report, which was accepted by Government under previous legislation, and which NLH was directed to use in this Application.

NLH's proposal to implement the Island Interconnected rate structure (six classes) for the Labrador Interconnected system will be approved.

NLH's proposal to phase in a cost based rate system for the Labrador Interconnected system as of the implementation of rates that arise from this decision will be approved. NLH will be required to file a five year plan outlining further alterations in rates on the Labrador Interconnected system, with the cost recovery targets as identified in this Application to be incorporated as part of NLH's next rate application.

The Board notes that its decision to deny NLH's proposed change in assignment of GNP assets in the COS will result in additional costs being assigned to the Labrador Interconnected system (See pg. 110 of this decision). The Board estimates that maintaining the assignment of GNP plant to the Rural Interconnected class will result in additional costs of over \$1,000,000 being assigned to the Labrador Interconnected system due to the allocation of the rural deficit. These additional costs will have to be recovered through rates from customers on that system.

In this Application NLH recognized that the restructuring of the existing rates and rate classes in Labrador will result in a wide range of increases and decreases in rates due to rate structure changes and differences in customer usage patterns. NLH implemented the following guidelines for its first step in its plan to move to the cost recovery levels indicated earlier: (Pre-filed Evidence, P. R. Hamilton, pg. 7/10-12)

1. *Move all customers to the relevant standard rate classes;*
2. *No rate class (based on the standard rate class categories) should receive an increase of more than 20%;*
3. *No Domestic or small General Service customer should receive an increase of more than \$20 per month;*
4. *Larger General Service customers should receive increases of no more than 20% unless circumstances are unique; and*
5. *Street and Area Lighting Rates should move toward specific costs of providing the service.*

The Board recognizes NLH's efforts in this Application to minimize rate increases to its customers on the Labrador Interconnected system to a level that, in its view, would not cause "rate shock" by applying these guidelines in its rate design. The Board sees these guidelines as reasonable and encourages NLH to adhere to these guidelines as it redesigns its rates to be submitted to the Board as a result of this decision. If application of the guidelines, as they are, prevent the design of rates that will recover costs, the Board will support some adjustment in the parameters if required. The Board reiterates its support of keeping the level of rate increases on the Labrador Interconnected system as low as possible as NLH moves to a uniform rate structure.

ii) **CFB Goose Bay (5 Wing) Secondary Power Rate**

NLH has proposed a secondary energy rate to apply to customers serviced from the Labrador Interconnected System that can avail of fuel switching and can purchase a minimum of 1 MW load, such as an electric boiler, when it is available. CFB Goose Bay (5 Wing) currently has a contract with NLH for secondary service for their electric boiler plant. NLH has proposed a rate for this service based on the greater of 90% of the value of the customer's avoided fuel cost (as calculated in Clause A) or NLH's opportunity cost based on revenues it could receive by selling the power elsewhere. (Clause B) For the 2002 test year the revenue from this secondary energy rate is forecast to be \$3,980,020 (2nd Supplementary Evidence, P. R. Hamilton, pg. 9) with a net revenue of approximately \$3,750,754 (2nd Supplementary Evidence, J. A Brickhill, JAB-1, Rev. 2, pg. 3 of 94).

Submission of CFB Goose Bay (5 Wing)

In his presentation to the Board Colonel McCabe, the Commander of CFB Goose Bay (5 Wing), stated that the proposed Clause B in the secondary rate structure leaves the Base liable for increases in cost for energy beyond those in the current arrangement. He also expressed concern that this Clause will limit the amount of secondary energy that is offered to CFB Goose Bay (5 Wing), causing them to have to burn oil to generate steam heat. (Transcript, Oct. 19, 2001, pg. 5/82-90) There was also some disagreement between CFB Goose Bay (5 Wing) and NLH as to whether this provision (Clause B) existed in the prior arrangement between the parties. [Submission of CFB Goose Bay (5 Wing), pg. 3-4]

In their submission (pg. 7-8) CFB Goose Bay (5 Wing) suggested that the rates charge for secondary energy were unreasonable, unjustly discriminatory and without rational connection to the cost. Concern was expressed both in relation to Clause B and the high revenue cost coverage ratio for the secondary energy which, according to CFB Goose Bay (5 Wing), suggests that they are subsidizing other customers through their secondary energy purchases, and to a lesser extent, their firm power purchases

In final argument (pg. 81) NLH states that the evidence shows that the rate for secondary service is based on 90% of the customers avoided fuel cost with NLH's opportunity cost being a floor.

The Board does not agree with the submission of CFB Goose Bay (5 Wing) that the rate proposed by NLH for secondary energy is unreasonable and unjustly discriminatory. The rate is not a cost of service based rate but rather a market based rate for non-firm sales. The energy is only provided by NLH when CFB Goose Bay (5 Wing) wants it and when NLH has it available. The cost of service for the Labrador Interconnected system does not assign any firm load requirements to CFB Goose Bay for this energy (since it is non-firm) and so there is no demand cost assigned to them. NLH's proposal to price the energy on the basis of the greater of 90% of the customers avoided fuel cost or NLH's opportunity cost is, in the Board's opinion, fair and practical to both CFB Goose Bay (5 Wing) and NLH. It is also not correct to compare this non-firm rate with the industrial non-firm rate on the Island Interconnected system. The Island Interconnected non-firm rate includes both a demand charge and an energy charge, meaning that

those customers are assigned a portion of the costs on the Island Interconnected system in the COS in the non-firm rate. The secondary rate on the Labrador Interconnected system is an energy only rate and CFB Goose Bay (5 Wing) is not assigned any portion of other costs on the Labrador Interconnected system. The Board has no basis on which to calculate an alternate rate for CFB Goose Bay (5 Wing) and feels NLH's proposal is fair.

The secondary energy rate as proposed by NLH for customers serviced from the Labrador Interconnected system will be approved.

Allocation of Revenue from Secondary Rate

In its Application NLH has proposed applying the net revenue of \$3,750,754 from secondary energy sales to CFB Goose Bay (5 Wing) against the overall revenue requirement for the Labrador Interconnected system to reduce firm service rates. Both Mr. Osler and Dr. Wilson suggested that the Board has discretion in how it deals with this surplus and that one option would be to apply the surplus against the rural subsidy to reduce the overall level of the deficit. In final argument (pg. F-6) NP also asked that the excess revenue from CFB Goose Bay (5 Wing) be applied to reduce the rural deficit. Mr. Hamilton, on behalf of NLH, acknowledged that there is no rate design principle that requires that this excess of revenue over costs be applied against the Labrador Interconnected system. He states that NLH's reasoning to apply it in the manner proposed is to keep the revenue from the Island portion on the Island and the Labrador portion in Labrador. (Transcript Nov. 29, 2001, pg. 35/92-94)

The Board notes that the excess revenues from GFB Goose Bay (5 Wing) are not cost based and are separate from the cost of service revenue requirements used to set rates for the Labrador Interconnected system. There is also no guarantee that the revenues will continue into the long term, meaning that if the excess revenue is applied against the revenue requirement, rates would have to change if the secondary energy sales were to change or end. It does seem fairer to all consumers in the Province that the surplus from secondary sales to CFB Goose Bay (5 Wing) be applied against the rural deficit which both NP and Labrador Interconnected customers will pay for as part of the implementation of this decision.

As noted previously in this section the Board is cognizant of the impact of its decision on the Labrador Interconnected system to not confirm the proposed change in GNP plant assignment to common as discussed on pg. 113 of this decision pending further study by NLH. If the Board were to also order that the excess revenue from secondary energy sales to CFB Goose Bay (5 Wing) be applied to reduce the rural deficit and not used to reduce the revenue requirement of the Labrador Interconnected system, the costs to be recovered through rates on this system would increase significantly.

The Board finds that the credit from secondary energy sales to CFB Goose Bay (5 Wing) would be more appropriately applied against the rural deficit before allocation to NP and Labrador Interconnected customers. However, because of the magnitude of this adjustment relative to the total revenue requirement on the Labrador Interconnected, together with the impact of other decisions of the Board, the Board believes that implementation of this decision would introduce rate shock for the Labrador

Interconnected customers. For the 2002 test year, the credit should be applied to the Labrador Interconnected system as proposed by NLH. The Board will require NLH to include, as part of its five year rate plan to be submitted at the next rate hearing, a plan which phases in to the Labrador Interconnected customers, the impact of applying the credit for secondary energy sales to the rural deficit.

iii) Wabush Surplus

NLH has applied to the Board for an order determining the disposition of the Wabush surplus. The total accumulated surplus from 1987 to the end of 2001 is \$2,922,755, which includes an interest component of \$916,370. (Pre-filed Evidence, D. W. Osmond, Schedule 1)

The issue of the Wabush surplus arose as a result of a number of decisions and recommendations of the Board and subsequent Appeal Court decisions following the transfer of the electrical distribution system in Wabush from Wabush Mines to the PDD in 1985. In an interim report to Government dated November 18, 1985 the Board recommended approval of rates for Wabush customers as proposed by the NLH as of January 1, 1989 and also stated that *“If, in future years, PDD achieves a surplus in Wabush, the surplus shall be refunded to the customers.”* (pg. 6)

In 1991 the *Electrical Power Control (Amendment) Act*, SN, 1991, c-48 removed the exemption given to Labrador Interconnected customers with respect to their share of the funding of the rural deficit. This change also applied to customers in Wabush. In late 1991 NLH referred to the Board an application for rate and classification changes to the Labrador Interconnected grid customers. Subsequent to the filing, the referral was amended to delete the increases requested with respect to electricity rates on the Labrador Interconnected system, including Wabush. NLH has not filed a rate referral or application on Labrador Interconnected rates since that time, which means that these customers have not been sharing in the funding of the rural deficit (as required by the EPCA) and also that the issue of the Wabush surplus was still outstanding.

NLH proposed two options for dealing with the Wabush surplus to the Board in correspondence dated February 26, 1993 (Pre-Filed Evidence, D. W. Osmond, Schedule II). The first option was to refund the surpluses for 1989-1992 in 1993 based on each customer's share of 1992 revenue. The second option proposed was to defer the matter until such time as there is a rate referral to review electricity rates for customers served from the Labrador Interconnected grid. In proposing this option NLH recognized that the 1993 COS methodology allocates more costs to Labrador interconnected customers than before and that the existing surplus could be used to offset increases in rates for these customers at the next rate hearing. In response the Board agreed with the second option, which was to defer the matter until the next rate referral, and stated *“At that time the existing surplus would be used to offset increases in rates for the customers in Wabush.”* (Pre-Filed Evidence, D. W. Osmond, Schedule III)

NLH has continued to record the surpluses for Wabush based solely on the costs recorded in the accounting records, which was the accepted method for recording the Wabush COS prior to 1992. This cost does not include any overhead cost allocation, margin allocation, or rural deficit allocation. (NP-134) In this Application NLH is proposing to refund the surplus of \$2,922,755, accumulated and calculated as described above for the years 1989-2001, to Wabush customers in 2002, based on each customer's proportionate share of the 2001 revenues. (Pre-filed Evidence, D. W. Osmond, pg. 17)

The only major issue raised by the intervenors on the Wabush surplus was with respect to the fairness of refunding the balance to customers based on their share of 2001 revenues. The CA questioned whether this was fair to the customers who have left the system since 1989. (CA-62) In response NLH agreed that, to be theoretically precise, the refund should be made to all customers who have been billed on the Wabush system since 1989. NLH submits that it would be impossible to track those customers who have left the system. It would also be a significant administrative exercise because of the lack of electronic records.

In dealing with this issue the Board is influenced by the direction given to NLH in its letter of March 19, 1993, which stated that at the next rate referral "*the existing surplus would be used to offset increases to rates for customers in Wabush*". It is clear to the Board that NLH has followed that direction in this Application by proposing to refund the surplus to the Wabush customers in 2002. This would have the effect of offsetting rate increases that would be implemented in 2002. The Board is also of the view, however, that at that time the Board would not have contemplated such a long period of time elapsing until the issue was dealt with.

Changes in circumstances and issues that have arisen as a result of the long delay in NLH coming before the Board to deal with this issue would require that the Board explore whether there are other alternatives for the disposition of the Wabush surplus. The Board notes that it appears that NLH had already made representations to the people in Wabush that they would be getting a refund prior to the commencement of the hearing of this application. Even though the Board does not feel it is bound by the direction in its 1993 letter it does feel that the fairest and most equitable way to dispose of the surplus is to refund it back to the customers in Wabush as proposed by NLH.

The Board does appreciate the issue raised by the CA regarding the perceived unfairness of providing refunds to current customers for surpluses that have arisen from operations dating back to 1989. However the Board accepts NLH's explanation and reason on why this is not possible and will not require NLH to trace customers that have since left the system.

The Board will approve the refund of the Wabush surplus of \$2,922,755 as proposed by NLH.

3. Industrial Contracts

i) General

NLH filed with the Application copies of the contracts for each of the Industrial Customers, Corner Brook Pulp and Paper Limited, Abitibi Consolidated Company of Canada, Grand Falls and Stephenville Divisions, and North Atlantic Refining Limited. Final copies of the contracts were filed on January 9, 2002 incorporating changes. NLH is requesting the Board approve these contracts, pursuant to Section 71 of the Act. Prior to this Application the rates and contracts for the IC were not regulated by the Board and this is the first time that the Board will be dealing with this issue.

Section 71 of the Act states:

“A public utility shall submit for the approval of the board the rules and regulations which relate to its service, and amendments to them, and upon approval by the board they are the lawful rules and regulations of the public utility until altered or modified by order of the board.”

In final argument (pg. 126) the IC agree that Section 71 gives the Board the authority to approve the form of contract for the IC, and that this approval is the equivalent of setting rules and regulations. Alternatively the Board can approve a set of rules and regulations which incorporates the provisions of the contracts which are approved by the Board. Section 3 of the EPCA also contemplates approval of rates to be charged under specific contracts, referring to *“rates to be charged, either generally or under specific contracts, for the supply of power within the province...”*

The contracts filed by NLH for approval have been developed in consultation with the IC and it was confirmed that Corner Brook Pulp and Paper Limited and Abitibi Consolidated Company of Canada agree with the contractual language proposed with the exception of the treatment of transformer losses as discussed elsewhere in this decision. North Atlantic Refinery Limited also agrees with the contract language proposed with the exception of Article 9.04 relating to NLH’s proposed limitation of liability for damages arising from NLH’s own negligence, and in particular the proposed cap on the liability. As of the end of the hearing this issue is still outstanding and both parties have put their positions to the Board for resolution.

The Board will approve the rules and regulations set out in NLH’s contracts with the IC, with the exception of the proposed contract with North Atlantic Refinery Limited.

ii) Limitation of Liability – North Atlantic Refinery Limited

NLH currently has a power supply agreement, dated December 16, 1987, in place between Newfoundland Processing Limited [now North Atlantic Refinery Limited (North Atlantic)] for the supply of power to the refinery at Come by Chance.

In the proposed Industrial Contracts NLH included a revised Article 9 dealing with liability for service. Specifically Clause 9.04 limits NLH's liability in respect of direct loss or damage caused by NLH:

- 9.04 (1) *Subject to Clause 9.04(2) hereof, Hydro shall be liable for and in respect of only that direct loss or damage to the physical property of the Customer caused by any negligent act or omission of Hydro, its servants or agents. Customer agrees that for the purpose of this Clause 9.04, "direct loss or damage to the physical property of the Customer" shall not be construed to include damages for inconvenience, mental anguish, loss of profits, loss of earnings or any other indirect or consequential damages or losses.*
- 9.04 (2) *Hydro's liability under sub clause 9.04(1) applies only when the direct loss or damage to the Customer arising from a single occurrence exceeds the sum of \$100,000. In no event shall the liability of Hydro exceed the sum of \$1,000,000 for any single occurrence.*
- 9.04(3) *Customer further agrees that any damages to which it may be entitled pursuant to clause 9.04(1) shall be reduced to reflect the extent to which such losses or damages could reasonably have been reduced if the Customer had taken reasonable protective measures.*

North Atlantic does not agree with the proposed contract wording and believes that the ceiling of \$1,000,000 on damage claims is inadequate to address its anticipated losses in the event that its energy supply is interrupted as a result of NLH's negligence. (Pre-filed Evidence, G. Mifflin, pg. 2) During oral testimony Mr. Mifflin described the effect of a disruption in energy supply on the refinery processes and operations by stating that this situation generally requires an emergency shutdown of all process units and causes loss of product through flaring. Mr. Mifflin further stated that once production has been interrupted as a result of a power failure it usually takes 5-7 days to bring the refinery back to full production. Examples were quoted of the extent of damages, estimated to be in excess of \$19,000,000, incurred by the refinery for two previous outages. It is North Atlantic's position that NLH should not be able to limit its exposure for direct losses incurred as a result of NLH's negligence and proposes that there be no ceiling on the amount recoverable from NLH. If the Board deems a ceiling necessary it should be set at \$10,000,000 per occurrence.

NLH's position is that, in light of the particular sensitivity of the refinery to power outages as short as 3 minutes or less, it is not appropriate that NLH and its customers bear the full cost of these damages. They submitted that the proposed \$1,000,000 cap, which is acceptable to the other IC, is a reasonable compromise and should be approved by the Board. (NLH, Final Argument, pg. 86/27-30)

The Board notes there is no mechanism in the Act for NLH and North Atlantic to bring this dispute before the Board to facilitate a mutually agreeable settlement. Instead NLH has submitted a contract, with the disputed clause, to the Board for approval. The Board also recognizes that the issues involved may have a significant impact upon both North Atlantic and

NLH. Implementation of the contract as proposed by NLH would require that the Board make an order which limits the common law rights of North Atlantic to pursue recovery in the courts of the Province. On the other hand, implementation of the contract as proposed by North Atlantic would require that NLH, and ultimately its customers, be liable for damages of a minimum of \$10,000,000 per occurrence.

In light of the importance of this issue upon both North Atlantic and NLH, and its other customers, it is imperative that sufficient evidence be offered to allow the Board to fully consider the two viewpoints. The Board sees merit in the argument that it is inappropriate for the other customers of NLH to bear the full cost of an industry specific sensitivity to power interruption, yet no evidence was called to show the impact upon the other NLH customers. It may also be argued that this risk is a cost of doing business, which should be absorbed by North Atlantic, yet no evidence was called to establish the costs and the impact upon North Atlantic of incurring these costs. No evidence was presented either as to potential sources of backup power or other ways in which damage from power interruption may be mitigated, nor was there any evidence on practices at other refineries. In addition, while there was some suggestion during the hearing that insurance is not available to cover this type of loss, the parties did not file any evidence on this point.

The Board finds that the evidence presented was inadequate to allow the Board to impose the liability provision as proposed by either of the parties. The Board is not satisfied that the liability provision is reasonable and necessary and will not accept clause 9.04 as part of the rules and regulations of the provision of service to North Atlantic. The Board acknowledges that the decision to exclude this provision from the contract will result in the continuance of the current situation in that the liability of NLH will have to be established and limited according to common law. However, the Board notes that it has not decided upon the merits of the liability provision and that, under the *Act*, the parties may bring this issue back before the Board.

The Board will approve the rules and regulations set out in NLH's contract with North Atlantic Refinery Limited, but excludes Clause 9.04, which describes the liability of NLH.

4. Wheeling Rate

NLH currently wheels energy for Abitibi Consolidated from Grand Falls to Stephenville under the following contract terms (pg.6, Industrial Contract):

"The Customer may wheel Energy through Hydro's transmission system from its Buchans, Bishop's Falls and Grand Falls generating stations to its Stephenville paper mill at those times when that Energy is surplus to the needs of its Grand Falls paper mill. Energy wheeled from the Customer's electric generating station shall be wheeled at the wheeling rate approved by the Board. In each Month the amount of Energy delivered to the Customer's paper mill at Stephenville will be the amount supplied by the Customer at Buchans or Grand Falls, or both, less the average percentage losses on the Hydro system approved by the Board and this amount shall be credited against the Customer's Firm Energy in that Month."

Currently NLH calculates the wheeling rate by dividing the total Island Interconnected transmission revenue requirement by the transmission energy output (Pre-filed Evidence, J. A. Brickhill, JAB-1, Schedule 1.5). The current wheeling rate is \$0.00649/kWh and NLH has proposed this rate increase to \$0.00695/kWh as calculated in IC-34. The forecast revenue from the wheeling rate is \$6950 (IC-34). The IC have objected to the inclusion of non-grid radial transmission expenses in setting the wheeling rate.

NLH's wheeling rate is based on costs and energy associated with the common transmission grid. NLH has proposed that the GNP transmission assets be assigned common and are included in the calculation of the total Island Interconnected system transmission revenue requirement. The allocation of radial transmission costs in the calculation increases the wheeling rate by 28.47% for the GNP interconnection alone. (IC-241) Because of the Board's decision to continue the assignment of the GNP transmission assets to rural interconnected, the calculation of the wheeling rate will have to be revised.

The issue for decision by the Board is whether the calculation of the wheeling rate should only include those transmission costs associated with the 230 kV grid since, according to the IC, the wheeling involves only grid transmission. The IC have also objected to the calculation of transmission losses in the wheeling rate. NLH assumes 4% transmission losses in its calculation of the proposed wheeling rate, which is the average percentage losses of 3.6% on the NLH system as determined for 1999. (IC-118) The IC point out that the average system losses over the last five years is 3.47% and the nine year average is 3.48%. (IC, Final Argument, pg. 132)

The wheeling rate is not a cost based rate but rather a rate for a service that can be provided since the plant is in place. In order to calculate the "value" of the service, NLH has tried to use a method that reflects both the benefit derived by the customer and its contribution in providing the service. The Board agrees with NLH that it would not be efficient or practical to undertake a load flow study in order to find where the energy is actually going and the Board is not convinced this is necessary in any event. NLH's methodology appears to be a good approximation of the average cost per kWh for interconnected transmission system that is assigned common use. The Board agrees with IC that the calculation of transmission losses should reflect experience over the last number of years and will order that the calculation be revised as in IC-256.

The Board accepts NLH's methodology for calculating the wheeling rate but will require the calculation of the rate to be revised in light of the Board's decision on the assignment of the GNP costs. In the case of the transmission losses, NLH will be required to use the average losses on the system for the last five years (1996-2000) calculated at 3.47%.

5. Rate Design

i) NP Energy Only Rate

NP initiated a proposal at NLH's 1990 rate referral for a demand energy rate form from NLH. In its report 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 the 1992 rate referral NLH proposed an energy only rate but filed alternative rate forms for consideration by the Board. In the 1992 report 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 COS hearing NLH and NP informed the Board that the development of an alternative rate form for NP was not yet finalized. 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 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.

In this Application NLH states that *“Hydro and Newfoundland Power have reviewed this issue and both companies concur that an energy only rate to Newfoundland Power is still appropriate.”*(Pre-filed Evidence, D. W. Osmond, pg. 9/27-31). NLH provided a copy of a letter from NP to NLH outlining its current position which states:

“It is Newfoundland Power’s view 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”. (PUB-68)

The letter also outlined NP’s reasons in support of maintaining the existing energy only rate form:

1. A demand energy rate would have a tendency to create volatility in the earnings of both NLH and NP from year to year.
2. The increased business risk earnings volatility would be reflected in the utilities’ cost of capital and tend to put upward pressure on consumer rates.
3. Potential for variability in consumer electrical rates.
4. A demand energy rate is not necessary to provide appropriate signals with respect to the cost of electrical demand as the demand component of current consumer rate structures appropriately reflects all cost components and are sufficient in their present form to deter consumers from placing unwarranted demands on the electrical system.

ii) NLH’s Proposal

For the reasons outlined above NLH is proposing an energy only rate for NP in this Application. In IC-239 NLH confirms that it concurs with NP’s conclusion outlined in the letter of PUB-68 and referenced above. One of the primary reasons cited by NLH is the fact the NP is not an end-user of the electricity it purchases and so the load pattern of NP to NLH is affected by the demand of NP’s customers and how they respond to NP’s rate structure (IC-239). In contrast the IC are an end-user and able to change their load pattern and affect the demand charge paid. NLH also submits that the energy only rate allows for better cooperation between the two

utilities regarding the operation of NP's generation and also reduces revenue volatility and corresponding lowers business risk for both utilities (CA-55).

iii) Positions of the Parties

Mr. Osler supports the establishment of a multi-part rate for NP stating:

"We agree that the NP rate structure appears to be inappropriate for this type of customer. It is clear that NP subjects Hydro to similar cost pressures as large GS and industrial customers, and for simple cost causation reasons should have a similar multi-part rate in place which includes demand charges (including appropriate ratchets), energy charges and fixed charges as necessary (compared to the status quo energy charge which notionally includes the demand and fixed components of NP's cost of service). (Pre-filed Supplementary Evidence, C. F. Osler, pg. 29)

Dr. Wilson suggests that NLH's costs and wholesale rate structure (to NP) be calibrated in this proceeding so that retail rate design in the next NP rate case can reflect the appropriate cost based charges that NP will actually realize as its retail sales volumes change. (Pre-filed Evidence, Dr. J. W. Wilson, pg. 21)

Mr. Bowman states that the current wholesale rate design for sales to NP with only a flat per kWh energy charge sends incorrect price signals to NP and is not reflective of the costs it imposes on the system (Pre-filed Evidence, C. D. Bowman, pg. 4). A rate design incorporating time varying demand and energy charges as well as an interruptible rate option is suggested. It is Mr. Bowman's position that a more complex rate structure to NP is justified based on the fact that NP represents over 60% of NLH's sales in the test year.

On the issue of revenue volatility for both utilities Mr. Bowman does not agree that this is a reason to forgo this type of rate structure, stating that: *"....companies the size of Hydro and Newfoundland Power should be able to manage this low level of volatility with little impact on rates"* and that IC are able to manage the volatility in manufacturing costs associated with demand charges. His summary position is that *"a small increase in volatility is a minor consideration when weighed against the benefits arising from the introduction of more complex rate structures for large volume customers."* (Pre-filed Evidence, C. D. Bowman, pg. 13-14)

Mr. Brockman does not agree with Mr. Bowman's suggestion that the current energy only rate does not reflect the costs NP imposes on the system, stating that: *"The rate that NP pays flows directly out of the cost of service study and therefore by definition recovers the cost of serving NP. The demands of NP are fully reflected in the cost of service study, and as these demands change, the costs allocated to NP change."* (Supplemental Evidence, L. B. Brockman, pg. 4)

Mr. Brockman also does not agree with Mr. Bowman that a more complex rate structure is justified for NP based on the amount of power it purchases from NLH. He suggests the real issue is: *"whether a demand/energy rate will cause NP to change their rate designs to their current customers, or to perform more cost-based DSM, balanced against whether the*

demand/energy rate will create such volatility in the earnings streams of both utilities that it is inadvisable.” (Supplemental Evidence, L. B. Brockman, pg. 4)

In reply evidence, Mr. Brickhill responded to the position of the parties with respect to a demand energy rate for NP. He outlined a number of reasons why he supports the use of an energy only rate for NP, including the operational coordination between NP and NLH and the fact that NP is not able to respond fully to NLH’s price signals since its demand is derived from the demands of its customers (Supplementary Evidence, J. A. Brickhill, pg. 9/8-26; pg. 6/1-8). Mr. Brickhill also states that an energy only rate in conjunction with the RSP for NP is appropriate and provides a more precise matching of revenue and cost (Supplementary Evidence, J. A. Brickhill, pg. 8/12-16). He agrees that the demand energy charge for NP could create earnings volatility for NP, but does not agree that such a rate structure would cause the same level of earnings volatility for NLH because of the RSP (Transcript, Nov. 26, 2001, pg. 35/55-59 & 75-77).

As noted above the issue of whether a wholesale rate structure for NP should be designed consisting of both an energy and demand charge has been before the Board since 1990 when it was first raised by NP. At that time NP argued that it was unable to send proper pricing signals to its customers until it gets a proper pricing signal from NLH. NP also argued that NLH’s rate structure should expressly or implicitly have a demand charge component to track costs more closely (Board’s 1990 report, pg.76). It was stated by NP that the lack of a proper rate design (from NLH) gives little incentive for NP to engage in demand side management programs which were seen at the time to be important responses to increases in rates forecast. At this hearing NP states that agreement between NLH and NP on an appropriate demand energy pricing structure could not be reached because of the potential earnings volatility. The importance attributed by NP in NLH sending proper price signals in its rates was not addressed and it is not clear from the evidence whether this is (or ever was) important or in fact what has happened in the interim to result in a change in position.

In response to the Board’s recommendations and directions to both utilities since 1992 to develop an acceptable rate form for review by the Board, NLH filed a letter from NP outlining their position and reasons why they have not been able to agree on an acceptable demand-energy rate form. No analysis or supporting detail was filed with the letter and no additional evidence was brought forward by either NP or NLH on the issue.

The Board has also attempted to deal with this issue as part of recent hearings. In particular, the terms of reference for the 1998 hearing for NP stated that the Board wished to receive evidence on the issue of a demand energy rate for power purchased by NP from NLH. 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 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 on-going Energy Policy Review and that the Board should delay consideration of these matters. The Board agreed at that time but notes that the Energy Policy Review (now the Electricity Policy Review) is still ongoing.

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 hearing. 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.

iv) Other Rate Design Issues Raised

Seasonal Cost Variations and Marginal Considerations

The issue of seasonal cost variations and marginal costs as it relates to rate design was raised during the hearing by several of the expert witnesses.

Dr. Wilson recommended that NLH should prepare and file rates that reflect seasonal cost variations. He also recommended that marginal cost considerations should receive greater attention by NLH in its rate design. (Pre-filed Evidence, Dr. J. W. Wilson, pg. 7/4-10)

Mr. Brickhill addressed this issue in Supplementary Evidence, stating that he agreed that marginal costs convey better price signals and achieve greater allocative efficiency than embedded cost rates. However it is his view that marginal cost based rates have no meaningful relevance in this Province because of the existence of the rural subsidy and the RSP, which distort price signals and confuse the picture on marginal cost based rates. As well, NLH has filed its COS study with this Application using embedded costs (and not marginal costs) as directed by the Board. He states that NLH takes marginal costs into consideration when designing rates when it is clearly appropriate, such as when it designs non-firm service rates. (Supplementary Evidence, J.A. Brickhill, pg. 1-3)

The CA recommends in final argument that the Board hire an independent consultant to review and recommend rate designs for electricity consumers in the Province and that this report should be considered as part of a public hearing. Part of this recommendation is based on the fact that NLH does not have updated studies of marginal costs and time-of-use rates. It is the CA's position that NLH is *"missing an opportunity to better meet its rate design criteria related to market efficiency and cost based rates, and to improve customer service by offering rate options, and providing consumers a level of control over their bills."* (CA, Final Argument, pg. 46)

The Board notes the recommendations put forward by the CA and Dr. Wilson with respect to marginal cost pricing and rate design. It also acknowledges the position of NLH put forward in its final argument (pg. 75) that *"it would not be appropriate to study marginal cost considerations in Newfoundland for the reasons set out in Mr. Brickhill's supplementary evidence."* As noted previously, the Board had a pre-hearing conference for NP in September 1998 to consider, in part, the issues of rate design alternatives based upon marginal costs, time-of-use design principles and other innovative rate options. The Board deferred consideration of

this matter (and others) after hearing representations from NLH, NP and the Government that the Energy Policy Review announced by Government would be addressing these issues and that the Board should await the results of that review.

The Board believes that, in light of the many other matters which it has requested NLH to address and also the fact that the Electricity Policy Review is ongoing, it would not be timely to commence any study of marginal costs considerations at this time. The Board will continue to monitor this situation with a view to determining an opportune time to act on this initiative.

6. Rules and Regulations for Service

NLH proposes to use one set of Rules and Regulations for all service areas as set out in Schedule B to the Application. (Pre-Filed Evidence, P. R. Hamilton, pg. 14-15/31-2) These proposed Rules and Regulations are essentially the same as those already approved by the Board for NP. The most substantive change involves the rate descriptions for NP and the IC dealing with transformer losses. This issue was raised during the hearing and has been dealt with on pg. 117 of this decision.

The only intervenor who raised any issue with the Rules and Regulations was the CA. Mr. Bowman, on behalf of the CA, suggested changes to Clauses 4, 10 (c) and 10 (g). (Pre-Filed Evidence, L. A. Bowman, pg. 17-18)

Clause 4 deals with NLH's policy on return of a customer's security deposit, which states this will occur only "...*When the Customer ceases to use the service...*". In response to CA-93 NLH indicates that its practice is to refund a security deposit after a customer has demonstrated a good credit history of greater than 2 years. Mr. Bowman recommends that Clause 4 be revised accordingly. NLH does not disagree with this proposed change.

Clause 10 (c) of NLH's proposed Rules and Regulations states, "...*Hydro may charge interest at a rate equal to the prime rate charged by chartered banks on the last day of the previous month plus five percent.*" In response to CA-95 NLH indicates that once its new customer service system is in place it will charge the full amount outlined in Clause 10 (c). Mr. Bowman recommends that Clause 10 (c) be changed to state that NLH will charge an interest rate of prime plus 5% on delinquent accounts. He suggests this change will avoid confusion and potential accusations of discrimination. NLH does not disagree with this proposed change.

Clause 10 (g) states that "*When a Customer has been under-billed due to an error on the part of Hydro or due to an act or omission by a third party, the Customer may, at the discretion of Hydro, be relieved of the responsibility for all or any part of the amount of the under billing.*" In response to CA-96 NLH states that its current practice is to recoup all under billings; however where a period of time exceeding one year has elapsed, only the portion owing in the current calendar year will be collected. Mr. Bowman submits that NLH should collect the total amount of under billings and recommends that the wording of Clause 10 (g) be changed to reflect this. NLH does not agree with this change as suggested by Mr. Bowman, stating in final argument

that the current practice of collecting under billings due to its error, for up to a period of a year, is appropriate. (NLH, Final Argument, pg. 85)

The Board agrees with the suggested wording changes to NLH's proposed Rules and Regulations for Clause 4 and Clause 10 (c) as suggested by the CA. In respect of Clause 10 (g) the Board notes that the wording proposed by NLH is the same wording as in NP's Rules and Regulations. The Board is also not aware of any concerns or problems of customers regarding NLH's current practice of collecting under billings. Accordingly, the Board will not direct NLH to adjust the wording of Clause 10 (g) as proposed by the CA.

NLH will be required to submit revised Rules and Regulations incorporating changes to Clause 4 and Clause 10 (c) as accepted by the Board for final approval with the revised Rate Schedules to be filed.

7. Effective Date and Method of Rate Change

This Application was prepared and submitted on the basis of forecast test year costs for 2002, as required by Subsection 3 (a) (ii) of the *EPCA*. Normally this would mean that rates would be implemented at the beginning of the test year, in this case January 1, 2002. Because of the length of the proceeding this implementation date is no longer possible. NLH has proposed in its final argument that the same rates that would have been effective on January 1, 2002 based on the Board's final ruling, be ordered to become effective at the earliest possible implementation date.

Specifically NLH has requested the following:

1. That the rates, excluding Labrador Interconnected rates for firm customers, be effective from 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, 2002.
2. That the rates for Labrador Interconnected firm 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, 2002.

With respect to the RSP, NLH has proposed that customer balances in the respective plans and year-to-date RSP activity be fixed at the month end prior to rate implementation based on the current approved methodology. Changes to the RSP, as a result of this Order, would be implemented concurrent with implementation of new rates.

The Board agrees with NLH's proposal regarding the method of implementation of rate changes. Given the length of the proceeding and the fact that rate changes are not likely to be implemented until after July 1, 2002 the Board does not view the prospect of prorating rate changes based on customer's electricity consumption since January 1, 2002 as practical. In considering this proposal the Board recognizes that there will be an impact on the RSP balance for the period prior to implementation of any changes in rates and RSP recovery. This impact is

primarily the result of the price of oil in base rates for the first part of 2002 remaining at \$12.50 Cdn/bbl as set in the existing RSP.

While the Board has attempted to assess the magnitude of the impacts of the decisions it has made using the COS studies filed in evidence, it is not possible to determine the specific rate impacts on the various customer classes.

In order to finalize rates to be implemented as a result of this Application, NLH will be required to incorporate the decisions of the Board by:

- 1. adjusting its revenue requirement and calculation of rate base and return on rate base;**
- 2. completing a revised COS study for the 2002 test year; and**
- 3. revising its proposed Schedule of Rates for the various customer classes based on the updated cost of service.**

and filing the above with the Board for approval. The Board will review NLH's revised filing to ensure its decisions are appropriately incorporated and then issue a final Order approving or modifying, as it deems appropriate, the rate base, NLH's return on rate base and the revised rates for NLH's customers for the 2002 test year.

X. OTHER ISSUES

1. Code of Accounts

Section 58 of the *Act* states:

“58. The board may prescribe the form of all books, accounts, papers and records to be kept by a public utility and a public utility shall keep its books, accounts, papers and records and make its returns in the manner and form prescribed by the board and comply with all directions of the board relating to those books, accounts, papers, records and returns.”

During 1998 NLH implemented a new accounting system which resulted in a new chart of accounts and changes in the coding of accounts. In 2000 several additional changes affecting the account groupings of inventory and non-inventory items were implemented (GT, 2001 Annual Financial Review of NLH, pg. 2). On October 4, 2000 the Board advised NLH that its code of accounts was approved on a provisional basis, subject to final approval at a general rate hearing. This rate hearing is the first application subsequent to the provisional approval.

GT has expressed the opinion in reports to the Board that NLH's code of accounts is adequate to meet the reporting requirements of the Board. (GT 2000 Annual Financial Review of NLH, pg. 3; GT 2001 General Rate Hearing Report, pg. 3)

NP questioned whether the accounts should be set up to separate the regulated and non-regulated operations of NLH. (Transcript, Jan. 8, 2002, pg. 22-23/23-102) NP recommended that the Board order NLH to maintain separate accounting records and produce separate financial results for its regulated operations. (NP, Final Argument, pg. H-2) Mr. Brushett of GT suggested that NLH be specifically directed to set up an account code structure that will allow them to identify regulated from non-regulated activities. (Transcript, Jan. 8, 2002, pg. 22/52-58)

The Board is not convinced that NLH needs separate accounting records to facilitate the distinction between regulated and non-regulated activities. The existing code of accounts should be structured to account for regulated and non-regulated activities as a normal reporting function. The Board is also of the opinion that there should be clearly defined policies and procedures to account for intra and inter-corporate transactions which apply to all related parties.

The Board will approve the code of accounts submitted by NLH and will require NLH to file written policies and procedures for the accounting of all intra and inter-corporate transactions, indicating what is to be included in regulated and non-regulated activities.

2. Regulatory Reporting

NLH is directed by Section 17 of the Hydro Corporation Act to maintain certain accounting methods and a Rate Stabilization Plan. The Board is authorized by Sections 58-69 of the Act to give direction on how NLH is to maintain their accounts and reporting requirements.

During the hearing NP pointed to current regulatory reporting of NLH and provided commentary on improvements that could be made in order to create a more transparent regime. Mr. J. T. Browne focused on the idea that proper regulatory reporting must focus on policies and procedures and avoid detailed reviews and controls (Pre-filed Evidence, J. T. Browne, pg. 6/2-3). These policies and procedures must be reviewed in an open and transparent process (Transcript, Nov. 2, 2001, pg. 9/83-85), and used until the utility comes back to the Board to have the changes approved (Transcript, Nov. 2, 2001, pg. 9/85-87). Mr. J. T. Browne suggested policies and procedures in the following areas:

1. A very clear definition of regulated operations. This would include providing separate financial reports on the regulated activities of the utility (Pre-filed Evidence, J.T. Browne, pg. 9/12-13).
2. The identification of various types of goods and services that the utility provides to or acquires from its affiliates and non-regulated operations, and the establishment of transfer prices (Pre-filed Evidence, J. T. Browne, pg. 27/16-19).
3. The determination of how the revenue requirement will be established and how that revenue requirement will be recovered through rates (Pre-filed Evidence, J. T. Browne, pg. 7/4-6).

Mr. J. T. Browne points out that *“a regulatory board should rely on internal compliance procedures of the utility rather than imposing additional external controls”* and that *“the imposition of regulatory controls should consider the direct dollar costs to impose and comply with the controls, costs borne by both the utility and the regulator. It should also consider other costs of imposing the controls, including the loss of management flexibility.”* (Pre-filed Evidence, J. T. Browne, pg. 6/8-9;pg. 5/17-20).

In cross-examination the CA explored the method of determining the rates charged for inter-company transactions.

Since 1996, when NLH came under the jurisdiction of the Board, the system of reporting has been evolving to meet regulatory needs. However, it became clear during the hearing that the current system of reporting does not promote the efficient production of relevant information on the regulated activities of NLH. The consolidated statements which included non-regulated activities, although useful in creating an overall picture, did not provide the information required for a full understanding of NLH’s regulated activities.

Although the regulated activities of NLH are defined by various pieces of legislation, the Board concluded that it would be useful to summarize these activities, with references to the appropriate legislation, and place this summary on file with the Board.

NLH will be required to file separate financial statements for regulated and non-regulated activities. This will apply to all regulatory reporting including both quarterly and annual reports. NLH will continue to file annual consolidated statements which should be accompanied by precise reconciliation between regulated and non-regulated activities.

NLH will be directed to prepare a summary and index of all policies related to regulated activities and place this summary on file with the Board on or before June 30, 2003.

3. Duplication

Observing the day-to-day activity of NLH and NP within the Province, one can readily understand the public perception that duplication exists since both companies appear to be carrying out some of the same work in the same industry, using similar vehicles and performing similar work activities in common geographic areas on the Island portion of the Province. That perception is a correct one in that NLH and NP are electric utilities delivering electricity to its customers using transmission and distribution lines and poles that are not distinguishable as being owned by one or the other. Furthermore, both utilities are delivering electricity to customer classes that are similar in many respects and both draw upon the same system elements to serve their customers. For example, depending on circumstances, both companies employ the same generation plants and portions of the island transmission and distribution grid from time to time.

Following various exchanges of correspondence between the CEO's of both utilities in 1995 and 1996, Mr. Reeves testified that a joint task force was established in 1997 consisting of representatives from each utility making up 18 working groups or committees mandated to explore reduction in costs through sharing of services or the removal of duplication. A steering committee was put in place consisting of Mr. John Evans from NP, Mr. Dave Reeves from NLH and Mr. Bob Clarke and Mr. Gerard O'Rielly, business managers of the unions representing the workers in the respective utilities. (Transcript, Oct. 2, 2001, pg. 32-33/90-37) The responses to requests for information CA-190 and CA-201 included copies of the minutes and reports of the various working groups and the steering committee meetings that were held commencing in 1997 and continuing to 2000. It appears from the evidence that the working groups concluded their assignments without achieving any substantial savings to consumers. According to CA-201, no final report of the task force was ever completed although the Board gained some insight into the resulting challenges confronting both organizations from the excerpts contained in the latest draft report:

- *“There were a number of positive benefits flowing from the process of carrying out this study. The most significant benefit was the enhanced communication between over 70 employees of both organizations.*
- *The structure of the review did not, however, lend itself to recommended changes which impacted negatively one or more parties.*
- *While all participants support the concept of providing reliable customer service at the lowest reasonable cost, the tactics of measuring and achieving this are often viewed quite differently.*

- *It was generally felt that while there are not a lot of areas of overlap, there are a few where a different approach may result in lowering costs.*
- *A plan could be developed to work toward a more streamlined operation over (say) five years. This could result in requiring fewer workers with associated cost savings. This might involve a reduction in total numbers of staff and may involve doing work for each other at times. An agreement such as this could not be reached given the diversity of the group.”*

The final argument of the CA recommended that the Board devise a standard to deal with duplication of operations and services between the two utilities and commission a third party report on the cost of duplication with appropriate recommendations to be filed by the next rate hearing. (CA, Final Argument, pg. 53-54) The IC in their final argument recommends the Board conduct a similar study and direct the utilities in accordance with its recommendations (IC, Final Argument, pg. 124)

The Board recognizes the considerable time (in excess of five years) and resources committed by both utilities in wrestling with duplication. This effort combined with repeated draft reports raises serious concerns for the Board given the inability of both utilities to properly conclude on the mandate of the joint task force, the difficulties encountered throughout the process and the limited value added at the end of the day for electrical consumers throughout the Province. It is not surprising, therefore, that the perception of duplication persists among the public in light of such precarious circumstances and the lack of closure being brought to this recurring issue.

The Board is not persuaded to commission a costly study into duplication at the present time, particularly with a view to the structural issues involving both utilities being addressed through the Electricity Policy Review. Neither is the Board prepared to let the continuing uncertainty surrounding duplication remain. The Board is of the opinion that with the right mindset by both utilities the question of duplication can be effectively and definitively resolved without the future intervention of the Board.

The Board will require that NLH submit a final report on the results of joint efforts to date to reduce duplication between NLH and NP. The report should identify and make recommendations concerning additional collaborative opportunities between the two utilities on eliminating duplication and expanding cooperation in the interests of electricity consumers. This report should be concluded by both utilities, if possible, and in any event should be provided to the Board no later than December 31, 2002.

