

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

DECISION 13-2007

August 29, 2007

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

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

THE PUBLIC UTILITIES BOARD

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ABBREVIATIONS

AECO-C	Alberta Energy Company Gas Storage Facility
AFUDC	Allowance for Funds Used During Construction
AMR	Automatic Meter Reading
ARO	Asset Retirement Obligations
BC	British Columbia
BCUC	British Columbia Utilities Commission
BR	Board Information Request
CE	Comparable Earnings
CEO	Chief Executive Officer
CICA	Canadian Institute of Chartered Accountants
CO ₂	Carbon Dioxide
DCF	Discounted Cash Flow
DPC	Dogrib Power Corporation
ERP	Equity Risk Premium
FAA	<i>Financial Administration Act</i>
FMV	Fair Market Value
FSF	Fuel Stabilization Fund
FTE	Full-Time Equivalent
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
GNWT	Government of the Northwest Territories
GRA	General Rate Application
GWh	Gigawatt-Hour
HC	Hydro Communities
HDD	Heating Degree Days
HR	Human Resources
IT	Information Technology
kWh	Kilowatt-Hour
L	Liter
m ³	Cubic Meter
MERP	Market Equity Risk Premium
MWh	Megawatt-Hour
NB	New Brunswick
NCP	Northern Canada Power Corporation
NTEC	NWT Energy Corporation

NTHC	Northwest Territories Hydro Corporation
NTPC	Northwest Territories Power Corporation
NUL	Northland Utilities
NWT	Northwest Territories
NYMEX	New York Merchantile Exchange
O&M	Operation & Maintenance
PLC	Power Line Carrier
<i>PUA</i>	<i>Public Utilities Act</i>
PUB	Northwest Territories Public Utilities Board
R.S.N.W.T.	Revised Statutes of the Northwest Territories
RFID	Reserve for Injuries and Damages
ROE	Return on Equity
S&P	Standard & Poors
SM	Senior Management
TCS	Terms and Conditions of Service
TGC	Thermal Generation Communities
TSX	Toronto Stock Exchange
TWU	Technical Workshop Undertaking
U.S.	United States
WCB	Worker's Compensation Board
YK	Yellowknife
Yr	Year

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1. BACKGROUND & APPLICATION

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

In its Application (Ex.2), the Corporation requested an order or orders of the Board to approve the 2006/07 and 2007/08 Revenue Requirement at \$79.909 million and \$84.331 million, respectively, including approval as required of the operating and maintenance expenses, amortization expenses and return on rate base. NTPC is also requesting an order or orders of the Board to approve the forecast 2006/07 and 2007/08 Rate Base, approve revised Terms and Conditions of Service, approve revised Maximum Corporation Investment levels, stabilization funds and accounting provisions.

Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letter dated November 30, 2006, directed NTPC to publish notice of the public hearing of the GRA in newspapers that circulate in the Northwest Territories. The notices published in December 2006 included details and schedule of the GRA, and invited interested persons to file a request with the Board for intervenor status (Ex.1)

By letter dated December 4, 2006, NTPC informed all communities that they had filed a GRA with the Board (Ex. 21).

NTPC, by e-mail dated December 18, 2006, advised all registered parties, that the Corporation would be holding a technical workshop on January 8, 2007 in Yellowknife.

NTPC, by e-mail dated January 9, 2007, provided all registered parties with a list of parties who attended the workshop, a copy of NTPC's presentation and a list of undertakings (Ex. 3). NTPC responded to the undertakings on January 12, 2007 (Ex. 4).

Interested parties were provided the opportunity to make request further information through information requests of NTPC and to file evidence. The requests elicited written responses from NTPC. Written evidence was filed on behalf of the City of Yellowknife and the Towns of Fort Smith and Hay River ("**Hydro Communities**" "**HC**") by letter dated February 23, 2007 and on behalf of the communities of Fort Liard, Fort Simpson and Inuvik ("**Thermal Generation Communities**" "**TGC**") by letter dated March 16, 2007. Information requests were issued by the Board and NTPC to the HC and the TGC in response to their written evidence. All written information requests by the Board and intervenors together with the responses were made available to all parties before the hearing.

The Corporation submitted a letter, dated May 16, 2007, setting out certain revisions to its GRA and supporting materials (Ex. 13).

2. PUBLIC HEARING

The hearing was held in the City of Yellowknife on May 23, 24 and 25, 2007. During the course of the hearing, members of the public who had not requested intervenor status were invited to participate in the proceeding. NTPC's panels were cross-examined by counsels for the HC and the TGC on the elements of the GRA. The TGC and HC panels were cross-examined by the counsels for the NTPC.

Board staff examined NTPC's panels and the interveners' panels with respect to a number of issues arising out of an analysis of the Application, including community specific issues. During the hearing, NTPC provided responses to a number of undertakings given at the hearing.