4. Customer Service Issues-Labrador Isolated Diesel System

Throughout the course of the hearing the Board heard little evidence critical of the reliability of NLH’s service. The exception arose during public participation days in Happy Valley-Goose Bay where representatives from communities along coastal Labrador served by isolated diesel systems appeared before the Board.

Mr. Nat Moores, Mayor of L'Anse-au-Clair representing the Combined Councils of Labrador stated, *"that's always been a concern, especially reliability. The diesel power, many complaints you will have from communities is not enough power, a lot of outages, problems associated with that. And in our region, the uncertainty of what's happening with the power in Quebec, and again, having to go back on diesel. So there's always been concern from the entire membership or the membership in the coastal Labrador"*. (Transcript, Oct. 19, 2001, pg. 24/45-52)

Mr. Henry Broomfield, the Deputy Mayor of Nain, outlined many of the concerns of residents in his community who experienced brown outs and voltage fluctuations, particularly at night. (Transcript, Oct. 18, 2001 pg. 44/74, pg. 45/20-47, pg. 50/62) The Board heard from several other presenters who were concerned that regular power outages may affect the economic viability of some of the businesses. Ms. Melita Power, Town Manager of Charlottetown, told the Board that the shrimp processing facility opened in the summer of 2001 had daily power failures. Although there was some intervention by NLH service personnel, power failures continued until early October. The power outages resulted in lost production time, equipment failure and increased expenses. (Transcript, Oct. 19, 2001 pg. 29/5-76)

The Board also heard of other problems with NLH's overall service. Amongst the issues raised were issues with the format of NLH's billings. It was also noted that many of the community elders, besides not being able to read English, could not understand the bill presentations. (Transcript, Oct. 18, 46/21-34 & lines 55-73) It was further noted that incidents of incorrect readings, overcharges, and, in particular, discount forfeits compound the problem. (Transcript, Oct. 18, 2001, pg. 45/63)

The Board was informed that meeting bill payment discount dates was a particular problem because of regularly disrupted mail service, particularly in the winter months. On-line banking is an option but many residents do not have access to a computer. (Transcript, Oct. 18, 2001 pg. 47/32-45) When the Board inquired why it took so long for payments to reach NLH, Mr. Broomfield advised that the return payment envelopes were addressed to St. John's and not to the regional office in Goose Bay. (Transcript, Oct. 18, 2001 pg. 52/41-46)

The important message heard from the community representatives from coastal Labrador was that there are common concerns with NLH's service throughout the region. This was evident by the recurring issues repeated throughout the presentations. The Board, guided by its general supervisory responsibilities in Section 16 of the *Act*, and specifically by the reasonably, safe and adequate service provision in Section 37 of the *Act*, is concerned with customer service issues raised by the community representatives served by the Labrador Isolated Diesel system.

The Board will direct NLH to review the issues raised during the hearing and file with the Board a summary report with recommendations on how NLH may reasonably improve the reliability and quality of service for customers in coastal Labrador communities.

5. Conservation

The issue of conservation and Demand Side Management (DSM) was raised by the CA. The Board also heard several presentations during public participation days which spoke to the importance of conservation, especially as it relates to reducing costs for consumers. In particular, the Board heard from Mr. Bruce Pearce, Climate Change Action Coordinator and Ms. Sarah Peckford, Eco-Team Director for the Eco-Team Program, both of the Conservation Corps of Newfoundland and Labrador (the Corps). They presented the results of some of the work the Corps has undertaken with both NLH and NP, and as well with the Federal and Provincial Governments and others. Mr. Pearce suggests that conservation can play a role in incorporating social and environmental concerns into the area of energy management and can assist consumers in cushioning the impact of the proposed rate increase. Information was provided on the EnerGuide for Houses Program offered by the Corps and the potential reduction in energy use and resulting financial savings that can be achieved. Typical improvements that consumers make as a result of the energy assessment offered under this program include insulation upgrades, air sealing to prevent heat loss, and installation of water conservation kits. (Transcript, Oct. 26, 2001, pg. 9-12/69-26)

As part of its evidence the Corps provided a copy of a letter from NP outlining the results of a meeting between NP and the Corps on agreed discussion areas for possible broader partnerships. The areas identified were:

1. *Greater integration of efforts* - to avoid duplication of efforts, especially in the area of energy advice and assessment services to its customers.
2. *Increasing promotion coordination* - to assist in increasing the profile of the Corps in the Province, including its core conservation message.
3. *Providing financial support* - to assist customers in availing of the services of the Corps, including the possible provision of financial assistance for energy assessments.
4. *Improving customer support* - to explore initiatives such as equal payment and financing plans, which may assist customers in undertaking energy conservation measures, especially those where immediate benefits are not realized.

Ms. Mullalley-Pauly of the Office of Energy Efficiency, Natural Resources Canada in Ottawa spoke during the public participation day in St. John's of the challenges of delivering the message of conservation. The traditional methods of getting this message out, such as bill inserts and advertising, have been generally ignored by consumers. (Transcript, Oct. 26, 2001, pg. 14/40-53) As well, DSM programs of the past, advocated by the utilities, have been met with skepticism by consumers who doubt that a seller of a product would have a real interest in reducing its sales. (Transcript, Oct. 26, 2001, pg. 13/21-30)

However, according to Ms. Mullalley-Pauly, the use of a community based approach, with third party delivery agents, and with a service supplied for a fee has been well received by the same people who have taken little notice of bill inserts and advertising. The efforts of the Corps to relate a conservation program to an energy efficiency program that results in real savings to the end-user are getting the attention of consumers in a way that has not happened with most demand side management programs. This is evident from the number of home assessments that have taken place since January 2000 and the fact that 70% of the assessments result in the recommendations being implemented (Transcript, Oct. 26, 2001, pg. 14/63-66).

The Corps charges a fee of \$100 to consumers for an energy assessment. Ms. Peckford and Mr. Pearce, both of the Corps, explained how the fee of \$100 is a barrier to some consumers who would like to avail of the service (Transcript, Oct. 26, 2001, pg. 27/66-97). The CA in final argument (pg. 53) recommended that *“the utilities work with the Conservation Corps in the implementation of DSM programs and contribute to the \$100 fee for services provided to ratepayers by the Conservation Corps.”*

In response to a request to list the DSM and energy efficiency programs that NLH has implemented in the past five years, NLH replied (CA-20):

“Hydro has not implemented system wide conservation and load management programs in the past five years and has no definitive plans to undertake system wide programs in the next five years. Hydro has undertaken to complement its customer service delivery function with energy management training and education as outlined in CA-24. Hydro also evaluates opportunities as they arise on island systems for conservation and load management with an objective of rural subsidy minimization. See NP-184(e).”

In CA-126 NLH further described their current efforts to encourage conservation by its customer groups. In the early 1990s the focus for conservation efforts was on reducing load through reducing energy consumption in electric space and water heating. NLH states *“conservation is now more routinely viewed as a component of an overall customer service function that seeks to maximize customer value in the content of market price signals.”*

The Board agrees that the message of conservation is an important one, for both utilities and consumers. The Board recognizes and supports NLH’s efforts to date in partnering with the Corps and encourages NLH to engage in further discussions with the Corps to explore areas where there are opportunities for further initiatives along the lines of those outlined above by NP. It is recognized that progress by NLH and the Corps in these areas will improve customer access to conservation tools and will assist in customers being able to realize the results of undertaking conservation and energy saving initiatives. The Board also believes that, while these efforts do result in benefits to both NLH and its customers, the implementation and monitoring of such activities are best achieved within the customer service group of NLH. NLH should consider including the area of conservation and customer support on its customer satisfaction surveys. The Board will be able to monitor the results of these efforts in its review of these reports which are provided by NLH as part of its ongoing regulation.

The Board is persuaded that community based conservation initiatives, similar to those undertaken by the Conservation Corps of Newfoundland and Labrador, have merit in assisting consumers and reducing energy demands which, if sustained, may lower generating capacity requirements into the future. The Board believes NLH should focus attention on conservation and bring forward to the Board a multi-year plan directive to these kinds of initiatives.

One of the other areas to focus on in terms of the potential for energy conservation and savings is in the Isolated Rural systems on the coast of Labrador. The Board heard from many NLH customers from the coast of Labrador about their high electricity costs. From an economic perspective, although it seems reasonable to expect that a decrease in energy consumption will result in lower energy costs to all consumers, this is not always the case. As described previously in Rural Systems (pg. 120) these systems currently operate at a substantial deficit with rural customers paying considerably less in certain cases than their full COS. In some of the Isolated Rural systems the loss in revenue from reduced consumption may more than offset any savings that may be achieved from DSM programs, with a resulting increase in the rural deficit. This will then cause an increase in the rates to be charged to NP and to Labrador Interconnected customers. However, in systems where capital costs can be avoided through conservation and DSM measures, such as the elimination of a need for capital expenditures resulting from load growth, the results may be different. The Board studied this issue as a part of its 1995 Rural Electrical Service Inquiry and found that *“Conservation programs for isolated areas should be designed to defer expansion of capacity and to target for subsidy reduction rather than lower energy use”*. (CA-2, Report ... On A Referral By The Lieutenant-Governor in Council Concerning Rural Electrical Service, July 29, 1996, pg. 37) The Board believes this recommendation is still valid and may provide future opportunity for cost savings. NLH should continue to explore these opportunities as the need arises for replacement or expansion of generation systems, especially on the Isolated Rural systems.

The Board will require NLH to include, in all applications for capital expenditure programs where generation is being replaced or upgraded, a cost benefit analysis of any alternatives that may result in reduced load or a deferral of capacity expansion.

6. Long Term Regulation

The Board, in reflecting on its decisions, is motivated to establish a stable regulatory environment which will serve to effectively communicate the regulatory role and decisions of the Board to all NLH's stakeholders.

For example, the Board notes the importance NLH attached throughout the hearing to the Board sending appropriate signals to the capital markets in the interests of NLH's yet to be determined long range financial targets. Until such time as NLH brings forward its comprehensive financial goals in an application, the Board is not in a position to deal with them. As demonstrated following the review of the evidence in relation to NLH's debt/equity ratio (See pg 42), the Board notes Government's guarantee remains in place which will ensure NLH the same access to the capital markets that it has traditionally maintained. NLH's future intention to operate on a stand-alone basis similar to an investor owned utility is entirely within the hands of

NLH's management. The Board points to the existing regulatory framework that currently regulates NP, an investor owned utility, and suggests it is up to NLH to present sufficient justification in its next application to support its intended longer term directions. In relation to NLH's long term financial targets, the application should contain a comprehensive assessment of regulatory, financial and business risks for NLH compared to similar utilities operating without a Government guarantee. At that time, presumably NLH will bring forward recommendations on an appropriate long term capital structure in light of the costs associated with these risks.

Appropriate financial targets represent only one example of what needs to be done in the long term to effectively regulate NLH. The Board references other areas incorporated in its decisions where it has placed considerable responsibility on NLH, and for this matter itself, to address future regulatory requirements. The Board concurs with Mr. Wells comments in his opening statement "*it will be necessary to achieve the ultimate objective (regulatory) through a period of adjustments*", and notes the Board is prepared to facilitate and expedite its regulatory obligations as quickly as practical.

During the hearing NLH referred to the fact that it was in the process of developing a strategic plan. Clearly, elements of a strategic planning exercise should involve a visioning process, stakeholder consultations and an analysis of opportunities and risks associated with the organization. These and other components of a strategic plan manifest themselves into integrated corporate goals, financial targets and operating plans based on performance measures designed to specifically achieve these goals and targets. Mr. Osmond confirms the financial targets for 2002 are temporary and that NLH needs to put forth a plan to determine where things are going in the longer term and to map this out in the scheduled 2003 application. Mr. Osmond also indicated the link between the strategic plan and the financial structure and points to the need to review these results with the Province particularly in light of the Energy (now Electricity) Policy Review (EPR) (Transcript, Nov. 26, 2001, pg. 22/16-42)

The Board supports the strategic plan initiative of NLH and believes it provides an excellent opportunity to address the intended vision of NLH as an investor owned utility along with related corporate goals and financial targets. The Board strongly believes this process will permit NLH to present to the Board an actual plan on how it intends to achieve and execute its long term goals and objectives, including the Board's regulatory requirements. In particular, the Board encourages NLH during its strategic planning process to incorporate the findings of the Board and integrate the planning and coordination of these regulatory requirements into the process. Examples would include findings related to regulatory reporting, regulatory performance measures, long term financial targets, public policy costs, policies and procedures as well as studies/evaluations.

Integrated planning will permit regulatory decisions in future that are rationally based while minimizing the regulatory risk to NLH. Communications resulting from regulatory decisions will send credible messages that are consistent with the plan and targets of NLH. This will benefit NLH and its stakeholders as well as allow the Board to move forward with the effective regulation of the utility.

NLH is encouraged to integrate the Board's findings into its strategic planning process.

7. Next Application

LC-5, in response to a question arising from Mr. Wells' evidence, states that NLH plans to file its next rate application in 2003. Repeatedly throughout the course of the hearing NLH reiterated this timeframe. Mr. Wells in response to questioning from Commissioner Saunders on this issue stated:

"We can only state our intent at this time and the circumstances of this application and the issues that are being considered, you know, pretty well dictate that we should be back in 2003, but again the Board is going to be aware of all the factors at the end of this hearing and has the jurisdiction." (Transcript, September 28, 2001, pg.7/33-38)

Having now dealt with this Application the Board is very cognizant of the challenges it has faced resulting from the more than five year hiatus between NLH becoming a fully regulated utility in January 1996 and its first rate application as such in May 2001. Notwithstanding, the Board is of the view that this decision completes the first phase in the process to effectively regulate NLH. The timing of its next rate application is critical to sustaining the momentum established and providing continuity to the process. In relation to the approach taken to this Application, the Board believes NLH also acknowledges the importance of this timing. For example, NLH throughout the course of the hearing referred to long term financial targets, preferential rates, forecast fuel costs and numerous other issues which would be best addressed at their next rate application scheduled for 2003.

The Board notes as well that this decision sets out several directives which are designed to lay the groundwork for the next phase of regulating NLH. Much of this work requested of NLH and indeed other work to be conducted by the Board is time sensitive and is linked to NLH's anticipated date for its next rate hearing in 2003. For these reasons, the Board strongly believes that a commitment to this date is in the interest of all parties involved at this hearing.

The Board will order pursuant to Section 70 of the Act, that NLH submit its next general rate application to the Board no later than December 31, 2003.

XI. HEARING COST AWARDS

Both the IC and the Towns of Labrador City and Wabush requested that 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.”

Under normal circumstances the Board is guided by the “*ability to pay*” principle in adjudicating requests for cost awards. The Board believes there are a number of circumstances surrounding this Application that are unusual and have resulted in the length and complexity of the hearing being beyond the norm. The Application represents the first time that NLH is before the Board as a fully regulated utility under the *EPCA* and 10 years have elapsed since the last general rate review. The Board believes the delay in NLH appearing before the Board has complicated the hearing process for the IC through no fault of their own. These circumstances have contributed unduly to the IC’s hearing costs and the Board believes that it would be unfair to expect them to cover their total costs.

The Board will award costs to the IC. Upon receipt of a detailed statement of costs the Board will fix an amount. The Board’s decision in this matter is solely to recognize the circumstances surrounding this Application and is not intended to set a precedent.

On the matter of the application by the Towns of Labrador City and Wabush, the Board is not compelled to grant their costs. The CA was appointed by the Lieutenant-Governor in Council to represent all of the Domestic and General Service customers in the Province and most municipalities were served in this way. Labrador City and Wabush decided to directly intervene to represent their particular interests and were in partial attendance during the course of the hearing.

The application by the Towns of Labrador City and Wabush for costs will be denied.

PART THREE. SUMMARY OF BOARD DECISIONS

I. CAPITAL STRUCTURE

1. The Board accepts that the Government guarantee plays a fundamental role in NLH's ability to maintain a sound credit rating in the financial markets of the world. The Board concurs that the guarantee fee of \$12,336,000 in the 2002 test year is appropriate.
2. The Board feels the proposed dividend payment of \$70,000,000 in the 2002 test year places an excessive burden on consumers when it is included in revenue requirement. The Board finds that the interest expense and return on equity in the 2002 test year revenue requirement should be based on NLH's dividend policy providing for dividends of up to 75% of its net operating income. The interest cost for the 2002 test year will be required to be reduced using the embedded cost of debt to reflect the cost of financing the dividend in excess of NLH's dividend policy. A corresponding increase in return on equity or net earnings reflecting the requested 3% return on the notional increase in equity will partially offset the interest reduction.
3. 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.
4. The Board accepts NLH's proposals for a debt/equity ratio in the 2002 test year of 83/17 and a target short term debt/equity ratio of 80/20. The Board concludes the evidence does not support the principle of NLH moving to a capital structure of 60/40 at the present time. If NLH is committed to move in this direction, it must formulate an appropriate long term financial plan to present to the Board.
5. The Board accepts NLH's request for a 3% ROE in the 2002 test year. The Board acknowledges this level of ROE is below normal market returns because of NLH's position taken in this Application to lessen the rate impact on its customers. Consideration of a more normal return will be subject to a future request by NLH.

II. FORECASTING: PRODUCTION AND FUEL COSTS

6. 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 the study will be required to be filed with the Board as part of NLH's next rate application.

7. The 2002 test year forecast of thermal generation will be adjusted to reflect a forecast hydraulic production of 4,425 GWh.
8. The Board finds that a fuel efficiency factor in the range of 615-620 kWh/bbl is warranted. To mitigate potential impacts on NLH's margin which, at 3%, is already below a normal market rate the Board will order an efficiency factor of 615 kWh/bbl. This efficiency factor will also be used for calculating hydraulic variation in the Rate Stabilization Plan (RSP).
9. The Board accepts the 2002 test year forecasts for fuel prices as filed.
10. The Board will require NLH to file by December 31, 2002 a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing. The statement should address managerial accountability for fuel purchasing along with consideration of such issues as an oil hedging program and the adequacy of existing storage capacity.

III. REVENUE REQUIREMENT

11. The Board accepts the depreciation study and approves the changes in depreciation policies as filed by NLH. The depreciation expense proposed by NLH will be required to be adjusted to reflect the Board's decisions on NLH's 2002 capital budget. NLH will be required to submit its next depreciation study in 2005.
12. The Board will approve the extension of the service lives for the transmission lines affected by the Avalon upgrade program as proposed by NLH.
13. The forecast price for No. 6 fuel, as set out by NLH in Table 1 on page 1 of R. J. Henderson's 2nd Supplementary Evidence (See Schedule 1 attached to the Order), which shows a 2002 weighted annual average price of No. 6 fuel of \$25.91 Cdn/bbl, will be used in the 2002 test year costs for No. 6 fuel.
14. The Board accepts the diesel fuel costs of \$6,508,000 for the 2002 test year.
15. The Board accepts the Other Fuel Costs of \$871,000 for the 2002 test year.
16. The Board accepts purchased power costs in the amount of \$15,100,000 for the 2002 test year.
17. Certain other costs (insurance, transportation, office supplies, building rentals and maintenance, equipment rentals and loss on disposal) as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set (See No. 27) by the Board.

18. The Board finds that any reduction in salary costs to be incorporated in the 2002 test year is best managed by NLH within the scope of the vacancy credit adjustment (See No. 19) and in the application of the productivity allowance set by the Board.
19. The Board will order NLH to reduce salaries and fringe benefit expenses for the 2002 test year by an additional \$500,000 to reflect a higher vacancy credit.
20. The Board accepts NLH's proposals for the treatment of employee future benefits and accepts the 2002 test year costs.
21. System equipment maintenance costs as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.
22. NLH will be required to submit to the Board by December 31, 2002 a detailed plan of projected maintenance expenditures over the next ten years for the Holyrood Generating Station.
23. Professional services costs as proposed for NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.
24. Travel costs as proposed by NLH for the 2002 test year are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board. NLH will be directed to exclude spousal travel costs from regulated expenses. NLH will also be required to file its policies and procedures for employee travel with the Board.
25. The Board approves NLH's proposal to discontinue treatment of Bay D'Espoir street lighting costs as a regulated expense and will order its removal from the 2002 test year revenue requirement.
26. Miscellaneous costs as proposed by NLH for the 2002 test year, including inventory gain/loss, are accepted subject to any reduction by NLH resulting from the productivity allowance set by the Board.
27. In addition to the other adjustments to the 2002 test year revenue requirement, the Board will require a reduction of \$2,000,000 on NLH's "*other costs*" for the 2002 test year to reflect a productivity allowance.
28. The Board will request its financial consultants to work with NLH to recommend suitable regulatory performance standards which will be used to measure operating efficiencies at NLH and these will be incorporated as part of NLH's ongoing reporting to the Board.
29. The Board will not accept the \$75,000 for "*Communication Plan*" advertising as a regulated expense for the 2002 test year.

30. Subject to adjustments for Bay D'Espoir street lighting, spousal travel and "*Communication Plan*" advertising, the Board concludes that non-regulated expenses are properly excluded from NLH's 2002 test year costs.
31. The Board accepts the capitalized expenses in the amount of \$5,722,000 as proposed by NLH for the 2002 test year.
32. The Board accepts the CF(L)Co allocation in the amount of \$1,910,000 as proposed by NLH for the 2002 test year.
33. The Board acknowledges the benefit to ratepayers of the flow through income from recall power in that it reduces NLH's borrowing costs during the year and accepts NLH's calculation of the notional interest in the 2002 test year revenue requirement.
34. The Board will require NLH to file prior to June 30, 2003 details of the methodology used for calculation of notional interest.
35. The Board will require NLH to include in the 2002 test year revenue requirement an appropriate credit for interest collected on overdue accounts.
36. NLH will be required to revise the calculation of the interest expense for the 2002 test year to incorporate the decisions of the Board.

IV. RATE STABILIZATION PLAN

37. The Board is not convinced that the interests of the consumers or NLH would be served through the elimination of the RSP and, other than the specific adjustments and changes described in this decision, will not make any other change in the RSP or its operation at this time.
38. The Board is convinced, based on the evidence and issues raised at the hearing, that the design and elements of the existing plan should be reviewed. To that end the Board will commission a study of the RSP, which will include a review of the plan since its implementation, together with the operational issues raised by the intervenors at the hearing. The Board will decide based on the results of that study what action should be taken.
39. The COS price for No. 6 fuel to be used in the RSP for calculating the fuel price adjustment will be based on the monthly 2002 forecast fuel prices as filed in Table 1 of R. J. Henderson's, 2nd Supplementary Evidence. This table indicates that the weighted average fuel price for the test year will be \$25.91 Cdn/bbl. In addition, NLH will be required to file updated 12-month fuel forecasts as part of its quarterly report to the Board.

40. The Board does not accept NLH's proposal to increase the cap on the retail portion of the RSP to \$100,000,000. The Board will remove the existing cap of \$50,000,000 on the retail portion of the RSP.
41. Because of the magnitude of the anticipated rate increases which will result from the Board's decision to use the forecast average fuel price in base rates, the Board will not allow any additional recovery of the existing RSP balance until 2003. The Board believes that deferral of the RSP mill rate adjustments together with an extended recovery period mitigates the impact of moving to true "*cost based*" rates incorporating the forecast price of No. 6 fuel.
42. With respect to the recovery of the balance in the RSP the Board will order the following:
 - The existing balances in the RSP are to be fixed as of the end of the month prior to the effective date of rate implementation based on the current methodology.
 - The RSP mill rate for the IC will be reset as of the effective date of rate implementation for the remainder of 2002 to 2.80 mills/kWh, which was the rate effective January 1, 2001.
 - The RSP mill rate for 2002 for NP will remain at 1.77 mills/kWh, which was the rate effective as of July 1, 2001.
 - Recovery of the fixed balance outstanding will be spread over a five year period commencing in 2003 using a straight line recovery method. The method for calculating the mill rate adjustments and the date of the adjustments for both the IC and NP will remain the same. The amounts recovered will be credited against the outstanding balance of the plan. Interest will be accumulated and maintained on the balance using the WACC.
 - Recovery or credits of balances that accumulate in the plan after the effective date of rate implementation will be calculated using a straight-line method over a two year period, to be effective January 1, 2004 for the IC and July 1, 2004 for NP.
43. The Board will not make any adjustments to the RSP prior period balances as requested by the IC.
44. The Board accepts the changes in the RSP as proposed by NLH with the exception of the price of No. 6 fuel, the Holyrood efficiency factor, the test year hydraulic production and the increase in RSP cap which are dealt with elsewhere in this decision.

V. CAPITAL BUDGET

45. The Board will require NLH, commencing with its 2003 capital budget application, to use a net present value methodology together with supporting justification to evaluate projects of a material amount. Where a project is not evaluated against other acceptable alternatives and/or, if the project does not produce a positive net present value, sufficient rationale must be provided to justify implementation. The Board has set out guidelines to be used by NLH in future capital budget applications in Schedule 3, attached to this decision.

46. The Board will order that, for the purposes of establishing the revenue requirement, NLH reduce its approved capital budget by 7½%. This downward adjustment will reduce depreciation and interest expense as well as the forecast rate base for the 2002 test year.
47. The Board will approve an “*Allowance for Unforeseen Events*” of \$1,000,000 as part of the 2002 capital budget but will impose conditions on its use.
48. The Board agrees that further justification should be completed of NLH’s proposal to replace its VHF Mobile Radio system, including a cost benefit analysis of alternatives. The Board will also require NLH to prepare and file an updated version of its Telecommunications Plan with the Board.
49. The Board will approve the remaining capital budget projects not approved in P.U. 30 (2001-2002) with the exception of B-66 (VHF Mobile Radio system).
50. The Board will approve a 2002 test year capital budget of \$36,765,000, adjusted to remove the VHF Mobile Radio system project.

VI. RATE BASE

51. At the present time the Board will not act to adjust the CWCA to reflect the timing difference between the payment of semi-annual long term bond interest and the receipt of the funds for their payment. The Board feels this issue warrants further consideration and will require NLH to submit to the Board, prior to the next rate application, an analysis of this issue.
52. The Board accepts NLH’s proposed treatment of amortizing the foreign exchange loss at the rate of \$2,157,000 per year and its inclusion in the 2002 test year revenue requirement with the average balance of \$85,200,000 forming part of the rate base.
53. The Board approves the approach and methodology used by NLH in determining the 2002 test year rate base.
54. NLH will be required to file a revised rate base and revised calculation of return on rate base which reflects the decisions of the Board.

VII. COST OF SERVICE

55. The Board is not convinced that the LOLH study provides sufficient evidence to justify using a 2 CP allocator for generation demand costs. Furthermore, the Board is not persuaded that the use of any other multiple allocator is correct in this situation. The Board finds that the evidence supports the use of a 1 CP allocator and the Board will order that NLH use a 1 CP allocator for allocation of generation demand costs.

56. The Board finds that the use of the zero intercept method for classification of distribution system costs as proposed by NLH is an acceptable method for dividing distribution costs into demand and customer related components.
57. The Board accepts the use of a 1 CP allocator for distribution demand costs, as approved by the 1993 generic COS methodology.
58. Based on the evidence before it at 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 reconsider this issue at NLH's next rate hearing. 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.
59. The Board accepts NLH's proposal that the frequency converters be specifically assigned to the IC in the COS.
60. The Board accepts NLH's treatment of the generation credit for NP and the Interruptible 'B' credit for the IC.
61. The Board accepts NLH's treatment for classification of hydraulic plant as being in accordance with the 1993 generic COS methodology.
62. NLH's proposal for treatment of transformer losses is accepted.
63. The Board has already ruled in the 1993 generic COS methodology that there be a single cost of service study for the Labrador Interconnected system and is not persuaded that there is sufficient evidence to reconsider the matter at this time.
64. The Board accepts NLH's proposal and reasons to use a 1 CP allocator for generation demand costs for the Labrador Interconnected system.

VIII. RURAL SYSTEMS

65. The Board will direct 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.

66. The Board will order that the existing policy be continued of allowing NLH, as NP changes its rates, to automatically adjust the rates it charges its Island Rural Interconnected customers, its customers serviced from the L'Anse au Loup system and its Isolated Rural customers for the first 700 kWh per month of consumption, other than Government departments and agencies so that rates are the same as the rates charged by NP to its customers and to automatically change the rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural customers, other than Government departments and agencies, by the average rate of change granted to NP.
67. The Board finds preferential rates are discriminatory and will order that NLH increase rates to the Federal and Provincial Governments effective with the implementation of other rate changes arising from this decision to recover the full costs of providing this service in rural areas. Preferential rates will continue to apply to hospitals, fish plants, churches, schools, community halls, municipal buildings and like facilities currently benefiting from preferential rates. NLH's proposal is accepted to present to the Board at its next rate application a plan to phase out preferential rural rates.
68. The Board will approve the existing "*lifeline block*" of 700 kWh for both domestic and general service customers. NLH will be required to undertake a review of the existing "*lifeline block*" for domestic customers to assess its adequacy and prior to December 31st, 2002 file a report with the Board.
69. The Board accepts NLH's proposal to address at its next rate application the elimination of the "*lifeline block*" for general service customers on isolated systems. This proposal is to be appropriately coordinated with the Board's decision to implement a demand energy rate structure for this same class of customers.
70. NLH will be required to take the necessary steps required to prepare for implementation of a demand energy rate structure for general service customers on isolated systems and to file at its next rate application a proposal for such a rate structure. The implementation of this decision is to be coordinated with the elimination of the "*lifeline block*" for general service customers to be addressed by NLH at its next rate application.
71. The Board will not direct NLH to provide a refund to reflect a gradual reduction of the IC portion of the rural subsidy over the period 1996-1999.

IX. RATE ISSUES/RATE DESIGN

72. NLH's proposal to implement the Island Interconnected rate structure (six classes) for the Labrador Interconnected system will be approved.
73. NLH's proposal to phase-in a cost based rate system for the Labrador Interconnected system as of the implementation of rates that arise from this decision will be approved. NLH will be required to file a five year plan outlining further alterations in rates on the Labrador Interconnected system, with the cost recovery targets as identified in this Application to be incorporated as part of NLH's next rate application.

74. The Board recognizes NLH's efforts in this Application to minimize rate increases to its customers on the Labrador Interconnected system to a level that, in its view, would not cause "*rate shock*" by applying these guidelines in its rate design. The Board sees these guidelines as reasonable and encourages NLH to adhere to these guidelines as it redesigns its rates to be submitted to the Board as a result of this decision. If application of the guidelines, as they are, prevent the design of rates that will recover costs, the Board will support some adjustment in the parameters if required. The Board reiterates its support of keeping the level of rate increases on the Labrador Interconnected system as low as possible as NLH moves to a uniform rate structure.
75. The secondary energy rate as proposed by NLH for customers serviced from the Labrador Interconnected system will be approved.
76. The Board finds that the credit from secondary energy sales to CFB Goose Bay (5 Wing) would be more appropriately applied against the rural deficit before allocation to NP and Labrador Interconnected customers. However, because of the magnitude of this adjustment relative to the total revenue requirement on the Labrador Interconnected, together with the impact of other decisions of the Board, the Board believes that implementation of this decision would introduce rate shock for the Labrador Interconnected customers. For the 2002 test year, the credit should be applied to the Labrador Interconnected system as proposed by NLH. The Board will require NLH to include, as part of its five year rate plan to be submitted at the next rate hearing, a plan which phases in to the Labrador Interconnected customers, the impact of applying the credit for secondary energy sales to the rural deficit.
77. The Board will approve the refund of the Wabush surplus of \$2,922,755 as proposed by NLH.
78. The Board will approve the rules and regulations set out in NLH's contracts with the IC, with the exception of the proposed contract with North Atlantic Refinery Limited.
79. The Board will approve the rules and regulations set out in NLH's contract with North Atlantic Refinery Limited, but excludes Clause 9.04, which describes the liability of NLH.
80. The Board accepts NLH's methodology for calculating the wheeling rate but will require the calculation of the rate to be revised in light of the Board's decision on the assignment of the GNP costs. In the case of transmission losses, NLH will be required to use the average losses on the system for the last five years (1996-2000) calculated at 3.47%.

81. 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 hearing. 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.
82. The Board believes that, in light of the many other matters which it has requested NLH to address and also the fact that the Electricity Policy Review is ongoing, it would not be timely to commence any study of marginal costs considerations at this time. The Board will continue to monitor this situation with a view to determining an opportune time to act on this initiative.
83. NLH will be required to submit revised Rules and Regulations incorporating changes to Clause 4 and Clause 10 (c) as accepted by the Board for final approval with the revised Rate Schedules to be filed.
84. In order to finalize rates to be implemented as a result of this Application, NLH will be directed to incorporate the decisions of the Board by:
 1. adjusting its revenue requirement and calculation of rate base and return on rate base;
 2. completing a revised COS study for the 2002 test year; and
 3. revising its proposed Schedule of Rates for the various customer classes based on the updated cost of service.

and filing the above with the Board for approval. The Board will review NLH's revised filing to ensure its decisions are appropriately incorporated and then issue a final Order approving or modifying, as it deems appropriate, the rate base, NLH's return on rate base and the revised rates for NLH's customers for the 2002 test year.

X. OTHER ISSUES

85. The Board will approve the code of accounts submitted by NLH and will require NLH to file written policies and procedures for the accounting of all intra and inter-corporate transactions, indicating what is to be included in regulated and non-regulated activities.
86. NLH will be required to file separate financial statements for regulated and non-regulated activities. This will apply to all regulatory reporting including both quarterly and annual reports. NLH will continue to file annual consolidated statements which should be accompanied by precise reconciliation between regulated and non-regulated activities.
87. NLH will be directed to prepare a summary and index of all policies related to regulated activities and place this summary on file with the Board on or before June 30, 2003.

88. The Board will require that NLH submit a final report on the results of joint efforts to date to reduce duplication between NLH and NP. The report should identify and make recommendations concerning additional collaborative opportunities between the two utilities on eliminating duplication and expanding cooperation in the interests of electricity consumers. This report should be concluded by both utilities, if possible, and in any event should be provided to the Board no later than December 31, 2002.
89. The Board will direct NLH to review the issues raised during the hearing and file with the Board a summary report with recommendations on how NLH may reasonably improve the reliability and quality of service for customers in coastal Labrador communities.
90. The Board is persuaded that community based conservation initiatives, similar to those undertaken by the Conservation Corps of Newfoundland and Labrador, have merit in assisting consumers and reducing energy demands which, if sustained, may lower generating capacity requirements into the future. The Board believes NLH should focus attention on conservation and bring forward to the Board a multi-year plan directed to these kinds of initiatives.
91. The Board will require NLH to include, in all applications for capital expenditure programs where generation is being replaced or upgraded, a cost benefit analysis of any alternatives that may result in reduced load or a deferral of capacity expansion.
92. NLH is encouraged to integrate the Board's findings into its strategic planning process.
93. The Board will order pursuant to Section 70 of the *Act*, that NLH submit its next general rate application no later than December 31, 2003.

XI HEARING COST AWARDS

94. The Board will award costs to the IC. Upon receipt of a detailed statement of costs the Board will fix an amount. The Board's decision in this matter is solely to recognize the circumstances surrounding this Application and is not intended to set a precedent.
95. The application by the Towns of Labrador City and Wabush for costs will be denied.

PART FOUR. THE ORDER**IT IS THEREFORE ORDERED THAT:****CAPITAL STRUCTURE**

1. NLH's debt/equity ratio in the 2002 test year of 83/17 and a short term debt/equity target rate of 80/20 is approved for use in calculating the rate of return on rate base.

FORECASTING: PRODUCTION/FUEL COSTS

2. The 2002 test year forecast of hydraulic production shall be 4,425 GWh.
3. The 2002 test year forecast of thermal generation shall be reduced to reflect the revised hydraulic forecast.
4. A fuel efficiency factor of 615 kWh/bbl shall be used to calculate 2002 test year fuel costs for No. 6 fuel.
5. NLH shall file with the Board:
 - i. As part of its next general rate application, an independent study of its hydraulic production forecasting methodology and the terms of reference shall be filed with the Board for approval in advance.
 - ii. On or before December 31, 2002, a statement of policies and procedures outlining a coordinated, integrated and strategic approach to fuel purchasing; as outlined in the decision of the Board.

REVENUE REQUIREMENT – TEST YEAR 2002

6. NLH shall calculate and file a revised total revenue requirement for the 2002 test year based on its proposals in this Application, incorporating the changes set out in this Order, which include:
 - i. Depreciation expense, adjusted to reflect NLH's 2002 Capital Budget as revised by this Order, including the elimination of the VHF Mobile Radio system project and the reduction of 7½%.
 - ii. The monthly forecast price of No. 6 fuel, as set out in Schedule 1 attached to this Order.
 - iii. Salaries and Fringe Benefits, reduced by an additional \$500,000 to reflect a higher vacancy credit.

- iv. “Other costs”, reduced by \$2,000,000 to incorporate a productivity allowance.
 - v. An appropriate credit for interest collected on overdue accounts.
 - vi. The interest expense component of the 2002 test year return on rate base, incorporating:
 - (a) a reduction (calculated using the embedded cost of debt) to reflect the cost of financing the dividend in excess of NLH’s existing dividend policy; and
 - (b) an adjustment to reflect the reduction of 7½% to NLH’s approved 2002 capital budget for revenue requirement purposes.
 - vii. The return on equity component of the 2002 test year return on rate base, incorporating an adjustment to reflect the 3% return on the notional increase in equity resulting from payment of a dividend which is consistent with NLH’s existing dividend policy.
7. Regulated expenses for the 2002 test year and subsequent years shall exclude:
- i. Spousal travel;
 - ii. “Communication Plan” advertising; and
 - iii. Bay D’Espoir street lighting.
8. NLH shall file with the Board:
- i. On or before December 31, 2002, a detailed plan of projected maintenance expenditures for the Holyrood Generating Station for the period 2003-2013.
 - ii. On or before December 31, 2002, a statement of policies and procedures governing employee travel.
 - iii. On or before June 30, 2003, details of the methodology used for calculation of notional interest.
 - iv. On or before December 31, 2005, an updated depreciation study.

RATE STABILIZATION PLAN

9. NLH shall continue to utilize the RSP, incorporating the changes proposed by NLH and those set out in this Order including:
- i. A Cost of Service price of No. 6 fuel, as set out in Schedule 1 attached to this Order.
 - ii. A fuel efficiency factor of 615 kWh/bbl.
 - iii. A forecast hydraulic production of 4,425 GWh.
 - iv. The elimination of the cap on the retail portion of the RSP.
10. The existing balances in the RSP shall be fixed as of the end of the month prior to the effective date of rate implementation based on the current methodology, and additional recovery of this balance is not allowed in the 2002 test year.

11. The balance in the RSP shall be recovered in the following manner:
 - i. The RSP mill rate for the IC shall be reset as of the effective date of rate implementation for the remainder of 2002 to 2.80 mills/kWh, which was the rate effective January 1, 2001.
 - ii. The RSP mill rate for 2002 for NP shall remain at 1.77 mills/kWh, which was the rate effective as of July 1, 2001.
 - iii. Recovery of the fixed balance outstanding shall be spread over a five year period commencing in 2003 using a straight-line recovery method.
 - iv. The method for calculating the mill rate adjustments and the date of the adjustments for both the IC and NP shall remain the same.
 - v. The amounts recovered shall be credited against the fixed balance of the plan.
 - vi. Interest shall be accumulated and maintained on the balance using the WACC.
 - vii. Recovery or credits of balances that accumulate in the plan after the effective date of rate implementation (the new balance) shall be calculated using a straight-line method over a two year period, to be effective January 1, 2004 for the IC and July 1, 2004 for NP.
12. NLH shall file with the Board updated 12-month fuel forecasts as part of its quarterly reports.

2002 CAPITAL BUDGET

13. The capital budget projects, excluding the VHF Mobile Radio system, as listed in Schedule 2 attached to this Order, are approved, pursuant to subsection 41(3) of the Act.
14. The 2002 capital budget in the amount of \$36,765,000, adjusted to reflect the removal of the \$3,081,000 associated with the VHF Mobile Radio system is approved, pursuant to subsection 41(1) of the Act.
15. Order No. P.U. 30 (2001-2002) is hereby amended to reflect the removal of B-47 (Replace 75 kW Diesel Unit No. 252, Petites).
16. An *“Allowance for Unforeseen Events”* fund of \$1,000,000 shall replace the Contingency Fund and shall be used by NLH pursuant to the guidelines of the Board as set out in the decision which may be amended by the Board from time to time.

17. NLH shall file with the Board:
- i. Upon further application for approval of the VHF Mobile Radio system project, a full cost benefit analysis of the project.
 - ii. As part of its 2003 capital budget application, an updated Telecommunications Plan.
 - iii. In all applications for approval of capital projects where generation is being replaced or upgraded, a cost benefit analysis of alternatives that may result in reduced load or a deferral of capacity expansion, including appropriate conservation or DSM programs.
 - iv. In all applications for approval of capital budget projects under subsection 41(3) of the Act, documentation showing the use of a net present value methodology to evaluate projects, pursuant to the guidelines of the Board as set out in Schedule 3 attached to this Order, which may be amended by the Board from time to time.

RATE BASE

18. NLH shall calculate and file a revised rate base, using the approach and methodology proposed in this Application incorporating the changes set out in this Order.
19. NLH shall file with the Board, prior to its next general rate application, 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.

COST OF SERVICE

20. NLH shall complete and file a revised COS study for the 2002 test year, using the COS methodology as proposed by NLH, incorporating the changes set out in this Order, which include:
- i. The allocation of generation demand costs for both the Island and Labrador Interconnected systems based upon a 1 CP allocator.
 - ii. The COS assignment of GNP assets, proposed to be assigned to common in this Application, to rural.
 - iii. The COS assignment of the Doyle's-Port aux Basques assets, proposed to be assigned to common in this Application, to NP specifically assigned.
21. NLH shall file with the Board, as part of its next general rate application, a detailed study as outlined in the decision of the Board, as to the proper COS assignment of the GNP assets, the DoYLES-Port aux Basques assets and the Burin Peninsula assets.

RURAL SYSTEMS

22. Pursuant to section 70, the existing rate structures in respect of the rural systems are approved, except that NLH shall increase the rates it charges to the Federal and Provincial Governments effective with the implementation of rates arising from this Application, to recover the full costs of providing this service in rural areas.
23. Preferential rates shall continue to apply to hospitals, fish plants, churches, schools, community halls and municipal buildings and like facilities currently benefiting from preferential rates.
24. Pursuant to Section 70, the existing “lifeline block” of 700 kWh is approved for both domestic and general service customers.
25. Pursuant to Section 70, the existing policy of allowing NLH, as NP changes its rates, to automatically adjust the rates it charges its Island Rural Interconnected customers, its customers serviced from the L’Anse au Loup System and its Isolated Rural customers for the first 700 kWh per month of consumption, other than Government departments and agencies, so that the rates are the same as the rates charged by NP to its customers and to automatically change the rates charged for consumption over 700 kWh per month of electricity sold to Isolated Rural customers, other than Government departments and agencies, by the average rate of change granted to NP, is approved.
26. NLH shall file with the Board:
 - i. On or before December 31, 2002, a report in respect of the existing “lifeline block” for domestic isolated rural customers to assess its adequacy.
 - ii. As part of its next general rate application, a multi-year plan to phase out preferential rural rates and move to a full cost recovery rate structure.
 - iii. As part of its next general rate application, a proposal for the implementation of a demand energy rate structure for general service customers on isolated systems.
 - iv. As part of its next general rate application, a plan to eliminate the “lifeline block” for general service customers on isolated systems, co-ordinated with the implementation of a demand energy rate structure for these customers.
 - v. As part of its next general rate application, an evidentiary record in respect of the rural deficit which addresses the relevant issues, including those outlined by the Board in its decision.

RATE ISSUES/RATE DESIGN

27. NLH shall apply to the Board for approval of a revised 2002 test year rate base, return on rate base, and Schedule of Rates incorporating the changes set out in this Order.

28. The revised Schedule of Rates shall be based on the proposals of NLH in this Application incorporating the changes set out in this Order.
29. NLH shall refund the Wabush surplus in the amount of \$2,922,755, in the manner proposed.
30. NLH shall calculate the wheeling rate based upon transmission losses of 3.47%.
31. The Rules and Regulations as set out in the contracts with the industrial customers, except North Atlantic Refinery Limited, are approved.
32. The Rules and Regulations as set out in the contract with North Atlantic Refinery Limited, excluding Clause 9.04, which describes the liability of NLH, are approved.
33. NLH shall submit revised Rules and Regulations for its rural customers, incorporating the changes to Clause 4 and Clause 10 (c) set out in the decision of the Board.
34. NLH shall file with the Board, as part of its next general rate application, a five year plan outlining further alterations in rates on the Labrador Interconnected system, with the cost recovery targets as identified in this Application, including a phase in of the impact of applying the credit for secondary energy sales to CFB Goose Bay (5 Wing) to the rural deficit.

OTHER/GENERAL

35. NLH shall file its next general rate application, pursuant to Section 70 of the Act, no later than December 31, 2003.
36. Pursuant to Section 58 of the Act, the code of accounts submitted by NLH, is approved.
37. Pursuant to Section 68 of the Act, the changes in depreciation policies as proposed by NLH, including the extension of the service lives for the transmission lines affected by the Avalon upgrade program, are approved.
38. NLH shall file with the Board:
 - i. On or before September 30, 2002, a report with recommendations on how NLH may reasonably improve the reliability and quality of service for customers served in coastal Labrador communities.
 - ii. On or before December 31, 2002, a final report on the results of joint efforts to date to reduce duplication between NLH and NP.

- iii. 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.
- iv. On or before December 31, 2002, a multi-year plan directed towards its community-based conservation initiatives.
- v. On or before June 30, 2003, a summary and index of all policies related to regulated activities.
- vi. In all regulatory reporting, separate financial statements for regulated and non-regulated activities, including reconciliation with annual consolidated statements.

HEARING COSTS

- 39. The IC be awarded costs in an amount to be determined by the Board, following receipt of a detailed statement of their costs.
- 40. The application by the Towns of Labrador City and Wabush for costs is denied.
- 41. NLH shall pay the expenses of the Board arising from this Application, including the expenses of the Consumer Advocate as ordered by the Lieutenant-Governor in Council pursuant to Section 117 of the Act.

Dated at St. John's, Newfoundland and Labrador this 7th day of June 2002.

Robert Noseworthy,
Chair & Chief Executive Officer.

Darlene Whalen, P.Eng.,
Vice-Chairperson.

G. Fred Saunders,
Commissioner.

Don Powell, C.A.,
Commissioner.

G. Cheryl Blundon,
Board Secretary.

SCHEDULE 1

**HOLYROOD NO. 6 FUEL PRICE FORECAST
AS FILED BY**

**R. J. HENDERSON
2nd SUPPLEMENTARY EVIDENCE**

ORDER NO. P.U. 7 (2002-2003)

Holyrood No. 6 Fuel Price Forecast (\$Cdn/bbl)	
December 2001	22.70
2002	
January	24.30
February	25.20
March	25.20
April	25.70
May	25.80
June	25.50
July	25.70
August	26.50
September	26.60
October	26.80
November	26.60
December	27.10
2002 Weighted Annual Average	25.91
2003	26.55
2004	26.50
2005	27.50

(2nd Supplementary Evidence, R. J. Henderson, pg. 1)

SCHEDULE 2

**2002 CAPITAL BUDGET PROJECTS
APPROVED BY**

ORDER NO. P.U. 7 (2002-2003)

GENERATION:

Install 25kV Distribution Line - Ebbeginbaeg (\$1,555,000)

Nature of Project

This project involves the construction of 20km of new 25kV distribution line and associated equipment from the North Salmon Dam to interconnect the Ebbeginbaeg control structure. This structure is presently serviced through diesel generation. The distribution interconnection will permit the diesel generators and their associated infrastructure to be retired thereby avoiding future maintenance and capital costs.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A cost benefit study was completed and concluded an interconnection would have a payback period of 8 years.

Future Commitments

There are no future commitments, this project will be completed in 2002.

GENERATION:

Install Fault Recorder - Upper Salmon Generating Station (\$127,000)

Nature of Project

This project involves the installation of a digital fault recorder at the Upper Salmon Generating Station. Installation of this equipment will enable Hydro to analyze faults and generator outages in an effort to reduce downtime.

Customer Impact

This equipment would assist in fault analysis and trouble shooting after any major system disturbance or equipment failure and would assist in faster system restoration.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments, this project will be completed in 2002.

GENERATION:

Install Intake Stoplogs - Paradise River (\$158,000)

Nature of Project

This project involves the installation of stoplogs at the Paradise River Generating Station to maintain a safe environment for proper maintenance of the intake gate, gate guides and sill.

Customer Impact

Failure to complete this work could result in the extended interruption of this power supply to Hydro's customers.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments, this project will be completed in 2002.

GENERATION:

Replace Control Cables - Bay d'Espoir (\$131,000)

Nature of Project

This project involves the replacement of the two thirty-six (36) pair control cables between powerhouse No. 1 and Intake No. 2 and No. 4 with a fibre optic cable. The existing cables are over twenty-three years old and over the years, lightning has damaged a significant number of cable pairs.

Customer Impact

Any further damages to the additional cable pairs in future could result in lack of data or control function monitoring, between generating units and intake, that would affect the reliability of the units and supply of power to Hydro's customers.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments, this project will be completed in 2002.

GENERATION:

Replace Ventilation System at Powerhouse No. 1 - Bay d’Espoir (\$164,000)

Nature of Project

This project involves the replacement of 12 wall mounted exhaust fans with 6 roof mounted exhaust fans to reduce the ambient air temperature in the powerhouse especially during summer operation when it reaches 34°C. Due to their location, the existing fans are very difficult to maintain and require unit outages. The high ambient air temperatures are also a concern for the continued operation and equipment performance.

Customer Impact

Failure to maintain a reasonable ambient air temperature in the plant could cause equipment problems resulting in forced outages which could result in the interruption of power to Hydro’s customers.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments, this project will be completed in 2002.

GENERATION:

Purchase Track Machine - Cat Arm (\$177,000)

Nature of Project

This project involves the purchase of an enclosed track machine that is used to transport personnel, tools and equipment to the Cat Arm site during adverse weather conditions.

Customer Impact

Failure to get personnel and equipment to the Cat Arm site could result in extended outages at this facility.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments, this project will be completed in 2002.

GENERATION:

Purchase and Install Continuous Emission Monitoring (\$801,000)

Nature of Project

This project involves the installation of a continuous emission monitoring system on each of the three stacks at the Holyrood Generating Station.

Air emissions from the Holyrood Generating Station include particulate matter, NO_x, SO_x and acid aerosols. Although the emissions are below the statutory limit, a recent health risk assessment concluded that quantification of the emissions should be undertaken. A continuous emission monitoring system (CEM) will allow direct quantification. A CEM will enhance control of the combustion process and will permit management of emissions, which is currently not available.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments, this project will be completed in 2002.

GENERATION:

Purchase and Install Closed Circuit Surveillance System - Holyrood (\$152,000)

Nature of Project

This project involves the purchase and installation of a closed circuit TV surveillance system at the Holyrood Plant site. The system will have cameras at the main gate, the dock and at the northwest and southeast corners of the power house with monitors installed in the guardhouse and the control room. This system will provide enhanced security for the site and will improve public safety.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

GENERATION:

Replace Turbine Electrohydraulic Control System - Unit No. 1 - Holyrood
(\$34,000; Future \$1,084,000)

Nature of Project

This project involves the replacement of the obsolete Governor Control System for the Unit No. 1 Turbine at Holyrood. The improved features of the new control system will enable the unit to pick up loads when the Holyrood Plant is isolated from the power system. A similar system on Unit No. 2 was replaced in 1999.

Customer Impact

The new electrohydraulic control system will improve unit reliability and the supply of power to Hydro's customers.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

This is a two-year project. The engineering and material ordering will be completed in 2002 and the construction completed in 2003.

TRANSMISSION:

Pave Parking Area - Bishop's Falls Complex (\$69,000)

Nature of Project

This project involves the paving of the gravel parking lot at the Bishop's Falls Complex which is used by heavy equipment such as muskegs, line trucks, etc. The surface of the existing parking lot is difficult and costly to maintain as it is often in poor condition in the spring and during wet conditions.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments, this project will be completed in 2002.

TRANSMISSION:

Replacement of Poles - TL215 (69kV Doyles - Port aux Basques) (\$138,000)

Nature of Project

This project involves the replacement of poles on the 28 km, 32-year-old 69 kV line from Doyles Terminal Station to Grand Bay Terminal Station which is primarily of single pole wood structures. A Wood Pole Inspection Program in 2000 assessed 220 poles (50%) on this line and identified twenty (20) poles requiring replacement by 2002. Four (4) structures were considered highest priority and are scheduled for replacement in 2001. The remaining sixteen (16) structures will be replaced in this capital project.

Customer Impact

Failure to complete this work could result in the interruption of power supply to Hydro's customers.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments, this project will be completed in 2002.

TRANSMISSION:

Purchase and Install Remote Communication Equipment - Buchans & Stony Brook
(\$51,000)

Nature of Project

This project involves the purchase and installation of a number of relays and associated communications equipment which store fault information at Stony Brook and Buchans Terminal Stations. Currently, personnel must travel to each station in order to retrieve this information. With the purchase and installation of proposed communications equipment, the relays can be remotely accessed. This will assist in the timely analysis of faults, and in the case of permanent faults, will provide fast access to the fault type and location.

Customer Impact

This project will decrease the time required to locate permanent faults and therefore decrease the outage time of the faulted equipment line.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

TRANSMISSION:

Purchase and Install Digital Fault Recorder - Stony Brook (\$92,000)

Nature of Project

This project involves the purchase and installation of a 32-channel digital fault recorder for Stony Brook Terminal Station. This recorder would record voltages, currents and other important data, before, during and after a fault. Information from this recorder will be used to assist in the analysis of faults in and around the Stony Brook area. The analysis will be used to verify the correct operation of protection and control relaying, breakers and other equipment, and whether any additional follow-up action is required.

Customer Impact

This project will decrease the time required to locate permanent faults and therefore decrease the outage time of the faulted equipment line.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Acquire Document Management & Imaging System (\$104,000)

Nature of Project

This project involves the development of a Corporate Document Management and Imaging System . An electronic Document Management solution is required to provide the Corporation with effective control, management and access to such documents.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

This is the first phase of implementation and requests for the approval of additional phases will be in future submissions to PUB.

GENERAL PROPERTIES:

Purchase Additional Corporate Applications (\$517,000)

Nature of Project

This project involves the assessment and purchase of technical and business software. Where a business case warrants, speciality software will be purchased and implemented to address planned business processes.

Hydro must be able to address additional software requirements to support the streamlining, enhancement, and automation of business functions as required during the budget year.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was required.

Future Commitments

There are no future commitments; the project will be completed in 2002.

GENERAL PROPERTIES:

Purchase and Install Uninterruptable Power Supply - Computer Room (\$70,000)

Nature of Project

This project involves the purchase and installation of an on-line Uninterruptable Power Supply (UPS) to the Computer Room at Hydro Place. The UPS will supply conditioned and backup power for the mainframes and servers which support the corporate financial applications and all local area network based applications.

The present configuration is inadequate to meet current needs.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Replacement of Printers (\$130,000)

Nature of Project

This project involves the replacement of obsolete printers throughout Hydro offices.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

2002 Capital Projects Over \$50,000 - Explanations

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GENERAL PROPERTIES:

Purchase of Existing AS400 Computers and Additional Disk Space (\$143,000)

Nature of Project

This project involves the purchase of the existing AS400 computers, which are currently being leased. It also involves the purchase of additional disk space to support the corporate integrated financial applications. The five (5) year lease for the existing AS400 computers will expire during 2002.

The specific components are:	AS400 Model 640	\$	39,000
	AS400 Model 720	\$	25,000
	Misc. Associated Equip.	\$	12,000
	Additional Disk Space	\$	64,000
	Installation	\$	3,000
	Total	\$	143,000

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

Further Explanation

This capital budget proposal replaces a previously submitted proposal for "Replacement of AS 400 Computers" for an amount of \$2,109,000. The new computers were necessary for Hydro to begin a transition from JD Edwards World Software product to JD Edwards World Vision. The reason for this transition was that support for the World Software product was to expire in 2005 and Hydro was to begin the process in 2002. This would allow timely transition to the new applications in a more orderly fashion and without needing a major human resource in a short period of time and permit minimum disruption to the current operations.

On November 13, 2001 Hydro was advised, as were all other JD Edwards World Software users, that support for the World product will be extended indefinitely. For this reason this significant expense can be delayed. Hydro will continue to assess the functionality of the JD Edwards World product and its potential advantages as well as the performance of the current hardware and may, in the future, if justification exists, propose the transition to other JD Edwards software and/or initiate a major upgrade of the existing computing platform.

The additional disk space is necessary to ensure adequate operation of current applications. Current utilization is at approximately 75% which is the maximum recommended level to ensure efficient operation of the applications.

GENERAL PROPERTIES:

Replace Teleprotection - Stony Brook - Grand Falls Frequency Converter (\$58,000)

Nature of Project

This project involves the replacement of the existing teleprotection units used for voice, data and teleprotection at the Stony Brook Terminal Station and the Grand Falls Frequency Converter at the Abitibi Mill in Grand Falls. The manufacturer does not support the current equipment.

Customer Impact

Failure to replace the teleprotection equipment may have a direct impact on the Abitibi Mill in Grand Falls.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Replace UHF Radio - Upper Salmon (\$556,000)

Nature of Project

This project involves the replacement of obsolete UHF radio links from Upper Salmon Generating Station to West Salmon Spillway, North Salmon Spillway, and Ebbegunbaeg Control Structure that supports operational voice, data and control signals at these sites. The existing UHF radio equipment is 20 years old, spares are not available and the equipment is no longer supported by the manufacturer. The radio equipment will be replaced with a combination of digital radio and fibre optic technology.

Customer Impact

Failure to replace this equipment will have an impact on the reliability of the Upper Salmon Generating Station and this may directly impact customers.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Complete Microwave Radio System Interconnection (\$269,000; Future \$8,673,000)

Nature of Project:

This project involves the purchase, installation and testing of a new digital microwave radio system to interconnect Hydro's telecommunications facilities on the west and east geographical regions of the Island. The proposed radio system will provide a high-speed teleprotection voice and data communications between the Company's generating and transmission facilities in the central, western and eastern areas of the island with the Energy Control Center located in St. John's. The system shall consist of four new radio repeater sites between the existing radio sites at Sandy Brook Hill and Bull Arm Hill.

This project is Phase 3 of Hydro's five phase Telecommunications Plan that was previously filed with the PUB in 1998.

This project is an important step in enhancing the reliability of the provincial power grid while providing an infrastructure that will meet the future telecommunication bandwidth requirements of the Company.

Customer Impact

Completion of this project will enhance system performance and customer reliability.

Cost Benefit Study

A cost benefit study was not required.

Future Commitments

This is a two-year project. The engineering and material ordering will be completed in 2002 and the construction will be completed in 2003.

GENERAL PROPERTIES:

Provide Global Positioning System Time Synchronization - Phase 2 (\$211,000)

Nature of Project

This project involves the installation of twenty-two Global Positioning System (GPS) clocks. These clocks will provide the data used in the evaluation of system performance and control systems.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Install Interactive Voice Response System - Hydro Place (\$171,000)

Nature of Project

This project involves the installation of an Interactive Voice Response (IVR) system at Hydro Place to support the Customer Services Call Center. This system will provide advanced customer information retrieval capability.

Customer Impact

This project will improve customer service.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

GENERAL PROPERTIES:

Replace Vehicles (\$1,897,000)

Nature of Project

This project is for the replacement of 35 (thirty-five) units in the Hydro and Rural Systems which includes 6 (six) cars, 17 (seventeen) pickups and 12 (twelve) line trucks.

Hydro's policy is to operate its vehicles in a manner which minimizes new investment, and operating and maintenance costs. Vehicles are assessed on an annual basis for replacement taking into account the overall condition of each vehicle and its distance driven, as well as history of maintenance costs.

Customer Impact

There is no direct customer impact.

Cost Benefit Study

A formal cost benefit study was not required.

Future Commitments

There are no future commitments; this project will be completed in 2002.

SCHEDULE 3

**GUIDELINES AND CONDITIONS
FOR FILING OF
FUTURE CAPITAL BUDGET APPLICATIONS
IN ACCORDANCE WITH
ORDER NO. P.U. 7 (2002-2003)**

NLH shall file future capital budget applications in according with the following guidelines and conditions as outlined in Order No. P.U. 7 (2002-2003):

- i) A concise description of the project, including classification and location.
- ii) The projected cost of the project in the current year (year of budget).
- iii) The anticipated future expenditures; shown by year, of the project.
- iv) The current age of any plant being replaced or overhauled.
- v) The measurable usage to date of any plant being replaced or overhauled.
- vi) The date and cost of the most recent overhaul, repair, or replacement.
- vii) Copies of any engineering studies, consultants' reports, environmental studies, or dealer documentation outlining the current condition and future requirements of the plant. If these documents are already on file with the Board, reference may be made to these documents
- viii) A cost benefit analysis of all alternatives, both internal and external, that have been considered, including any DSM measures that have been evaluated.
- ix) A description and related documentation outlining the results of any discussions of the project that have taken place between the utilities in an effort to reduce expenditures by avoiding duplication of services, or increased sharing of resources and expenses.
- x) Documentation of any safety or reliability issues that have arisen, in this jurisdiction or elsewhere, indicating a need for the project at the time. (Describe any efforts that have already been made to deal with these issues, and outline any related costs that have been incurred.)
- xi) Documentation, including maintenance records and reports of outages, that indicate whether this project is remedial or preventative, and that support the current undertaking of the project.
- xii) A general description of any major replacements, upgrades, or repairs to this plant that are expected to be undertaken within the next three years.



Newfoundland & Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
120 TORBAY ROAD, ST. JOHN'S, NL

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Telephone: 726-8600
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TAB 11

P.U. 40 (2003)

IN THE MATTER OF the *Electrical Power Control Act*, 1994 (the “EPCA”) and 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 (“Hydro”) for approval of, *inter alia*, rates to be charged its customers (the “Application”);

AND IN THE MATTER OF proposed amendments to the Rate Stabilization Plan.

Before:

Robert Noseworthy
Chair and Chief Executive Officer

Darlene Whalen, P. Eng.
Vice-Chair

G. Fred Saunders
Commissioner

WHEREAS Hydro filed the Application with the Board of Commissioners of Public Utilities (the “Board”) on May 21, 2003, which Application was amended on August 12, 2003, for an Order of the Board approving, among other things, the proposed rates for the various customers of Hydro to be effective January 1, 2004; and

WHEREAS the registered intervenors for the proceeding are the Consumer Advocate, Mr. Dennis Browne, Q.C.; Newfoundland Power Inc.; Hydro’s Industrial Customers, 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; and the Towns of Labrador City and Wabush; and

WHEREAS as part of the proceeding the “Participating Parties”, which for the purposes of this Order include Hydro and the registered intervenors, excepting the Towns of Labrador City and Wabush, held settlement discussions with respect to amendments to the Rate Stabilization Plan (the “RSP”); and

WHEREAS the RSP is established for two of Hydro’s customers - Newfoundland Power and the Island Industrial customers - to smooth rate impacts for certain variations between actual results and Test Year Cost of Service estimates for (i) hydraulic production; (ii) No. 6 fuel cost used at Hydro’s Holyrood generating station; (iii) customer load (Newfoundland Power and Island Industrial); and (iv) rural rates; and

WHEREAS Hydro advised during the hearing that the Participating Parties proposed that the RSP be amended as set out in Sections A, B, C and D of Schedule A to this Order (filed as Consent #2 in the proceeding) and further that, with the exception of the Industrial Customers who took no position, amendments as set out in Section E of Schedule A to this Order (filed as Consent #3 in the proceeding) should be made; and

WHEREAS Hydro has requested that the Board issue an Order on the proposed amendments prior to January 1, 2004 since the proposed changes to the RSP would, if accepted by the Board, result in changes to the January 1, 2004 annual RSP adjustment for the Industrial Customers; and

WHEREAS the Board has received no objection to the proposed amendments to the RSP set out in Schedule “A” to this Order or to the proposed timing of this Order; and

WHEREAS the Board is satisfied that the proposed amendments will not affect the rates charged to the Labrador Interconnected customers of Hydro or otherwise impact the issues to be determined in this Application in respect of the Labrador Interconnected System; and

WHEREAS the Board has considered the proposed amendments to the RSP and the relevant evidence and concurs with the amendments as presented; and

WHEREAS the Board will address any other specific issues surrounding the RSP, such as the monitoring issues raised during the hearing, as part of the ongoing regulatory supervision of the Board or in the final order flowing from the Application.

IT IS THEREFORE ORDERED THAT:

Unless otherwise ordered by the Board, the Rate Stabilization Plan is hereby amended as set out in Schedule "A" effective January 1, 2004.

DATED at St. John's, Newfoundland and Labrador, this 16th day of December 2003.

Robert Noseworthy,
Chair & Chief Executive Officer.

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

G. Fred Saunders,
Commissioner.

G. Cheryl Blundon,
Board Secretary.

SCHEDULE “A”

ORDER NO. P.U. 40 (2003)

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro) is established for Hydro's Utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations between actual results and Test Year Cost of Service estimates for:

- hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- customer load (Utility and Island Industrial); and
- rural rates.

The formulae used to calculate the Plan's activity are outlined below. Positive values denote amounts owing from customers to Hydro whereas negative values denote amounts owing from Hydro to customers.

Section A: Hydraulic Production Variation

1. Activity:

Actual monthly production is compared with the Test Year Cost of Service Study in accordance with the following formula:

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

Where:

- A = Test Year Cost of Service Net Hydraulic Production (kWh)
- B = Actual Net Hydraulic Production (kWh)
- C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
- D = Monthly Test Year Cost of Service No. 6 Fuel Cost (\$/Can /bbl.)

2. Financing:

Each month, financing charges, using Hydro's approved Test Year weighted average cost of capital, will be calculated on the balance.

3. Hydraulic Variation Customer Assignment:

Customer assignment of hydraulic variations will be performed annually as follows:

$$(E \times 25\%) + F$$

Where:

- E = Hydraulic Variation Account Balance as of December 31, excluding financing charges
- F = Financing charges accumulated to December 31

The total amount of the Hydraulic Customer Assignment shall be removed from the Hydraulic Variation Account.

4. Customer Allocation:

The annual customer assignment will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island



NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (continued)

Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the hydraulic customer assignment which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The Newfoundland Power and Island Industrial customer allocations shall be included with the Newfoundland Power and Island Industrial RSP balances respectively as of December 31 each year. The Labrador Interconnected Hydraulic customer allocation shall be written off to Hydro's net income (loss).

Section B: Fuel Cost Variation, Load Variation and Rural Rate Alteration

1. Activity

1.1. Fuel Cost Variations

This is based on the consumption of No. 6 Fuel at the Holyrood Generating Station:

$$(G - D) \times H$$

Where:

D = Monthly Test Year Cost of Service No. 6 Fuel Cost (\$/Can /bbl.)

G = Monthly Actual Average No. 6 Fuel Cost (\$/Can /bbl.)

H = Monthly Actual Quantity of No. 6 Fuel consumed less No. 6 fuel consumed for non-firm sales (bbl.)

1.2. Load Variations

Firm: Firm load variation is comprised of fuel and revenue components. The load variation is determined by calculating the difference between actual monthly sales and the Test Year Cost of service Study sales, and the resulting variance in No. 6 fuel costs and sales revenues. It is calculated separately for Newfoundland Power firm sales and Industrial firm sales, in accordance with the following formula:

$$(I - J) \times \{(D \div C) - K\}$$

Where:

C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)

D = Monthly Test Year Cost of Service No. 6 Fuel Cost (\$/Can /bbl.)

I = Actual Sales, by customer class (kWh)

J = Test Year Cost of Service Sales, by customer class (kWh)

K = Firm energy rate, by customer class

Secondary: Secondary load variation is based on the revenue variation for Utility Firmed-Up Secondary energy sales compared with the Test Year Cost of Service Study, in accordance with the following formula:

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (continued)

$$(J - I) \times L$$

Where:

I = Actual Sales (kWh)

J = Test Year Cost of Service Sales (kWh)

L = Secondary Energy Firming Up Charge

1.3. Rural Rate Alteration

(a) Newfoundland Power Rate Change Impacts:

This component is calculated for Hydro's rural customers whose rates are directly or indirectly impacted by Newfoundland Power's rate changes, with the following formula:

$$(M - N) \times O$$

Where:

M = Cost of Service rate ¹

N = Existing rate

O = Actual Units (kWh, bills, billing demand)

(b) Rural Labrador Interconnected Automatic Rate Adjustments:

This component reflects the impact of the automatic rate adjustments for Hydro's rural customers on the Labrador Interconnected system, which arise from the five-year phase-in of the application of the credit from secondary energy sales to CFB Goose Bay to the rural deficit.

Monthly adjustments commence January, 2005, and will be subject to revision when a new Test Year Cost of Service is approved by the Public Utilities Board for Hydro. The amount of the automatic rate adjustment is calculated as follows:

$$P = (Q - R) \div 12$$

Where:

P = the monthly amount of the automatic rate adjustment

Q = the CFB Revenue Credit applied to the rural deficit in Hydro's Final 2004 Test Year Cost of Service

R = the CFB Revenue Credit applied to the rural deficit in 2005 to 2008, included in existing rates and outlined in the table below:

¹ Hydro's schedule of rates for its rural customers impacted by Newfoundland Power's rate changes as a result of the pass-through of Hydro's rate changes associated with the Test Year Cost of Service Study.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (continued)

	Q	R	Q – R	P
2005	\$ 0	\$445,722	(\$445,722)	(\$37,143)
2006	\$ 0	\$593,461	(\$593,461)	(\$49,455)
2007	\$ 0	\$1,477,393	(\$1,477,393)	(\$123,116)
2008 ²	\$ 0	\$2,504,056	(\$2,504,056)	(\$208,671)

2. Monthly Customer Allocation: Load and Fuel Activity

Each month, the load variation will be assigned to the customer class for which the load variation occurred.

Each month, the year-to-date total for fuel price variation will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The year-to-date portion of the fuel price variation which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The current month's activity for Newfoundland Power, Island Industrials and regulated Labrador Interconnected customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected customers will be removed from the Plan and written off to Hydro's net income (loss).

3. Monthly Customer Allocation: Rural Rate Alteration Activity

Each month, the rural rate alteration will be allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study. The portion allocated to regulated Labrador Interconnected will be removed from the Plan and written off to Hydro's net income (loss).

4. Plan Balances

Separate plan balances for Newfoundland Power and for the Island Industrial customer class will be maintained. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year weighted average cost of capital.

Section C: Fuel Price Projection

A fuel price projection will be calculated to anticipate forecast fuel price changes and to determine fuel riders for the rate adjustments. For industrial customers, this will occur in October each year,

² Monthly adjustments will continue after 2008 until a new Test Year Cost of Service is approved by the Public Utilities Board.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (continued)

for inclusion with the RSP adjustment effective January 1. For Newfoundland Power, this will occur in April each year, for inclusion with the RSP adjustment effective July 1.

1. **Industrial Fuel Price Projection:**

In October each year, a fuel price projection for the following January to December shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[(S - T) \times U - V] \times W$$

Where:

S = the September month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following January to December

T = Hydro's average Test Year contract discount (US \$/bbl)

U = the monthly average of the \$Cdn / \$US Bank of Canada Noon Exchange Rate for the month of September

V = average Test Year Cost of Service purchase price for No. 6 Fuel (\$Can /bbl.)

W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year.

The industrial customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of September and is the ratio of Industrial Firm invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of an estimate of the fuel rider based on 12 months-to-date kWh sales to the end of September will be reported to industrial customers, Newfoundland Power, and the Public Utilities Board, by the 10th working day of October.

2. **Newfoundland Power Fuel Price Projection:**

In April each year, a fuel price projection for the following July to June shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[(X - T) \times Y - V] \times W$$

Where:

T = Hydro's average Test Year contract discount (US \$/bbl)

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (continued)

- V = average Test Year Cost of Service purchase price for No. 6 Fuel (\$/Can /bbl.)
- W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year.
- X = the average of the March month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following July to December, and the most recent long-term PIRA Energy Group average annual forecast for No. 6 fuel prices at New York Harbour for the following January to June.
- Y = the monthly average of the \$Cdn / \$US Bank of Canada Noon Exchange Rate for the month of March.

The Newfoundland Power customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of March and is the ratio of Newfoundland Power Firm and Firmed-Up Secondary invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of the resulting fuel rider applied to the adjustment rate will be reported to Newfoundland Power, industrial customers, and the Public Utilities Board, by the 10th working day of April.

Section D: Adjustment

1. Newfoundland Power

As of March 31 each year, Newfoundland Power's adjustment rate for the 12-month period commencing the following July 1 is determined as the rate per kWh which is projected to collect:

Newfoundland Power March 31 Balance

less projected recovery / repayment of the balance for the following three months (if any), estimated using the energy sales (kWh) for April, May and June from the previous year

plus forecast financing charges to the end of the 12-month recovery period (i.e., June in the following calendar year),

divided by the 12-months-to-date firm plus firmed-up secondary kWh sales to the end of March.

A fuel rider shall be added to the above adjustment rate, based on the Newfoundland Power Fuel Price Projection amount (as per Section C.2 above) divided by 12-months-to-date kWh sales to the end of March.

Where a new Test Year comes into effect while there is an existing fuel rider in place, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

2. Island Industrial Customers



NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (continued)

As of December 31 each year, the adjustment rate for industrial customers for the 12-month period commencing January 1 is determined as the rate per kWh which is projected to collect:

Industrial December 31 Balance

plus forecast financing charges to the end of the following calendar year,

divided by 12-months-to-date kWh sales to the end of December.

A fuel rider shall be added to the above adjustment rate, based on the Industrial Fuel Price Projection (as per Section C.1 above) amount divided by 12-months-to-date kWh sales to the end of December.

Where a new Test Year comes into effect while there is an existing fuel rider in place, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN

Section E: Historical Plan Balances:

1. August 2002 Balance:

Newfoundland Power and Island Industrial customer balances accumulated in the Plan as at August 2002 will be recovered over a 5-year collection period, with adjustment rates established each December 31, commencing December 31, 2002. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year annual weighted average cost of capital.

Newfoundland Power

The adjustment rate for each year of the five-year adjustment period will be determined as follows:

$$A = (B - C + D) \div E \div F$$

where

A = adjustment rate (\$ per kWh) for the 12-month period commencing the following July 1.

B = Balance December 31

C = projected recovery to the following June 30 (if any), estimated using the most recent energy sales (kWh) for the period January to June.

D = projected financing charges to the following June 30

E = number of years remaining in the adjustment period

F = energy sales (kWh) (firm and firmed-up secondary) to Newfoundland Power for the most recent 12 months ended December 31

Recovery and financing will be applied to the balance each month. At the end of the five-year recovery period, any remaining balance will be added to the plan then in effect.

Island Industrial Customers

The adjustment rate for each year of the five-year adjustment period will be determined as follows:

$$G = H \div I \div J$$

where

G = adjustment rate (\$ per kWh) for the 12-month period commencing the following January 1.

H = Balance December 31

I = number of years remaining in the adjustment period

J = firm energy sales (kWh) to Industrial Customers for the most recent 12 months ended December 31

Recovery and financing will be applied to the balance each month. At the end of the five-year recovery period, any remaining balance will be added to the plan then in effect.



NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (continued)

2. RSP Balance, December 31, 2003:

Newfoundland Power and Island Industrial customer balances accumulated in the Plan as at December 31, 2003 will be consolidated with the outstanding August 2002 customer balances as of December 31, 2003, and will be included with the Newfoundland Power and Island Industrial customer balances respectively for rate-setting purposes as of December 31, 2003.

TAB 12

**NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES**

AN ORDER OF THE BOARD

NO. P.U. 9(2014)

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

IN THE MATTER OF an application by Newfoundland and Labrador Hydro ("Hydro") for approval of amendments to the Rate Stabilization Plan rules and a refund to Newfoundland Power Inc. ("Newfoundland Power") customers and certain Hydro Rural customers.

Background

On April 4, 2013 the Lieutenant Governor in Council, pursuant to section 5.1 of the *EPCA* and section 39 of the *Hydro Corporation Act, 2007*, issued OC2013-089, OC2013-090 and OC2013-091 in relation to Hydro's general rate application, the phase-in of rates for Island Industrial customers and a refund to ratepayers. OC2013-089 directs the Board of Commissioners of Public Utilities (the "Board") that, among other things, the balance in the January 1, 2007 to June 30, 2013 accumulated Load Variation component of the Rate Stabilization Plan (the "Rate Stabilization Plan Surplus") is to be used to credit the Island Industrial customers' Rate Stabilization Plan with \$56.5 million effective June 30, 2013. The remaining balance in the Rate Stabilization Plan Surplus is to be transferred to the credit of Newfoundland Power's Rate Stabilization Plan. On July 16, 2013 OC2013-089 and OC2013-090 were amended by OC2013-207 and OC2013-208 respectively such that the effective date for the Island Industrial customers' balance transfer was August 31, 2013 and the amount to be transferred was reduced to \$49 million.

OC2013-089 as amended also directs the Board that Hydro's general rate application process include a Rate Stabilization Plan surplus refund plan to ratepayers. Specifically with respect to the refund to ratepayers the direction states:

6) Newfoundland and Labrador Hydro's General Rate Application process shall include a Rate Stabilization Plan surplus refund plan to ratepayers. The refund plan shall comprise direct payments or rebates to ratepayers and shall not be in the form of an electricity rate adjustment. This refund plan will exclude Island Industrial customers who will receive

Rate Stabilization Plan surplus funds through the three year phase-in of new rates. The Board of Commissioners of Public Utilities shall make the final determination on the details of the refund to remaining ratepayers;

7) Newfoundland Power's portion of the Rate Stabilization Plan Surplus shall be distributed as a direct payment or rebate to its ratepayers and shall not be in the form of an electricity rate adjustment; and...

OC2013-091 directs Hydro that:

2) during its General Rate Application process, it shall file a Rate Stabilization Plan surplus refund to ratepayers. The refund shall be a direct payment or rebate to ratepayers and shall not be in the form of an electricity rate adjustment. This refund plan will exclude Island industrial customers who will receive Rate Stabilization Plan surplus funds through the three year phase-in of new rates; and...

On July 30, 2013, in compliance with OC2013-091, Hydro filed an application requesting approval of, among other things, changes to the Island Industrial customer rates and to the Rate Stabilization Plan rules. Hydro also filed a general rate application on July 30, 2013. On August 30, 2013 the Board issued Order No. P.U. 26(2013) approving, effective August 31, 2013, the credit of \$49 million to the Island Industrial customers' Rate Stabilization Plan and the transfer of the remaining balance in the Rate Stabilization Plan Surplus to the credit of the Newfoundland Power Rate Stabilization Plan. The Board did not approve Hydro's other proposals in relation to rate changes for the Island Industrial customers, leaving these proposals to be addressed in a subsequent Order of the Board.

On September 30, 2013 the Board issued Order No. P.U. 29(2013) addressing the remaining proposals in Hydro's July 30, 2013 application. The Board finalized rates up to August 31, 2013 for Hydro's Island Industrial customers and Hydro's rate to Newfoundland Power. The Board did not approve the proposed changes to the Rate Stabilization Plan rules to phase-in Island Industrial customer rates and rates for these customers were continued on an interim basis. The Board also accepted Hydro's proposal to segregate within the Rate Stabilization Plan the August 31, 2013 plan balances related to the load variation for both the Island Industrial customers and Newfoundland Power. Hydro was directed to file revised interim Rate Stabilization Plan rules effective September 1, 2013 reflecting the findings of the Board. This application was filed on October 18, 2013 and approved in Order No. P.U. 32(2013).

The amount of the Rate Stabilization Plan Surplus as of August 31, 2013 was \$161.6 million. The allocation of the \$49 million to the Island Industrial customers' Rate Stabilization Plan on August 31, 2013 resulted in a credit of \$10.9 million in the Island Industrial customers' Rate Stabilization Plan. The remaining Rate Stabilization Plan Surplus balance of \$112.6 million is segregated into a separate plan referred to as the Newfoundland Power Rate Stabilization Plan Surplus ("NP RSP Surplus").

The Application

On October 31, 2013, pursuant to OC2013-091, Hydro filed an application for approval of a Rate Stabilization Plan surplus refund plan (the "Application"). A minor amendment to this

1 Application was filed on November 7, 2013. In the Application Hydro requests an Order of the
2 Board approving:

- 3
- 4 a) That the NP RSP Surplus refund be paid to Newfoundland Power, and to those rural
5 customers whose rates are based on the rates charged by Newfoundland Power.
 - 6 b) That the NP RSP Surplus be refunded to Newfoundland Power customers on their
7 April 2014 electricity bills and be based on their total energy consumption on bills
8 issued during the period January 2013 to December 2013.
 - 9 c) That Hydro's Rural customers, whose rates are based on Newfoundland Power rates,
10 receive a similar refund on their April 2014 electricity bills based on their total
11 energy consumption on bills issued during the period January 2013 to December
12 2013.
 - 13 d) That the refund to Rural customers be funded from the NP RSP Surplus.
 - 14 e) That any net refund to Newfoundland Power's customers and Hydro's customers be
15 in the form of a credit to each customer's account.
- 16

17 The Application was copied to Newfoundland Power, the Consumer Advocate, and Island
18 Industrial customers (Corner Brook Pulp and Paper, North Atlantic Refining Limited and Teck
19 Resources Limited, Praxair Canada Inc., and Vale Newfoundland and Labrador Limited
20 Limited).

21

22 On November 5, 2013 the Board forwarded the Application to the Intervenor in Hydro's general
23 rate application. Newfoundland Power and the Consumer Advocate notified the Board that they
24 wished to participate in the Application. The Industrial Customer group of Corner Brook Pulp
25 and Paper Limited, North Atlantic Refining Limited and Teck Resources Limited advised that
26 they would not be participating in the Application. The Innu Nation and the Towns of Labrador
27 City, Wabush, Happy Valley-Goose Bay and North West River also advised that they would not
28 be participating. The Board did not receive any correspondence from the other general rate
29 application Intervenor.

30

31 On November 14, 2013 the Board wrote the parties to the Application requesting submissions on
32 the issue of whether the Application should be addressed in Hydro's general rate application or
33 should proceed as a separate matter. On November 27, 2013 the Board determined that the
34 Application involves a discreet issue which does not require the resolution of other issues
35 flowing from Hydro's general rate application. The Board found that addressing this matter
36 before the completion of the general rate application would allow for the early distribution of the
37 refund. The Board did note, however, that if it appears that, as the matter progresses, the
38 consideration of issues should be brought together with other matters in the general rate
39 application, the schedule and process would be appropriately adjusted.

40

41 On December 4, 2013 the Board set a schedule for the review of the Application. On January 28,
42 2014 the Board revised this schedule to allow for the filing of additional requests for information
43 ("RFIs") and evidence. A total of 95 RFIs were issued to Hydro and one RFI was issued to
44 Newfoundland Power. On February 24, 2014 Newfoundland Power filed evidence in relation to
45 the Application proposals.

On February 27, 2014 the Board wrote the parties advising that it would give early consideration to Hydro's proposal to give a refund to certain Rural customers. In its letter the Board noted that there is an outstanding ruling expected from the Canada Revenue Agency ("CRA") in relation to the HST treatment of the proposed refund which must be resolved before the matter can be concluded. The Board advised that, to provide clarity and focus to the remaining issues, it would address Hydro's proposals in relation to the refund to its Rural customers in advance of the other issues in the Application. The Board requested that the parties' submissions address Hydro's proposals that:

- i) the NP RSP Surplus refund be apportioned to Newfoundland Power and to Hydro's Rural customers whose rates are based on the rates charged by Newfoundland Power;
- ii) Hydro's Rural customers whose rates are based on the rates charged by Newfoundland Power, receive a similar refund to Newfoundland Power's customers; and
- iii) the refund to Hydro's Rural customers be funded from a portion of the NP RSP Surplus.

The Board advised that it would establish the process for the remainder of the issues in the Application when Hydro confirms that it has received the ruling of the CRA.

Written submissions were filed by the Consumer Advocate and Newfoundland Power on March 7, 2014. Hydro filed a reply submission on March 11, 2014. This Decision and Order addresses the Board's findings on Hydro's proposals in relation to the refund to its Rural customers. The remaining issues in the Application, including the calculation methodology and recovery of administrative costs, will be addressed in a subsequent Order of the Board.

Evidence and Submissions

Hydro

Hydro proposes that the NP RSP Surplus be refunded to Newfoundland Power customers and Hydro Rural customers whose rates are based on Newfoundland Power rates. Rates for Hydro's Rural customers, with the exception of customers on the Labrador Interconnected system and Government customers on the Isolated systems, are based on the rates approved by the Board for Newfoundland Power customers, in accordance with Hydro's *Policies for Automatic Rate Changes* set out in its Rules and Regulations. Hydro states that, had the fuel cost savings reflected in the NP RSP Surplus been passed on to Newfoundland Power customers in accordance with the Rate Stabilization Plan rules, Newfoundland Power customers' rates would have been lower as a result of the annual July 1 Rate Stabilization Plan adjustment rate. Hydro states that, based on the *Policies for Automatic Rate Changes*, reduced rates for Newfoundland Power customers would have also resulted in lower rates for certain Rural customers.

Hydro considered two alternatives for treating the proposed refund to its Rural customers whose rates are based on Newfoundland Power's customer rates:

- i) Upon refund of the NP RSP Surplus to Newfoundland Power customers a similar percentage refund would be given to Hydro Rural customers whose rates are based on Newfoundland Power rates. The amount required to offer this refund would then be collected from Newfoundland Power customers through the operation of section 1.3 of the Rate Stabilization Plan.
- ii) Similar to the first scenario, the same percentage refund would be given to both Newfoundland Power customers and Hydro Rural customers whose rates are based on Newfoundland Power rates, with both funded from the NP RSP Surplus. To effect this approach Hydro proposes to set aside an amount from the NP RSP Surplus to cover the proposed refund to its Rural customers.

Hydro proposes the second alternative in the Application whereby the refund to its Rural customers whose rates are based on Newfoundland Power rates is funded from the NP RSP Surplus and not through the subsequent operation of the Rate Stabilization Plan. The amount of the refund to be credited to customers' accounts is estimated by Hydro to be approximately two cents per kWh for the billed energy over the January 1, 2013 to December 31, 2013 period.

In its submission at page 2 Hydro argues that the issue of whether the Rate Stabilization Plan refund should apply to both Newfoundland Power's customers and certain Hydro Rural customers depends on the correct interpretation of OC2013-089. Hydro explains:

The Order in Council can be said to contain two distinct steps that are to be applied to make refund payments to customers. Paragraph 2 of the Order (the first step) divides the RSP surplus amount so as to determine the amounts of entitlement amongst two components of the RSP (Industrial and Newfoundland Power).

Once the RSP surplus is divided, paragraphs 6 and 7 of the Order (the second step) focuses on the rebates to customers other than the Industrial Customers; that is these paragraphs address the method of disposition of the amount credited to the "Newfoundland Power Rate Stabilization Plan" amongst "the remaining ratepayers".

Hydro suggests that, if the Order in Council was intended to restrict the disposition of the funds to Newfoundland Power customers only, this would effect a substantive change from the normal disposition of positive balances in the Rate Stabilization Plan and as such would require very clear language. Hydro further states at page 4 of its submission:

In particular, if it were the intention that the Order in Council was to direct the Board to make a refund plan that gave amounts to Industrial Customers and Newfoundland Power customers only, that intention could have been easily expressed by substituting "Newfoundland Power's customers" for "ratepayers" and "remaining ratepayers" where they appear in paragraph 6 of the Order in Council.

Hydro sets out its interpretation of paragraph 6 of OC2013-089 at page 5 of its submission:

Only two groups of customers are referred to there as entitled to receive portions of the RSP surplus: Island industrial customers and remaining ratepayers. Hydro submits that these words in the Order in Council are not imprecise, incorrect nor ambiguous; on the contrary, they were carefully chosen and their meaning and effect are clear. Where the

Order in Council addresses the manner by which the Board is to make refunds with respect to the customers affected by the RSP surplus funds disposition, that authority and discretion is given to the Board with respect to the "remaining ratepayers".

Hydro argues that the Order in Council makes clear which customers the Board is authorized to consider for refunds - all customers that are involved in and affected by the Rate Stabilization Plan Surplus, being Newfoundland Power customers and Hydro Rural customers whose rates are based on Newfoundland Power rates.

Newfoundland Power

In its evidence, at page 3, Newfoundland Power states that the Orders in Council do not contain a direction to pay any portion of the NP RSP Surplus to Hydro Rural customers and that OC2013-089 directs that Newfoundland Power's portion of the Rate Stabilization Plan Surplus be distributed as a direct payment or rebate to its customers.

Newfoundland Power further states that the rates of Hydro Rural customers do not recover the costs of serving those customers. Newfoundland Power notes that, in accordance with provincial government policy, the deficit between the cost of serving Hydro Rural customers and the rates paid by those customers is subsidized in large part by the rates paid by the customers of Newfoundland Power. According to Newfoundland Power's evidence (page 4) the forecast of the amount of this deficit which will be included in Newfoundland Power's 2014 customer rates is approximately \$54 million, which represents approximately 8% of the rates paid by customers of Newfoundland Power. Newfoundland Power states that, in these circumstances, Hydro's Rural customers should not receive a portion of the NP RSP Surplus.