All parties, at the hearing, agreed to file Argument by June 18, 2007 and Reply Argument by June 29, 2007.

TGC, by letter dated June 8, 2007, requested an extension to the Reply Argument from June 29, 2007 to July 3, 2007, because their consultant was involved in another proceeding commencing the week of June 27, 2007 and attending a regulatory conference during this period. By letter dated June 13, 2007, the Board approved the requested extension to July 3, 2007.

3. RATE BASE

This section of the Decision examines the issues raised with respect to determination of the Corporation's rate base for the test years. Rate base includes gross plant in service and working capital.

3.1 Gross Plant in Service

This section of the Decision examines the issues raised with respect to determination of the mid year gross plant in service.

3.1.1 L199 Re-commissioning

The L199 transmission line experienced difficulties with respect to splices in 1996/97. The line was recommissioned in 1999 and the Corporation sought to include the costs of the recommissioning in its rate base at the 2001/03 Phase 1 GRA. At the time, NTPC was also pursuing legal claims against various parties who were involved in the initial construction of L199.

Pursuant to the 2001/2003 GRA Negotiated Settlement ("**01/03 Settlement**"), the L199 recommissioning expenses were not included in NTPC's rate base pending resolution of the outstanding legal claims. NTPC was to establish a deferral account to record the expenditures made to recommission the transmission line, which accrued interest at the rate used for the Corporation's fuel and water stabilization funds.

The 01/03 Settlement further provided that “*Following the final resolution of the existing litigation respecting the Transmission Line L199, the Corporation will apply to the Board to determine the final disposition of the balance in the deferral account.*”

The total cost of the project was \$3.494 million. Interest charged to the deferral account since the 01/03 Settlement totals \$0.765 million. The net recoveries from the legal claims were \$1.191 million (\$1.605 million gross proceeds minus \$0.414 million legal and related costs). Consequently, the net addition to rate base is \$3.068 million.

The HC submitted customers have already paid once in rates for the construction of the L-199 line and as a result of its having failed prematurely, they are being asked to pay again for all portions of the loss not assumed by one of the parties to the lawsuit (other than NTPC) through the 01/03 Settlement.

The HC noted the difference between the reported project costs of \$3.494 million and the gross proceeds of the 01/03 Settlement of \$1.605 million is \$1.899 million. The HC submitted pursuant to Section 49 of the *Public Utilities Act* (“**PUA**”) R.S.N.W.T. 1988, c.24 (supp.), the Board is to determine a rate base based on prudent costs. The Board is not empowered to reward the utility for the financial consequences of negligent (imprudent) behavior on its part. This is true whether the imprudence is characterized as the failure to properly inspect the splices and dead ends, as alleged by the parties to the lawsuit, or a failure to ensure that there were prudent contractual arrangements with contractors including the reasonable provisions for insurance and guarantees of proper workmanship and materials that a prudent owner would require.

The HC submitted failure on the part of NTPC to be prudent in this regard, should not lead to increased rate base or increased rates for customers. In light of the fact there is no evidence that the lawsuit was not pursued vigorously, and given that the deferral account, including interest, can be interpreted as arising at the request of customers at the time of approval of the 01/03 Settlement, the HC requested a reduction to the direct or “hard costs” identified by NTPC in Chapter 6 of Exhibit 2. Accordingly, the HC submitted that the net addition to rate base of \$3.068 million requested by NTPC should be reduced by \$1.899 million, being the difference between the total cost of the project and the amount recovered in the 01/03 Settlement. (HC Argument, p. 53 – 54)

In its reply argument, NTPC submitted that there is absolutely no evidence on the record with respect to the degree or truth that NTPC’s inspection of the splices during the original construction of the transmission line was inadequate. The Corporation stated the HC called no evidence on the inspection procedures followed by prudent utilities when supervising contractors on transmission projects, nor did they request any evidence on NTPC’s own procedures in respect of this project to permit a comparison in support of their allegation. NTPC submitted the HC provided no evidence that any inspection process commensurate with industry-standard practices in 1989 (which would clearly meet any reasonable test of prudence) would have uncovered the inadequate splices. The only material filed in this proceeding that relates in any way to the inspection of splices are the unsworn Statements of Defence filed by parties that were being sued by NTPC – which parties went on to pay substantial sums to NTPC in order to settle said lawsuit. NTPC submitted it is important to recognize that the allegations made by the Defendants reflect typical defendant pleadings, and were never proven or conceded by the Corporation. Consequently, the HC have failed to rebut the presumption of prudence and the Board has no basis

whatsoever on which to make a finding of fact with respect to NTPC's 1989 inspection practices in relation to the splice failures.