In its final submission Newfoundland Power argues that the proposed refund to Hydro's Rural customers is inconsistent with (i) the directions given in OC2013-089; and, (ii) the language contained in Hydro's *Policies for Automatic Rate Changes*. Newfoundland Power submits that OC2013-089 contains no explicit direction to pay any portion of the NP RSP Surplus to Hydro's Rural customers and, in fact, there is no mention of Hydro's Rural customers in any of the Orders in Council related to the Application. Newfoundland Power states at page 2 of its submission:

OC2013-089 directed the Board to divide the Rate Stabilization Plan Surplus into 2 portions. The first portion (\$49 million) was to be credited to the Rate Stabilization Plan of the Island Industrial customers. The "remaining balance" was to be credited to Newfoundland Power's Rate Stabilization Plan. The Order directs that the portion credited to the Island Industrial customers is to be used to phase-in industrial rates over a defined phase-in period. Newfoundland Power's portion is to be distributed as "a direct payment or rebate to its ratepayers.... (emphasis added)

Newfoundland Power also reiterates its position that, during the period when the Rate Stabilization Plan Surplus accumulated, Newfoundland Power's customers were effectively paying more than the full cost of their service, while Hydro's Rural customers whose rates are based on Newfoundland Power rates paid less than the full cost of their service and were in large

part subsidized by Newfoundland Power customers. Hydro's position is not, according to Newfoundland Power, consistent with a reasonable, contextual interpretation of OC2013-089.

Newfoundland Power argues that Hydro's proposition that a rebate should be considered a rate adjustment for the purposes of the *Policies for Automatic Rate Changes* but not a rate adjustment for the purposes of the Government direction is not supported by regulatory precedent and is not reasonable. At page 3 of its submission Newfoundland Power states:

Hydro suggests that Government intended that the Policies for Automatic Rate Changes be triggered by changes in "effective rates". According to Hydro, this is reflected in the fact that certain rate adjustments for Hydro's customers on Isolated Systems are based on "the average rate of change granted Newfoundland Power from time to time". It is not clear how this supports Hydro's interpretation, since the purpose of the averaging mechanism is simply to facilitate rate adjustments where there are no equivalent Newfoundland Power rates.

On the question of the funding of the proposed refund Newfoundland Power submits that, should the Board determine that certain Hydro Rural customers are entitled to a refund, it is appropriate that the refund be calculated in the same manner for customers of both Newfoundland Power and Hydro and that the refund to Hydro's Rural customers be funded from the NP RSP Surplus.

Consumer Advocate

The Consumer Advocate supports Hydro's proposals as set out in the Application. He submits that any assessment of Hydro's proposal must take cognizance of the fact that the refund amount accumulated over several years in the Rate Stabilization Plan owing to the load variation component. The Consumer Advocate notes that, under current rules of the Rate Stabilization Plan, this amount would normally form part of the balance used to calculate the Rate Stabilization Plan adjustment to be applied to energy consumption (for Newfoundland Power customers) for the period July 1, 2014 to June 30, 2015. In accordance with Hydro's *Policies for Automatic Rate Changes*, lower rates for Newfoundland Power customers would result in lower rates for Hydro Rural customers whose rates are based on Newfoundland Power rates.

The Consumer Advocate submits that the question of which customers should benefit from the refund should not depend on whether the refund plan takes the form of direct payments or is in the form of an electricity rate adjustment. He notes that Government in enacting OC2013-089 would be aware of the fact that Hydro's Island Interconnected customers pay the same rates as Newfoundland Power's customers and that rate changes for Newfoundland Power customers also impact certain of Hydro's Rural customers. In his submission at pages 2-3 the Consumer Advocate references the language of OC2013-089 and notes that the reference in paragraph 6 "*is made to "ratepayers" – not to a particular group or class of ratepayers.*" He goes on to note that the only group excluded are the Island Industrial customers and that paragraph 6 provides for the Board to make the final determination on the details of the refund to remaining ratepayers. He submits:

The term "remaining ratepayers" evidences the fact that there is no intent to limit the refund to a particular group or class of ratepayers. The term "remaining ratepayers"

clearly encompasses more customers than just customers of Newfoundland Power. Having excluded only the Island Industrial customers for consideration for the refund, it would simply not make sense to use the term "remaining ratepayers" if the intent was to exclusively benefit Newfoundland Power customers.

The Consumer Advocate agrees with Hydro that the right to receive the refund extends to the ratepayers who normally receive Rate Stabilization Plan related rate changes and submits that the Order in Council did not exclude from the refund those customers whose rates are subsidized. He submits that OC2013-089 does not leave it open to the Board to deny a refund to those customers who normally receive Rate Stabilization Plan related rate changes.

Discussion and Board Findings

Under section 5.1 of the *EPCA* the Lieutenant Governor in Council can direct the Board with respect to the policies and procedures to be implemented in certain aspects of its regulation of public utilities, and specifically with respect to certain matters related to Hydro. The Lieutenant Governor in Council has, under section 5.1 of the *EPCA*, directed the Board in OC2013-089, as amended, as to the ultimate disposition of the Rate Stabilization Plan Surplus. This direction firstly distributes the Rate Stabilization Plan Surplus between the Island Industrial customers' Rate Stabilization Plan and Newfoundland Power's Rate Stabilization Plan. This first step of dividing the Rate Stabilization Plan Surplus amounts between the two components of the Rate Stabilization Plan was dealt with in Order No. P.U. 26(2013) in which the Board ordered:

1. Hydro shall on August 31, 2013:

- i) credit \$49 million to the Island Industrial Customers' Rate Stabilization Plan; and*
- ii) transfer the remaining balance in the January 1, 2007 to August 31, 2013 accumulated Load Variation component of the Rate Stabilization Plan to the credit of the Newfoundland Power Inc. Rate Stabilization Plan.*

The matter before the Board now is the disposition of the amount transferred to Newfoundland Power's Rate Stabilization Plan, which has been segregated as the NP RSP Surplus. The amount at issue to be refunded to ratepayers as of August 31, 2013 was \$112.6 million.

There is fundamental disagreement between Hydro and the Consumer Advocate on the one hand and Newfoundland Power on the other as to the interpretation of OC2013-089 in relation to which customers should receive a refund. The question of which customers are entitled to the payment/rebate is important as the amount to be distributed from the NP RSP Surplus is substantial and the amount to be refunded to each customer will be affected by the decision as to which customers are included in the refund plan.

In making a determination on this issue the Board must look to the language of the Order in Council which directs the Board. Paragraph 6 of OC2013-089, which directs the form of the refund and to whom it is to be paid, states:

6) Newfoundland and Labrador Hydro's General Rate Application process shall include a Rate Stabilization Plan surplus refund plan to ratepayers. The refund plan shall comprise direct payments or rebates to ratepayers and shall not be in the form of an electricity rate adjustment. This refund plan will exclude Island industrial customers who will receive Rate

1 *Stabilization Plan surplus funds through the three year phase-in of new rates. The Board of*
 2 *Commissioners of Public Utilities shall make the final determination on the details of the*
 3 *refund to remaining ratepayers; (emphasis added)*
 4

5 Paragraph 7 of OC2013-089 further states:

6
 7 *7) Newfoundland Power's portion of the Rate Stabilization Plan Surplus shall be*
 8 *distributed as a direct payment or rebate to its ratepayers and shall not be in the form of*
 9 *an electricity rate adjustment; and...*

10
 11 The Board also notes paragraph 2 of OC2013-091 which sets out the direction of Government to
 12 Hydro states:

13
 14 *2) during its General Rate Application process, it shall file a Rate Stabilization Plan*
 15 *surplus refund plan to ratepayers. The refund shall be a direct payment or rebate to*
 16 *ratepayers and shall not be in the form of an electricity rate adjustment. This refund plan*
 17 *will exclude Island industrial customers who will receive Rate Stabilization Plan surplus*
 18 *funds through the three year phase-in of new rates; and... (emphasis added)*
 19

20 The only distinction made in paragraph 6 of OC2013-089 with respect to the refund plan is
 21 between the Island Industrial customers and remaining ratepayers. Paragraph 6 does not contain
 22 any reference to Newfoundland Power or its customers, Hydro's Rural customers, or any other
 23 specific Hydro customers. Similarly, paragraph 2 of OC2013-091 directs Hydro to file a refund
 24 plan whereby there is direct payment or rebate to ratepayers excluding Island Industrial
 25 customers. The Government direction does not restrict or narrow the customers to receive the
 26 refund except to say that it is to go to remaining ratepayers after the exclusion of the Island
 27 Industrial customers. It does not direct the Board further or set out any criteria as to specific
 28 classes of customers eligible or entitled to the refund. The Board does not accept Hydro's
 29 suggestion that OC2013-089 makes it clear that the Board is authorized to consider ordering
 30 refunds to all customers that are involved in and affected by the Rate Stabilization Plan Surplus.
 31

32 Hydro's position that the term ratepayers is meant to include Newfoundland Power's customers
 33 and certain Hydro Rural customers appears to be based on the established rate policy. Hydro's
 34 policy for automatic rate changes is based on long standing government direction and provides
 35 that rates for its Rural customers (other than Labrador Interconnected and Government customers
 36 on Isolated systems) are based on the rates established by the Board for Newfoundland Power's
 37 customers. Section 16 of Hydro's approved Rules and Regulations of Service provides that rates
 38 for these customers are automatically adjusted based on changes to Newfoundland Power's rates:
 39

40 *Policies for Automatic Rate Changes*

41 (a) *Island Interconnected System:*

42 (i) *As Newfoundland Power changes its rates, Hydro will automatically adjust all rates*
 43 *such that these customers pay the same rates as Newfoundland Power customers.*

44 (b) *L'Anse au Loup System:*

45 (i) *As Newfoundland Power changes its rates, Hydro will automatically adjust all rates*
 46 *such that these customers pay the same rates as Newfoundland Power customers.*

47 (c) *Isolated Systems:*

(i) *Isolated Rural Domestic customers, excluding Government departments, pay the same rates as Newfoundland Power for the basic customer charge and First Block consumption (outlined in Rate 1.2D). Rates charged for consumption above this block will be automatically adjusted by the average rate of change granted Newfoundland Power from time to time.*

(ii) *Rates for Isolated Rural General Service customers, excluding Government departments, will increase or decrease by the average rate of change granted Newfoundland Power from time to time.*

(iii) *As Newfoundland Power changes its rates, Hydro will automatically adjust Rural Isolated street and area lighting rates, excluding those for Government departments, such that these rates are the same as charged Newfoundland Power customers.*

The Board notes that Government has specifically directed in OC2013-089 that the refund is not to be in the form of an electricity rate adjustment. As there is to be no change in rates as a result of the refund to ratepayers, Newfoundland Power's rates will not change and the *Policies for Automatic Rate Changes* is not operative in this case. Therefore the Board does not accept Hydro's position that certain Rural customers are entitled to the refund because the rules set out that the rates for these customers are based on Newfoundland Power's customer rates.

Newfoundland Power argues that paragraph 7 of OC2013-089 directs that its portion of the Rate Stabilization Plan is to be distributed as a direct payment or rebate to its ratepayers and relies on this paragraph to support its position that the entire amount of the NP RSP Surplus is to be refunded to Newfoundland Power customers only. In the absence of paragraph 6 of OC 2013-089 this position would be persuasive. However paragraph 6 states that only the Island Industrial customers are excluded and "remaining ratepayers" are entitled to the refund. Given the specific language of paragraph 6 the Board takes paragraph 7 as direction on how Newfoundland Power is to distribute the refund to its customers once it receives its portion of the Rate Stabilization Plan Surplus, and that it must be in the form of a direct payment or rebate and not as an electricity rate adjustment. The Board does not accept the argument of Newfoundland Power that it should order a refund only to Newfoundland Power customers.

In the Board's view the expressed intent of OC2013-089 as set out in paragraph 6 is that ratepayers, other than the Industrial Customers, shall receive a refund in the form of a direct payment or rebate. The Board cannot take from the language any other intent, meaning or understanding of what Government may or may not have known at the time of drafting of the Order in Council. Government has directed a refund in the form of a direct payment or rebate to ratepayers except the Island Industrial customers.

The Board also does not agree with the argument of Hydro and the Consumer Advocate that the derivation of the Rate Stabilization Plan Surplus must be considered when deciding which customers are entitled to the refund. The amount in the Rate Stabilization Plan Surplus accumulated largely as the result of changes in load over the period January 1, 2007 to August 31, 2013. The Board has been directed by Order in Council and it must comply with the provisions of this direction. In ordinary circumstances a significant reduction in customer load, such as occurred on the Island Interconnected system beginning in 2007, would be addressed in a general rate application during which the components of the Rate Stabilization Plan and base rates would be reset to reflect the updated costs of service. In this case Hydro did not file a

1 general rate application until 2013. The Board notes that the manner in which the Order in
2 Council directs the segregation of the Rate Stabilization Plan Surplus does not suggest that the
3 refund is compensatory. The direction of Government allocates an amount of \$49 million of the
4 Rate Stabilization Plan Surplus to the Island Industrial customers. OC2013-089 states that this
5 amount is *"the estimated Rate Stabilization Plan amount required to phase-in industrial*
6 *customer rates, based on Newfoundland and Labrador Hydro's General Rate Application."* The
7 amount allocated is not stated to be calculated in accordance with the Rate Stabilization Plan
8 rules. Rather the \$49 million is expressed to be an amount estimated to be required to offset
9 future rate increases for Island Industrial customers. The remaining balance is the amount
10 transferred to the Newfoundland Power Rate Stabilization Plan to be refunded to ratepayers,
11 without any calculation of what was or should have been paid by each customer class based on
12 the Rate Stabilization Plan rules.

13
14 In the circumstances the Board does not accept that the determination of which customers are
15 entitled to the refund should be made based on how the Rate Stabilization Plan may have/would
16 have operated in the period 2007 to 2013. The Rate Stabilization Plan Surplus has been allocated
17 by Government direction without reference to the impact the normal operation of the Rate
18 Stabilization Plan would have had on rates for that period. The Government direction expressly
19 requires that the form of the refund shall be a direct rebate or payment to ratepayers. The words
20 of the Government direction are clear and unambiguous. Any interpretation of the direction that
21 looks beyond the plain meaning to try to determine the intention of Government based on
22 existing rate policies may lead to results which are inconsistent with the language of the Orders
23 in Council.

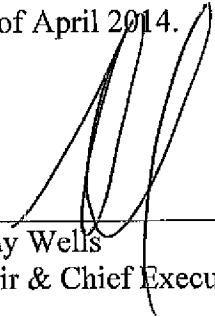
24
25 The Board agrees with Hydro that it must have regard to the language of the Order in Council.
26 Based on plain reading of the language of OC2013-089 the Board cannot accept Newfoundland
27 Power's position that only its customers are entitled to the refund. Similarly the Board cannot
28 accept the position of Hydro and the Consumer Advocate that certain of Hydro's customers are
29 entitled to a refund and certain customers are not entitled to a refund. If it was the intent of
30 Government that only certain customers were entitled to the surplus refund this could have been
31 clearly stated. In the absence of language that expressly excludes certain customers the Board
32 interprets the terms "ratepayers" and "remaining ratepayers" to mean all ratepayers, except those
33 specifically excluded - the Island Industrial customers. Therefore the Board finds that the amount
34 in the NP RSP Surplus should be refunded as a direct payment or rebate to Newfoundland Power
35 customers and customers on each of Hydro's systems - Rural Island Interconnected, Island
36 Isolated, Labrador Isolated, L'Anse au Loup, and Labrador Interconnected.

37
38 Hydro has advised that it is awaiting a ruling from the CRA on the HST treatment of the refund,
39 which may affect the total amount of the refund to each customer. The Board expects that Hydro,
40 Newfoundland Power and the Consumer Advocate will work jointly to determine a reasonable
41 and appropriate approach in relation to the refund consistent with the direction of Government
42 and file a consensus proposal with the Board for its consideration.

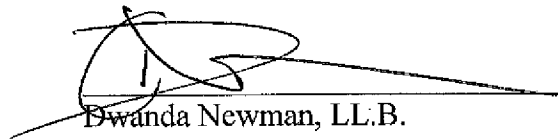
IT IS THEREFORE ORDERED THAT:

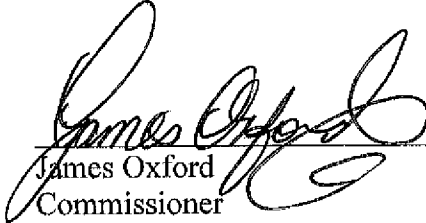
1. The Newfoundland Power Rate Stabilization Plan Surplus shall be refunded to all ratepayers, with the exception of the Island Industrial customers, in the form of direct payment or rebate and in a manner to be approved by the Board.
2. Hydro shall pay the expenses of the Board incurred with this matter.

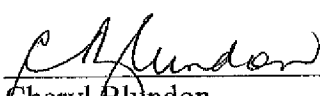
DATED at St. John's, Newfoundland and Labrador, this 9th day of April 2014.


 Andy Wells
 Chair & Chief Executive Officer


 Darlene Whalen, P.Eng.
 Vice-Chair


 Dwanda Newman, LL.B.
 Commissioner


 James Oxford
 Commissioner


 Cheryl Blundon
 Board Secretary

TAB 13

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT



- and -

IN THE MATTER OF AN APPLICATION by **NOVA SCOTIA POWER INCORPORATED** for Approval of Certain Revisions to its Rates, Charges and Regulations, including the review of the Fuel Adjustment Mechanism Audit

BEFORE:

Peter W. Gurnham, Q.C., Chair
Roland A. Deveau, Q.C., Vice-Chair
Kulvinder S. Dhillon, P.Eng., Member

APPLICANT:

NOVA SCOTIA POWER INCORPORATED
Terry Dalglish, Q.C.
John J. (Jack) Marshall, Q.C.
René Gallant, LL.B.
Nicole Godbout, LL.B.

INTERVENORS:

AFFORDABLE ENERGY COALITION
Claire McNeil, LL.B.

ALTON NATURAL GAS STORAGE LP
Alan V. Parish, Q.C.

AVON GROUP
Nancy G. Rubin, LL.B.
Maggie A. Stewart, LL.B.

CONSUMER ADVOCATE
John P. Merrick, Q.C.
William L. Mahody, LL.B.

SMALL BUSINESS ADVOCATE
E.A. Nelson Blackburn, Q.C.
Paul B. Miller, LL.B.

HALIFAX REGIONAL MUNICIPALITY

Martin C. Ward, Q.C.

Angus Doyle

Julian Boyle

LIBERAL CAUCUS OFFICE

Stephen McNeil, M.L.A.

Andrew Younger, M.L.A.

Shawn Lawlor

**MUNICIPAL ELECTRIC UTILITIES
OF NOVA SCOTIA CO-OPERATIVE**

David MacDougall, LL.B.

Albert Dominie

Donald Regan

PROGRESSIVE CONSERVATIVE CAUCUS OFFICE

Jamie Baillie, M.L.A.

Chuck Porter, M.L.A.

Jennifer Edge

**PROVINCE OF NOVA SCOTIA
(Departments of Energy and Environment)**

Stephen T. McGrath, LL.B.

BOARD COUNSEL:

S. Bruce Outhouse, Q.C.

Richard J. Melanson, LL.B.

LIST OF PARTICIPANTS:

Appendix "A"

HEARING DATE(S):

September 13-14, 18-20, October 29-31 and
November 1, 2 and 9, 2012

UNDERTAKINGS:

November 19, 2012

FINAL SUBMISSIONS:

November 30, 2012

DECISION DATE:

December 21, 2012

DECISION:

**Settlement Agreements approved with adjustments
for pension costs and executive compensation.
Three FAM related disallowances totaling \$6,503,000.
See Summary of Findings starting at paragraph 460.**

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1.0 INTRODUCTION

[1] This Decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the “Board”) on September 13-14, 18-20, October 29-31, and November 1, 2 and 9, 2012, in the matter of an application by Nova Scotia Power Incorporated (“NSPI”, the “Company”, the “Utility”), dated May 8, 2012, for approval of revisions to its Rates, Charges and Regulations (the “Application” or “GRA”).

[2] Consistent with the Plan of Administration (“POA”) for NSPI's fuel adjustment mechanism (“FAM”), Liberty Consulting Group (“Liberty”) was engaged to do a comprehensive audit with respect to the FAM for the period covering 2010 and 2011 (“FAM Audit”). The POA provides that an audit of the FAM will be done every second year. Liberty filed its FAM Audit with the Board on July 10, 2012. The Board directed that its consideration of the FAM Audit would be consolidated into the hearing of NSPI's general rate application. This Decision also includes the Board's findings relative to the FAM Audit.

[3] The NSPI Application seeks the Board's approval of a Rate Stabilization Plan (“RSP”). The proposed RSP is a two-year rate plan, with net increases of three percent per year effective on each of January 1, 2013, and January 1, 2014. According to the Application, the increases will cover a portion of the increased costs forecast by NSPI in each of the next two years. NSPI proposes the remaining revenue requirement be deferred for future recovery commencing in 2015. The various elements of the proposed RSP are explained in further detail later in this Decision.

[4] The public hearing was duly advertised in accordance with sections 64 and 86 of the *Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended (the “Act”), which read as follows:

Approval of schedule of rates and charges of utility

64 (1) No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.

(2) The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act.

Notice of hearing of application for rate changes

86 Notice of the hearing of any application, for the approval of or providing for an increase or decrease in the rates, tolls and charges of any public utility, shall be given by advertisement in one or more newspapers published or circulating in the cities, towns or municipalities where such changes are sought, for three consecutive weekly insertions preceding the date of said hearing, unless otherwise ordered by the Board.

[5] A total of 15 formal Intervenors responded to the application of NSPI. A number of these parties were represented at the hearing by counsel. The Small Business Advocate (“SBA”); the Consumer Advocate (“CA”); the Affordable Energy Coalition (“AEC”); Alton Natural Gas Storage LP (“Alton”); Avon Group (“Avon”), whose counsel represented 13 Intervenors; Halifax Regional Municipality (“HRM”); the Liberal Caucus Office; the Progressive Conservative Caucus Office; the Municipal Electric Utilities of Nova Scotia Co-operative (“MEUNSC”); and the Nova Scotia Departments of Energy and Environment (the “Province”) all participated in the hearing. The Board also received numerous submissions from members of the public opposing NSPI’s Application.

2.0 WRITTEN AND ORAL SUBMISSION FROM THE PUBLIC

[6] In the advertised Notice of Public Hearing, the public was advised that they could file submissions with the Board outlining their views regarding NSPI's Application. In response to this notification, the Board received 64 written submissions from the public and 13 individuals made presentations at the evening session on September 18, 2012.

[7] Most of the written submissions noted impacts that another rate increase would have on customers, especially on low and fixed-income customers. Some of the concerns noted were: the number of recent rate increases; executive compensation levels; rate of return and company earnings; the need for renewable energy; and employee bonuses.

[8] During the evening session, some of the same concerns were raised. Presentations were made by 10 individuals and by a representative from the Canadian Federation of Independent Business ("CFIB"), by the M.L.A. for Pictou West, and the President of the Halifax-Dartmouth and District Labour Council.

[9] The Honourable Charlie Parker, M.L.A. for Pictou West and Minister of Energy, stated that his government has heard the concerns of Nova Scotians, caused by higher electricity rates, and planned to introduce legislative amendments in the fall of 2012 to deal with executive salaries and bonuses, reducing the number of rate hearings, and dealing with the performance of NSPI in general.

[10] Leanne Hachey, representing the CFIB and 5,200 small and medium size businesses in Nova Scotia, noted that her membership cannot absorb any further increases and also cannot pass these on to its customers. She stated NSPI should find

efficiencies within its organization to pay for increased operating costs. She requested that the demand meter threshold be raised to allow additional small businesses to migrate out of this rate class.

[11] Kyle Buott, representing the Halifax-Dartmouth and District Labour Council and 25,000 union workers, stated that within the last four months his delegates have voted twice, unanimously, against the rate increase. He made three points: objecting to the process followed in the rate hearing via settlement agreement; the rate hike proposed does not reflect the cost of electricity but profit for the company; and the Board should get more input from ratepayers who live outside the Halifax area.

[12] Archie Stewart collected an electronic petition which he filed with the Board before the evening session. He noted that he was speaking on behalf of 31,334 Nova Scotia families and the Board should deny the proposed rate increase, including the Settlement Agreement.

[13] Gene McManus stated that the NSPI pension plan is being run by its employees who are also the beneficiaries of the plan. He suggested that the NSPI pension plan should be run by an independent third party.

[14] The Board considered all the comments made in the written submissions and during the evening session in making its decision on the Application. The Board is mindful of its responsibility to protect the public interest and does give due weight to the comments received from the public. The Board has to balance this with the needs of the Utility to provide a safe and reliable service at a minimum cost. No one likes rate increases; however, the Utility's costs are increasing, similar to other businesses, and rates need to be adjusted in order to recover these cost increases.

3.0 BACKGROUND

[15] NSPI is a vertically integrated, investor-owned, regulated public utility with a virtual monopoly on electricity service throughout the province. It is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the province. The Act gives the Board broad regulatory oversight over public utilities and provides it with the authority to discharge its regulatory responsibilities. The Act requires the Board to use a cost for service method for setting rates. The Board must allow NSPI to recover its prudent and proper costs of providing each type of service and a return on its rate base or capital assets.

[16] In legislation, the word “shall” is mandatory. Therefore, the Board is required to determine NSPI’s costs and assets in providing each type of service.

Section 42(1) provides:

42(1) The Board shall fix and determine a separate rate base for each type or kind of service furnished, rendered or supplied to the public by a public utility. [Emphasis added]

[17] The Board must provide a rate of return to NSPI each year. Section 45(1) reads:

45(1) Every public utility shall be entitled to earn annually such return as the Board deems just and reasonable on the rate base as fixed and determined by the Board for each type or kind of service furnished, rendered or supplied by such public utility, provided, however, that where the Board by order requires a public utility to set aside annually any sum for or towards an amortization fund or other special reserve in respect of any service furnished, rendered or supplied, and does not in such order or in a subsequent order authorize such sum or any part thereof to be charged as an operating expense in connection with such service, such sum or part thereof shall be deducted from the amount which otherwise under this Section such public utility would be entitled to earn in respect of such service, and the net earnings from such service shall be reduced accordingly. [Emphasis added]

[18] This return must be in addition to NSPI’s prudent and proper operating expenses of providing the services. Section 45(2) states:

45(2) Such return shall be in addition to such expenses as the Board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Board according to this Act and the rules and regulations of the Board. [Emphasis added]

[19] NSPI, like all other business, experiences cost increases in virtually every expense it incurs to produce electricity for the people of Nova Scotia. The Act requires the Board to ensure these prudent and proper costs are recovered in NSPI's rates.

[20] A fair return on rate base is important for the sustainability of the service. A low return on rate base may cause people to not invest in the Utility. It may also lead to a poor bond rating, which may cause financial institutions to increase the rate of interest on monies NSPI needs to borrow to provide the service. This may result in NSPI's rates increasing solely to cover the additional costs of borrowing money, without even addressing the increases in the operating expenses.

[21] In addition to statutory requirements to be considered during a general rate application, the Board is also guided by long-established, fundamental ratemaking principles. In its Decision dated March 31, 2005, on a rate application by NSPI, the Board explained these guidelines as follows:

In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.

A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates**, sets out the following guidelines for determining appropriate rates:

CRITERIA OF A SOUND RATE STRUCTURE

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
 - (a) in the control of the total amounts of service supplied by the company;
 - (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

[Decision, March 31, 2005, p. 14]

[22] The Board continues to make its decisions in accordance with the *Act*, and the principles noted above.

[23] After seeking an adjournment at the commencement of the public hearing on September 13, 2012, NSPI notified the Board on September 14th that it had reached a Settlement Agreement (the "GRA Agreement") on many of the outstanding issues in the NSPI Application. The GRA Agreement has the support of the CA, the SBA and Avon. The Board adjourned the hearing to provide an opportunity for all other parties to review the GRA Agreement. The hearing reconvened on September 18, 2012, at which point NSPI witnesses explained the terms of the GRA Agreement and testified with respect to the outstanding issues. However, the GRA Agreement was only executed as of October 15, 2012 and was not filed with the Board until November 2, 2012.

4.0 SETTLEMENT AGREEMENT

4.1 The Board's approach to settlement agreements

[24] In its previous Decisions, the Board has set out the principles it applies in its consideration of settlement agreements. Those principles bear repeating. In its Decision dated November 5, 2008, the Board outlined its general approach to settlement agreements submitted to it for approval:

[12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.

[13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.

[14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.

[15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.

[16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.

[17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.

[18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.

[Decision, 2008 NSUARB 140]

4.2 The GRA Agreement in the present case

[25] The GRA Agreement addresses many outstanding issues between NSPI and most of its customers. However, several issues were not resolved, including the FAM audit, pension costs, LED street lighting and the underground storage of natural gas.

[26] Notably, the GRA Agreement adopts the two year RSP proposed by NSPI.

[27] The GRA Agreement reads as follows:

**2013-2014 General Rate Application
Settlement Agreement
October 15, 2012**

Whereas NS Power filed a General Rate Application for 2013 and 2014 on May 8, 2012;

And Whereas the Board Hearing Schedule provided for Information Requests to NS Power and Responses, Testimony from Board and Intervenor consultants with corresponding Information Requests and Responses, Reply Evidence from NS Power, and Opening Statements from parties and consultants;

And Whereas the Parties to this Settlement Agreement, which include NS Power, Avon Group, the Consumer Advocate and the Small Business Advocate, desire to resolve the General Rate Application by way of this Agreement;

The Parties agree:

1. The 2013-2014 Rate Stabilization Plan is accepted and adopted, as filed, subject to the changes contained in this document. This includes a three percent overall rate increase for each of 2013 and 2014, plus a deferral of forecasted revenue requirement that is not otherwise recovered by the two rate adjustments, using the August 31 update. The deferral recovery would begin in 2015 in an amount that is equivalent to the s.21 amount in rates.
2. NSPI will identify, at its own discretion, and manage the business in order to achieve a \$27.5 million reduction in the deferral balance over the two year period. None of the reductions will be achieved through fuel forecast reductions. This will resolve all issues relating to revenue requirement, subject to items 3 and 6 (below).
3. ROE will be set at 9.0% for rate making purposes, with a 0.25 band. Therefore the ROE range will be from 8.75% to 9.25%.
4. The result of the changes in items 2 and 3 will be that the fixed cost deferral amount will not exceed \$84.8 million, which includes the financial effect of the lower ROE and the resulting lower interest costs relating to financing a lower deferral amount. For the purpose of calculating interest, the deferral will be reduced by \$13.75 million in each year of 2013 and 2014.
5. S.21 amounts will be accepted as filed. The S.21 AAA Mechanism will continue as part of the Rate Stabilization Plan, as proposed in the Application.
6. Fuel - Base Cost of Fuel will be set as per the August 31 update. Liberty's proposals regarding natural gas will be determined by the outcome of the FAM Audit process. If the UARB accepts Liberty's views in that process, the Base Cost of Fuel and therefore the revenue requirement (and deferral) will be reduced to the extent the audit outcome affects the fuel forecast for 2013 and 2014. Liberty's suggested

- reductions relating to imports are not adopted but the suggestion will be referred to the Small Working Group for study and possible changes to the forecasting methodology for future implementation.
7. The FAM Audit issues will continue to be litigated in accordance with the Board schedule for the hearing that commences October 29. The financial result of the hearing, if any, will be implemented beginning January 1, 2013 separate and apart from the Rate Stabilization Plan.
 8. NS Power's proposal to update OATT pricing, with the exception of its request for an ECRM (which has already been determined by the Board), will be accepted as filed. The matter of the MEUNSC responsibility for deferrals, in the event of departure from the system, may be determined in a future application before the UARB. Parties are free to take any position on OATT related matters in future proceedings.
 9. The SBA request for an adjustment to the R/C ratios for small business classes and narrowing of the band (0.95 to 1.05) will be referred to the Cost of Service Study proceeding.
 10. Adjustments will be made to the Large Industrial Interruptible class to ensure this class of customers receives the same 3% adjustments as experienced by other customer classes, similar to the approach taken in the 2009 GRA Settlement Agreement.
 11. The Interruptible Rider to the Large Industrial Tariff will be revised as provided in the attached September 28, 2012 letter from NS Power to the UARB.
 12. During the hearing parties to the agreement will refrain from seeking any changes to the agreement or additional reductions to revenue requirement. This settlement is without prejudice to any position that parties may take on these issues in future proceedings.

[Exhibit N-201]

[28] The GRA Agreement has an attachment related to the Interruptible Rider.

[29] In his Opening Statement at the hearing, Rob Bennett, NSPI's CEO, stated that the GRA Agreement, which incorporates the RSP, provides the Utility and its customers with the time to adjust to significant changes in NSPI's load and costs:

The Rate Stabilization Plan provides the best approach to the complex challenges we face, together, with the Board and our customers. Input costs are rising, new renewable energy is being added to the system, and load is dropping – quickly and dramatically. Any of these challenges would create upward pressure on electricity rates; and we are experiencing them all at once.

Mr. Chairman, we will continue to work on behalf of our customers to meet the challenges that will arise during this Rate Stabilization period. This agreement gives everyone time to adjust to the lost pulp and paper load, but does not solve that problem. In 2015 we will have to incorporate the lost load into general rates, including the final payment of the 2012 Fixed Cost Deferral, and any other changes in our cost structure that are forecast for that test year.

[NSPI Opening Statement, Exhibit N-123, p. 1]

[30] In NSPI's Closing Submission, counsel for the Company submitted:

The Settlement Agreement reflects agreement by the parties to accept and adopt the Rate Stabilization Plan, as filed, subject to specific changes provided in the Settlement Agreement. That includes a net 3 percent overall increase in each of 2013 and 2014, with a deferral of forecast revenue requirement, based on the Company's August 31 Load and Fuel Update filing, not otherwise recovered by the 3 percent rate increases in each of the next two years. ...

Key to the settlement is the fact that it reflects a commitment by the Company to be responsible for \$27.5 million of the original deferral of revenue requirement. The parties agreed that no deferral reductions will be made through fuel adjustments, but that the Company will identify at its own discretion, and manage the business in a manner that will achieve the \$27.5 million deferral reduction. This commitment represents a significant challenge to the Company over the next two years, and will provide a substantial long term benefit to customers.

[NSPI Closing Submission, November 23, 2012, p. 12]

[31] NSPI counsel also noted the benefits to customers of reducing the return on equity:

...This includes the agreed reduction in NS Power's return on equity (ROE) for rate setting purposes from 9.2 percent to 9.0 percent along with a change to the earnings band to +/- 0.25 percent, making the earnings band 8.75 to 9.25 percent. This change also contributed to reductions to the Company's revenue requirement for 2013 and 2014, leading to further reductions made to the deferral amount, over and above the \$27.5 million.

[NSPI Closing Submission, November 23, 2012, p. 15]

[32] The CA supports the approval of the GRA Agreement. In his view, after analyzing all of the Pre-filed Evidence, the result was not likely to be better by pursuing a contested hearing:

It is to be noted that the settlement agreement calls for a reduction in NSPI's requested revenue requirement. The Consumer Advocate and other signatories to the settlement agreement analyzed all of the pre-filed evidence and, with the benefit of assessments by expert consultants, concluded that rate increases proposed in the settlement agreement are reasonable and justified. Furthermore, it is the view of the Consumer Advocate and the settling intervenors that the agreed-upon reduction in revenue requirement was not likely to be improved through additional litigation. One important aspect of the proposed settlement agreement, as noted by Commissioner Dhillon in his questioning of the NSPI panel, is that the proposed increases are 3% class revenue increases. ...

In addition to the rate increases in 2013 and 2014, the settlement agreement also provides for deferred collection of a significant portion of NSPI's revenue requirement. Although the Consumer Advocate continues to be leery of deferral mechanisms, there was an identified and important correlation between the deferral proposed in this settlement agreement and the extinguishment of the section 21 deferral which is presently in rates. The net effect is that the deferral contemplated in this settlement will

be collected once the section 21 deferral has been paid off and therefore represents an opportunity to smooth or even out rate increases experienced by customers.

[CA Closing Submissions, November 23, 2012, p. 4]

[33] The SBA also submitted that, after a review of the evidence, the GRA Agreement represented a reasonable resolution of most issues in the Application:

The Settlement Agreement signed by the Consumer Advocate, the Avon Group, Nova Scotia Power and the SBA, was the result of much consultation and discussion and was not taken lightly. Accordingly, after assessing the Application and merits of achieving greater results by litigating before the Board, and after reviewing the experts' reports, asking numerous questions, followed by numerous hours of negotiations, the SBA was satisfied the Settlement Agreement dated October 15, 2012, represents a reasonable resolve with respect to many items referred to in the General Rate Application when compared with the uncertainty of successful litigation.

[SBA Closing Argument, November 23, 2012, pp. 1-2]

[34] Counsel for Avon noted that the GRA Agreement represents a resolution of issues between all customer classes, excluding municipal customers:

In each case, Intervenor must carefully evaluate the evidence to judge the costs and risks of challenging the Utility's application against the advantage of a negotiated settlement. With the exception of the Municipal customers, the Settlement Agreement has the support of representatives of all customer classes who participated in the process - the Avon Group (Large Industrial), the Consumer Advocate (Residential) and the Small Business Advocate (Small General, General, Small Industrial), as well as NSPI. It is a reflection of the good faith efforts of the participants that a settlement was achieved in a very compressed time frame. There were compromises among all signatories but only time will tell whether it is a "good" deal for all concerned.

[Avon Final Submissions, November 23, 2012, para. 5]

[35] Counsel for Avon also highlighted a number of the elements of the GRA Agreement which will benefit customers:

The Agreement results in an across-the-board 3% increase in each of 2013 and 2014 plus a deferral of forecasted revenue requirement not to exceed \$84.8 million (clause 4). At the end of the two years, the deferral is planned to be recovered in an amount equal to the Section 21 payment that is already embedded in rates (clause 1). As part of the Settlement Agreement, NSPI has agreed to a \$27.5 million reduction in the deferral balance spread equally over the two year period (clause 2). In addition, the ROE will be set at 9.0% plus or minus 25 basis points, i.e. 8.75% - 9.25% (clause 3). *The Settlement Agreement continues the previously agreed-upon cap on ROE through the s.21 AAA mechanism with any excess applied against the deferral (clause 5). This is an element of*

the negotiated Agreement that would not have been achieved through a contested proceeding. [emphasis added]

[Avon Final Submissions, November 23, 2012, para. 7]

[36] Moreover, Avon Counsel noted that the GRA Agreement contains two clauses which are particularly significant for large industrial interruptible customers, including a clause which provides that this class receives the same 3% increase in rates as other classes, together with revisions to the Interruptible Tariff Rider which balances the risk between NSPI and its interruptible customers respecting notices to reduce load.

[37] The Province does not oppose the settlement process and suggests that the proposed GRA Agreement is worthy of serious consideration by the Board:

Although it is not a signatory to the Settlement Agreements filed in this case, the Department of Energy does not oppose the settlement process, as outlined and applied by the Board in its past decisions. In this case, the Settlement Agreement has been executed by representatives of almost all of NSPI's classes of customers and therefore we would respectfully suggest warrants serious consideration.

[Province Closing Submissions, November 23, 2012, para. 12]

[38] The Province also noted that the GRA Agreement benefits customers. Counsel pointed out that the proposed \$27.5 million non-fuel cost reduction in NSPI's deferral is not to be achieved through reductions in forecasted fuel costs. After noting the benefits of the RSP, as described immediately below in this Decision, counsel for the Province added:

...At the same time, the revenue requirement reductions agreed to in the proposed settlement agreement will reduce the extent to which future rates are impacted as a result of the stabilization plan. These revenue requirement reductions include a lowering of NSPI's return on equity, which the Department of Energy applauds.

[Province Closing Submissions, November 23, 2012, para. 13]

4.3 Rate Stabilization Plan

[39] A major component of the NSPI Application is the RSP. Subject to the changes noted in the GRA Agreement, the 2013-2014 RSP is adopted as part of the GRA Agreement.

[40] NSPI has forecast the revenue requirement for each of the next two years instead of the traditional single year approach. The elements of the RSP are set out in the NSPI Application:

The Rate Stabilization Plan, which provides for recovery of the 2013 and 2014 revenue requirements is as follows:

- i. For each customer class, an average three percent increase on January 1, 2013 and an average three percent increase on January 1, 2014, after factoring in the 2010 FAM deferral reductions in 2013 and 2014,
- ii. Deferral of any portion of the Board approved revenue requirement not recovered by the average 3 percent annual increases. Effectively, this will continue the 2012 Fixed Cost Recovery deferral, which will continue to grow until the end of 2014, with recovery of the deferral over an 8 year period beginning in 2015,
- iii. FAM adjustments, other than for the 2010 FAM deferral reductions and the 2011 FAM imbalance both of which are reflected in the 2013 Balance Adjustment, will be deferred, to be incorporated into customer rates in 2015, and the FAM incentive will remain suspended until the end of 2014.

[NSPI Application, Exhibit N-3(i), pp. 2-3]

[41] The 2012 Fixed Cost Recovery Deferral, which accommodated uncertainty about the province's pulp and paper load, was approved by the Board as part of NSPI's 2012 general rate application. In that proceeding, the settlement agreement approved by the Board initiated the Fixed Cost Recovery Deferral. The 2012 Fixed Cost Recovery Deferral was accepted by the same parties to the present GRA Agreement.

[42] NSPI's Application provided that the RSP deferral would be \$130.7 million [Undertaking U-6]. Under the proposed GRA Agreement, the deferral will not exceed

\$47.1 million at December 31, 2013 and will not exceed \$84.8 million at December 31, 2014.

[43] NSPI's Application states that the amount of the deferral will be calculated separately for each class of customer, such that the "across-the-board 3-percent increase" will result in deferrals that accurately reflect the specific cost of serving each class of customer.

[44] Under the proposed RSP, the annual three percent adjustment will incorporate forecast decreases connected to the phase-out of the 2010 FAM Deferral. Also, the FAM will continue to operate, but additional AA and BA changes in 2013 and 2014 fuel costs will be deferred within the FAM until the RSP ends.

[45] NSPI submits that recovery of the deferral, commencing in 2015, will coincide with the end of the Section 21 Tax Deferral, which NSPI has been collecting from ratepayers over eight years ending in March 2015:

In the current situation, NS Power believes a modest, short-term deferral of increased expenses is an appropriate way to stabilize rates for customers over the next two years. We propose to begin recovering the deferred costs in 2015, just as the Section 21 Tax Deferral expires. By timing the deferral this way, and if the deferred amount is less than \$110 million, [NSPI] will be able to recover it in full over eight years, with no change in rates. In effect, as soon as [NSPI] finish[es] collecting the Section 21 Tax Deferral, [NSPI] will replace it with an eight-year recovery of the Fixed Cost Recovery deferral.

[NSPI Application, Exhibit N-2, p. 28]

[46] Counsel for Avon also submits that the RSP benefits the members of the Avon Group by providing a "predictable measure of stability" over the next two years:

From the perspective of the Avon Group, the Settlement Agreement results in a predictable measure of stability for the next two years and avoids the time, expense and uncertainty of a contested rate case. ... Members of the Avon Group shoulder their own regulatory costs, so the ability to predictably budget for energy costs over the next two years without the risks and costs of contested proceedings was attractive.

[Avon Final Submissions, November 23, 2012, para. 6]

[47] Similar reasoning was expressed by the SBA:

The SBA is further of the belief the two (2) year rate stabilization plan which calls for an overall average 3 percent rate increase for customer classes effective January 1, 2013, and further increase of 3 percent effective January 1, 2014, will help reduce litigation fatigue, and give stability for small business with respect to rate stabilizing increases for the next two (2) years. ...

[SBA Closing Argument, November 23, 2012, p. 2]

[48] Counsel for the Province refers to the RSP as a positive aspect of the GRA Agreement:

From the Department of Energy's perspective, there are many positive aspects to the proposed Settlement Agreement. The acceptance and adoption of the 2013-2014 Rate Stabilization Plan, while not avoiding rate increases, will dampen the impact of those increases. At the same time, the revenue requirement reductions agreed to in the proposed settlement agreement will reduce the extent to which future rates are impacted as a result of the stabilization plan...

[Province Closing Submissions, November 23, 2012, para. 13]

4.4 Findings

[49] The GRA Agreement represents a comprehensive resolution of many contested issues between NSPI and the Intervenor representing most of its customers. It addresses a number of significant components raised in the NSPI Application.

[50] The Board is mindful that the GRA Agreement represents a negotiated settlement by most represented customer classes, with the exception of the municipalities, whose involvement was directed to other issues in the GRA proceeding as described later in this Decision.

[51] In the Board's view, an important component which will benefit customers is the RSP, which limits across-the-board increases of 3% in each of 2013 and 2014, while deferring recovery of NSPI's remaining revenue requirement to 2015 when the Section 21 Tax Deferral will be fully retired. The net effect of the RSP is that the

revenue requirement deferral will only be collected after the Section 21 Tax Deferral has been retired. The deferral will be collected over an 8 year period beginning in 2015.

[52] Without the RSP, customers would have faced much larger rate increases, particularly in 2013. As noted by the CA, this will "smooth or even out rate increases experienced by customers". Counsel for Avon agreed that this will provide ratepayers with a "predictable measure of stability" over the next two years.

[53] In its original Application, NSPI had proposed that the deferral would be about \$124.4 million (Exhibit N-3(i), Appendix P, Attachment 2), later amended to \$130.7 million in Undertaking U-6. The GRA Agreement provides for a \$27.5 million non-fuel cost reduction in NSPI's deferral. Accordingly, the deferral will not exceed \$84.8 million at December 31, 2014, which includes additional adjustments made by NSPI in the hearing.

[54] The GRA Agreement also reduces NSPI's return on equity from 9.2% to 9.0%, along with a revised earnings band of 8.75 % to 9.25 %. This will also result in further reductions to NSPI's revenue requirement for 2013 and 2014, leading to further reductions made to the deferral amount, over and above the \$27.5 million non-fuel cost reduction.

[55] Finally, as noted by counsel for Avon, the GRA Agreement continues the previously agreed-upon cap on return on equity through the s.21 AAA mechanism, with any excess applied against the deferral. This would not have been achieved through a contested proceeding.

[56] Taking into account the evidence and the submissions, the Board is satisfied that the GRA Agreement is in the public interest and that it should be

approved. In the view of the Board, the GRA Agreement provides for rates that are just and reasonable.

[57] The Board approves the NSPI Application, except as amended by the terms of the GRA Agreement or as otherwise varied in this Decision. Rates will increase by 3% for each customer class on January 1, in each of 2013 and 2014. The Board notes that it also approves the requested changes to Accounting Policy 5900 – Tax and the proposed updated OATT pricing.

[58] The Board directs NSPI to outline in 2013 and 2014 where it has applied the \$27.5 million non-fuel cost reductions negotiated in the GRA Agreement. This disclosure is to accompany the year-end financial statements in the respective years.

5.0 PENSION COSTS

5.1 Regular Pension Plans

[59] In its Decision of November 28, 2011 (2011 NSUARB 184), the Board indicated that it would investigate the issue of pension costs in this proceeding.

[60] Peter Hayes, of Eckler Ltd., was retained by Board Counsel to examine NSPI's pension costs.

[61] Mr. Hayes noted that Company contributions to the NSPI pension plan have grown to be several multiples of what employees contribute. He goes on to say:

In managing its pension costs, I believe NSPI faces serious impediments. These impediments are largely self-imposed, and to an extent cultural, but until they are removed it will be difficult for NSPI to gain control of its pension costs. In the meantime, these costs will continue to grow at a high level.

[Exhibit N-59, p. 2]

[62] Among the impediments Mr. Hayes noted were:

- a) A management focus on the performance of plan assets at the exclusion of more holistic plan management;
- b) A lack of willingness to engage unionized employees in meaningful discussion around the reform of the pension;
- c) Certain concerns raised in confidence about the governance structure.

[63] It appears to the Board that until very recently NSPI has done little, if anything, to address increasing pension costs. The Company witnesses cited constraints of the collective agreement with NSPI's Union and the recent influence on pension expense of the financial market losses as reasons for not doing so earlier.

[64] Among other recommendations Mr. Hayes suggested the test year revenue requirement should be set at a level which reflects higher employee contribution rates.

[65] NSPI was, in fact, engaged in collective agreement negotiations during the course of the hearing.

[66] NSPI confirmed to the Board that it had reached an agreement with the IBEW on the terms of a new collective agreement which was approved on November 5, 2012. In a letter dated November 16, 2012, NSPI outlined changes to the pension plan.

Employee contributions:

- Employee contributions to the DB Plan will change from the current level of 5.4% of pensionable earnings up to the Year's Maximum Pensionable Earnings ("YMPE") plus 7.0% of pensionable earnings in excess of the YMPE as follows:
 - o Effective January 1, 2013, members will contribute 6.15% of pensionable earnings up to the YMPE and 8.00% of pensionable earnings in excess of the YMPE;
 - o Effective January 1, 2014, members will contribute 6.90% of pensionable earnings up to the YMPE and 8.75% of pensionable earnings in excess of the YMPE; and

- o Effective January 1, 2015, members will contribute 7.40% of pensionable earnings up to the YMPE and 9.50% of pensionable earnings in excess of the YMPE.

Final Average Earnings definition:

- Effective January 1, 2013, the Final Average Earnings definition will change from the "best average four years" to the "best average five years".

[67] The Board sees these changes as a significant step in pension reform. The Board accepts these changes as adequate initial steps.

[68] NSPI, in its Final Submission, submitted that the changes that had been recently negotiated to the pension plan should be considered as part and parcel of NSPI's effort to reduce expenses by the \$27.5 million agreed to in the GRA Agreement. Clearly contract negotiations were well advanced when NSPI agreed to the GRA Agreement and the Board accepts that there does not need to be a further adjustment to the revenue requirement to reflect these changes that were achieved through negotiation.

[69] In future years these costs savings will be embedded in the revenue requirement asked of customers.

[70] The Board, however, expects NSPI in future to take additional steps to improve contributions to, and the funding of, the pension plan.

5.2 Supplemental Executive Retirement Plan

[71] Two issues arose in the course of the hearing with respect to NSPI's Supplemental Executive Retirement Plan (SERP). This plan is available to employees who earn more than approximately \$150,000 per year.

[72] Such plans are not unusual; indeed the Province of Nova Scotia provides a SERP plan for certain of its employees who earn above the pensionable payout limits permitted by the Canada Revenue Agency.

[73] The first issue is that NSPI secures this pension by purchasing a letter of credit. The letter of credit is, in part, to secure the pension plan in the event NSPI was to discontinue operations and therefore be unable to fund this obligation.

[74] The other issue is that the eligible employees of NSPI do not make any contribution towards these additional benefits. In other words, the Company, using funds paid by ratepayers, is funding 100% of this pension plan.

[75] Contrast that with the Province of Nova Scotia where employees eligible for the Province's SERP fund 50% of the contributions to the SERP with the employer paying the other 50%.

[76] With respect to the letter of credit, it appears to the Board that the letter of credit places the senior executives at NSPI in a more secure position than any other employee in the Company with respect to their pension entitlement. The NSPI employee pension plan is not secured by a letter of credit. NSPI is a regulated monopoly in the Province of Nova Scotia. The chance of NSPI going out of business is extremely remote.

[77] In the Board's view, payment for that portion of the letter of credit that secures the SERP is an unnecessary expense and is not an expense that should be borne by ratepayers. Accordingly, the Board disallows that amount from the revenue requirement.

[78] With respect to the SERP, the Board considers it unreasonable that the most highly paid employees working for NSPI make no contribution to the supplemental pension plan.

[79] NSPI is free to continue to provide that benefit. However, the Board directs that in the test years and in future NSPI must adjust the revenue requirement to deduct an amount from the SERP pension payments to reflect a deemed employee contribution to the SERP, on the assumption that the employee had contributed 50% to the pension plan and the employer 50%. In the test years, the Board, based on projected benefit payments identified in Exhibit N-3(v), believes the amount to be disallowed is \$2.05 million in 2013 and \$2.2 million in 2014.

[80] NSPI can discuss with Board Counsel the most tax efficient way of implementing this direction from the Board.

[81] These deductions and the letter of credit deduction are in addition to the \$27.5 million provided for in the GRA Agreement.

6.0 EXECUTIVE COMPENSATION

[82] The Legislature has passed amendments to the *Public Utilities Act* limiting the amount of remuneration, bonuses and other benefits that can be recovered from rates with respect to compensation of executive employees of NSPI.

[83] By regulation, the remuneration amounts are governed by amounts contained in the Province of Nova Scotia's Senior Officials Pay Plan.

[84] The Board assumes that pension payments on behalf of executives would reflect only amounts of salary permitted by the *Act*.

[85] In its Compliance Filing, NSPI is to reduce its revenue requirement to reflect the changes as a consequence of this legislation. This reduction is in addition to the \$27.5 million agreed to as part of the GRA Agreement.

7.0 LED STREETLIGHTING

7.1 Evidence

[86] The *Energy-efficient Appliance Regulations* were amended by the Province on September 10, 2012, requiring all NSPI owned streetlights to be of the LED type after December 31, 2019. NSPI proposed to implement this change over a number of years as a part of its Annual Capital Expenditure plan. The cost of this changeover is the responsibility of the municipalities based on the number of streetlights in each jurisdiction. The Union of Nova Scotia Municipalities (“UNSM”), which represents all municipalities in the Province, is objecting to the cost which NSPI plans to pass on to the municipalities.

[87] NSPI proposes to defer a decision on the LED streetlight stranded cost to a later date, stating it plans to file a capital work order with the Board:

...As explained in Appendix I of this Evidence, NS Power proposes to treat the non depreciated net book value of these streetlight fixtures as a stranded cost that constitutes a regulatory asset. We propose to defer the amortization of this asset until the Board approves the recovery of this cost through the implementation of appropriate LED streetlight conversion charges. This will happen in concert with the Capital Work Order Application for the LED streetlight conversion program. We propose to recover the capital carrying costs associated with this regulatory asset from the full service LED streetlight customers.

[Exhibit N-2, p. 130]

[88] In Appendix I of its Application, NSPI provided a *Cost of Service and Pricing Study for Unmetered Services* which included streetlights and other services such as traffic lights, ornamental streetlights, crosswalk lights, etc. The report provided

details of NSPI's proposed rate making methodology and calculations of streetlight rates.

[89] The UNSM, in its Pre-filed Evidence, noted that municipalities are struggling to provide normal services and an additional \$100 million for LED streetlights conversion is a significant burden. The UNSM has concerns with the cost of stranded assets and time allowed for conversion of these streetlights. The UNSM's understanding is that as a part of the 2012 GRA Settlement Agreement, the net book value of stranded streetlights is \$12 million and is supposed to decline over time as only LED streetlights are installed/replaced after 2011. The UNSM also noted inconsistencies when NSPI deals with the municipalities in billing and stranded asset fees for streetlights.

[90] HRM, in its Pre-filed Evidence, noted its concerns with NSPI overcharging municipalities. HRM noted its concern with respect to the total charge for streetlights. It stated that NSPI's maintenance and capital charges do not align with the actual cost for these services. HRM also disagreed with NSPI that the energy component is being subsidized by the other components of the total streetlight charge.

[91] HRM further noted that NSPI's evidence over time has been inconsistent and difficult to follow:

On the rate setting front, the LED street light conversion has exposed some of the long standing issues with respect to the lack of accounting detail in the unmetered Cost of Service. It appears NSPI has made it extremely complex to use cost of service accounting principles for a simple street light because it has not tracked the age or quantity of lights properly. The process has become very onerous, non-transparent and inefficient. Clearly NSPI has had significant challenges in determining unmetered rates over a protracted period.

[Exhibit N-54, p. 7]

[92] HRM agreed with UNSM that the issues in dispute are the stranded cost and phase-in time for LED streetlights conversion. HRM noted that its understanding of the 2012 GRA settlement is different from NSPI's understanding.

[93] Albert Dominie, a consultant for HRM, noted problems with the current pool of assets in the streetlights category. This includes types, quantity and how the stranded costs are allocated between streetlights and other assets in the pool.

[94] Mr. Dominie questioned the use of the Bank of Canada Inflation Calculator to determine the net book value of retired streetlights. He recommended the use of the Handy-Whitman Index of Public Utility Construction Costs which is also used by the Federal Energy Regulatory Commission. He explained that the Bank of Canada Inflation Calculator provides a higher actual installed cost than the Handy-Whitman Index.

[95] Mr. Dominie does not agree with NSPI's method to calculate the stranded cost of current streetlights. He proposed a true up and reconciliation process during the LED streetlights conversion by carrying out a physical survey of each streetlight to determine actual life based on the date stamp.

[96] NSPI, in its Reply Evidence, noted that the net book value of streetlights has been approved by the Board in past applications, including the depreciation hearings and it is entitled to recover these costs from its customers. It disagrees with the use of the Handy-Whitman index method and field survey proposal by Mr. Dominie.

[97] NSPI outlined the process it has followed to calculate the stranded cost of streetlights:

NS Power's approach with regards to calculating a stranded asset pool is simple and has not changed. That is, the net book value of the assets is the unrecovered investment. To determine per unit value, NS Power has proposed dividing the asset pool by the number

of lights billed in the Customer Information System. NS Power has repeatedly stated through the 2013 & 2014 GRA application that the rates should be set with the capital work order process consistent with the 2012 Settlement Agreement. In an effort to be helpful, NS Power has provided information over the last couple of years. In fact, draft regulations were only issued April 25th, 2012.

[NSPI Reply Evidence, Exhibit N-106, pp. 96-97]

[98] The Board and HRM during the hearing requested clarification on the type of streetlights being replaced after the 2012 GRA Settlement Agreement approved by the Board in the 2012 GRA. That Settlement Agreement required NSPI to install only LED streetlights when replacing the old streetlights. NSPI responded:

...So we've been continuing on using materials that were already in inventory, not buying -- not in any way, shouldn't be characterized as spending more than we should have. We're just fixing the lights that people call in and say are broken.

[Transcript, September 19, 2012, p. 547]

7.2 Findings

[99] The Board has considered the evidence filed and issues raised by the UNSM, HRM and NSPI. NSPI proposed that the matter of LED streetlights be deferred to a later date when it intends to file a capital work order with the Board. HRM does not have a problem with this approach except the amount of net book value of current streetlights which NSPI plans to use in its work order.

[100] NSPI proposed to use the current net book value of streetlights (estimated at \$23 million) based on methods and records it has used in the past including depreciation hearings. However, HRM argued that the net book value NSPI proposes to use is not correct and should be \$12 million as noted in the 2012 GRA Settlement Agreement. HRM further stated that this amount is to be confirmed by actual survey of all current streetlights, which will also determine the number and age of streetlights.

HRM also raised the issue of non-streetlight assets being in the streetlight class and whether some of the current net book value belongs to these other assets.

[101] The Board agrees that dealing with the streetlight issue as a part of a capital work order is a reasonable approach, with the exception of the net book value question. The net book value of streetlights has been calculated under the current method for a long time and any change in the net book value now would be unfair to other ratepayers. The current method has been approved in prior depreciation Decisions of the Board. The net book value amount is the responsibility of the streetlight class and any reduction in this amount would shift the responsibility to other customer classes. The Board does not agree with HRM's proposal to change the net book value of streetlights currently included in the NSPI rate base. How this amount is shared between municipalities is something NSPI should work out with them.

[102] The Board denies HRM's request to recalculate the net book value of streetlights.

[103] The second issue raised by HRM is the type of replacement streetlights used by NSPI since the Board's 2012 GRA Decision [2011 NSUARB 184]. It is the Board's understanding of the 2012 Settlement Agreement that NSPI was to use only LED streetlights when replacing the current streetlights. NSPI has stated that it has only used non-LED streetlights which were in its inventory.

[104] In the circumstances, if the non-LED streetlights were already in inventory, the Board finds this to be an acceptable approach. However, NSPI should have clarified the use of inventory with Intervenors during the 2012 GRA settlement discussions.

[105] The Board is not certain, based on the evidence, if NSPI has purchased new non-LED streetlights after the 2012 GRA Board Decision.

[106] The Board orders NSPI to confirm by February 28, 2013 that no new non-LED streetlights were ordered or purchased after the Board's 2012 GRA Decision.

8.0 LOW INCOME RESIDENTIAL CUSTOMERS

8.1 Submissions

[107] At the request of the CA item 15 was added to the Final Issues List, "Matters Related to Low Income Residential Ratepayers".

[108] The Affordable Energy Coalition, the CA and NSPI tabled a Settlement Agreement which the CA described as an agreement which addresses many long-standing issues faced by low income customers. Essentially the Agreement sets up a consultative process "with a view to resolving bill payment, credit and collection matters affecting low income residential customers". The text of the Agreement is as follows:

The following provisions are requested to be included in final Order of the NSUARB in GRA 2013 NSUARB-NSPI-P-893 - Matter M-04972 with the consent of NSPI, the Consumer Advocate, and the Affordable Energy Coalition.

Residential Low Income Issues

1. NSPI, the Affordable Energy Coalition and the Consumer Advocate, shall seek an adjournment of the hearing on the matters identified in paragraph 4 of this joint proposal in this proceeding, in order to engage in a consultative process with a view to resolving bill payment, credit and collections matters affecting low income residential consumers, and the parties reserve the right to contest any of the evidence filed with the NSUARB in this proceeding, as may be appropriate, at a future hearing.
2. The consultative process shall be non-binding and without prejudice to either side to request the matters be brought back before the NSUARB to resolve any issue in relation to Board regulations or other matters and the parties agree to the appointment of a facilitator by the NSUARB on an as-needed basis.
3. The consultative process may solicit input from other social service agencies, non-governmental organizations involved in low income energy issues, as well as other resources and supports, as agreed to by the parties.
4. The items to be discussed by the parties are:
 - a. Development of a Low-income Customer Charter;
 - b. Changes to NSPI policy regarding deposits and payment agreements;

- c. Development of joint recommendations, where appropriate, with respect to regulatory reforms, including with regard to deposits, payment agreements, interest charges and other miscellaneous charges, disconnection procedures, and requirements for the residential budget plan as they affect low income residential consumers;
 - d. Any other matters as agreed to by the parties.
5. The parties shall meet on a regular basis, at a minimum once every two months. The parties shall agree on a timetable, which shall reflect the following:
- a. The first meeting shall take place not later than November 1, 2012;
 - b. The parties shall report back regarding the status of the consultation, with any agreements reached by the parties, and to the extent that agreement is not reached, request a further appearance and hearing before the NSUARB not later than June 30, 2013, and the evidence filed on behalf of the AEC in this proceeding shall form part of the evidence at that hearing;
 - c. NSPI shall provide a proposal regarding items (b) and (c) to the Affordable Energy Coalition and the Consumer Advocate one week in advance of the first meeting;
 - d. NSPI shall provide the results of its research with respect to regulatory differences in other jurisdictions to the Affordable Energy Coalition and the Consumer Advocate not later than December 1, 2012.

[Exhibit N-116]

[109] The Board approves the Agreement which will be appended as a Schedule to the Compliance Order and acknowledges, with appreciation, the work of the Affordable Energy Coalition, NSPI and the CA in moving this initiative forward.

[110] The Board receives literally hundreds of letters and emails a year from consumers who are struggling to pay their power bills and at the same time manage the cost of home heating, medication, groceries, etc. There is only so much the regulatory system can do to respond to these concerns but this Settlement Agreement is a welcome development.

9.0 COST OF SERVICE – BIOMASS

[111] NSPI has recently constructed a 60 MW biomass plant at Point Tupper, Nova Scotia. For purposes of rate base NSPI has determined the biomass plant is being added for environmental purposes only and should be classified totally as energy.

With respect to OM&G costs, however, the classification is the same as for all other steam plants, a portion of which is classified to demand, and a portion that is classified as energy.

[112] Mel Whalen, a witness on behalf of Board Counsel, recommended that until a more complete assessment is done as part of the upcoming cost of service review, NSPI should classify the biomass plant on the basis of system load factor, the same as other thermal plants, for the following reasons:

- a) Biomass is a steam plant.
- b) Biomass makes a contribution to capacity.
- c) The biomass plant was justified in part on the grounds that it would provide firm, dispatchable power and alleviate some of the concerns with respect to adding only non-dispatchable renewable resources.
- d) Classifying the biomass as other steam plants are classified is consistent with NSPI's classification of the biomass OM&G as all other steam OM&G is classified.

[Exhibit N-42, p. 10]

[113] NSPI, in its Reply Evidence, says that even though the biomass generation is firm and is dispatchable, it considers the capacity related aspects of this plant to be of secondary importance to that of RES compliance. NSPI says classifying the asset on the basis of system load factor would mean there would be no distinction between this project and ordinary fossil fuel baseload generation.

[114] The Board notes that recent *Regulations* passed by the Province of Nova Scotia require that this plant, as opposed to being dispatchable, is essentially must-run.

[115] The Board agrees with Mr. Whalen that the characteristics of this plant are similar to any other steam plant. It makes a contribution to capacity and provides firm power, meaning that it should be classified on the basis of system load factor and

directs NSPI to do so. This issue may be reviewed in the upcoming cost of service proceeding.

10.0 NATURAL GAS STORAGE

10.1 Evidence

[116] Alton, in its Pre-filed Evidence, stated that the New England and Maritime market currently does not have a natural gas storage facility which can provide security of supply and manage the price of natural gas used by NSPI. The natural gas prices in this region have been volatile and NSPI can benefit from the use of a storage facility given the amount of natural gas used, which Alton estimates to be \$110 million annually.

[117] Alton retained Gregory W. Hopper of Black & Veatch who, in his Pre-filed Evidence, provided analysis of the Maritime and New England natural gas market and price behavior. He noted that the lack of a natural gas supply in the region could make natural gas prices rise even higher and also increase volatility.

[118] Alton also retained Jan van Egteren of Anthem Economic Consulting Inc. who, in his Pre-filed Evidence, outlined various hedges used by NSPI to reduce gas price volatility. The hedges currently used by NSPI are financial, physical and geographic hedges. He then calculated the savings NSPI could achieve by using the natural gas storage facility by buying when the prices are low and using when prices are high. He noted that there is a possibility of additional savings in case of a “basis blowout” similar to what happened in December 2010.

[119] Alton proposes to construct a natural gas storage facility off the Halifax lateral to supply gas to Tufts Cove generating station. The proposed storage facility is

being designed to store a minimum of 4 BCF of natural gas at a maximum pressure of 2,028 pounds per square inch gauge (“psig”) and a minimum operating pressure of 418 psig. The storage facility can also be used in the integration of intermittent renewable energy generation such as wind energy.

[120] NSPI, in its Reply Evidence, argued that this proceeding is not the place to discuss this issue which, in future, could be the subject of negotiations between Alton and NSPI. NSPI questioned the commissioning of the storage facility, which has an expected in-service date of April 1, 2015.

[121] NSPI disagreed with the benefits noted by Alton because in its opinion Alton has not considered certain items in its calculations to determine the cost savings.

[122] In response to Alton counsel’s question on the use of natural gas storage facility, NSPI explained:

MR. SIDEBOTTOM: I think storage can play an important part in the portfolio. The question to be asked is when is it the right time to enter into an agreement to secure storage? To date, it hasn’t been the right choice for us and our customers. There could be a point in the future when it is the right time to secure some storage. So it’s very much dependent on what’s going on at a point in time.

If gas sources were not as reliable there is an advantage to natural gas storage. Whether it completely justifies itself today or from some future date really is dependent on what your market circumstances are.

[Transcript, September 18, 2012, p. 164]

[123] NSPI further stated that:

MR. SIDEBOTTOM: To be partners with a potential supplier of that and have them be intimately knowledgeable of the value proposition to customers puts me or us in a compromised position in negotiating effectively the best overall cost to customers.

I believe we will be looking at natural gas storage and studying that in the coming year when we have more information on wind integration. But Nova Scotia Power is happy to do that at its own cost. And we would see that it is difficult to be in a co-authored study with a potential recipient of the contract at the end of the day.

[Transcript, September 18, 2012, p. 183]

...

All we're trying to say here is that we think it's appropriate to study the viability of natural gas storage. We think it's appropriate for it to be done on an impartial basis, not including the people who potentially propose to provide the storage.

[Transcript, September 18, 2012, p. 193]

[124] In its Closing Submission, NSPI objected to Alton's request to order that NSPI be part of the study because this issue is not on the Board's Final Issues List for this hearing. NSPI stated that, if approved, other parties doing business with NSPI may view the GRA as a forum to advance their interest.

10.2 Findings

[125] Alton requested the Board order NSPI to participate in a natural gas storage study being carried out by Alton and Heritage Gas. NSPI objected to this request as this item is not on the Board's Final Issues List and also may interfere in its ability to minimize fuel cost and achieve a cost effective alternative for fuel purchases.

[126] Alton argued that NSPI's fuel cost can be reduced by the use of a gas storage facility.

[127] The Board understands that the use of gas storage is a type of hedge against higher gas prices in the future. Similar to other hedges, for the gas storage to be cost effective, there are many factors and assumptions one has to make so that the cost of the hedge is beneficial to ratepayers. These include the amount of gas, price of other fuels, and the cost of storage, to note a few.

[128] NSPI purchases fuel in conformance with its Fuel Manual developed over time with input from its stakeholders. The purpose of the Fuel Manual is to reduce cost and to secure a reliable fuel supply. NSPI actions in the purchase and management of fuel are audited every two years for prudence. Directing NSPI to purchase a certain

type of fuel or follow certain procurement procedures in advance of the audit may compromise the Board's ability to make a fair judgment on the audit findings.

[129] During the hearing NSPI agreed that gas storage does have benefits, but disagreed with Alton that now is the time to enter into a long-term gas storage commitment. NSPI intends to do its own study later in 2013 after the IRP update planned for 2013. NSPI's customer load has changed substantially due to the reduction in electricity demand caused by reduction in two paper mills' production volumes in the Province. The matter is further complicated by the *Renewable Electricity Regulations* requirements. The proposed IRP update is expected to provide directions on the amount and type of generation required to keep customer cost to a minimum and also meet renewable energy targets.

[130] The Board's intention is not to micromanage NSPI. Its management needs flexibility in its operations if it is to be judged on the prudence of its actions.

[131] The Board denies Alton's request to order NSPI's participation in a natural gas study with Alton and Heritage Gas.

11.0 FAM AUDIT

11.1 Introduction

[132] It should be noted that much of the evidence regarding the FAM Audit was filed in confidence and discussed during confidential sessions of the hearing. Accordingly, the Board is only in a position to provide an overview of the evidence and a summary of its findings.

[133] The FAM has generally been described as a mechanism that allows periodic adjustments to customer rates, outside general rate proceedings, to reflect

increases and decreases in the Utility's cost of fuel, provided they are prudently incurred.

[134] In its Rate Decision dated February 5, 2007, the Board identified at least four prerequisites prior to the implementation of a FAM:

[45] For the guidance of the parties, however, and without in any way prejudging the issue, in the Board's view there are several prerequisites that must be in place in order for the Board to consider the adoption of a FAM now or in the future:

1. an adequate and appropriate fuel procurement policy at NSPI in which the Board has confidence;
2. timely disclosure of complete and adequate information by NSPI so as to ensure confidence that the procurement policy is being appropriately administered;
3. disclosure and transparency with respect to the administration of the FAM;
4. a meaningful audit process under the administration of the Board.

[46] This list is not meant to be exhaustive.

[Decision, 2007 NSUARB 8, paras. 45-46]

[135] In its GRA Decision dated November 5, 2008 the Board approved the FAM to take effect on January 1, 2009, conditional on the final approval of the Tariff and POA. A revised Tariff and POA were received on November 26, 2008 and approved by the Board in a letter dated December 11, 2008.

[136] Section 5 of the POA addresses the audit requirements and excerpts are included below:

5.0 AUDIT AND OVERSIGHT

The amounts charged through the FAM shall be subject to periodic audit to assure completeness and accuracy and to assure fuel and purchased power costs were incurred reasonably and prudently. The results of any audit shall form part of the issues for consideration by the Board in a subsequent FAM proceeding to consider the re-setting of the Base Cost of Fuel, or setting of the Fuel Adjustment Factor, or a General Rate Case at the request of NSPI or any interested stakeholder or upon Board order. Following consideration of the audit in any such hearing, the Board may make such adjustments (with interest if

appropriate) to existing balances or to already recovered amounts as it may find necessary.

Audit Process

The Board shall provide for the conduct of a Fuel Adjustment Mechanism (FAM) audit every second year. The Board shall have a qualified independent firm conduct the audit. The audit will address the financial and management/performance aspects of NSPI's fuel procurement and recovery under the FAM. The audit will include the FAM Formula, actual fuel and purchased power costs, contracts and management performance that affect the audit period from January 1, 20XX to December 31, 20XX+1. The first audit period will be for the year 2009. Subsequent audits will cover two-year periods.

Objectives and Scope of the Audit

The overall objective of the FAM audit will be to examine operational and managerial aspects of the fuel and energy procurement, management, and production functions and activities of NSPI, including any fuel or energy related affiliate transactions that involve these functions and activities directly or indirectly. The review will address adherence to good utility practice and consistency with the policies and procedures governing NSPI's procurement as described in the NSPI Fuel Manual.

The Scope of the Audit will include a review of fuel and energy procurement, fuel management, and generation production ...

...

Prior to setting the final audit scope, the auditor shall meet with NSPI and interested stakeholders.

Timing of the Audit

The first audit will commence on February 1, 2010, and subsequent audits are expected to commence in February of every second year. The final report for the first audit will be filed with the Board and Stakeholders by July 2, 2010. Final reports for subsequent audits will be filed by July 2 of every second year. The final report will evolve from a draft report which is provided to NSPI and the Board within 30 days of the filing of the final report. The draft report should contain functional area task reports, a management summary, and include findings of operating effectiveness and efficiency, as well as any recommendations for adjustments in costs or changes in functions and activities.

[FAM POA, August 13, 2010, pp. 13-15]

[137] It should be noted that the original POA anticipated that the first audit would cover 2009 and 2010 and that the draft report would be provided to NSPI and the Board "forty-five days before the final report is filed". During 2010, following stakeholder engagement, NSPI requested Board approval of certain changes to section 5 of the

POA. Specifically, those changes included recognition that the first audit covered only 2009 and also a revision to the audit timing to state that the draft report will be provided to NSPI and the Board “within 30 days of the filing of the final report”. Those changes were approved in the Board’s letter dated October 12, 2010.

[138] As noted above, the first FAM Audit was conducted in 2010 and covered the 2009 calendar year. The Liberty Audit Report, which was filed with the Board on July 2, 2010, presented Liberty’s findings, conclusions, and recommendations in eleven chapters, each of which comprised a principal area of examination and review. A total of thirty-one recommendations were included in Liberty’s Audit Report.

[139] The 2010 Audit Report was included as an exhibit in the proceeding to set the Base Cost of Fuel (“BCF”) for 2011. On page 12 of its evidence filing in the 2011 BCF proceeding, NSPI stated:

The Company generally agrees with most of the recommendations of the Report. There are recommendations that require additional context or currently have alternative solutions that the Company has carried out or is in the process of implementing. NSPI suggests that the FAM can continue to provide an effective forum for dialogue about the conclusions and recommendations of the Audit Report.

[Decision, 2010 NSUARB 219, p.12]

[140] NSPI’s response to that Audit report was contained in Appendix C of its evidence Exhibit N-10 which outlined agreement and/or comments regarding each of the recommendations.

[141] As directed by the Board, NSPI filed its FAM Audit Recommendation Action Plan on December 9, 2010. Following subsequent discussions between NSPI and Liberty, a report dated June 9, 2011 was filed by Liberty which noted that NSPI had established acceptable action plans for 25 of the 31 recommendations. Some of the

outstanding issues were resolved, but others remained and were carried over to the 2012 FAM Audit.

[142] It bears repeating that in approving the FAM in 2007, the Board highlighted the importance of transparency and timely disclosure in its approval of the FAM:

[59] NSPI now indicates it is committed to transparency and timely disclosure.

[60] The Board wishes to make it clear to NSPI that if full and timely disclosure of complete and adequate information to assess its fuel procurement practices continues to be a problem, the implementation of a FAM will not occur...

[Decision, 2007 NSUARB 174]

11.2 Prudency Test

[143] In 2005 NSUARB 27 (NSPI - P-881), the Board adopted the definition of prudence as set out in a decision of the Illinois Commerce Commission as a reasonable test to be applied in Nova Scotia.

[144] That test was set out at paragraph 84 of the Board's Decision:

The standard for determining prudency of a utility's fuel procurement practices is well established. As stated by the Illinois Commerce Commission, "prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made....Hindsight is not applied in assessing prudence....A utility's decision is prudent if it was within the range of decisions reasonable persons might have made. ... The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.

[Decision, 2005 NSUARB 27, para. 84]

[145] The Board went on to say:

[89] While the Board recognizes that the definition of imprudence varies somewhat among the jurisdictions cited, there are several fundamental principles which are common. These include:

- Were the utility's decisions reasonable in the context of information which was known (or should have been known) at the time?
- Did the utility act in a reasonable manner and use a reasonable standard of care in its decision-making process?

- The imprudency test should relate to the circumstances at the time in question and not to hindsight.

[Decision, 2005 NSUARB 27, para. 89]

[146] NSPI, in its Closing Submission in the present matter, confirmed that from its perspective this is the test the Board should apply.

11.3 Lingan Derates

11.3.1 Evidence

[147] Liberty recommended a disallowance with respect to derates which occurred at the Lingan generating plant in December 2010. Derates occur when an operator must reduce, for one or more of a variety of reasons, the anticipated level of plant output.

[148] In its FAM Reply Evidence, Liberty described the risks known to NSPI in July and August 2010, when it re-introduced the local Prince coal, after the Province relaxed the mercury limits:

The specific quality aspects of concern for the reintroduced local supply were ash, sulphur, and Btu content. Resuming its use in the Lingan fuel blend caused July and August results that failed to meet NS Power's own recognized guideline for identifying opacity risks. The operative metric was maintaining or exceeding a 1,000 parts per million concentration of SO₂ in unit stacks. Following the reintroduction of local supply, those concentrations fell well below the minimum guideline, ...

Moreover, variability in the quality of reintroduced local supply and problems in its conformity to contract specifications were known issues. The coal's Btu content fell below minimum specification in January, July, and August 2010. Ash content was at the upper limit of specification in January, was well above the limit in July, and remained at the upper limit in August. ... Experience in January 2010 (after which NS Power discontinued use), and July 2010 (when NS Power resumed use) demonstrated, particularly in light of concern about stack SO₂ levels, that what was impossible to predict was that the coal blend, including reintroduced local supply, would sustain the ability to meet opacity limits without curtailing generation...

[Liberty FAM Reply Evidence, Exhibit N-170, PDF pp. 110-111]

[149] In Liberty's opinion, NSPI was imprudent in that it did not appropriately address coal quality issues in July/August 2010 when there were signs that there were substantial risks of failure to meet opacity limits.

[150] While Liberty was mindful that NSPI was running the plant aggressively close to the limits, it stated that NSPI should have planned its coal burns to avoid the potential for problems, especially when Prince coal exhibited quality issues in July/August 2010.

[151] It bears repeating that some of the relevant evidence related to the Langan derates in the FAM Audit was filed in confidence and discussed during confidential sessions of the hearing. Therefore, the Board is only in a position to provide an overview of the evidence and a summary of its findings.

[152] Some background on the importance of coal blends will be helpful to the reader.

[153] The Langan generating facility was designed to operate at optimum efficiency while burning coal having specific characteristics. The primary fuel that the plant was originally designed to use was high sulphur coal that was available from the local mines in Cape Breton. Over the years, availability of that coal decreased while, at the same time, federal and provincial environmental regulations mandated reduced emission levels from generating stations burning fossil fuels.

[154] NSPI has regularly blended high sulphur domestic coal with low sulphur imported coal in order to optimize compliance with overall utility sulphur emission restrictions. It has also used mid-sulphur imported coal in its blend.

[155] In order to satisfy opacity limits and reduce emission levels, electrostatic precipitators are used at Langan along with varying combinations of coal blends. Coals with various levels of sulphur, ash, moisture, and Btu are included in the blends. Changing the type of coal being burned can also change the efficiency of the plant. For example, burning coal that has a higher Btu content essentially means that higher levels of energy output can be obtained, while burning less fuel and producing lower overall emissions. However, this must be balanced against the design parameters of the generating facility and the effects of other fuels and chemicals in the fuel mix.

[156] Typically, the higher quality coals, in terms of lower sulphur, ash, moisture and higher Btu, are more expensive. Thus, coal blends must be carefully planned in order to maximize output at the lowest possible cost, while not exceeding emission limits.

[157] Further, government regulations which mandated a reduction in the mercury levels being emitted from the stacks required additional equipment and operational changes. This included altering fuel blends to reduce the mercury content and installing mercury abatement equipment along with chemical additives, such as powder activated carbon, to capture the mercury in the stack emissions. This abatement equipment and the powder activated carbon were designed to perform well with lower sulphur levels, but its use with higher sulphur coal can result in reduced performance.

[158] As of July 2010, the Province relaxed the targeted levels for mercury emission. This change identified graduated levels of mercury reduction, which also extended the compliance timeframe for achieving the revised emission target. As a

result of this, NSPI was able to use larger quantities of high sulphur, high mercury, domestic coal from the local Prince mine. Prince coal was available at a lower cost than imported coal. One of the benefits of burning this higher sulphur coal is that it improved precipitator performance so that derates due to exceeding stack opacity limits were less likely to occur.

[159] Along with managing the levels of sulphur dioxide and mercury emissions, NSPI needs to manage nitrogen oxide emissions, greenhouse gas emissions, and to ensure that the opacity of the stack emissions does not exceed the acceptable level specified in the operating permit. Clearly, a process of balancing fuel blends and chemical additives is needed in order to satisfy emission restrictions, while still maintaining efficient plant operation, maximizing energy output levels, and minimizing costs.

[160] In its Audit Report regarding derates at Lingan, Liberty stated:

NSPI experienced the derates because the station precipitators were operating at the margin of performance, and could not tolerate any changes in coal quality, coal flow rates, or additional moisture in the coal. When above normal amounts of rain were experienced in December 2010, the station had no choice but to derate in order to comply with stack opacity limits. If NSPI had taken action to make the appropriate alternative coals [i.e., blends], there would have been the necessary margin in stack performance to have continued operation at normal power levels without derating. ...

[Liberty FAM Audit Report, Exhibit N-171, p. IV-28]

[161] In response, NSPI stated that the derates were caused by an uncharacteristically high amount of rainfall in December 2010. In its view, the 1 in 30 year rainfall event increased the moisture level in the coal (which is typically stored outdoors), which, in turn, reduced the MW output of the plant because it reduced the mill grinding efficiency, reduced the mill temperatures and resulted in feeder pluggages.

[162] NSPI also noted that the quality of the local Prince coal deteriorated in the relevant time period, further exacerbating the situation. However, Liberty states this is the risk when using poorer quality coal in that it can be unpredictable.

[163] In its Reply Evidence, NSPI summarized its view of the causes of the derations:

1. Many factors - moisture, initial sizing, wear, inlet temperatures - affect the performance of coal mills. In December, 2010, the Lingan Generating Station experienced a 1-in-30 year rainfall event. When coal contains unusual moisture levels, it reduces the temperature inside the coal mill, so the coal does not dry properly. Grinding efficiency and combustion are compromised, lowering generation. Coal with increased moisture levels has a greater tendency to build up on surfaces until the coal feeders that regulate the amount of coal going into the mills begin to plug up. When a feeder plugs, the flow of fuel to the boiler slows and the units are derated.
2. In December, the ash, moisture, and sulphur content of Prince coal all increased. The increased moisture resulting from the rainfall event, together with the increased ash content, reduced the effectiveness of the precipitators and led to derations. NS Power could not reasonably be expected to mitigate the effects of a 1-in-30 year event, especially one that coincided with high ash content in the coal received from a low cost supplier. When the impact of the record rainfall event began to subside, the Lingan units returned to full load capability.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 27]

[164] While Liberty stated in the FAM Audit that its review of the documentation “disclosed no expression of concern about opacity issues at the Lingan station” leading to the December 2010 derates, NSPI replied that it had identified the moisture issue and the precipitator performance, and its action to address the issue, in its April 2011 presentation of November - December Plant Performance.

[165] NSPI engaged Dr. Stan Harding to assist in its response to Liberty’s claim of imprudence respecting the Lingan derates. He is a consultant with experience in coal generation facilities.

[166] Dr. Harding's conclusions included:

...

- The unusually high precipitation in December 2010 combined with the high moisture levels in the coal, resulted in significant boiler derates and mill pluggages during this time period.
- The load reductions noted in December 2010/January 2011 were primarily due to coal quality and high moisture-related pulverizer pluggages rather than opacity.
- The high precipitation in December 2010 would have resulted in an increase in mill pluggages and boiler derates even if a design coal was being used. ...

[Harding Report, Exhibit N-77, p. 14]

[167] NSPI also called Emily Medine as a witness on this issue. She is a consultant who regularly assists NSPI in its solid fuel management issues. In her view, Liberty ignored the impact of a 1 in 30 year rainfall event in December 2010, which she stated was the primary reason for the derates. She added that Liberty ignored NSPI's strategies for addressing all potential derates due to provincial limits on SO₂ emissions. She also noted that NSPI immediately dealt with the derates after 2010.

11.3.2 Findings

[168] The Board considers NSPI's evidence on the Lingan derating issue to be tenuous and unreliable in several respects.

[169] First, the Board has several concerns about the evidence of Dr. Harding.

[170] In Information Requests IR-6(d) and 7, Dr. Harding was asked to provide a description of the design and operational features at Lingan, including the spare mill capacity on each unit, which was designed to avoid unit operational consequences due to mill plugs. He was also asked to provide the number of pulverizers assigned to each of the four Lingan units and to provide information about the derates specifically caused by pulverizer pluggages, including the generating unit involved. He responded by stating that he had not received this information from NSPI. He stated that the issue of

spare mill capacity was outside his scope of work, although he acknowledged it was relevant to the derate issue.

[171] Based on Liberty's investigation, it confirmed that "Lingan's use of four mills per unit allows for each unit to remain at full load with one of its mills down" [Liberty FAM Reply Evidence, Exhibit N-170, PDF p. 115].

[172] Surprisingly, in questioning by Board Counsel, NSPI Fuel Panel member John Hawkins acknowledged that Dr. Harding had asked him for information about spare mill capacity, but NSPI did not provide him with that information.

[173] As a result, on an issue as important to derates as spare mill capacity, which Dr. Harding conceded was a relevant consideration, he was not provided with the information, even when he inquired about it.

[174] Another aspect of Dr. Harding's testimony which concerns the Board is that he did not test the data for seasonality. In response to questions from the Board, he testified:

MR. DHILLON: Now, did you consider expanding the database to consider the seasonality factor in the -- in your issues that maybe because a different season of the year might affect your results?

MR. HARDING: That's a good question.

No, I did not. The reasoning was the -- when I was contacted and asked to evaluate the data, the event was in December and so I had just asked for information a few months prior to that.

And when I got the rainfall information, which is shown in my report also for November/December for the previous -- I think -- five years, I didn't -- I didn't go back any farther, for example, in 2009 or '08, anything like that, no.

MR. DHILLON: So I guess did you go back five years in December each year?

MR. HARDING: Just with -- just with -- no. Just with the rainfall data to show that it was indeed, a different -- something out of the ordinary occurred in December 2010 in terms of rainfall.

...

MR. DHILLON: But if you had considered wider data and there was derating beyond July to February the following year, would that have given any indication that there are reasons in the past this issue may have arisen and that there's reason to have some kind of a study done or something?

MR. HARDING: Okay. That's a good point. I think had I noticed -- or had there been some information in this July-August-September time period that showed me that they were -- again, the -- we were focusing on de-rates due to opacity. So had there been some significant opacity de-rates -- de-rates due to opacity -- excuse me -- I would have asked for additional data.

But since -- again, as I mentioned, perhaps not the greatest consultant, I should have asked for another study, but I didn't. Once I asked for the information I had, I -- it became quite obvious to me that there was an event, something happened in December of 2010 that was different than the previous five months that I had looked at. ...

[Transcript B, November 1, 2012, pp. 1304-1306]

[175] Further, despite Dr. Harding's theory that the derates were attributable to the December 2010 rainfall, the NSPI data requested by Liberty confirmed that the moisture level of the coal in July/August 2010, or after January 2011 (when the plant was not derating), was equal to or higher than moisture levels during the December 2010 deratings:

...The response to IR-8 shows moisture data from July 2010 through June 2011. The response to this IR-8 (see attachment II-2) shows several periods in July and August 2010 and in June 2011 with moisture levels at or exceeding the December 2010 [values](when a 30-year rain was experienced)...

Thus, Lingan operated both: (a) in July and August 2010, without derating, despite equal or higher moisture levels than under the coal blend being used through the December deratings, and (b) after January 2011, without derating, despite equal or higher moisture levels than under the revised coal blend.

[Liberty FAM Reply Evidence, Exhibit N-170, PDF p. 113]

[176] Accordingly, in the Board's view, Dr. Harding's opinion that moisture and mill pluggages caused the derates is not supported by the evidence.

[177] In the end, Dr. Harding's engagement seemed to have been simply to correlate the rainfall to the derates. However, he did not conduct a root cause analysis; he did not fully investigate the pluggages (including spare mill capacity); he did not

consider seasonality; and did not evaluate ash. Despite his undoubted expertise in this field, NSPI did not provide him with the information or the necessary latitude in his scope of work to conduct an independent evaluation of the Langan derates. As a result, the Board is not able to assign much weight to his evidence, if any.

[178] The Board also concludes that it cannot accept the evidence of Ms. Medine in this proceeding. Counsel for Avon described the concerns with Ms. Medine's testimony:

40. The Avon Group respectfully submits that the objectivity of Ms. Medine's opinion that NSPI's actions were prudent during this time period is undermined by the fact that she was actively advising NSPI on the very issues (coal procurement and the Langan derates) that are central to the disallowance recommendation. ...Ms. Medine's lack of objectivity was further apparent when she consistently referred to the actions of NSPI using the pronoun "we". She is now showing a laudable degree of loyalty to the utility, consistent with her long-term engagement by NSPI, but it appears to have coloured her perspective, to the extent that she would not even acknowledge that she characterized NSPI's actions in the 2002 GRA as "imprudent" despite being presented with her sworn response to IR which described NSPI's "imprudent practices".

[Avon Final Submissions, November 23, 2012, para. 40]

[179] The Board accepts Avon's submission on this point.

[180] The Board observed Ms. Medine to be combative and non-responsive in her testimony at the hearing, as demonstrated by her refusal to acknowledge her recommendation of imprudence in the 2002 GRA hearing (where she previously appeared as a witness for Avon before being engaged by NSPI).

[181] She acted at times as an advocate, rather than as an expert witness. While the Board has accepted Ms. Medine's evidence on numerous instances in past proceedings, it concludes that her relationship with NSPI in its solid fuel activities, including the events related to the derates at Langan, coloured her objectivity in this proceeding. The Board assigns little weight to her evidence.

[182] At the hearing, NSPI urged the Board to consider the benefits to ratepayers of NSPI staff “pushing” the limits of its generation fleet. Mr. Bennett stated:

MR. BENNETT: We’re not asking for a free pass, we’re just asking for a realization that this is not easy, it doesn’t happen by itself, and when you’re pushing the limits in order to keep costs low, an unpredictable event like extremely heavy rains causes you to have to be nimble. And we’ve been as nimble as you can reasonably be without pushing costs up.

[Transcript, November 9, 2012, p. 1720]

[183] The Board is mindful that the task of “pushing” the Ligan units is a challenging one for NSPI’s staff. The Utility and ratepayers benefit from the high output that can be achieved from the successful operation of these units.

[184] However, the Board also expects NSPI to act prudently in the operation of its generation fleet, including Ligan. It is not reasonable for the Utility to push its coal plants while disregarding the known risks of its choices of coal blends over a period of time.

[185] Mr. Spangenberg noted the importance of foresight and proper operational planning in striking the appropriate balance:

MR. SPANGENBERG: ...what we’re saying is that in the middle of the year, when they started to get an indication that they were going to have some operational problems in terms of opacity, the bell should have gone off and they said, “Now, how -- what can we do at this Ligan station to make sure we don’t have trouble when the real high load period comes in the winter, in December, January and February? Because if we can’t run this unit, we’re going to have to go out and buy very expensive power from some alternate source. And we don’t know what that’s going to be, but generally the power is either going to be another combustion turbine generating more expensive power or power that you buy.”

And so the issue to them should have been, “Let’s balance the economics.” You know, inventory that you’re talking about is an issue. The existing blend of contracts coming in is an issue. Cost associated with derating the unit should be an issue and what alternate energy was going to cost you.

And they have models to perform these calculations, and they should have been doing that. So that’s -- that’s really ---

MR. MARSHALL: So are you saying the trigger for this look they should have taken that at this would have come in, what, July or so, in the summer? You say they were beginning to experience some ---

MR. SPANGENBERG: Well, this particular coal was not a surprise coal. They had been burning this coal for 10 years.

...

MR. MARSHALL: Local domestic coal.

MR. SPANGENBERG: And that's the one that should have caused them to perk up their ears and say, "Hey, we'd better worry about what's going to happen in December to make sure that we've got this economical Ligan unit available to run and that we don't have to derate it because of opacity violations."

[Transcript, October 29, 2012, pp. 100-102]

[186] The Board accepts Mr. Spangenberg's description of the appropriate balance that should be reasonably expected of NSPI in the operation of this type of coal fired plant.

[187] Based on its review of the evidence, the Board finds, on the balance of probabilities, that NSPI was aware in July/August 2010 that there were quality issues related to the Prince coal. NSPI also acknowledged "pushing" the Ligan plant in order to achieve maximum output. Notwithstanding this factual background, NSPI did not investigate and test other coal blends to mitigate the risks of the failure to meet opacity limits.

[188] In failing to mitigate the known risks of derates from using Prince coal, the Board finds that NSPI was imprudent. The Board also concludes that imprudence on the part of NSPI led to the derate of the Ligan facility.

[189] Accordingly, the Board orders a disallowance with respect to the derates.

[190] In the event of a finding of imprudence on the Ligan derate, Liberty and NSPI disagree on the calculation of the amount of the disallowance.

[191] The total \$3.6 million amount of the disallowance proposed by Liberty is based on the sum of two \$1.8 million amounts (the fact that the two amounts are identical is coincidental). The first \$1.8 million relates to corrections made by Liberty to NSPI's assumptions in its calculation of replacement energy. The second \$1.8 million disallowance was proposed by Liberty as a consequence of the fuel cost savings that NSPI could have realized if a prudent coal blend was used.

[192] In determining the disallowance, Liberty calculated a cost associated with replacement energy resulting from the 21% derating at Lingan. In its Reply Evidence, Liberty stated:

The Audit Report calculated the cost consequences of Lingan December 2010 deratings using data for the whole month. We recognized that hourly data would provide a more accurate basis for calculation, but did not have that data at the time we provided the draft report to NS Power for comment. NS Power did not comment or provide hourly data then, but did so [later] in support of its determination that the number was \$750,000.

[Liberty FAM Reply Evidence, Exhibit N-170, pp. 20-21]

[193] In reviewing its calculation of the disallowance based on NSPI's methodology, Liberty made two adjustments. The first adjustment takes account of the reduced output from specific Lingan units in calculating the amount of replacement energy. Liberty modified this adjustment slightly to reflect that NSPI's model underestimated the amount of replacement energy resulting from reduced output at Lingan. The second adjustment made by Liberty to improve the accuracy of the calculation was related to the assignment and pricing of the replacement energy to the units that provided that power. NSPI had applied a figure which reflected an average for all units in the fleet. Liberty concluded that the "true cost of the Lingan derates should be calculated at the margin, not homogenized over the other units...". Accordingly, Liberty calculated the Lingan replacement costs "at the top of the dispatch

stack rather than the average” [Liberty FAM Audit Reply Evidence, Exhibit N-170, PDF pp. 108-109].

[194] The Board considers these two adjustments in the calculation to be reasonable.

[195] Liberty also stated:

...Our basis for the proposed disallowance is NS Power's decision to undertake operating risks without evaluating those risks and taking mitigating measures as deemed appropriate. The optimum solution could have resulted in higher or lower fuel costs. Taking the coal blend eventually utilized by NS Power in early 2011, which did indeed solve the opacity issues, our calculations show that fuel costs would have actually declined, not increased. Consideration of changed fuel costs, which NS Power appears to consider the appropriate method, would have thus produced an additional \$1.8 million of avoided costs. That approach would call for increasing the proposed disallowance by that amount.

[Liberty FAM Reply Evidence, Exhibit N-170, PDF p. 99]

[196] The \$1.8 million disallowance calculated by Liberty as replacement energy cost did not take account of replacement fuel costs. As noted by counsel for Avon, it was NSPI which suggested that Liberty should have considered how fuel costs would have changed if a fuel solution had been introduced earlier. This methodology results in an additional \$1.8 million disallowance attributed to fuel cost savings that NSPI could have realized if a prudent coal blend was used.

[197] The Board finds that it is appropriate to calculate the disallowance by considering, as NSPI suggested, how fuel costs would have changed if a fuel solution had been introduced earlier.

[198] Accordingly, the Board disallows \$3.6 million related to the Langan derates.

11.4 Natural Gas Contracts

11.4.1 Evidence

[199] With NSPI's long term natural gas supply contract with Shell (the "Shell contract") coming to an end on October 31, 2010, NSPI issued a Request for Proposals ("RFP") in September 2008 and August 2009 to acquire replacement quantities of natural gas to supply its projected needs.

[200] Four counterparties submitted seven proposals in response to the September 2008 RFP. One of the two lowest offers ("Bid A") was withdrawn after NSPI felt it had already accepted the offer via a term sheet. The other lowest offer ("Bid B") was rejected by NSPI, largely due to NSPI's concern about associated transportation costs and potential risk of supply interruption. That particular bid included primary injection into the Maritime and Northeast Canadian Pipeline ("M&NP-CA") at Goldboro but did not include primary delivery rights to the Tufts Cove plant. However, it did include firm secondary delivery rights to points along the M&NP-CA pipeline. Its duration was for eleven years, from November 1, 2010 to October 31, 2021.

[201] In the FAM Audit, Liberty addressed NSPI's natural gas purchases and highlighted issues regarding the two low contract bids which were not taken by NSPI. In recommending a disallowance of \$5,969,252 for costs deemed to have been avoidable, Liberty identified five principal components associated with that cost determination. Those components included two base load contracts (\$3,436,000), monthly purchases (\$1,512,250), seasonal purchases (\$276,800), and daily and intra-day purchases (\$744,202).

[202] During the hearing John Adger, of the Liberty Group, was asked to explain how the \$3.4 million proposed disallowance regarding the two base load contracts was

determined. His response was a simple calculation consisting of the daily contracted supply amounts in MMBtu between November 2010 and December 2011, multiplied by the price differential between the contracts taken and the lowest offers not taken.

[203] Also during the hearing Liberty was asked to provide their calculations of Bid B with transportation attached, which illustrated how long it would take for the commodity cost savings under that bid (with the transport cost included) to offset any transportation costs that would remain if NSPI was faced with an inability to continue using that transportation component at some future time. Liberty provided that information in their Undertaking U-15 which showed that the crossover point would have occurred about five years into the contract period.

[204] Regarding Bid A, Liberty acknowledged that there was not an accepted offer that was repudiated by Bidder A. Liberty's concerns were two-fold.

[205] Firstly, in early 2009, a subsidiary of Emera, Emera Energy Inc., entered into an agreement to market the Bid A gas. This was seen by Liberty as part of a pattern where the interests of Emera affiliates were favoured over NSPI.

[206] Secondly, Liberty felt NSPI should have been more aggressive with the offeror in attempting to obtain a suitable resolution to the issue.

[207] In his Pre-filed Evidence, dated September 17, 2012, NSPI's expert witness, Leonard Crook, stated that Liberty's characterization of Bid A is incorrect in just about all particulars. With respect to the other rejected offer, Bid B which included the transportation component, Mr. Crook stated that Liberty mischaracterized the offer to make it something that it never was.

[208] Mr. Crook recommended that the Board reject Liberty's proposed disallowance of \$1,512,000 related to the first base load contract, as well as the proposed disallowance of \$1,924,000 related to the second base load contract. He also recommended rejection of the proposed disallowance of \$1,512,250 for excess monthly purchase costs and the proposed net disallowance of \$1,021,002 associated with seasonal, daily, and intra-day purchases.

[209] In his Opening Statement at the hearing, Mr. Crook stated that:

Liberty has an erroneous theory that all gas sold in Nova Scotia should be at a full Dracut netback price and NSPI overpaid whenever it bought gas at a price higher than that, although yesterday, Liberty does seem to have modified its position somewhat.

...

Liberty's recommendations for disallowances follow this logic. As others have pointed out, this theory is incorrect and Liberty's recommendations based on it should be rejected.

My testimony also challenges Liberty's allegations in the particulars of two specific decisions on bids to supply NSPI. Contrary to Liberty's assertions, the first offer, once it was clarified, not repudiated, was not at the price that we originally thought it was, but would have been at a price higher than the offer of the bidder whose NSPI -- whose gas NSPI ultimately selected. NSPI properly declined, after negotiation, to take this gas at the higher price, and the offer was withdrawn.

...

Contrary to Liberty's assertions, my recommendation to reject the second offer, which was an apparent full netback price, was based on sound judgment about the reliability of the supply and the risks associated with pipeline capacity.

...

Liberty maintains that secondary delivery rights under the M&NP Canadian tariff would have provided sufficient assurance of deliverability, but the Maritimes tariff is clear; secondary delivery rights are subordinate to primary firm delivery rights.

The issue with the contract is fairly straightforward -- is a fairly straightforward matter. I considered it an unacceptable risk to take ownership of a long-term firm gas transportation contract for the purpose of delivering gas to a point not along the pathway of that contract, simply to access what might be a favourable supply contract that itself might not be reliable.

[Transcript B, October 31, 2012, pp. 848-851]

[210] Regarding Bid A, Mr. Crook was asked about his understanding of the price stated by the offeror and about actions that should have been taken by NSPI when the offer was withdrawn. Mr. Crook confirmed that he and the NSPI team all understood the price to be the same as the price that was understood by Liberty. He also noted that this same understanding was presented to NSPI's Fuel Strategy Table where approval was granted to proceed with the contract. At that point NSPI emailed a term sheet to the offeror and understood that it had accepted the offer. It was not until about six days after the term sheet was emailed that NSPI was informed its price interpretation was incorrect.

[211] Board Counsel asked NSPI's fuel witnesses how NSPI dealt with the situation in order to ensure that its acceptance of the offer could be preserved. Ms. Trenholm stated NSPI did not want to damage the relationship with the counterparty. She confirmed that NSPI did contact Bidder A and expressed as strongly as they could their disappointment but did not feel they could negotiate a better price:

... to express as strongly as we could our disappointment, at the same time acknowledging that this is a very illiquid market.

This is actually a new counterparty for us...

...

...It wasn't to the point where it was enforceable, and that was our view, it is -- it's too bad, and it is really -- I think it as a lot of hopeful thinking, maybe, on our part that blinded us a little bit, that we didn't push on that more, to hope that we had actually got [redacted] pricing...

[Transcript, November 9, 2012, pp. 2060 - 2061]

MS. TRENHOLM: --- we had gotten an approval to transact with them... It was a simple misunderstanding, a confusion on their part.

MR. OUTHUSE: Did you attempt to negotiate a better price? Did you attempt to use that occasion to strike a better price than you had from [redacted]?

MS. TRENHOLM: ...They weren't willing to move off of that price; that was their final price.

[Transcript, November 9, 2012, pp. 2065-2066]

[212] NSPI's primary concern with respect to Bid B, the rejected offer, was the risk of transportation interruption if the main line became full or congested.

[213] While the gas under that contract was favourably priced, indeed comparable to the price NSPI had enjoyed under the Shell contract, this contract had a transportation obligation attached to it with a secondary delivery point at Halifax. The primary delivery point was upstream of Halifax.

[214] NSPI pointed out that, to the best of its knowledge, no other market player in the Maritimes' market took an assignment of the Bid B contract.

[215] As noted, Liberty stated that, based on its analysis, the Bid B offer was sufficiently favourable in that after five years NSPI would have suffered no loss. In other words, there would have been a net benefit even if the balance of the transportation rights had become valueless at that time.

[216] This was explored with Liberty during the hearing:

THE CHAIR: It's a contract with transportation attached. And I guess my question is, is it your opinion that that contract would, after approximately five years, have proved so valuable that even if Nova Scotia Power could not get the gas to Halifax after five years, customers would have been better off with the acceptance; is that what that line is telling me?

MR. ANTONUK: That was actually the crossover point. Up to that -- if the crossover came roughly five years into the contract, on a strict economic basis, the offer that they rejected was better than the offer they accepted.

THE CHAIR: So they only needed to get the gas to where they wanted it to go for five years?

MR. ANTONUK: It was --- yes.

THE CHAIR: In your opinion?

MR. ANTONUK: Yes.

[Transcript, October 29, 2012, pp. 332-333]

[217] During cross-examination of NSPI's expert witness, Mr. Crook, counsel for the Avon Group explored the issues regarding primary and secondary delivery rights on the M&NP:

MS. STEWART:

...

I just have a few questions about the gas contract that involved transportation rights. Would you agree that curtailment of secondary firm delivery on a pipeline would only occur when the pipeline capacity was fully contracted under primary firm contracts?

MR. CROOK: Depending on the locations of the -- of the pathways. My concern about that contract was that it was firm but outside the pathway that needed to have secure deliverability to the Halifax Lateral.

...

So you were right, it has to be -- all of the shippers have to be shipping at their maximum daily quantity or our -- and that maximum daily quantity then precludes delivery of secondary -- of gas under secondary delivery rights.

MS. STEWART: And are you aware of whether or not there is today capacity on the M&NP Canada Pipeline?

MR. CROOK: The M&NP Canada Pipeline is not fully subscribed at this point.

MS. STEWART: Was it fully subscribed in 2008?

MR. CROOK: It was approximately, maybe 500, 520,000 out of the 600,000, I believe, was -- subject to check, of the maximum quantity of the pipeline. So you had some spare in there.

MS. STEWART: Has there, in your experience, been curtailment on the M&NP Canada Pipeline?

MR. CROOK: I'm not aware of any particular incident.

...

MS. STEWART: Sure, maybe I'll rephrase it. So there's been concern that there's risk associated with this contract, and the risk is that there -- because there's only secondary delivery rights, that in the event of curtailment the transportation that has been paid for would not be -- could not be used because it would only -- because there would be curtailment.

MR. CROOK: Correct.

...

MS. STEWART: Unless there is curtailment, secondary firm delivery is adequate to delivering gas?

MR. CROOK: I'm going to hedge the question -- hedge my answer a little bit on that. It should be adequate. I think, depending on the pathway, it may have some bearing on that.

...

So if you have a firm delivery pathway that goes from Goldboro all the way to Baileyville and there is some curtailment on the pipeline, then -- that is, that the pipeline is at maximum capacity, you would still be able to deliver gas to some secondary points along the way, provided there wasn't, you know, firm there already blocking you.

...

MS. STEWART: And I think your answer there, again, was with the hypothesis that there is curtailment, and I understand what you're explaining, but I'm not sure that it was responsive to the question.

So the question that I was saying was that, in the absence of curtailment, and the experience has been, and your evidence is that you are not aware of any curtailment on the M&NP CA, that without curtailment, secondary firm delivery is adequate and even possibly equal to primary firm delivery?

MR. CROOK: Yes.

[Transcript B, October 31, 2012, pp. 902-909]

[218] Following up on this questioning about transportation rights, counsel for the Province sought further clarification from Mr. Crook and asked if it was possible to have firm delivery rights on a lateral without having associated rights on the main pipeline. He replied that in order to get the natural gas to the specific lateral being discussed, transport along the mainline would be necessary. Firm delivery rights on the upstream lateral also include associated rights on the main pipeline in this instance. Mr. Crook also confirmed that payment for service anywhere on the M&NP, with a primary delivery point on the lateral, is covered by a single postage-stamp toll.

[219] Board Counsel also sought further clarification on this issue.

MR. CROOK: Well, as I say, it's a common practice in the industry that you can -- that you can deliver to secondary delivery points along your pathway as long as that secondary delivery point is available. Outside your pathway you can't.

MR. outhouse: And so when I read the tariff which says a particular customer who has a primary delivery point on the pipeline and -- primary delivery point, and then says that he can deliver anywhere else on the pipeline at a secondary delivery point that doesn't apply, that doesn't apply to this particular customer?

MR. CROOK: It applies as long as there's capacity available on the Mainline, but it doesn't -- the problem would occur is if sometime between now and 2021 some congestion would occur onto the Mainline...

[Transcript B, October 31, 2012, p. 919]

[220] Mr. Crook provided a response to Undertaking U-16 regarding available capacity on the Canadian portion of the M&NP. Mr. Crook advised that the physical capacity of the M&NP is 600,000 MMBtu per day. During 2008, the contracted capacity was 511,792 MMBtu which represents about 85% of the physical capacity. He also stated that the average daily flow throughout 2008 was 482,091 MMBtu or 80% of capacity. In addition, the average daily flow during March 2008, the peak month, was 527,383 MMBtu or 88% and on the peak day, also during March 2008, the maximum flow was 560,098 MMBtu or 93%. These figures clearly indicate that throughout 2008, capacity was available on the main pipeline to accommodate secondary delivery rights.

[221] Mr. Crook also noted that the pipeline capacity on the US side of the border was higher than the Canadian side in order to accommodate additional flows from the LNG facility at Canaport.

[222] Board Counsel sought further clarification of transportation rights:

MR. outhouse: Mr. Crook you remember yesterday when we were discussing this we were looking at 6.1?

MR. CROOK: Correct.

MR. outhouse: And it says:

"That the quantity is nominated for transportation by customers shall be scheduled by Pipeline for receipt and delivery in the following order." (As read)

And the first tier in that order, the first tier of customers:

"Firm service utilizing primary points of receipt and primary points of delivery." (As read)

Right?

MR. CROOK: Yes.

MR. OUTHOUSE: And the second (b) is:

"Firm service utilizing second points of receipt and/or second points of delivery provided, however, that if a pipeline is restricting service at a particular receipt or delivery point, then a customer utilizing that point as a primary point, regardless of the status at the corresponding delivery or receipt point, shall have priority over a customer using that restrained point as a secondary point or receipt of delivery." (As read)

In other words, and my understanding of that and you can correct me if I'm wrong obviously, is that if I have -- if both of us have primary receipt points at Goldboro and I have a primary delivery point at Halifax and you have a primary delivery point in Saint John and there's a constriction at Saint John, then you have priority over me at Saint John; is that correct? If I want to use my secondary rights to deliver to Saint John and it's a primary point of delivery for you, you have priority over me in scheduling.

MR. CROOK: You mean, if I -- mine was at Halifax?

MR. OUTHOUSE: If -- no.

MR. CROOK: I'm sorry, I ---

MR. OUTHOUSE: If your primary point of receipt -- of delivery is Saint John, my primary point is Halifax.

MR. CROOK: Yes.

MR. OUTHOUSE: And there's a constraint at Saint John, but I'm trying to get in there using my secondary delivery rights, you have priority over me because it's your primary point of delivery?

MR. CROOK: Yes.

MR. OUTHOUSE: Correct?

MR. CROOK: I believe so.

MR. OUTHOUSE: All right. But if neither of us have primary points of delivery at Saint John, but we both want to exercise secondary rights to deliver there, we're on an equal footing; are we not?

MR. CROOK: Yes.

MR. OUTHOUSE: Okay. And when you look at 6-3, and this is the part that wasn't in the tariff that's in your document. Six three (6-3) says that:

"In the event a tie for capacity exists among category A, B, C, or D customers, quantities within that category will be scheduled pro rata on the basis of the customer's MDTQs." (As read)

Correct?

MR. CROOK: Yes.

[Transcript A, November 1, 2012, pp. 937-941]

[223] In an effort to obtain a better understanding of the pipeline constraint issue, the Board requested further clarification from Mr. Crook:

THE CHAIR: So I guess once it enters the Mainline, I'm having difficulty understanding what the constraints are, then getting it to the Halifax Lateral given that there's no gas entering the Maritimes & Northeast Pipeline between Goldboro and New Glasgow, where the Halifax Lateral comes off. Could you help me with that?

MR. CROOK: My understanding is that there is a decline in pressure over the length of the line and that you can take quantities off a short distance down the line and not affect - and by terms of the tariff then, you have secondary rights to any downstream takeoff points from your -- from the [redacted]. I'm not a pipeline engineer so I don't know exactly ---

THE CHAIR: So are you saying that ---

MR. CROOK: --- the dynamics of the flows.

THE CHAIR: So if you put 600,000 MMBtu's in at Goldboro, you're saying you can't get that to, say, New Glasgow?

MR. CROOK: Point taken. Yeah, I'm not sure then.

THE CHAIR: And you'd agree with me that no gas enters that line, or frankly, is likely to enter that line between Goldboro and New Glasgow?

MR. CROOK: That's correct.

[Transcript A, November 1, 2012, pp. 995-996]

[224] Mr. Crook was asked if he did any economic analysis of the price of gas under Bid B, compared to the contract that eventually was entered into by NSPI, to determine what the economic benefit would have been versus the risk on the pipeline. His response was that he did not do the sort of analysis that Liberty had done with respect to the benefit of the contract. Likewise, John Reed, another one of NSPI's expert witnesses, did no such economic analysis.

[225] As NSPI's generation pattern moved toward greater reliance on gas-fired units, a requirement for additional supplies of natural gas was identified. In addressing that need, NSPI entered into a number of short-term agreements resulting from bilateral negotiations, rather than through an RFP process. These purchases consisted of various forms of seasonal, monthly, daily, and intra-day agreements and involved a range of transaction pricing. In the FAM Audit Report, Liberty identified excess costs of \$276,800 for seasonal purchases, \$1,512,250 for monthly purchases, \$767,706 for daily purchases, and an intra-day saving of (\$23,504). Liberty's calculations are based on the difference between the price paid by NSPI and the price that Liberty determined NSPI could have achieved with more informed and aggressive negotiations and with access to LNG from Canaport.

[226] NSPI responded to those conclusions regarding excessive costs for natural gas by dismissing Liberty's assertions that lower prices could have been achieved. NSPI stated that it is committed to champion customer interests in the pricing of natural gas supplies and it takes the position that Liberty is confused about the operation of the natural gas market in the Maritimes.

[227] In his Pre-filed Evidence, NSPI's expert witness, Mr. Crook, addressed the excessive procurement costs identified by Liberty regarding seasonal, monthly, daily and intra-day purchases. Mr. Crook noted that the characteristics of gas contracting include various obligations such as delivery, duration, and different supply tranches which will result in gas prices that are higher than those attributed to basic gas commodity trading. He also stated that:

...My observation here is that in the daily and intraday market, where supply is short, one can expect to pay higher prices than when supply is at surplus or for previously contracted supply. The argument that these volumes also should have been priced at

[redacted] misunderstands the operations of the gas market. Liberty's recommendations for eliminating these expenditures from the FAM should be rejected by the Board.

[Exhibit N-129, p.10]

[228] Mr. Reed also disagrees with Liberty's recommended disallowances for NSPI's seasonal, monthly, daily and intra-day purchases. In his direct evidence, Mr. Reed stated:

Liberty believes that higher natural gas prices in the Maritimes that have been experienced since the expiration of NSPI's Original Shell Contract are inconsistent with the NEB's prior findings regarding exports of natural gas from Canada. Liberty states that "NSPI's expectations of [redacted] did not appear to be consistent with either the general regulatory regime for gas exports from Canada or the specifics of the authorities granted to Repsol." (Liberty Audit, p. III-5).

[Exhibit N-134, p. 25]

...it is my opinion that the changes in wholesale gas pricing in the Maritimes reflect exactly the way a functioning market would work as it moves from having a supply surplus to a supply deficit. The increasing natural gas prices in the Maritimes are not due to market flaws, but rather a shortage of indigenous supply.

[Exhibit N-134, p. 31]

[229] He went on to say that in determining these disallowances, Liberty based its finding on its interpretation of prior NEB decisions regarding natural gas exports from the Maritimes. Mr. Reed stated that he agrees:

...the NEB's policies are that the natural gas needs of Canadians are to be met on terms that are similar to those charged to export customers. However, I strongly disagree with Liberty's interpretation of these NEB rulings and how Liberty has applied its conclusions to NSPI's circumstances in this proceeding.

...

Contrary to Liberty's interpretation, the NEB has not previously concluded that purchasers of natural gas in the Maritimes are entitled to a Dracut netback price. In fact, the NEB specifically recognized in MH-2-2002 that producers/marketers selling in the Maritimes natural gas market are entitled to seek reimbursement for transportation costs to which they have committed.

[Exhibit N-134, pp. 32 - 34]

[230] In its Closing Submission, with respect to Bid A, NSPI stated that Bid A suffered from vagueness in its terms such that NSPI and the bidder had two

understandings of the offer. NSPI argued that Liberty's position with respect to Bid A was not as much about the ability of NSPI to obtain competitively priced gas but related to Liberty's concern about affiliate transactions.

[231] With respect to these affiliate concerns, NSPI noted the evidence of its expert, Mr. Reed, who found no evidence that the affiliate or NSPI violated the Affiliate Code of Conduct or conspired in any way in connection with Bid A.

[232] In the final analysis NSPI stated that:

NS Power could not have forced [Bidder A] to honour a proposal that [Bidder A] believed it had not made.

[NSPI Closing Submission, November 23, 2012, p.66]

[233] NSPI goes on to state:

Liberty initially claimed NS Power to have been imprudent in respect of the [Bidder A] offer because NS Power did not obtain the benefit of the pricing structure as that structure had initially been understood by NS Power. In contradiction to Liberty's position, the discussion could simply not get to a consideration of whether it was within the band of reasonable choices to have rejected the [Bidder A] proposal because there was no legally enforceable proposal on the table – a fact acknowledged by Liberty during its testimony. [Bidder A] withdrew its proposal and accordingly that alternative choice was simply not available. It cannot be unreasonable or imprudent not to accept an offer that no longer existed.

[NSPI Closing Submission, November 23, 2012, p. 66]

[234] With respect to Bid B, NSPI argued as follows:

NS Power had sought gas for terms of 1-5 years and up to 20,000 MMBtu/day. The [Bid B] offer had several components – one was a 4,000 MMBtu/day supply to which NS Power already had access, while the second was for a gas supply contract of 7,000 MMBtu/day of additional gas supply (non-firm for as many years as SOEP supply would support). The third and final component was 11,000 MMBtu/day of must-take pipeline capacity through a Firm Service Agreement whose term extended until 2021 – well beyond the term of the associated gas supply.

It was NS Power's and ICFI's considered view that the value of the 7,000 MMBtu/day did not outweigh the risk of committing to paying transmission costs to 2021 on a portion of pipeline that has no (firm) primary delivery rights to the Halifax lateral. In fact, NS Power's financial analysis indicated that the contract would cost customers almost \$20 million due to the capacity costs outweighing the cost of gas. Given what we now know about [Bid B], it is understandable that [Bid B] would have wanted to find a way out of its costly transportation contract.

NS Power tried, and failed, to get firm transportation to Halifax. It is also worthy to note that [Bid B's] offer to sell gas under its proposed conditions was not accepted by any other buyer.

[NSPI Closing Submission, November 23, 2012, p. 60]

[235] In its Closing Submission, Avon noted that NSPI's involvement in the regional natural gas market had been an issue of concern raised by Liberty in the 2010 FAM Audit and again in the 2012 FAM Audit. Avon also stated:

The evidence that has emerged through this process demonstrates that while NSPI has a strong understanding of the complexities of the natural gas market, it tends to take a conservative approach to its role within the market and, in some key instances, failed to undertake rigorous analysis of its natural gas contracting and hedging options. As a result, stakeholders are left to question whether NSPI has truly made every reasonable effort to ensure that it is obtaining the lowest possible natural gas prices.

[Avon Closing Submission, November 23, 2012, p. 8]

[236] Regarding NSPI's activity with natural gas contracts, Avon noted that NSPI and its expert witnesses have repeatedly stated that natural gas prices, as low as those contained in the two lowest bids from the 2008 RFP, have not been seen for several years. Therefore, prior to rejecting the bids:

One would expect that this decision would come after a serious analysis of the financial and operational risks associated with the bids. However, it appears that this is not entirely the case.

[Avon Closing Submission, November 23, 2012, p. 9]

[237] Regarding the lowest bid which had been withdrawn (Bid A), Avon stated this situation appeared to be:

...a significant miscommunication between NSPI and the counterparty, at best, or interference from an NSPI affiliate, at worst.

...In the NSPI evaluation of the RFP outcomes, this bid was ranked number one. Based on the wording of the bid and ongoing negotiations, it was widely believed by NSPI and its consultant, Mr. Crook, that the counterparty was offering gas with a deduction for both Canada and US pipeline transportation charges.

The bid was selected by staff and was presented for approval to the Fuel Strategy Table; upon approval, a term sheet was provided to the counterparty. Only then did the bidder indicate that it had only intended to deduct a portion of the transportation costs. This significantly changed the economics of the bid and, ultimately, the offer was determined to be unfavourable. It is surprising that there would be such a significant miscommunication between NSPI and a potential counterparty.

[Avon Closing Submission, November 23, 2012, p. 12]

[238] Although NSPI testified that it had discussed this situation with the counterparty and voiced its dissatisfaction with what appeared to be a change in the bid, Avon noted that:

NSPI's full reaction to the clarification with respect to the bid did not become apparent until Ms. Trenholm was under cross-examination during the audit hearing. Only then, did it come to light that NSPI voiced significant discontent with respect to the sudden change in the counterparty's bid. Ms. Trenholm stated that although NSPI was "indignant", the Utility ultimately preferred to preserve the relationship with the counterparty and so decided not to press the matter further. It is noted that both NSPI and Liberty agree that the bidding process, though advanced, had not, yet, resulted in an enforceable contract.

[Avon Closing Submission, November 23, 2012, p. 13]

[239] Regarding the rejected bid with the transportation component (Bid B), Avon noted that there was no dispute that NSPI would have accepted the bid if it did not have the specific transportation component attached to the offer. In this instance, Avon submitted that NSPI should have considered the actual capacity and forecasted capacity of the M&NP-CA pipeline as of 2008, prior to rejecting that bid.

The transportation contract had firm entry rights at Goldboro and so would be unaffected by increased use of the pipeline by Deep Panuke gas, insofar as entry rights are concerned. The issue, then, is whether potential increased gas supply to be shipped on the M&NP-CA would impact delivery, on a secondary basis, to Tufts Cove.

...We understand that Mr. Crook was suggesting that secondary delivery along the pathway between the primary injection site and the primary delivery site would have priority over secondary delivery along another "pathway" on the pipeline. This position does not appear to be supported by the tariff provisions or the logic of a postage stamp pipeline system, such as the M&NP-CA Pipeline.

Despite taking this position, Mr. Crook was not able to provide an example of priority being affected by pathways on a postage stamp pipeline in Canada...

...Little or no evidence was given with respect to sources of curtailment, either additional injections of gas between Goldboro and the Halifax Lateral or other major primary delivery rights' holders to the Halifax Lateral. Therefore, it seems that there was no particular risk of curtailment with respect to the intended secondary delivery point at Tufts Cove.

...

It is submitted that the risks associated with secondary delivery to Tufts Cove were not exceptional and that, in light of the preferential pricing of the natural gas that was being offered in the bid, one might expect that NSPI would undertake a rigorous financial analysis to determine whether the economic benefits outweigh the risks associated with the transportation portion of the contract. However, it does not appear that such an analysis was undertaken prior to rejecting the bid.

Although NSPI produced a table comparing the benefits (gas) and liabilities (transportation) associated with this bid, the Utility confirmed that this assessment was undertaken after-the-fact as part of NSPI's response to the 2012 Audit and that no economic analysis had been performed in 2008, because the *"exposure was easily understood at that time."*

Ms. Trenholm confirmed, on behalf of NSPI, that although Mr. Crook undertook an informal risk analysis of the contract, he did not produce an in depth economic analysis, either. Further, Mr. Reed gave evidence that he did not undertake any type of analysis in relation to preparing his evidence...

[Avon Closing Submission, November 23, 2012, pp. 10-11]

[240] Avon went on to point out that Liberty's analysis determined that the risks associated with the transportation component of Bid B would be outweighed by the benefits of the natural gas contract after about five years. Avon concluded that:

... the risks associated with the transportation contract were not properly analyzed, either by NSPI or its consultants, and a contract that could have provided gas at a price that NSPI acknowledges it has not been seen in many years was rejected without the type of rigorous analysis one might expect in this situation. In these circumstances, the Avon Group supports a finding of imprudence with respect to NSPI's rejection of this contract.

[Avon Closing Submission, November 23, 2012, p. 12]

[241] The Small Business Advocate, in its Reply Closing Argument, stated:

The FAM Audit Report provided recommended finding V-1, that added fuel costs were incurred due to NSPI's inaction addressing gas market conditions, which the Board's consultant recommends should be a disallowance of \$6 million. The SBA supports this finding because NSPI has not provided sufficient evidence in this proceeding or in its closing submission that this incremental cost could not have been avoided had NSPI

pursued earlier efforts to replace expiring contracts as well as more negotiated more aggressively for more favorable pricing terms in replacement contracts.

[SBA Reply Closing Argument, November 30, 2012, p. 3]

11.4.2 Findings

a) Bid A

[242] The Board does not believe that NSPI's actions with respect to Bid A were imprudent. Based on the evidence, it appears to the Board there was never a meeting of the minds between NSPI and Bidder A on the terms of the offer. Initially NSPI, and their advisor Mr. Crook, thought NSPI had a very favourable offer and recommended it to NSPI's Fuel Strategy Table. They agreed to accept it. However, when the term sheet confirming acceptance was presented to Bidder A, it then became clear that there was not agreement on the proposal. Liberty acknowledged that there was not an enforceable contract.

[243] While it may be argued that NSPI should have more aggressively pursued Bidder A to obtain a favourable compromise price, the Board does not believe NSPI's failure to do so was sufficient to meet the test of imprudence. Concern about the future business relationship with Bidder A is a relevant concern for NSPI to have taken into account.

[244] Finally, while Liberty was right to be concerned that Bidder A entered into a subsequent contract for the same gas with Emera Energy Inc., there is no basis, in the Board's view, to find that activity frustrated the contract or that NSPI played any role in the contact between Emera Energy Inc. and Bidder A.

b) Bid B

[245] The Board is very concerned about NSPI's failure to properly analyze the costs and benefits of taking an assignment of this very favourably priced contract.

[246] For ten years under the Shell contract, which expired in 2010, NSPI enjoyed a gas price that was favourable vis-à-vis the Dracut hub. The Bid B contract would have permitted that favourable pricing to continue, albeit for a much smaller volume of gas, possibly for an additional eleven years.

[247] NSPI stated that the gas supply contract was available "for as many years as SOEP supply would support". Mr. Crook noted that the gas supply contract had renewable provisions that made it potentially attractive.

[248] NSPI spent a great deal of time explaining during the hearing, principally based on the evidence of Mr. Reed and Mr. Henning, that the evolution of the gas market in the Maritimes had taken place in such a way that gas is now being less favourably priced in the Maritimes, vis-à-vis the Dracut hub, to the point where it is virtually impossible to obtain Dracut minus bids.

[249] Based on this evidence, by foregoing the Bid B contract, NSPI has passed up an opportunity that may never present itself again, at least in the foreseeable future.

[250] What appeared to concern NSPI was the associated transportation capacity. Halifax would have been a secondary delivery point on the M&NP pipeline.

[251] The evidence, however, is that virtually all of the gas being delivered to Tufts Cove is being delivered pursuant to transportation contracts where Halifax is a secondary delivery point. While a shipper with Halifax as a primary delivery point would have priority over other shippers with only secondary delivery rights to come to Halifax, there were no such shippers. If there were to be any constraints on the M&NP pipeline,

those with secondary delivery rights would share the capacity pro rata. However, in 2008 the M&NP pipeline was not being used to its full capacity. There was never a day, based on the evidence of Mr. Crook, where the pipeline capacity was met or exceeded.

[252] Mr. Crook's principal concern seemed to be that somehow the gas would not get to Halifax. That is not logical to the Board. The gas destined for the Bid B primary location must enter the M&NP mainline. It then proceeds along the M&NP pipeline until it reaches the upstream lateral leading to the primary delivery point. The Halifax lateral meets the M&NP pipeline near New Glasgow. There is no gas being injected into the M&NP pipeline between the take off point for the upstream lateral and the Halifax lateral. In the circumstances, therefore, it is not at all clear to the Board what the risk was that NSPI thought it was avoiding. Mr. Crook as much as conceded that under questioning from the Board.

[253] Liberty prepared an analysis that showed that NSPI was better off after five years, based on this favourable pricing, as compared to other pricing it was able to obtain even if the transportation contract was useless from that point forward.

[254] It is apparent to the Board that NSPI, at the time, did no such analysis.

[255] NSPI, in its Reply Brief, included a section which attempted to criticize and undercut Liberty's analysis. The Board is very concerned that this analysis was not made available in NSPI's principal argument and, by saving it for the Reply Brief, no party had a chance to respond or comment on it. In the circumstances, while the Board has reviewed this submission, the Board gives little weight to that analysis.

[256] In the Board's view, NSPI was imprudent in failing to properly analyze the risks and benefits associated with the Bid B contract which the Board believes could have been very beneficial for ratepayers.

[257] In the circumstances the Board disallows \$903,000 related to the failure to take an assignment of the Bid B contract for the period from November 1, 2010 to December 31, 2011 (i.e., 426 days). The details of the calculation are based on confidential information. As this was a longer term contract the impact of this finding on any future test years will be the subject of consideration in future audits.

c) Seasonal, Monthly and Daily Pricing

[258] Liberty's theory in recommending a disallowance with respect to monthly, seasonal and daily purchases has as its foundation its belief that inaction by NSPI contributed to the market conditions that existed.

[259] In terms of making its recommendation with respect to disallowance, it made certain assumptions as to how the market would have worked if buyers on the Canadian portion of the M&NP had access to LNG. On a seasonal basis Liberty felt there would be opportunities for NSPI to obtain favourably priced gas recognizing the volumes of LNG flowing into the U.S.

[260] All of this evidence was filed in confidence so it is difficult to be more precise about this calculation. Essentially what Liberty did was compare the market as it was compared to the market as it could have been.

[261] In respect to the Bid A and Bid B contracts, the circumstances are fairly clear and the Board is able to make a judgment as to whether or not NSPI acted prudently. With respect to seasonal, monthly and daily purchases the evidence is much

less clear. Based on the market conditions as the Board now understands them, and as more particularly described in the natural gas market section, the Board does not believe there is a sufficient basis for it to make any disallowance based on NSPI's monthly, seasonal or daily purchases. It is not at all clear to the Board that NSPI could have achieved what the FAM Audit suggests in terms of price in seasonal, monthly or daily contracts.

11.5 Natural Gas Markets

11.5.1 Evidence

[262] As noted elsewhere in this Decision, for ten years ending in late 2010, NSPI enjoyed the benefit of what is now considered to be a favourably priced natural gas contract with Shell Canada for Sable offshore gas.

[263] Indeed, during much of the life of that contract, NSPI was in a position of selling natural gas, not just purchasing it. The Shell contract provided much more gas than NSPI, in those years, could economically use to generate electricity. Among other things the Shell contract recognized, in terms of price, that Halifax was closer to the source of supply than the trading hub of Dracut, Massachusetts. By 2008, when NSPI started the process to find replacement gas, it appeared that market conditions had deteriorated with respect to the price for gas purchases in the Maritimes. It appeared that instead of paying a price that excluded transportation on the U.S. portion of the pipeline, NSPI would be faced with prices tending to a level reflecting increasing amounts of transportation from the Canadian border to Dracut because shippers had contracted for that capacity and, with dwindling gas supplies, needed to be reimbursed for that transportation commitment.

[264] In the 2010 Audit, Liberty made a number of recommendations to NSPI, including:

1. Become more proactive in obtaining competitive market prices for NSPI gas supplies;
2. Maintain contacts with existing sources of gas supply components and work aggressively to develop new ones.

[265] In both this audit and the previous audit Liberty expressed concerns that NSPI was being too passive with respect to obtaining competitively priced gas supplies by failing to be more aggressive with gas suppliers; by failing to take sufficient steps to enforce regulatory protections to Canadians, including the National Energy Board's ("NEB") Market Based Procedure; and, in Liberty's view, deferring to Emera affiliates with respect to the operation of the gas market.

[266] Liberty described the NEB's Market Based Procedure:

The Board adopted in 1987 a new "Market-Based Procedure" (MBP) for reviewing export applications. This decision observes that:

*The fundamental premise of the MBP is that the marketplace will generally operate in such a way that Canadian requirements for natural gas will be met at **fair market prices**. However, the MBP was designed to provide for intervention if there was evidence that the market was not working to **adequately and fairly serve** Canadian needs.*

This language does not define any of the emphasized terms. It does, however, appear to add a test beyond pricing at market, observing that whatever prices the market produces must be adequate to serve and fair in treating Canadian buyers.

This decision describes the Complaints procedure in connection with export licenses as follows:

Under the Complaints Procedure, Canadian natural gas buyers have an opportunity to intervene with respect to an application for a natural gas export license if they believe they have not been able to purchase natural gas on terms and conditions that were similar to those of the proposed export. [Emphasis in original]

[Exhibit N-171, pp. III-5 to III-6]

[267] Liberty relied significantly on a 2002 decision of the NEB where the Province of New Brunswick initiated an application requesting the NEB establish rules to apply when considering applications for short term exports for incremental supplies of Nova Scotia offshore gas. Gas exported under short term exports is subject to less regulatory oversight than long term licenses. While the NEB did not intervene directly in the exports of gas, it did signal that it would take on a heightened monitoring role.

In summary, the Board is of the view that the developing Maritimes gas market faces many challenges that are not faced by buyers in the mature export market.

Given these market realities, the Board shares the concerns of New Brunswick and PEI about access to incremental gas supplies on fair market terms. Although the Board does not believe that the record in this hearing warrants direct regulatory intervention, it did raise sufficient concern that the Board believes it must enhance its monitoring efforts in Maritime Canada

[NEB Decision MH-2-2002, Exhibit N-191, p. 42]

[268] Liberty also noted the NEB's findings in the Brunswick Pipeline decision related to LNG delivered to Canaport:

The NEB stated as follows:

... the Board is of the view that one aspect for the justification of this Project is its ability to provide an opportunity for access to a new source of natural gas supply to the Maritimes. While some parties expressed concerns regarding the ability of Maritime Canada markets to access the incremental gas supply provided by the Project, the evidence before the Board indicates that Irving Oil is the largest user of natural gas in Maritime Canada. Therefore, Irving Oil's access to the gas supply supports the Board's finding that there will be Canadian access to the Project's gas supply. Furthermore, Maritime Canada could also access this new natural gas supply source, to fulfill current and anticipated future natural gas needs, through the use of backhauls, swaps and direct connection to the Brunswick Pipeline.

[Exhibit N-171, p. III-13]

[269] Among Liberty's conclusions with respect to NSPI's conduct in the natural gas market are the following:

1. NSPI has demonstrated that customers cannot rely upon it to champion their interests with respect to prices for natural gas in the Maritimes market;
2. NSPI should have been contesting and should continue to contest gas market circumstances; however there is no basis for confidence that it can be relied upon to do so even if it did undertake the effort.

[270] Liberty's view is that NSPI should have more aggressively pursued discussions with the NEB, including a possible application to the NEB, and been more active with respect to negotiations in the gas market reminding suppliers, among other things, of the Market Based Procedure.

[271] In NSPI's view, Liberty had a flawed understanding of how the U.S. Northeast and Maritimes gas market operates. NSPI submitted:

The overwhelming weight of evidence is that NS Power's gas acquisition prices were sound and the contracts it achieved during the audit period delivered excellent value to customers.

[NSPI Closing Submission, November 23, 2012, p. 51]

[272] NSPI, in its Reply Evidence, stated:

Over the past five years, the balance of supply and demand in the Maritimes has shifted. Local supplies have dwindled, and local demand has increased. ... Since January 2010, the usage of natural gas on the M&NP system (both M&NP Canada and MN&P US) has ranged from approximately 200,000 MMBtu/day to 500,000 MMBtu/day. On the other hand, estimated production of natural gas in Atlantic Canada has ranged from approximately 280,000 MMBtu/day to 340,000 MMBtu/day (excluding supply disruptions).

...

The current supply/demand imbalance, and the cost of the next available supply source, has caused the spread NS Power pays for natural gas supply ... The price for natural gas supply in the Maritimes market will remain higher than it had been previously ... until such time that supply and demand return to a more balanced state.

[Exhibit N-98, pp. 34 & 36]

[273] With respect to its activity in the gas market, vis-à-vis customers and the NEB, NSPI points to a very favourable contract it entered into with a supplier for offshore natural gas. Unfortunately, supply conditions have not enabled NSPI to take full advantage of that contract through no fault of NSPI.

[274] With respect to the interaction with the NEB, NSPI stated as follows:

NS Power has not filed a complaint with the NEB over the gas supply/pricing structure. Nor has any other natural gas customer in this market. NS Power continues to believe there are no grounds for such a complaint. Apparently all market participants and stakeholders in the Maritimes market except Liberty agree. If circumstances change in the future such that filing a complaint with the NEB may have merit, NS Power will re-evaluate accordingly.

[Exhibit N-98, p. 39]

[275] With respect to LNG gas, NSPI pointed out that it is not economic to purchase gas at international LNG prices and bring the gas to Nova Scotia.

[276] In the view of NSPI's expert witness, John Reed, the change in market pricing in the Maritimes is not due to market flaws as he says Liberty alleges, but reflect a change in the market circumstances because of the region's shortage of supply. With respect to market conditions in the Maritimes and the role of the NEB, Mr. Reed stated as follows:

...it is telling that no other market participant in the Maritimes filed a complaint with the NEB to correct what Liberty concludes are market failures. In other words, of the many sophisticated market participants that were also affected by the market conditions for which Liberty has expressed concern in the audit, not one deemed that filing a complaint had merit. ...

Therefore, since NSPI's conduct in the market was consistent with all of the other sophisticated market participants that were also affected by changing market dynamics and prices, NSPI's conduct cannot be deemed to be outside the range of reasonable behavior during this same time period. ...

Furthermore, even if NSPI had asked the NEB to intervene in 2010 and the NEB had complied, it is not at all likely that the NEB's review would have led to lower gas prices for NSPI, and, presumably, if it did, that outcome would have been some years into the future, not for 2010/2011.

[Exhibit N-85, p. 27]

[277] On November 9, 2012, the last day of hearing and in a confidential session, NSPI disclosed new and important evidence concerning its activities in the market. Unfortunately, because of its confidential nature, the Board can disclose little, if any, of this evidence in this public Decision.

[278] It turns out that NSPI had indeed consulted a leading Calgary law firm concerning a possible complaint to the NEB and received advice. In part, based on that advice, NSPI had engaged in much more aggressive behavior with possible gas suppliers concerning price leading, in its view, to favourable pricing. NSPI also explained its strategic view with respect to LNG supply and its importance for supplying additional gas to a gas constrained market and the favourable effect that may have on the Maritimes market.

[279] Liberty had been advised in March of 2012 that NSPI had contacted outside counsel in 2010 but no reference to the fact they had contacted counsel prior to negotiations with the gas supplier where the favourable price was obtained. When asked about counsel's advice Liberty was advised by NSPI it was privileged.

[280] The Board was concerned as to the extent of Liberty's knowledge of this information, which came out on the last day of the hearing and asked for an Undertaking from Liberty, who responded in part as follows:

This undertaking addresses Liberty's knowledge of contacts that Mr. Janega testified he had with outside counsel and with [redacted] about NEB authority to address market concerns. To summarize, we were not aware until reading the transcript of Mr. Janega's reported contacts with outside counsel. We were aware that NS Power did communicate with [redacted] about supply, but not as Mr. Janega described those contacts.

Regarding consultation with outside counsel, we have no recollection of Mr. Janega's having discussed with Liberty any consultations regarding authority of the NEB to address gas market issues of concern to NS Power. A search of our notes since 2008 for reference to any such discussion found none. The issue of response to market concerns has been of interest to us since late 2008, at least. See for example, the April 2009 ICF International, *Report on Planning for Future Natural Gas Supply: A Review of the Activities of Nova Scotia Power, Inc.*, submitted by NS Power to the UARB, and

discussed during this proceeding. That report came at the UARB's request, following our expressions of concern in the 2009 NS Power GRA. Thus, it is extremely unlikely that statements by Mr. Janega or anyone of this nature would have escaped attention.

We addressed market-facing actions with Mr. Sidebottom in a March 31, 2010 interview during the prior FAM audit. He cited no communications with attorneys. He did say that he viewed [redacted] favorably, and cited no problems or concerns. He stated that he and Mr. Janega sought a meeting with [redacted] following its failure to bid in the Fall 2009 gas supply solicitation.

[Undertaking U-27, November 19, 2012, p.1]

11.5.2 Findings

[281] NSPI, in their Closing Submission, stated as follows:

After years of debate about the merits, or lack thereof, of filing a complaint with the NEB, it is now clear that NS Power has, in fact, done exactly what Liberty has wanted the company to do. [Emphasis added]

[NSPI Closing Submission, November 23, 2012, p. 59]

[282] The problem is that the extent and importance of this activity was not disclosed to Liberty, the Board, or the parties until the last afternoon of the hearing. NSPI says in its submission that this should have been clear from a reading of Responses to Information Requests during the 2010 FAM proceeding. The Board has re-read those responses and, while they do disclose details of contractual negotiations with the counterparty, they do not disclose in any way the evidence that was provided by Mr. Janega on the last afternoon of the hearing and its importance and effect. Even if the 2010 FAM Information Responses did disclose this information it seems odd NSPI would suggest the Board must plumb the depths of the evidence in a prior proceeding to find it.

[283] The Board's dismay and concern about this cannot be overstated.

[284] A fundamental underpinning of Liberty's criticism of NSPI over the years was NSPI's failure, in the view of Liberty, to pursue regulatory avenues open to it and,

as a companion to that, to more aggressively pursue marketers of gas, recognizing the existence of the Market Based Procedure.

[285] In 86 pages of FAM Audit Reply Evidence, the evidence provided by Mr. Janega was not disclosed. The Board can only assume that if NSPI had been forthcoming on the consultations with a leading Calgary law firm and conversations NSPI had with the counterparty following those consultations, in the thousands of pages of evidence and IRs and in the hearing, the nature of the Audit and most certainly the nature of the hearing, one of the most rancorous the Board has ever seen, would have been very different.

[286] NSPI's actions in withholding this information are both inexplicable and inexcusable.

[287] NSPI has criticized Liberty to the point of ridicule for this recommendation in the present Audit and, previously, that NSPI should more aggressively pursue discussions with the NEB and be more active with respect to negotiations with gas marketers given the existence of the Market Based Procedure.

[288] Remarkably, NSPI now says it was, in fact, following Liberty's advice which has been given over a period of four years. The Board cannot understand what NSPI thought it was doing by withholding that information and continuing to ridicule Liberty for making the recommendation.

[289] While it may have been slow to act, it now appears NSPI was acting appropriately with respect to their consultation with the Calgary lawyers and in certain of their recent dealings with suppliers, as a consequence. However, the failure to disclose that has added significant time, cost and rancor, unnecessarily, to this hearing.

[290] In the Board's view, that conduct cannot go unsanctioned. The Board will impose a financial disallowance as more particularly described in Section 11.10 of this Decision.

[291] In its Final Submission, Avon stated as follows:

158. It is understood that there is a long-standing disagreement between NSPI and Liberty with respect to the level of engagement or aggressiveness that NSPI ought to be demonstrating in respect of the development of the natural gas market in the Maritimes. The Avon Group agrees with Liberty that NSPI has demonstrated an unreasonably passive approach to the natural gas market and that it is likely that a more aggressive approach, one that is commensurate with NSPI's purchasing power in the market, may have produced more economically priced gas contracts for NSPI customers.
159. It would be acceptable if NSPI had tried and failed but it is problematic, from the perspective of the Avon Group, that NSPI continues to insist that the market is behaving well and that there are no problems that require the Utility's intervention. NSPI's approach to natural gas market, in the Avon Group's opinion, has had detrimental effects and leads us to question whether NSPI has made every reasonable effort to obtain economically priced natural gas.

[Avon Final Submission, November 23, 2012, p. 29]

[292] That submission was made even with the knowledge provided by NSPI in the last day of the hearing.

[293] The Board accepts that the gas market in the Maritimes has in recent years posed significant challenges to NSPI and other gas users. Mr. Reed described those challenges in response to a question from Board Counsel:

In fact, the prevailing market of course represents the confluence of all of those sources of supply and what you see in the Maritimes market is that the marginal source of supply sets the prevailing price and that marginal source of supply has shifted from being indigenous production to production that's outside the region. And in fact, as you start to bid gas away from either the Portland system or Dracut, you end up having to pay a higher price. In fact you -- again that marginal resource is setting the prevailing price in the region and that marginal resource is now coming from someplace else.

I expect that actually long term certainly will be the case. We may have an interim period in which the new gas causes us to go back to a Dracut netback market for a period of time; that would be great if it did. But long term, most people expect that in fact, gas will flow from south to north, into the Maritimes and that will be a Dracut-plus pricing regime. Even though there may be production in the Maritimes, the marginal source of supply will be from elsewhere.

[NSPI Closing Submission, November 23, 2012, p. 52]

[294] The Board accepts that the pricing dynamics of the Maritimes gas market have changed over the last few years as explained by Mr. Reed.

[295] Indeed, the evidence provided by Mr. Reed has given the Board an enhanced appreciation of how the gas market is unfolding in the Maritimes.

[296] Circumstances have given NSPI limited room to maneuver with respect to gas pricing given the shortage of supply.

[297] Finally, Liberty expressed its continued concern about affiliate relationships and, in particular, Emera's relationship as owner of the Brunswick Pipeline, with the principal shipper Repsol, a company who was also a dominant player in the Maritimes gas market. These concerns are reinforced by the fact that the Maritimes market is currently not transparent and is not liquid. The market has few buyers and sellers and a dwindling supply.

[298] While the Board is, and has been, concerned about affiliate relationships and as a consequence has imposed a rigorous code of conduct on NSPI, the Board does not see evidence in this proceeding which would, applying the test of a balance of probabilities, cause it to make any disallowance because of affiliate activity.

[299] In the circumstances, the Board makes no other disallowance with respect to NSPI's gas market activity. The Board, in future, expects NSPI to do "exactly what

Liberty has wanted the Company to do” with respect to aggressively pursuing any reasonable opportunities to purchase gas at as competitive as possible prices.

[300] Again, much of the evidence on this topic was filed in confidence and, accordingly, the Board is only in a position to give an overview of both the evidence and a summary of its findings.

11.6 Natural Gas Hedging

11.6.1 Evidence

[301] A common reference point for the pricing of natural gas in the Northeast is at Dracut, Massachusetts. The Henry Hub, a distribution hub at Erath, Louisiana, is used as the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). The price difference between the Henry Hub and another trading hub, including Dracut, is called the “basis differential”, or simply, the “basis”.

[302] In the winter of 2010-11, there was a marked increase in the “basis differential” with Dracut as a result of a series of events (referred to as a “basis blowout”), causing NSPI’s natural gas costs to rise.

[303] Liberty found NSPI’s natural gas costs for November and December 2010, and at least January 2011, were unreasonably high due to the Company’s failure to hedge Northeast Market “basis”. As a result of this finding, Liberty recommended the Board defer NSPI’s recovery of \$12.8 million pending a study of what hedges would have resulted under a properly designed hedging program for the winter of 2010-2011 and determine based on that program whether there would have been a cost associated with what Liberty identified as imprudent.

[304] The Northeast Market “basis blowout” was described by NSPI as follows:

A series of events starting in December 2010 caused the Dracut basis differential to rise throughout the winter of 2010-2011. First, the Henry Hub did not experience its usual winter price increase, so the baseline for the basis differential was lower than normal. Second, unusually cold weather in the northeast caused supplies in the area served by the Dracut hub to tighten. Third, severe weather prevented LNG tankers from docking at the Canaport terminal in Saint John, further exacerbating the supply shortage. Finally, in February, the Trans-Canada Pipeline ruptured and exploded at Beardmore, Ontario, 190 kilometres northeast of Thunder Bay, Ontario. This temporarily cut off supplies of Western Canadian gas to the Trans-Quebec and Maritimes pipeline and the Portland Natural Gas Transmission System, which serve the northeastern US. All these factors conspired to drive up the Dracut basis in an untypical and unforeseeable manner.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 54]

[305] Liberty indicates this \$12.8 million is a place-holder based on results NSPI provided as the potential savings for the two months, November and December 2010, extrapolated over the five winter months. A study was undertaken by NSPI after the “basis blowout” event in December 2010, related to the need to hedge the “basis”. However, Liberty indicates this study did not provide the proper hedging program to accomplish the objective of reducing basis volatility at least cost, nor did it identify the appropriate financial instrument that would accomplish this.

[306] NSPI indicated they appropriately considered these risks and addressed the risks associated with the change from the long-term Shell contract that expired October 31, 2010, stating the only significant change in risk was moving from monthly to daily pricing and that there was no material impact to basis exposure.

[307] NSPI took the position that its hedging during this period aligned with the objectives and requirements of the Fuel Manual, and that the direction within the Fuel Manual does not allow them to hedge the “basis”. It claims an appropriate study was completed in anticipation of the changes related to the long-term Shell contract, indicating it retained Black & Veatch to undertake a comprehensive study of natural gas pricing risks. Black & Veatch did not identify any need to change NSPI’s approach to

basis risk or hedging. This report dated November 23, 2010 was entered into evidence during the hearing. The Board agrees the Utility's consultant on hedging objectives and risks did not identify the "basis" risks. However, the Board notes that the scope of the study does not expressly include the assessment or identification of basis risks and the study makes no mention of them.

[308] NSPI also indicated their assessment of the risks associated with the expiration of the long term contract resulted in the implementation of swing/swaps at Henry Hub.

[309] During the hearing NSPI testified that an appropriate hedging program was in front of the FAM Small Working Group and that no other party identified a need to review basis differential.

[310] NSPI has also indicated that regardless of whether their response was appropriate, the cost to hedge the basis would have cost customers more than they would have saved from putting the hedges in place. Mr. Crook stated in his Pre-filed Evidence that there are no exchange traded hedging products for Dracut. Alternatives are costly, with few market participants willing to do it for Dracut.

[311] The SBA concurred with the recommendation to conduct a study of NSPI's hedging program. However, he did not recommend setting aside the \$12.8 million, stating this estimate is hypothetical. The SBA concluded though that, if it was found through the study that there is a cost associated with the imprudence, it should be disallowed.

[312] Other parties have supported Liberty's recommendations, including holding back \$12.8 million until the recommended hedging policy is studied and the cost determined.

11.6.2 Findings

[313] In setting the context for its consideration of this issue, the Board is mindful of the discretionary nature of hedging practices. Hedging, by any party, has never been intended to safeguard a company or utility from all risks that might occur in the future.

[314] The Board understands that NSPI, like any other party involved in hedging practices, requires some latitude to exercise judgment in the development and implementation of a hedging strategy. In the hearing, hedging was described as an art, rather than an exact science.

[315] In fact, the decision to enter into any specific hedge or hedging strategy is akin to the purchase of insurance to protect against future losses. Like insurance, there is a wide range of hedging products that are available to parties to protect their positions. These products also come at a range of prices. In choosing any particular hedging product, it is appropriate for a party to consider the reasonable risks which might be encountered in the future.

[316] Further, the Board recognizes that it is not appropriate to rely solely on hindsight in an analysis about the reasonableness or prudence of a hedging strategy. No person can predict the future. Accordingly, if circumstances occur which result in losses as a result of a particular event or a series of events, it does not necessarily follow that the chosen hedging strategy was wrong or unreasonable. Conversely, windfalls which occur as a result of unexpected future events which were not hedged do

not make the hedging decision a brilliant one. Further, the size of any loss does not factor into the consideration of the appropriateness of a hedging strategy.

[317] The Board considers that the reasonableness of a hedging strategy must be analyzed in the context of the facts or circumstances known or reasonably expected by the person or utility at the time the hedging strategy was developed or applied.

[318] In this instance, NSPI was faced in 2010 with a long term natural gas supply contract with Shell, which was coming to an end on October 31, 2010. In replacing that contract, two significant elements of NSPI's circumstances changed. First, the price of the gas under the new contract would be based on daily prices, which are more volatile, rather than monthly prices that existed under the former contract. Second, because of the interplay between natural gas and coal prices, NSPI generally started using the natural gas in its generation fleet under the new contract, rather than selling the gas to third parties. The impact of this latter element caused NSPI to bear the increased costs itself, rather than being able to pass them to third parties purchasing the gas.

[319] The Board is satisfied that NSPI did consider the impact of the impending conclusion of the long term Shell contract. In order to protect from negative fluctuations of prices for its gas purchases, it entered into a hedging strategy which adopted swing/swaps. This would help reduce the risk of volatility in daily natural gas prices, effectively replacing the daily prices with average monthly prices which were more stable.

[320] While the swing/swaps did provide some protection to NSPI from the above noted monthly/daily price risk, swing/swaps did not, unfortunately, protect from a

significant change in the “basis differential”. They are not intended to operate as a direct hedge of the “basis”.

[321] However, the Board accepts the hedging evidence of NSPI that an assessment of NSPI’s program in the fall of 2010 would not have reasonably uncovered the need to hedge the “basis”. The Board finds that no one could have reasonably foreseen the combined series of events which led to the “basis blowout”.

[322] The Board notes that NSPI had the benefit of expert advice from its consultants on the issue of hedging. As described in the hearing, both Black & Veatch and Leonard Crook have expertise in this area. Both consultants assisted NSPI with the development and implementation of its hedging practices. Black & Veatch was involved in a broad sense in its periodic review of hedging generally, while Mr. Crook was more actively involved in the decision-making process by advising NSPI in relation to gas purchases and hedging risk.

[323] The Board is satisfied that it was reasonable to retain and rely on the advice of Black & Veatch and Mr. Crook.

[324] Neither expert specifically identified a potential “basis differential” as a stand-alone risk to be hedged.

[325] The Board also notes that Liberty’s position on the issue of hedging practices appeared to change from the FAM Audit report through to the hearing. Initially in its report, Liberty concluded that NSPI should have placed a hedge on the basis differential, but at the hearing their opinion seemed to change to the view that NSPI should have examined this type of hedge in anticipation of the Shell long term contract coming to an end. Given the apparent softening of Liberty’s position on this issue, the

question becomes one of possible or potential imprudence, rather than actual imprudence. However, on the balance of probabilities, the Board concludes there is not sufficient evidence to warrant a finding of imprudence.

[326] After reviewing the evidence and the submissions, the Board is satisfied that NSPI could not reasonably have foreseen the events commencing in December 2010, which would lead to a significant change in the basis differential and result in the “basis blowout”.

[327] Further, even if NSPI had applied a hedging strategy to deal with a potential blowout in the basis differential, the cost of purchasing such hedging products, to the extent they were available, may possibly have cost ratepayers more than the “basis blowout” itself, which NSPI addressed immediately, early in 2011.

[328] Accordingly, the Board finds that no imprudence disallowance should be imposed on NSPI as a result of the “basis blowout” in the winter of 2010-11. Consequently, no specific review is required to study what amount NSPI might have saved in the winter of 2010-11 if it had adopted a different hedging strategy.

[329] During the hearing, NSPI’s hedging witness panel stated that a further examination of NSPI’s hedging practices would appear appropriate on a prospective basis.

[330] On the question of a prospective study, the Board does not consider that a specific direction is necessary. The Board expects that NSPI should be continually undertaking any studies or analyses about any aspect of its fuel management practices, including hedging, if considered prudent or appropriate to lower or stabilize fuel costs.

[331] Notwithstanding the Board's findings above, it wishes to comment on one submission by NSPI on this hedging matter. In its FAM Audit Reply Evidence, NSPI suggested that "the appropriate standard for judging our hedging program is to measure its compliance with the Fuel Manual" (p. 52).

[332] However, NSPI's own expert, Peter K. Nance, of Black & Veatch, stated that the Fuel Manual does not preclude NSPI from applying a new hedging strategy:

MS. STEWART: You would agree that the fuel manual doesn't dictate a certain strategy?

MR. NANCE: No, I don't think that it dictates one strategy. I think that it has guidelines, and fairly strong ones, for certain elements of the risk -- of the hedging strategy, and I tend to -- when I think about that, what I'm thinking about are the percentages of fixed price risk, as I refer to it, that is best to be -- suggested to be managed under the program. The less -- but in -- if -- but in terms of developing an overall response, my suggestion to you would be that, yes, I believe that NSPI has the authority and the ability to do that under the manual.

MS. STEWART: And so there could be different types of hedges that are entered into and still meet the requirements for fixed price management risk management ---

MR. NANCE: Yes.

[Transcript, October 31, 2012, pp. 868-869]

[333] Thus, in the Board's view, NSPI should not rely blindly on the express terms of the Fuel Manual to prevent it from using a new or different hedging strategy that would otherwise be reasonable in the circumstances.

11.7 FAM Audit Process

11.7.1 Evidence

[334] In its Reply Evidence, NSPI asserted that Liberty's FAM Audit is "fundamentally flawed", to the extent that the Board should reject all of the FAM Audit's conclusions and recommendations (including those which were supportive of NSPI's activities related to fuel).

[335] Among other criticisms, NSPI asserted that Liberty “has not acted in accordance with professional auditing standards”; “bases its major conclusions on a misapprehension of known facts”; its “approach, conclusions, and recommendations demonstrate insufficient knowledge and expertise in the subject matter of the audit”; and that “Liberty combines a lack of industry knowledge with a misguided approach to prudence review and a pre-existing bias against utility-affiliate relationships in order to develop a conspiracy theory that unjustly maligns NS Power, Emera, and the employees and executives of both companies”: see Exhibit N-135, pp. 4-5.

[336] NSPI asserted that:

The faulty conclusions of the FAM Audit arose from methodologies that were procedurally unfair and as such, did not meet the minimum professional standards for such an audit. Other than providing NS Power an opportunity to correct factual errors in the draft report, Liberty did not put its most serious allegations to NS Power during the course of the audit. This deprived NS Power of the chance to respond to these specifics, many of which could have been shown to be false merely by pointing to data already supplied to Liberty. Liberty’s investigative methodology was flawed. It took no steps to interview the Chief Executive Officers or the Chief Human Resources Officers of NS Power or Emera, each of whom are impugned by the Report.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 5]

[337] In addition to its request that the entire FAM Audit prepared by Liberty be rejected, NSPI suggests that Liberty should not conduct any future FAM Audit duties:

Despite [Liberty’s] extensive involvement with the creation, implementation, and operation of the FAM, Liberty Consulting Group has conducted the FAM Audits. We respectfully submit that Liberty’s deep involvement in the design and operation of the FAM precludes it from meeting the POA’s requirement that an “independent firm” conduct the audit.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 9]

[338] Moreover, NSPI also requests revisions to the FAM Plan of Administration:

NS Power proposes that the FAM Plan of Administration be revised in order to bring greater discipline and clarity to the audit provisions. These changes are designed to

ensure that the Board and customers are able to obtain the benefit of a constructive and efficient review of NS Power's fuel procurement and FAM compliance, and that the Company and its employees will not experience the kind of disruption and distraction that has been experienced in this most recent audit process.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 82]

[339] NSPI submits that the following changes be made to the POA:

- Adopt the Institute of Internal Auditors (IIA) – International Standards as applicable to FAM Audits;
- Define auditor independence, objectivity, and competence;
- Require FAM Auditors to be selected by competitive solicitation (RFP) under the authority of the UARB, independently of NS Power or FAM participants;
- Require the audit scope to be established and finalized, and provided to NS Power and interested parties to the FAM, prior to commencement of the audit;
- Establish fixed parameters for the audit, in terms of the time to complete the audit, and for NS Power to correct errors in the draft audit;
- Require auditors to raise serious matters of concern, or significant negative recommendations, with management during the course of the audit so that management can respond and action can be taken to remedy matters as appropriate;
- Establish a standard for the anticipated cost of the audit, with an appropriate process for the UARB to approve additional costs when appropriate, and allow the utility to recover the costs of the audit and related processes, pursuant to the FAM;
- Prohibit hindsight forecasting by auditors;
- Require that any subsequent consulting work that arises from an audit recommendation must be undertaken by a consultant that is not the auditor.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 83]

[340] In support of its position on the auditing standards to be applied in a FAM Audit, NSPI retained Deloitte.

[341] Deloitte drafted an audit plan and testimony that outlined potential differences between their audit approach and that of Liberty, based on a review of the final report. They observed:

- For some conclusions (presented in the section below), the report does not clearly state the evidence based on which the conclusions were drawn. We did not see evidence in the Liberty Report the Auditor conducted detailed audit procedures consistent with known standards of auditing to provide assurance to the NSUARB of compliance and use of good practices by NSPI in all cases as it relates to the FAM Audit

- The report appears to present points/conclusions relating to areas that extend beyond the scope of the FAM audit outlined under Section 5 of the POA. Circumstances/ other audit evidences that led to such extended scope will need to be examined or analyzed; and
- In specific cases (e.g., conclusions on hedging program), the conclusions appear to be based on a few selected months that might have had issues rather than the whole audit period or based on a randomly selected sample. It is important to examine if the same conclusions would be drawn on a random sample; Circumstances or selection criteria which led Liberty to form opinions based on specifically selected samples needs to be better understood to validate the conclusions.

[Exhibit N-131, p. 3]

[342] NSPI had Deloitte, Ms. Medine and Mr. Reed testify to auditing standards, with Deloitte recommending the Institute of Internal Auditors Standards and the US Government Accountability Office Auditing Standards, and others referring to the National Association of Regulatory Utility Commissions (“NARUC”) standards. During its testimony, Deloitte agreed the NARUC standards would also be appropriate:

MS. RUBIN: Would you concur that the NARUC guidelines would also offer suitable guidelines to the preparation of a FAM Audit?

MR. LOBAREC: Yes, I think that’s a reasonable question and I would agree, it could. It’s more about whether or not we go from assertion to specific ordered steps and then provide evidence that’s sufficient against those steps to reach a conclusion. Any of the ordered standards could lead you to that as long as those steps are followed in concert.

[Transcript, October 31, 2012, p. 820]

[343] NSPI experts also testified they had concerns related to Liberty’s compliance with auditing standards, referring to concerns with Liberty’s Audit Report with respect to the NARUC standards. Ms. Medine stated:

The FAM Audit and the FAM Audit Report do not meet industry standards with respect to guidelines established by the National Association of Regulatory Utility Commissioners (NARUC), the U.S. General Accounting Office (GAO), and other entities in a number of material ways. The most significant issues are as follows:

- Material areas of the FAM Audit were not conducted by individuals that have sufficient expertise and relevant experience.
- Confidential information was disclosed during the course of the FAM Audit.
- The FAM Audit Report was not objective and did not have a balanced tone.

- Liberty failed to support all material findings with relevant evidence.

[Exhibit N-133, pp. 2-3]

[344] In its FAM Audit Reply Evidence, NSPI placed particular emphasis on the Deloitte opinion, stating:

Deloitte's opinion is important for the Board to consider. Deloitte is a global auditing and consulting organization with the highest reputation for professionalism and integrity. The firm assigned accomplished international experts to the review of the FAM Audit. Deloitte identifies and applies established professional auditing standards. The Deloitte assessment identifies what NS Power respectfully suggests are serious gaps in the Liberty Report.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 81]

[345] The Board notes, as did Liberty in its Reply Evidence, that despite NSPI's characterization of Deloitte's evidence, nowhere did Deloitte describe any possible gaps in Liberty's audit as serious or significant in any way.

[346] Ms. Medine claimed other utilities have encountered similar problems with Liberty audits.

[347] However, Board Counsel witness Robert E. Curry, Jr., presented a different opinion. Mr. Curry is experienced in the field of utility regulation, including as a former Commissioner of the New York Public Service Commission. Based on responses from senior officials in 11 State regulatory entities, and based on his own personal experience with Liberty, he stated:

All of the respondents spoke highly of: Liberty's professionalism; the value Liberty's reports added to the regulatory process for both the utility and the regulator; its attention to keeping Staff of the client informed of its progress; the general interaction with the utility being audited (in spite of differences in views of the subject matter of the review); and, its overall effectiveness. No respondent reported any instance of prejudice or bias either for or against the utility or its regulator. "Tough but fair" was a term used by several commentators. ...

[Exhibit N-168, p. 5]

[348] In Board Counsel's questioning of the NSPI witness panel, he referred the panel to the views of National Grid about Liberty. National Grid delivers electricity to approximately 3.3 million customers in the U.S. Northeast. In a news release about a five month independent review of its accounting systems and practices, National Grid stated:

We engaged Liberty because of their reputation as being both thorough and independent. We wanted a report that would take a critical look at those areas where we need to improve, and this will help guide us going forward.

...

The company will share the report shortly with regulators in its various US operating areas. Liberty Consulting is a nationally recognized leader in providing independent reviews of regulated businesses. Its report is based on hundreds of data requests and employee interviews, site observations of systems operations, on-site document reviews, transaction testing and numerous working sessions

[Exhibit N-207]

[349] The NSPI witness panel did not challenge National Grid's view of Liberty.

[350] The Province also suggested that some revisions may be appropriate for the documents relevant to the FAM Audit:

The issues raised during the FAM audit suggest that it may be appropriate to consider a review of some of NSPI's guiding documents. It may be advisable for the FAM small working group to consider whether the hedging practices in NSPI's Fuel Manual should be assessed. It may also be appropriate to consider whether NSPI's Affiliate Code of Conduct should be reviewed to consider whether, and to what extent such a document can address NSPI's non-transactional relations with its affiliates (i.e., the extent to which NSPI's actions or inactions may or may not be influenced by the activities of its affiliates even when NSPI is not engaged in specific transactions with them).

[Province Closing Submissions, November 23, 2012, para. 26]

[351] However, the Province was concerned with the tone of the debate respecting the audit, including NSPI's response:

NSPI's FAM Plan of Administration ("POA") is also ripe for review. In many ways, the level of debate in this case over the FAM audit, a critical element of a successfully functioning NSPI FAM, was unfortunate. From NSDOE's perspective, the tone set by the FAM report audit could have been viewed negatively. Of course, tone can be difficult to

infer from the printed word, and sometimes tone can be imputed when it is not intended. Particularly if one is not engaged in actual dialogue.

Regardless of how it viewed the FAM Audit Report, NSDOE respectfully submits that NSPI's response did not help matters. NSPI apparently took the criticism as cause for war. Rather than responding quickly and confidently - it defensively called forth a battalion of high-priced experts to wage a war of words. And the FAM process has suffered collateral damage.

[Province Closing Submissions, November 23, 2012, paras. 27-28]

[352] The CA retained David P. Vondle to make recommendations with respect to the FAM Audit process. He is a partner with SAGE Management Consultants LLC, with 25 years of management consulting experience that includes leading 31 management audits. Mr. Vondle observed the NSPI response to the Audit was unprecedented, stating:

- With few exceptions, NSPI attacks conclusions and recommendations rather than findings (facts).
- NSPI admits it did not make factual corrections when it had the chance prior to the publication of the report. Normally, utilities take this opportunity to try to influence the conclusions and recommendations as well.
- NSPI attacks the NSUARB for hiring Liberty to do the FAM audit after Liberty acted as an extension of the NSUARB in putting the FAM process in place.
- The NSPI complaint about not having the scope of the audit is NSPI's own fault. NSPI could have insisted on having the work scope, work plan and schedule before beginning its participation in the audit. Also, the Liberty FAM Audit Report for 2010-2011 had the same chapters as the 2009 Report, with the exception that Economic Dispatch and Power Purchases and Sales were divided into two separate chapters for 2010-2011. (Tables of Contents) The 2009 Report had multiple negative conclusions and one quantification of excess cost, \$220 thousand, which could have been avoided by NSPI not granting a quantity flexibility option and more diligently enforcing the maximum volume limits of solid fuel contracts. (Page VI-21). The 2009 Report also recommended retroactive adjustments to the calculation of FAM carrying costs, but did not quantify the amount. (Page X-13) NSPI should not have been surprised by the scope of the 2010-2011 Audit.
- On the FERM staff turnover issue, the NSPI Reply Evidence confirms the Liberty finding that the entire FERM senior management team plus the next level-down Solid Fuels Scheduling and Logistics Coordinator turned over in the 2010-2011 period and that two of them left for affiliate positions. In the two-year period, FERM lost 10 of 18 employees and downsized to 16 positions – only eight employees were added. This is a lot of turnover in a small unit by any measure. At the end of the two year period, only eight of 18 original employees remained and none of the senior managers.
- The NSPI ad hominem attacks against Liberty are unprecedented in my experience.

- I am not familiar with Deloitte participating in the management audit or fuel audit business. I cannot recall them bidding or winning a Commission sponsored study. Perhaps they do in Canada or Europe. For example, the New Jersey Board just pre-qualified a set of seven management audit firms for the next round of management audits. Deloitte was not one of them. However, Liberty was one of the selectees.

[Exhibit N-169, pp. 8-10]

[353] Mr. Vondle does support potential changes to the Plan of Administration, however not as put forward by NSPI, indicating that some of NSPI's requests are "unusual" or "odd".

[354] The CA submitted in its Closing Submissions that it "has seen no evidence to support NSPI's attack on Liberty" (p. 8).

[355] The SBA submitted that there is no basis to reject the FAM Audit's findings or to dismiss Liberty as the auditor. He also noted NSPI's failure to respond to the FAM Audit as contemplated in the POA:

SBA argues there has been no substantive evidence filed or testimony heard at this FAM Audit hearing which supports the removal of Liberty as a FAM Audit Consultant. The uncomplimentary and unprofessional exchange of communication between Liberty and NSPI and the consultants is unfortunate. However, the SBA argues this does not establish that Liberty did not prepare an Audit report in an expert and detailed manner and they did forward a copy of the draft Audit report to NSPI for their review and comments; however, the reply that was forthcoming was to the effect, it was not worth replying to and the matter will be responded to through litigation at the FAM Audit hearing. SBA argues the long standing position of the Board was for the Board Consultant to prepare a draft report to be sent to NSPI for review and comments before finalization. It is undisputed that Liberty did send a draft audit report to NSPI for comments.

SBA argues there was ample opportunity before the time the report was filed, even up to the hearing, to attempt to negotiate areas of concern. Unfortunately, that did not occur.

...

Accordingly, SBA argues there was no substantive evidence filed by NSPI to have Liberty removed as auditor nor is there substantive evidence to request a new audit by a different auditor, and accordingly, this Board should reject NSPI's request in that regard and deal with the Audit Report on its merits.

[SBA Closing Argument, November 23, 2012, pp. 7-8]

[356] Avon also expressed its approval of the Audit conducted by Liberty, and its confidence in Liberty:

It appears to the Avon Group that upon finding that the Liberty Audit continued to press NSPI on certain issues, particularly related to the natural gas market and affiliate relationships, NSPI embarked on a strategy which focused on reputation management for NSPI through press conferences, media releases, direct contact with customers, expert evidence, overzealous confidentiality redactions and a concerted attack on the motives and credentials of the Liberty staff who performed the Audit, culminating in a recommendation that the entire Audit be rejected and Liberty prohibited from ever performing another audit of NSPI for the Board.

At the end of the day, and after all the noise, perhaps what was most telling is that despite the massive pre-hearing efforts to undermine the expertise of the Liberty witnesses, when given the opportunity during the hearing, NSPI did not ask one question to challenge the expert qualifications of the Liberty witnesses. Not one.

The Avon Group relies very much on the experience and expertise of Liberty and while there may be other auditors who could accomplish what is done by Liberty, there would be a steep learning curve which is neither efficient nor practical. It seems to the Avon Group that with Liberty's historical experience with NSPI comes greater knowledge regarding "problem areas" and the questions to ask. If Liberty ruffles feathers, so be it.

As noted by the Board in its decision on confidentiality of the FAM Audit, the focus in regulating NSPI is to examine whether NSPI's costs are prudently incurred. That goes to the heart of the regulatory compact, and the FAM is an integral component of the costs which NSPI seeks to recover. A meaningful, transparent audit is an essential part of the FAM. The Avon Group has seen nothing in the Liberty Audit Report or its dealings with Liberty that suggest that the Audit Report is so fundamentally flawed that it should be rejected in its entirety or declared "invalid" as urged by NSPI.

In the end, at best, NSPI's strategy in responding to the Audit was distracting; at worst, it served to frustrate the process. The Avon Group would strongly urge the Board in its decision to address not only the specific recommendations made in the Audit but also the Board's expectations regarding meaningful participation in the Audit process as a requirement for continued enjoyment of a FAM so as to ensure that these tactics do not interfere with the next audit process.

[Avon Final Submissions, November 23, 2012, paras. 33-37]

[357] Further, two Intervenor specifically noted their disappointment with the fact that NSPI only provided their opinion on the remaining recommendations in the FAM Audit in Undertaking U-22 filed at the very end of the hearing.

[358] The Province stated:

A response to the FAM Audit report, like the one seen in NSPI's response to Undertaking U-22 should have been a first response, and not dragged out during the last days of the hearing. ...

The FAM POA should be reviewed and revised to ensure that stakeholders receive appropriate responses to a FAM audit from NSPI, as soon as possible, and at a very early stage in the proceeding.

[Province Closing Submissions, November 23, 2012, paras. 29-30]

[359] Avon also expressed its concern with the lateness of NSPI's position on the remaining recommendations in the Audit report:

By failing to respond substantively to the draft Audit, and by taking the position that the entire Audit should be rejected by the Board, NSPI failed to provide key information to Liberty, the Board and stakeholders. Indeed, the Utility never indicated which of the 2012 Audit recommendations it accepted. This information was not provided until the last day of evidence in response to an undertaking given during the hearing.

Of 42 recommendations, NSPI apparently agrees with 27. Some of the recommendations with which NSPI does not agree were raised in a substantive way through this hearing, but others have not been addressed at all. NSPI's failure to provide this basic information in a timely fashion has impeded the Board and Intervenor from properly examining NSPI's position with respect to the 2012 FAM Audit.

[Avon Final Submissions, November 23, 2012, paras. 31-32]

11.7.2 Findings

a) Auditing Standards

[360] The Board will first address the issue of auditing standards. While NSPI cross-examined the Liberty witness panel at the hearing with respect to its evidence related to NSPI's fuel related activities (including the activities noted above which attracted disallowances), counsel for NSPI did not challenge or question any of Liberty's witnesses on their professional qualifications, nor did NSPI counsel cross-examine the Liberty witness panel on the auditing standards or methodology applied by Liberty in the FAM Audit.

[361] NSPI relied on Deloitte's evidence. However, the Board notes that while Deloitte is a reputable auditing and consulting firm, the scope of its engagement in this matter was limited.

[362] First, Deloitte was not engaged to express an opinion on the correctness of Liberty's FAM Audit opinions:

MS. RUBIN: And you were engaged to identify deficiencies in the report rather than provide an opinion on the correctness of Liberty's opinions?

MR. LOBAREC: We were engaged to identify potential differences, based on the way we would do our work and the way we're able to observe that it was done in the report we were provided from Liberty.

[Transcript, October 31, 2012, p. 814]

[363] Second, even though Deloitte was engaged to identify "differences" in the Liberty FAM Audit Report, Mr. Lobarec, Deloitte's national leader for energy and resources across Canada, acknowledged in his testimony that they did not review any of Liberty's working papers, nor did Deloitte even interview anyone at Liberty:

MS. RUBIN: ...And is it fair to say that the -- even at the end of your work, you were only able to identify some potential differences in approach?

MR. LOBAREC: That is correct. As we've said in our report, there may be factual evidence contained in work papers or other areas that we were not able to observe that would form a more reasonable basis for reaching some of those conclusions.

MS. RUBIN: Right. And the reason for that, identifying potential differences, is because you only took a high-level review of the Liberty report; correct?

MR. LOBAREC: It's probably more because we're engaged to develop an audit plan. So it's only based on the way that we would do the work and the factual basis or evidence that we would require against a report. So I hope that answers your question.

MS. RUBIN: But what you did was a high-level review of the Liberty report?

MR. LOBAREC: We were only able to read the report, that's correct.

MS. RUBIN: Right. You didn't review any supporting work papers?

MR. LOBAREC: No, we don't have access to that.

MS. RUBIN: Okay. And did you interview anyone at Liberty?

MR. LOBAREC: No.

[Transcript, October 31, 2012, pp. 814 – 816]

[364] Notably, Mr. Lobarec of Deloitte also admitted that none of the individuals involved in the preparation of Deloitte's evidence had, in fact, ever carried out a fuel management audit on behalf of a regulator:

MS. RUBIN: Were there -- how many people were involved in the preparation of the Deloitte evidence?

...

MR. LOBAREC: It is 10.

MS. RUBIN: It's 10, okay. Now, of those 10, is it correct that none have performed fuel management audits on behalf of a regulator?

MR. LOBAREC: In -- yes, that's correct.

[Transcript, October 31, 2012, pp. 816-817]

[365] Finally, Mr. Lobarec acknowledged that there is no single standard for an auditor conducting a fuel management audit:

MS. RUBIN: ...Now, would you agree that there's not one single correct approach to a fuel management audit?

MR. LOBAREC: Yes, it is open to interpretation. The adoption of standards and the way it's done varies. I do agree with that.

[Transcript, October 31, 2012, p. 814]

[366] In light of the above, the Board assigns little weight to Deloitte's evidence with respect to the issues in this FAM Audit.

[367] Ms. Medine was very critical of Liberty's auditing methodology.

[368] As noted earlier in this Decision, the Board gives little weight to Ms. Medine's evidence.

[369] This is not Liberty's first FAM Audit of NSPI. The 2010 Audit conducted in relation to the 2009 fuel related activities was met with general agreement by NSPI. At that time, NSPI did not express any concerns with the auditing standards applied by Liberty.

[370] Further, NSPI's assertions that Liberty has an "insufficient knowledge and expertise in the subject matter of the audit" and that it has a "lack of industry knowledge" is not borne out by the evidence. In this respect, the Board accepts the evidence of Mr. Curry, whose evidence was not challenged by NSPI, that Liberty possesses an excellent reputation with at least 11 regulatory commissions in the U.S., both in terms of Liberty's professionalism and its effectiveness in the conduct of audits.

[371] It is also instructive that NSPI did not cross-examine any member of the Liberty witness panel about their professionalism, qualifications or expertise.

[372] The Board is aware of the NARUC guidelines. On the basis of the evidence before it, the Board is satisfied that Liberty's FAM Audit is consistent with the NARUC guidelines. The FAM Audit was also conducted in a manner consistent with the process contemplated under the POA approved by the Board.

[373] In addition, it is noted that NSPI's customers were satisfied with Liberty's work on this file. The Board places significant weight on the support given to Liberty by the Intervenors representing most customer classes. The CA, the SBA and Avon all support Liberty in its conduct of the present audit and in future audits. It is clear that the present audit was conducted in a manner which met the expectations of these customer classes.

[374] The Board concludes that Liberty's FAM Audit followed appropriate auditing standards.

b) Future Audits

[375] The second issue considered by the Board relates to future audits. NSPI made a number of requests for changes to the POA and to restrict the engagement of Liberty on future FAM Audits.

[376] The Board notes that the issue of POA amendments or future audits was not on the Final Issues List approved by the Board for this proceeding.

[377] On this point, the Board indicated during the hearing that it would be more appropriate to review all aspects of the FAM in a separate proceeding where the FAM and all other issues related to it (including the POA) can be examined, rather than in a piecemeal fashion. The Board maintains its view on this issue.

[378] Accordingly, the Board makes no directive at this time with respect to possible changes to the POA or future FAM Audits.

c) NSPI's Response to the Audit

[379] Another issue which arose out of the evidence and submissions respecting the audit process relates to NSPI's response to the draft Audit Report submitted to it by Liberty. The Board shares many of the Intervenor's concerns.

[380] NSPI asserts that the nature of the allegations in the Audit Report justified its decision not to comment to Liberty on the draft Report and, instead, to launch a strong reply to the Report as part of the GRA hearing, including the engagement of numerous expert consultants.

[381] On the other hand, the CA, SBA, Avon, and the Province, submit that NSPI, in failing to respond to the draft Audit Report, acted contrary to the FAM Audit process contemplated in the FAM POA. Moreover, they assert that NSPI's failure to disclose material information in the hearing process, including in its FAM Audit Reply Evidence, in its Responses to Information Requests from Intervenors, and even in its testimony under cross-examination by the Intervenors, frustrated the FAM Audit process.

[382] These Intervenors are represented by experienced counsel who, except for the SBA, have been involved in the proceedings leading to NSPI's request for a FAM and the adoption of the FAM by the Board. NSPI's strategy in responding to the FAM Audit fell far short of the expectations of these counsel.

[383] As noted earlier in this Decision, the POA provides that NSPI would be provided with a draft Audit.

[384] When provided with the draft FAM Audit in June 2012, NSPI elected not to offer any comments to Liberty. It is clear from the terms of the POA that the final FAM Audit report is to "evolve" from the draft Report. This clearly contemplates input from NSPI about the contents of the draft Report. The POA provides that NSPI has 30 days to comment. Liberty specifically requested NSPI's comments. The prior 2010 FAM Audit had proceeded in this fashion.

[385] In its evidence, NSPI claimed that it did, indeed, respond to the draft Audit Report, referring to a reply email from its counsel Rene Gallant on June 24, 2012. However NSPI chooses to characterize Mr. Gallant's email, the Board finds that it

amounted, in effect, to a non-response on the substantive issues in the draft Report. Further, it was not the type of response contemplated under the POA.

[386] In choosing this course of action, NSPI did not provide Liberty with relevant information which might have caused Liberty to change its findings and recommendations, including possibly withdrawing some of the proposed disallowances. Further, if NSPI had discussed its concerns with Liberty about the tone of the draft Report, or about some of the observations in it, the language of a final Audit Report might have been more restrained. No one will ever know because of NSPI's response.

[387] NSPI's tactical response to the draft Audit Report contributed to further difficulties in the audit process. In accordance with the POA, Liberty did provide NSPI with a draft Report of its findings. NSPI's initial non-response led Liberty to file the draft Audit Report with the Board, in effect, becoming Liberty's final FAM Audit Report.

[388] In fuel management or prudence audits, the Board expects the auditor to report disputed or unresolved issues to the Board. Faced with NSPI's non-response to the draft Audit report, it was entirely reasonable for Liberty to then file its findings with the Board.

[389] Based on its review, the Board finds that NSPI's decision to ignore the draft Audit Report did not comply with the terms of the POA and its related conduct was unreasonable. Moreover, the Board notes that all of the auditing standards or guidelines cited by Deloitte, Ms. Medine, or Mr. Vondle contemplate the audited party reviewing a draft audit report and responding to any deficiencies that should be addressed. In this case, NSPI decided, for whatever reason, to forego the opportunity to respond and to challenge all of Liberty's findings and recommendations in the hearing

(even those findings which it later acknowledged it agreed with in Undertaking U-22). In so doing, the Board concludes that NSPI's conduct was contrary to what would have been reasonably expected under the POA. It certainly was contrary to the reasonable expectations of the Board and the Intervenors. NSPI also acted in a manner which is not consistent with the spirit and intent of audits generally, including fuel management or prudence audits.

[390] Further, NSPI's course of action distracted and misdirected all parties in this proceeding from addressing some of the other important issues in the hearing. NSPI's course of action had the effect of wasting scarce resources, in terms of time, money and human resources, for all parties.

[391] At this point, the Board notes that Liberty bears some of the responsibility for the acrimonious relationship which developed over the course of the FAM Audit process between NSPI and its FAM auditor. Some of Liberty's language was provocative in a way it did not have to be. In retrospect, the Utility's response might have been more tactful and reserved if Liberty had adopted a more measured tone in its criticism of NSPI's FAM activities. This would have resulted in a more productive Audit process.

[392] Nevertheless, the tone used by Liberty in a few of its findings is no excuse for the nature of NSPI's comments respecting the FAM Audit Report. NSPI's comments and non-responsive strategy only served to escalate the rhetoric and to hinder the efficient review of the Audit Report by the Intervenors and the Board.

[393] In making these findings, it is not the Board's intention to suggest that NSPI should not challenge any finding or recommendation by a fuel management

auditor, in a hearing if necessary. However, before it embarks on such a challenge, it has a responsibility under the POA, and to its ratepayers, to provide its comments in a timely fashion on a draft Audit Report delivered to it by the auditor. Such a response would help to resolve or narrow the issues identified during the Audit and would have allowed the Intervenors and the Board to conduct an efficient review of the Audit Report.

[394] In the future, the Board expects NSPI to conduct itself in accordance with the intent and the terms of the POA, including providing a meaningful response to the draft Audit Report.

d) Non-contested Recommendations in the Audit Report

[395] Finally, the Board is concerned with NSPI's failure to comment at an early stage with respect to the remaining recommendations in the FAM Audit. While it initially issued a blanket dismissal of the entire Audit Report (including the findings supportive of NSPI's fuel related activities), it ultimately agreed, at the end of the hearing, in an Undertaking requested by Avon, to identify which recommendations it agreed were reasonable. Initially, counsel for NSPI sought to limit the scope of the undertaking and questions about the other recommendations in the Audit Report. In Undertaking U-22, filed at the conclusion of the hearing, NSPI identified the recommendations it agreed with and which ones it did not. Interestingly, however, NSPI stated in its response to Undertaking U-22, "NS Power makes no comment on the conclusions in the Liberty report." Again, NSPI's approach unnecessarily lengthened the hearing and resulted in the inability of the Board and the Intervenors to delve into an efficient and meaningful assessment of the substantive issues identified in the FAM Audit.

[396] Despite its initial blanket rejection of all Liberty's FAM Audit recommendations, NSPI appeared to adopt a more conciliatory tone after the hearing was completed. In its Closing Submission, NSPI stated:

... NS Power's response to Undertaking U-22 outlines NS Power's position on each of the recommendations contained in the Liberty audit report. Out of 42 recommendations, NS Power agrees with 27 recommendations. At least 15 of these 27 Liberty recommendations are items that had already been undertaken by NS Power...or that are existing practices or plans of the Company...

[NSPI Closing Submission, November 23, 2012, p. 27]

[397] In its Reply to Closing Submission, NSPI asked the Board for the "rejection of the disputed conclusions and recommendations from the FAM Audit Report", offering no further comment on the remaining recommendations.

[398] Counsel for Avon noted that the late filing of such information deprived the Intervenor of the opportunity to conduct a meaningful assessment of the issues and, indeed, frustrated the conduct of the FAM Audit process itself. The Province, which typically takes no position in GRA proceedings, expressed similar concerns.

[399] In the future, the Board expects NSPI to outline, no later than in its Reply Evidence, which audit findings or recommendations it agrees with and which it does not.

11.8 FAM Small Working Group

[400] Another issue arose out of the FAM Audit hearing which the Board considers should be addressed. It is apparent that NSPI has a different view than the Board about the role of the various participants in the FAM Small Working Group ("SWG").

[401] In a few instances related to its gas hedging practices, NSPI indicated its reliance on the SWG for its decisions or course of action.

[402] For example, with respect to the losses incurred by NSPI as a result of the “basis blowout” commencing in December 2010, NSPI appeared to place some of the responsibility for its decisions on gas hedging strategies on Liberty and other members of the SWG:

Liberty is also a participant in the FAM Small Working Group. Minutes of the FAM SWG for the six months leading up to the basis blowout period make no reference to any comment by Liberty, or by any other stakeholder, identifying the need for a study to examine the potential for reducing fuel cost volatility by hedging the basis differential.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 55]

[403] Similarly, in its Closing Submission, NSPI stated:

As Mr. Bennett and Mr. Sidebottom explained, the Black & Veatch study was discussed with stakeholders during FAM Small Working Group (SWG) meetings, and the results of the study were provided to the FAM SWG. No concerns or objections were raised about the study or whether it was sufficiently comprehensive or focused. Liberty also reviewed the study and agreed with the study conclusions in a December 10, 2010 memo to NS Power. Despite Liberty providing its written comments just days before the December 2010 “basis blowout”, Liberty provided no complaint or criticism that the basis differential risk had not been addressed nor that additional focused study work should be done on basis differential or any other component of risk. Clearly Liberty did not, at the time, see basis differential as a significant risk any more than NS Power did. ...

[NSPI Closing Submission, November 23, 2012, p. 45]

[404] NSPI also appeared to implicate Liberty and the SWG in the “development” of the Fuel Manual:

The Fuel Manual is a highly prescriptive document, developed in close consultation with stakeholders and Liberty, and approved by the Utility and Review Board. NS Power believes the appropriate standard for judging our hedging program is to measure its compliance with the Fuel Manual.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 52]

[405] The Board wishes to reiterate that the role of the SWG, or any of its individual participants, is not to manage NSPI’s fuel related activities. The responsibility for such activities lies squarely on NSPI and not on any other SWG participant. Accordingly, NSPI should not seek to cast any responsibility on the participants for

particular actions taken by NSPI or to reproach the other participants for not suggesting an alternative course of action.

11.9 Remaining recommendations in FAM Audit

[406] As noted earlier in this Decision, NSPI did not initially indicate in its Reply Evidence which findings or recommendations of Liberty it agreed with. On the last day of the hearing, in an Undertaking requested by Avon, NSPI agreed to provide an Undertaking to the Board outlining which recommendations it rejects, which it accepts, and which it has implemented. In the latter case, NSPI was to outline its action plan.

[407] NSPI filed Undertaking U-22 on November 9, 2012. As noted by NSPI in its Closing Submission, it agrees with 27 of 42 recommendations. However, Avon states that NSPI's late filing of this information has impeded the Board and Intervenors from "properly examining NSPI's position with respect to the 2012 FAM Audit".

[408] The Board directs that NSPI proceed with the implementation of the recommendations it has agreed with in Undertaking U-22. In the instances where NSPI has not provided an action plan for the recommendations with which it agrees, it is directed to file its implementation plans by February 28, 2013.

[409] In the case of recommendations which are not agreed to by NSPI, it is to file a detailed explanation why it does not agree. This is also to be filed by February 28, 2013.

[410] The Intervenors will then be permitted to provide their comments to the Board by March 29, 2013, with respect to any of the remaining recommendations.

11.10 Disallowed Costs related to the FAM Audit

11.10.1 Evidence

[411] Earlier in this Decision, the Board reviewed instances in which NSPI undertook a course of conduct which, the Board considers, was contrary to what would have been reasonably expected under the FAM POA.

[412] NSPI repeatedly refuted a recommendation by Liberty to pursue concerns with the NEB and potential sellers of natural gas about the state of the Maritimes natural gas market. Moreover, Liberty's recommendation was, in effect, summarily dismissed by NSPI, who even went as far as to assert that Liberty did not understand the regulatory regime in Canada and that this was a basis for concluding that Liberty was inept and unqualified to perform its FAM auditing duties.

[413] However, on the very last day of the hearing, the NSPI witness panel, primarily Mr. Janega, revealed that NSPI had indeed carried out a course of action over the past few years which had actually taken into account Liberty's concern on the state of the natural gas market in the Maritimes. Of particular concern to the Board, in terms of the FAM Audit generally (including the administration of the POA), is the fact that NSPI, notwithstanding its course of action to the contrary, denied that Liberty's concern was in any way legitimate or worthy of any action.

[414] NSPI maintained its dismissal of Liberty's concern during the period leading to the release of the FAM Audit, as well as in its FAM Audit Reply Evidence, in its Responses to Information Requests from the Intervenors, and in its sworn testimony in cross-examination by these same Intervenors. NSPI's revelation about its actual course of action only occurred on the very last day of the hearing during questioning by Board Counsel.

[415] NSPI's course of action distracted and misdirected all parties in this proceeding (and the public) from the real issue which should have been addressed at the hearing about the natural gas markets. Moreover, NSPI's course of action had the effect of wasting scarce resources, in terms of time, money and human resources, for all parties, notably those of the Intervenor who participated in this proceeding, including experienced legal counsel and, likely in some cases, their expert consultants. This conduct resulted in increased costs for all Intervenor, including those representing most customer classes served by the Utility.

[416] The lack of disclosure by NSPI was not restricted to the matter involving the NEB.

[417] First, it was not until the hearing that NSPI disclosed the true extent of its response with the circumstances surrounding the withdrawal of Bid A by the counterparty, as described earlier in this Decision. It was not until her testimony that Ms. Trenholm, under cross-examination, revealed NSPI's actual reaction following those events. NSPI, in fact, voiced its strong displeasure with the counterparty, but decided that its interests would best be served in the long term by preserving the relationship. However, NSPI's actions and reasoning on this issue were not fully disclosed to Liberty or the Intervenor until the hearing.

[418] Another instance of inadequate disclosure arose in the context of the Lingard matter. Liberty had proceeded with its analysis of the issue using NSPI's schedule of different coal blends used at Lingard over the relevant period. However, during their cross-examination by NSPI, the Liberty witness panel was presented with a different schedule of coal blends used over the same time span. This required Liberty

to reconsider its analysis in an Undertaking. It is curious that, later in the hearing, when asked about the revised schedule by Board Counsel, Marie Thomas, of the NSPI Fuel Panel, was required to be briefly excused by the Board to confirm whether the revised schedule was, in fact, the correct schedule. Fortunately, her records matched the revised schedule, but what appeared to be confusion in communication among NSPI's different representatives was disconcerting to the Board.

[419] Yet another example of poor disclosure, for whatever reason, was in relation to the gas hedging issue and the Black & Veatch report. While it was clear from a plain reading of the Black & Veatch report that the issue of the "basis differential" could not reasonably be seen as a specific issue within the scope of the engagement, NSPI, in its testimony at the hearing, specifically its Fuel Panel, nonetheless characterized the Black & Veatch report as dealing directly with the issue. The Company had not previously disclosed its reliance on that report specifically for that purpose, even though it became a central theme of its testimony at the hearing on the hedging issue.

[420] The second issue which causes great concern to the Board is NSPI's failure to follow the process contemplated by the FAM POA for the development of the FAM Audit report itself.

[421] As noted earlier in this Decision, when provided with the draft FAM Audit in June 2012, NSPI elected not to offer any comments to Liberty. It is clear from the express terms of the POA that the final FAM Audit report is to "evolve" from the draft report. This clearly contemplates input from NSPI about the contents of the draft

Report. The prior 2009 FAM Audit had proceeded in this fashion. The POA provides that NSPI has 30 days to comment.

[422] In choosing this course of action, NSPI did not provide Liberty with relevant information which might have caused Liberty to change its findings and recommendations, including possibly withdrawing some of the proposed disallowances.

[423] On a related point, NSPI initially dismissed all the other FAM Audit findings and recommendations which were supportive of the Utility's fuel related activities or those which NSPI later indicated, in Undertaking U-22, that the Utility agreed with.

[424] Again, the result of NSPI's conduct, in failing to comment on the draft Audit report, is that it unnecessarily lengthened the hearing and wasted the time, money and effort of the Intervenors in this proceeding, as well as Board Counsel.

[425] In its Closing Submissions, the CA specifically requested that the Board sanction NSPI as a result of its conduct in responding to the FAM Audit:

In its pre-filed evidence and throughout much of its testimony before the Board, NSPI aggressively challenged Liberty's experience, qualifications, ethics, and independence.

Put simply, the Consumer Advocate has seen no evidence to support NSPI's attack on Liberty. Furthermore, the Consumer Advocate sees NSPI's attack as offensive to the regulatory process itself. Clearly, a mature utility needs to understand the difference between disagreeing with an auditor's recommendations and a baseless assault on the auditor's reputation.

In such circumstances, where a utility initiates and maintains baseless attacks on auditors appointed by the regulatory body, there ought to be a consequence for the utility.

An obvious consequence would be to assess some portion of the costs of the hearing which have been generated as a result of NSPI's intransience and to have them borne by the company and its shareholders. The assessment could consist of either a reduction of the costs that NSPI could otherwise recover and/or an assessment of a portion of the costs incurred by the Board and intervenors against NSPI. The assessment could be by way of a lump sum set by the Board in consideration of all the particular circumstances.

[CA Closing Submissions, November 23, 2012, p. 8]

11.10.2 Findings

[426] The Board is responsible for the general supervision of NSPI under the *Public Utilities Act*. Section 18 provides:

Supervision of utility by Board

18 The Board shall have the general supervision of all public utilities, and may make all necessary examinations and inquiries and keep itself informed as to the compliance by the said public utilities with the provisions of law and shall have the right to obtain from any public utility all information necessary to enable the Board to fulfil its duties.

[427] While the CA requests that NSPI be sanctioned for its conduct generally, the Board considers that any such sanction should relate to specific instances where NSPI has showed imprudence or ignored direction from the Board.

[428] In this respect, the Board expects NSPI to comply with its Decisions, Orders and directives, including its oversight procedures such as the FAM Audit and the POA. In the Board's opinion, NSPI's conduct in relation to the NEB issue and the aggressive pursuit of gas supplies, and its decision not to comment on the draft Audit Report, were both unreasonable and inappropriate. Further, as noted above, its conduct on these specific points resulted in unnecessarily extending the length of the hearing and wasting the time, money and effort of the Intervenors and Board Counsel.

[429] In these circumstances, the Board finds that a sanction is warranted as against NSPI. In accordance with its jurisdiction under s. 18 of the *Public Utilities Act*, as well as its mandate under the *Act* generally, the Board concludes that a disallowance of \$2 million is appropriate and it so orders.

[430] In determining the disallowance of \$2 million, the Board has relied, in part, on its evaluation of unnecessary costs incurred by the CA, SBA and the Board as a

result of NSPI's response to this FAM Audit. Likewise, NSPI, itself, would also have incurred unnecessary costs.

11.11 Implementation of the FAM disallowances

[431] As a result of the Board's findings earlier in this Decision, disallowances have been made as against NSPI with respect to its imprudence and its conduct in relation to directives by the Board. These disallowances must now be implemented in this Decision.

[432] As noted earlier, the Board has approved the GRA Agreement. Further, in a separate proceeding, by Order issued December 10, 2012, the Board has approved the 2013 FAM Actual Adjustment (AA) and Balance Adjustment (BA) recovery values. Both of these approvals were made subject to any further adjustment arising from this Decision.

[433] There are several options to implement the disallowances.

[434] The SBA recommended as follows:

SBA points out while the overall amount of imprudence disallowance amounts are small as a percent of revenues they still maintain an important monetary issue for small businesses of Nova Scotia. Small businesses have felt the hard impact of the current economic climate. Increases in electric rates associated with raising [sic] NSPI costs and the losses of large customer loads will present the SBA's constituents with yet [another] straw to add to a burdened back. SBA suggests that the manner to return the benefits of any disallowance is to first go to offset or wipeout the 2012 FAM AA adjustment. This would reduce the specter of looming future rate increases and the potential for the timing of recovery in 2015 to coincide with any other increases, including fuel prices. NSPI's business customers need stability as much as they would benefit from lower rates. SBA believes this is especially true of the small businesses where there is less medium and long term business and financial planning. This would allow the 3% already agreed upon to be implemented.

If there are disallowances in excess of the 2012 FAM AA adjustment SBA urges the Board to consider providing the benefit of the returning funds for disallowances to customer classes as a single month rebate within two months of the Board issuing a decision. This would provide a more pronounced benefit to SBA's small business constituents, an economic stimulus of sorts.

[SBA Closing Argument, November 23, 2012, p. 24]

[435] In its Closing Submissions, the Province “urged the Board to ensure that any savings that result from the FAM Audit be passed along to customers as soon as possible”.

[436] The political parties who participated in this proceeding submitted that any disallowance should be returned to ratepayers immediately.

[437] With respect to the fuel-related disallowances totaling \$4,503,000 for the Lingan derates and the Bid B natural gas contract, this amount must be applied to the 2013 FAM Balance Adjustment (“2013 BA”).

[438] The Board notes that applying this fuel disallowance to the 2013 BA will actually reduce the fuel deferral to be collected from ratepayers starting in 2015. This deferral of the fuel disallowance is consistent with the manner adopted by the Intervenor for the non-fuel reductions they negotiated in the GRA Agreement.

[439] More importantly, applying the fuel disallowance amount against the deferral will benefit ratepayers by reducing the deferral amount attracting interest and the 9% rate of return for NSPI.

[440] A different implementation procedure applies for the \$2 million disallowance arising from NSPI’s conduct contrary to the POA.

[441] While some Intervenor may have suggested different alternatives were available to the Board, it considers that this disallowance must be applied against NSPI’s 2012 earnings.

[442] The Board has decided that the 2012 revenue requirement is to be adjusted for purposes of applying clause 26 of the 2012 Settlement Agreement. Clause 26 reads as follows:

Subject to necessary adjustments to incorporate paragraph 7 above, the s.21 AAA Mechanism will continue to operate on a go forward basis until the s.21 amount is fully paid. Amounts in excess of both the range of return on equity and in excess of the room available in the s.21 AAA Mechanism will be returned to customers.

[Decision, 2011 NSUARB 184, p. 13]

[443] The threshold for triggering payment under clause 26 of the 2012 Settlement Agreement will be \$2 million lower than it otherwise would have been. If NSPI otherwise over earns in 2012, an additional \$2 million will be applied to the deferrals for the benefit of ratepayers.

[444] The Board notes that while this \$2 million disallowance does not provide a direct benefit to ratepayers going forward, it could, as explained above, benefit ratepayers if there is an impact on the treatment of the s. 21 amount under the 2012 Settlement Agreement.

[445] The Board directs the implementation of all the disallowances as described in this section.

11.12 Perspective

[446] NSPI's fuel budget over the two year period covered by the Audit is approximately \$1 Billion or \$500 Million per year. The Liberty Audit recommended a disallowance of approximately \$10 million in fuel spending, approximately 1% of the budget. Liberty recommended further investigation of the hedging issue. While Liberty made other recommendations in the Audit, it did not question 99% of the fuel spending undertaken by NSPI and indeed, parts of the Audit were very complimentary to NSPI's fuel acquisition activities.

[447] From the outset NSPI chose to focus its own and the public's attention on this 1% - ignoring the balance of the Audit and indeed trashing the whole Audit.

[448] NSPI also chose to focus on reputation; its own reputation alleging defamation, which lead to a separate preliminary hearing in August, and attacking Liberty's reputation, alleging bias, incompetence, and irresponsibility, among other things.

[449] Power rates are, at the best of times, a top of mind issue with the public in Nova Scotia. The majority of the members of the public are NSPI's customers.

[450] NSPI is free, and must be free, to conduct any case before the Board in the manner that best suits it.

[451] However, having read the comments of the CA, SBA and Avon, who are all regular parties to these proceedings, and having reflected on the matter, the Board cannot help but observe that NSPI's relationship with the public and other parties to most of these proceedings has suffered damage.

[452] One of the conditions attached to the approval of the FAM was "a meaningful audit process under the administration of the Board". The Board and customers expect the Board's auditor to ask the tough questions and to identify areas where costs might have been avoided. Simply because the Audit recommends a disallowance, does not mean the Audit is flawed or biased. In making a disallowance the Board is not finding that NSPI's fuel team are not competent or professional. They are both competent and professional.

[453] Credit rating agencies and others who follow these proceedings should understand this perspective. The FAM Audit process approved without question 99% of NSPI's fuel costs. The Audit was critical of only 1%. The Board has, in the result,

accepted two recommendations for disallowance, amounting to much less than 1%. NSPI has a functioning FAM.

12.0 MISCELLANEOUS

12.1 Information Requests

[454] The Board observed a practice NSPI adopted in this hearing which had not been prevalent in the past by answering an IR as follows:

NS Power will provide this information to the Board upon request.

[Exhibit N-32, IR-33]

[455] Such an answer is not responsive or helpful to the questioner. An IR is either “in scope” and relevant and deserves an answer or is “out of scope” and irrelevant, in which case NSPI can refuse to answer it. NSPI should take a position in the original answer which, if the questioner disagrees, can be further reviewed by the Board at the request of the questioner. The response noted above simply delays proceedings which are often on a very tight time schedule. This is not acceptable.

13.0 COMPLIANCE FILING

[456] The rates approved in this Decision are effective January 1, 2013 and January 1, 2014, respectively.

[457] NSPI is directed to file a Compliance Filing as soon as conveniently possible.

[458] The Formal Intervenors must provide comments, if any, no later than three full business days thereafter.

[459] Further, the Board directs NSPI to outline in 2013 and 2014 where it has applied the \$27.5 million non-fuel cost reductions negotiated in the GRA Agreement. This disclosure is to accompany the year-end financial statements in the respective years.

14.0 SUMMARY OF BOARD FINDINGS

Settlement Agreement

[460] This Decision deals with the Board's consideration of both NSPI's general rate application and of the FAM Audit Report.

[461] NSPI's Application requested the Board's approval of a Rate Stabilization Plan ("RSP"). The RSP is a two-year rate plan, with net increases of three percent per year effective on each of January 1, 2013, and January 1, 2014. According to the Application, the increases will cover a portion of the increased costs forecast by NSPI in each of the next two years. NSPI proposed the remaining revenue requirement be deferred for future recovery commencing in 2015.

[462] NSPI reached a settlement agreement ("GRA Agreement") with most of its customer classes, including the CA, the SBA and Avon.

[463] The Board approves the GRA Agreement, which adopts the two year RSP proposed by NSPI and represents a comprehensive resolution of many contested issues between NSPI and the Intervenors, who indicated that, without the RSP, customers would have faced much larger rate increases, particularly in 2013. They stated that the RSP will "smooth out rate increases experienced by customers" and provide a "predictable measure of stability" over the next two years.

[464] The GRA Agreement provides for a \$27.5 million non-fuel cost reduction in NSPI's deferral account balance. The deferral of forecasted revenue requirement will not exceed \$47.1 million at December 31, 2013 and will not exceed \$84.8 million at December 31, 2014.

[465] In the Board's view, an important component of the GRA Agreement which will benefit customers is the RSP, which limits across-the-board 3% increases in each of 2013 and 2014, while deferring recovery of NSPI's remaining revenue requirement to 2015. The recovery of the deferral, commencing in 2015, will coincide with the end of the Section 21 Tax Deferral, which has already been included in existing rates over eight years ending in March 2015. The deferral in the RSP will be collected over an 8 year period beginning in 2015.

[466] The GRA Agreement also reduces NSPI's return on equity from 9.2% to 9.0%, along with a change to the earnings band of 8.75 % to 9.25 %. This will also result in further reductions to NSPI's revenue requirement for 2013 and 2014.

[467] The rates approved in this Decision are effective January 1, 2013 and January 1, 2014, respectively. Rates will increase by 3% for each customer class on January 1, in each of 2013 and 2014.

Pension Costs

[468] In last year's general rate Decision, the Board indicated that it would investigate the issue of pension costs in this proceeding. It appears to the Board that until very recently NSPI has done little, if anything, to address increasing pension costs.

[469] NSPI confirmed to the Board that it reached an agreement with the IBEW on the terms of a new collective agreement which was approved on November 5, 2012, including changes to the pension plan.

[470] The Board sees this change as a significant step in pension reform. The Board accepts these changes as adequate initial steps.

[471] In future years these costs savings will be embedded in the revenue requirement asked of customers. However, the Board expects NSPI in future to take additional steps to improve contributions to, and the funding of, the pension plan.

[472] Two issues also arose in the course of the hearing with respect to NSPI's Supplemental Executive Retirement Plan (SERP). This plan is available to employees who earn more than approximately \$150,000 per year. The Board considers it unreasonable that the most highly paid employees working for NSPI make no contribution to the supplemental pension plan.

[473] NSPI is free to continue to provide that benefit, however, the Board directs that in the test years and in future NSPI must adjust the revenue requirement to deduct an amount from the SERP pension payments to reflect a deemed employee contribution to the SERP, on the assumption that the employee had contributed 50% to the pension plan and the employer 50%. The Board understands the amount to be disallowed is \$2.05 million in 2013 and \$2.2 million in 2014.

[474] Also, NSPI secures the SERP pension by purchasing a letter of credit, using funds paid entirely by ratepayers. In the Board's view, payment for that portion of the letter of credit that secures the pension is an unnecessary expense and is not an expense that should be borne by ratepayers. Accordingly, the Board disallows that amount from the revenue requirement.

[475] These deductions are in addition to the \$27.5 million provided for in the GRA Agreement.

Executive Compensation

[476] The Legislature has passed amendments to the *Public Utilities Act* limiting the amount of remuneration, bonuses and other benefits that can be recovered from rates with respect to compensation of executive employees of NSPI.

[477] In its Compliance Filing, NSPI is to reduce its revenue requirement to reflect the changes as a consequence of this legislation, including pension payments on behalf of executives.

LED Streetlighting

[478] The Board agrees that dealing with the streetlight issue as a part of a capital work order is a reasonable approach with the exception of the net book value question.

[479] The Board denies HRM's request to recalculate the net book value of streetlights currently included in the NSPI rate base. How this amount is shared between municipalities is something NSPI should work out with them.

[480] In a second issue raised by HRM, the Board orders NSPI to confirm by February 28, 2013 that no new non-LED streetlights were ordered or purchased after the Board's 2012 GRA Decision.

Low Income Residential Customers

[481] The Board approves the Settlement Agreement filed by the Affordable Energy Coalition, NSPI and the CA, which sets up a consultative process "with a view to resolving bill payment, credit and collection matters affecting low income residential customers".

Cost of Service – Biomass

[482] The Board finds that NSPI's recently constructed 60 MW biomass plant at Point Tupper, Nova Scotia, has similar characteristics to any other steam plant. The Board directs that it should be classified on the basis of system load factor, because it makes a contribution to capacity and provides firm power.

Natural Gas Storage

[483] The Board denies the request of Alton Natural Gas Storage L.P. to order NSPI's participation in a natural gas study with Alton and Heritage Gas.

FAM Audit

[484] The Liberty Consulting Group was engaged by the Board to conduct the FAM Audit for the period covering 2010 and 2011. The FAM Plan of Administration ("POA") provides that an audit of the FAM will be done every second year.

[485] The Board made a number of findings in relation to the FAM Audit Report. The Board noted the importance of transparency, as well as the full and timely disclosure of complete and adequate information, in its original approval of the FAM.

[486] Credit rating agencies and others who follow these proceedings, including the public, should understand that the FAM Audit process approved without question 99% of NSPI's fuel costs. The Audit was critical of only 1%. The Board has, in the result, accepted two recommendations for disallowance, amounting to much less than 1%. In making a few disallowances, the Board is not finding that NSPI's fuel team are not competent or professional. They are both competent and professional. NSPI has a functioning FAM.

Lingan Derates

[487] The Board finds, on the balance of probabilities, that NSPI was aware in July/August 2010 that there were quality issues related to the Prince coal. NSPI did not investigate and test other coal blends to mitigate the risks of the failure to meet opacity limits.

[488] In failing to mitigate the known risks of derates from using Prince coal, the Board finds that NSPI was imprudent. The Board also concludes that imprudence on the part of NSPI led to the derate of the Lingan facility.

[489] The Board orders a \$3.6 million disallowance with respect to the Lingan derates.

Natural Gas Contracts

[490] With NSPI's long term natural gas supply contract with Shell coming to an end on October 31, 2010, NSPI issued a Request for Proposals to acquire replacement quantities of natural gas to supply its projected needs. One of the two lowest offers ("Bid A") was withdrawn after NSPI felt it had already accepted the offer via a term sheet. The other lowest offer ("Bid B") was rejected by NSPI, largely due to NSPI's concern about associated transportation costs and potential risk of supply interruption.

[491] The Board does not believe that NSPI's actions with respect to Bid A were imprudent. Based on the evidence, it appears to the Board there was never a meeting of the minds between NSPI and Bidder A on the terms of the offer. Liberty acknowledged that there was not an enforceable contract.

[492] However, with respect to Bid B, the Board is very concerned about NSPI's failure to properly analyze the costs and benefits of taking an assignment of this very favourably priced contract.

[493] Liberty prepared an analysis that showed that NSPI was better off after five years, based on this favourable pricing, as compared to other pricing it was able to obtain even if the transportation contract was useless from that point forward.

[494] In the Board's view, NSPI was imprudent in failing to properly analyze the risks and benefits associated with the Bid B contract which the Board believes could have been very beneficial for ratepayers.

[495] The Board disallows \$903,000 related to the failure to take an assignment of the Bid B contract for the period from November 1, 2010 to December 31, 2011 (i.e.,

426 days). As this was a longer term contract the impact of this finding on any future test years will be the subject of consideration in future audits.

[496] Finally, the Board does not believe there is a sufficient basis for it to make any disallowance based on NSPI's monthly, seasonal or daily purchases.

Natural Gas Markets

[497] On the last day of hearing, and in a confidential session, NSPI disclosed new and important evidence concerning its activities in the natural gas market. Unfortunately, because of its confidential nature, the Board can disclose little, if any, of this evidence in this public Decision. This evidence was not previously disclosed to Liberty, the Intervenors or the Board.

[498] NSPI's actions in withholding this information are both inexplicable and inexcusable. In the Board's view, that conduct cannot go unsanctioned. The Board will impose a financial disallowance to NSPI, as described below.

[499] However, on the substantive issue related to natural gas markets, the Board makes no other disallowance with respect to NSPI's gas market activity.

Natural Gas Hedging

[500] The Board is satisfied that NSPI could not reasonably have foreseen the events commencing in December 2010, which would lead to a significant change in the "basis differential" and result in the "basis blowout". Accordingly, the Board finds that no imprudence disallowance should be imposed on NSPI with respect to this issue.

FAM Audit Process

[501] The Board concludes that Liberty's FAM Audit followed appropriate auditing standards. The FAM Audit was also conducted in a manner consistent with the process contemplated under the POA approved by the Board. In addition, the Board noted that Liberty's work on this file was supported by the Intervenor representing most customer classes.

[502] The Board makes no directive at this time with respect to possible changes to the POA or future FAM Audits. The Board indicated during the hearing that it would be more appropriate to review all aspects of the FAM in a separate proceeding where the FAM and all other issues related to it (including the POA) can be examined, rather than in a piecemeal fashion.

[503] The Intervenor and the Board were disappointed with NSPI's response to the FAM Audit. In failing to respond to the draft Audit Report, NSPI acted contrary to the process contemplated in the FAM POA. Its conduct was also contrary to the reasonable expectations of the Board and the Intervenor. NSPI also acted in a manner which is not consistent with the spirit and intent of audits generally, including fuel management or prudence audits.

[504] Further, NSPI's course of action distracted and misdirected all parties in this proceeding from addressing some of the other important issues in the hearing. NSPI's course of action had the effect of wasting scarce resources, in terms of time, money and human resources, for all parties.

[505] In the future, the Board expects NSPI to conduct itself in accordance with the intent and the terms of the POA, including providing a meaningful response to the

draft Audit Report, along with an indication of which audit findings or recommendations it agrees with and which it does not.

[506] The Board notes that Liberty bears some of the responsibility for the acrimonious relationship which developed over the course of the FAM Audit process between NSPI and its FAM auditor. Some of Liberty's language was provocative in a way it did not have to be. In retrospect, the Utility's response might have been more tactful and reserved if Liberty had adopted a more measured tone in its criticism of NSPI's FAM activities. This would have resulted in a more productive Audit process.

Remaining Recommendations in the FAM Audit

[507] The Board directs that NSPI proceed with the implementation of the remaining recommendations it has agreed with in Undertaking U-22. In the instances where NSPI has not provided an action plan for the recommendations with which it agrees, it is directed to file its implementation plans by February 28, 2013.

[508] In the case of recommendations which are not agreed to by NSPI, it is to file a detailed explanation why it does not agree. This is also to be filed by February 28, 2013.

[509] The Intervenor will then be permitted to provide their comments to the Board by March 29, 2013, with respect to any of the remaining recommendations.

Disallowed Costs Related to FAM Audit

[510] The Board expects NSPI to comply with its Decisions, Orders and directives, including its oversight procedures like the FAM Audit and the POA. In the Board's opinion, NSPI's conduct in relation to the NEB issue and its decision not to

comment on the draft Audit report were both unreasonable and inappropriate. Its conduct on these specific points resulted in unnecessarily extending the length of the hearing and wasting the time, money and effort of the Intervenors and Board Counsel.

[511] In these circumstances, the Board finds that a sanction is warranted as against NSPI and concludes that a disallowance of \$2 million is appropriate.

Implementation of the FAM Disallowance

[512] With respect to the fuel-related disallowances totaling \$4,503,000 for the Lingan derates and the Bid B natural gas contract, this amount must be applied to the 2013 FAM Balance Adjustment ("2013 BA").

[513] The Board notes that applying this fuel disallowance to the 2013 BA will actually reduce the fuel deferral to be collected from ratepayers starting in 2015. This deferral of the fuel disallowance is consistent with the manner adopted by the Intervenors for the non-fuel reductions they negotiated in the GRA Agreement.

[514] More importantly, applying the fuel disallowance amount against the deferral will benefit ratepayers by reducing the deferral amount attracting interest and the 9% rate of return for NSPI.

[515] A different implementation procedure applies for the \$2 million disallowance arising from NSPI's conduct contrary to the POA. This disallowance must be applied against NSPI's 2012 earnings.

[516] The threshold for triggering payment under clause 26 of the 2012 Settlement Agreement will be \$2 million lower than it otherwise would have been. If NSPI otherwise over earns in 2012, an additional \$2 million will be applied to the deferrals for the benefit of ratepayers.

Other Revenue Requirement Reductions

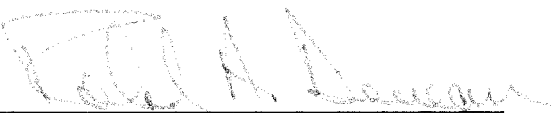
[517] As noted earlier in this summary, the reductions in pension costs and executive salaries will lower the test year revenue requirements, in addition to the \$27.5 million provided for in the GRA Agreement.

[518] An Order will issue following the Compliance Filing.

DATED at Halifax, Nova Scotia, this 21st day of December, 2012.



Peter W. Gurnham



Roland A. Deveau



Kulvinder S. Dhillon

APPENDIX A

NOVA SCOTIA POWER INC. 2013 RATE APPLICATION – INCLUDING THE FAM AUDIT P-893/M04972

LIST OF PARTICIPANTS

Affordable Energy Coalition

Alton Natural Gas Storage LP

Avon Group

(Avon Valley Greenhouses Ltd.)
(Canadian Salt Company Limited)
(CFK Inc.)
(Crown Fibre Tube Inc.)
(Halifax Grain Elevator Limited)
(Imperial Oil Limited)
(Lafarge Canada Inc.)
(Maritime Paper Products Ltd.)
(Michelin North America (Canada) Inc.)
(Minas Basin Pulp & Power Company Ltd.)
(Oxford Frozen Foods Limited)
(Sifto Canada Corp.)
(Nustar Terminals Canada Partnership)

Bowater Mersey Paper Company Limited

Cape Breton Explorations Ltd.

Consumer Advocate

Halifax Regional Municipality

Municipal Electric Utilities of Nova Scotia Co-operative

Municipality of the District of Yarmouth

Nova Scotia Department of Energy and Nova Scotia Environment

Nova Scotia Liberal Caucus

Nova Scotia Power Inc.

Progressive Conservative Caucus Office

Small Business Advocate

Strait Area Mayors & Wardens and Town of Port Hawkesbury

Union of Nova Scotia Municipalities

TAB 14



NS POWER DISCUSSES RATE STABILIZATION PLAN WITH CUSTOMER REPRESENTATIVES

[» MORE IN THIS SECTION](#)

MAY 5, 2011

HALIFAX, NS – Nova Scotia Power met with customer representatives today (May 5) to discuss a plan that would stabilize growth in electricity prices for three years. The proposed Rate Stabilization Plan would hold rate increases to four percent per year for 2012 to 2014 for each customer class.

“By using some short-term deferrals of expenses, we can smooth price changes for customers over the next three years,” said Rene Gallant, Vice President of Regulatory Affairs, Nova Scotia Power. “We strive to ensure that electricity prices are as low as possible for our customers, and that any price changes are as manageable as possible. This plan will help.”

Last month, NS Power initiated a public discussion with customer representatives aimed at developing a multi-year approach to smooth increases in electricity rates through 2014. The Rate Stabilization Plan builds on that effort. In order for a rate change to take effect on January 1, 2012, Nova Scotia Power will be required to file a General Rate Application with the Nova Scotia Utility and Review Board (UARB) later this month. Nova Scotia Power has not yet made a final decision to make such a filing. General rates were last adjusted on January 1, 2009. Nova Scotia Power has been able to avoid filing a general rate application for three years, thanks to prudent management of expenses, tax credits from renewable energy projects, and the ability of the UARB to adjust fuel expense recovery through the Fuel Adjustment Mechanism (FAM).

“Our customers have benefitted from Nova Scotia Power being able to avoid a general rate application for three years,” Mr. Gallant said. “However, since 2009, we’ve made substantial investments in infrastructure, reliability improvements, and recruiting and retaining skilled workers. Those investments haven’t been accounted for in rates, and coal prices are continuing to climb.”

Using current rates, 2012 revenues would be \$94.4 million less than forecasted requirements of \$1.34 billion. Without the Rate Stabilization Plan, NS Power is forecasting average increases in general rates of 9 percent in 2012, four percent in 2013 and two percent in 2014. The Plan proposes to defer recovery of fuel cost increases for three years. Recovery of deferred costs would begin in 2015.



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TAB 15



NOVA SCOTIA POWER: ELECTRICITY RATE STABILITY THROUGH 2015

» [MORE IN THIS SECTION](#)

APRIL 1, 2014

HALIFAX, NS - Nova Scotia Power (TSX: NSI.PR.D) announced today that the company does not plan to file a general rate application this year for higher electricity rates in 2015. The company is also proposing no fuel rate increase for 2015.

"We know price certainty, stability and affordability are important to our customers," said Bob Hanf, President and Chief Executive Officer. "Customers have also asked us for clarity on where rates are heading – particularly business customers who are preparing their 2015 budgets. It's important to provide certainty on base rates, and indicate our objective for no rate increases in 2015."

Since the Nova Scotia Utility and Review Board approved a two-year Rate Stabilization Plan in 2012, Nova Scotia Power has implemented internal productivity initiatives to significantly reduce operating costs. Focus on cost management remains a priority for the company in 2014.

"We are focused on affordability for customers," said Hanf. "The Rate Stabilization Plan has allowed the company to reduce costs while improving service and reliability. We continue to address the challenge of rising fuel costs."

Nova Scotia Power has initiated discussions with customer representatives regarding rate recovery of outstanding fuel costs, and has proposed no fuel cost increase for 2015, while managing these costs for our customers. Since January 2013, Nova Scotia Power has incurred approximately \$95 million more in fuel costs than those estimated and included in rates pursuant to the Fuel Adjustment Mechanism. Additional fuel costs have been primarily driven by constraints in the supply of natural gas in Nova Scotia.

Electricity rate adjustments in Nova Scotia occur through either a general rate application or the Fuel Adjustment Mechanism (FAM) process. The FAM ensures that customers pay only the actual, prudently incurred costs of fuel used to make electricity. Applications under either mechanism are adjudicated by the Utility and Review Board through a public process.