With respect to the prudent contractual arrangements issue raised by HC, NTPC stated its contract with MacGregor Construction Ltd is not in evidence in this proceeding. The HC did not request it be put into evidence, nor did they call any evidence in respect of the contractual terms that "a prudent owner would require" to contrast to the contents of NTPC's contract with MacGregor Construction Ltd. The Corporation submitted such evidence could have been secured, for example, by expert testimony in regards to utility contracting procedures at the time of the 1989 contract, had the HC sought to have the Board make this determination. NTPC stated the HC have failed to rebut the presumption of prudence and, absent any evidence addressing contracting standards of the day, there is no basis for the Board to make a finding on NTPC's contractual arrangements with its L199 contractors. (NTPC Reply, p.38)

The NTPC submitted that the HC Argument is entirely premised on the fact that the Corporation agreed to settle the case for \$1.605 million, rather than proceed to trial to pursue full recovery of the recommissioning costs; consequently, the HC conclude that a full finding of fault on the part of the defendants (and not on NTPC) is unavailable and further suggest that as a result, NTPC should be viewed to be partially at fault for the failures. NTPC stated this conclusion is incorrect and not appropriate. NTPC stated the reasons for its decision to accept the settlement, and not to proceed to trial, include the costs of a lengthy trial (which may not be all recovered even if the Corporation won at trial), the evidentiary difficulties stemming from the fact that the construction project was completed nearly 20 years ago and many of the parties to the project were no longer available, as well as substantial concerns over the ability of certain defendants to be able to satisfy any significant judgment against them. The

Corporation submitted a concern about a potential finding of fault did not factor into the Corporation's decision to settle the lawsuit. The Corporation submitted further that the decision of a plaintiff to accept a substantial sum of money in settlement of its lawsuit does not reflect an admission of negligence or even partial negligence on its part and any insinuation to this conclusion is wholly inappropriate.

Views of the Board

The Board is of the view that any disallowance of costs must arise from clear evidence that the Corporation was negligent in its actions with respect to the L199 repair project or that the management of the project or the lawsuit was in some other way imprudent. Based on the evidence in this proceeding, the Board finds that there is not sufficient evidence to arrive at a finding the Corporation was negligent, nor is there other evidence of poor management in respect of the L199 project or of a lack of prudence on the Corporation's part. Accordingly, the Board will allow the Corporation to include the \$3.068 million cost of the L199 transmission repair in rate base for the 2005/06 fiscal year.

The Board expects NTPC, in its dealings with contractors, to establish prudent contractual arrangements including the reasonable provisions for insurance and guarantees of proper workmanship and materials that a prudent owner would require.

3.1.2 Fort McPherson Power Plant

The Corporation included the following rate base additions in 2004/05 and 2005/06 with respect to a plant rebuild and other improvements resulting from a fire in the community of Fort McPherson:

	2004/05	2005/06	Total
	\$000	\$000	\$000
Diesel power plant additions	7336	660	7996
Insurance proceeds	-5085	0	-5085
Net Additions	2251	660	2911

NTPC indicated the \$2.911 million net additions to rate base consisted of betterments amounting to \$1.896 million as well as \$820,000 for capitalized overhead expenses not covered by insurance and \$193,000 deductible on the plant rebuild. (BR.NTPC-27)

The TGC submitted there is very little evidence on the significant difference between the forecast replacement costs (\$5.5 to 7.0 million) and the actual cost to rebuild of \$9.816 million. Given the sheer magnitude of the cost of the re-build, and the extent of cost overruns, the onus is on NTPC to demonstrate its costs were reasonably and prudently incurred. The TGC considered the Corporation might have incurred higher costs with respect to the project as a result of having to complete the project within a time frame stipulated by the insurance underwriter. TGC submitted there should be at least a 10% disallowance of costs incurred to re-build the Fort McPherson plant for the above reasons. (TGC Argument, p. 44)

NTPC indicated there is no evidence to suggest the Corporation incurred additional costs due to the requirement to complete the work within a stipulated timeframe. (NTPC Reply, p. 35)

Views of the Board

The Board notes the actual cost of plant rebuild excluding betterment costs is \$6.1 million [\$7.996 million total plant costs minus betterment costs of \$1.896 million]. The Corporation recovered \$5.085 million of the plant rebuild costs from insurance proceeds.

The Board notes from the response to TGC.NTPC-55(b) that the Corporation charged an amount of \$315,000 to the reserve for injuries and damages (“**RFID**”) in 2005/06 with respect to the Fort McPherson plant fire repair deductible and items not covered by insurance. Given that the plant fire repair deductible is already included as a charge against the RFID in 2005/06, the Board does not find NTPC’s explanation in BR.NTPC-27 that the deductible on plant rebuild in the sum of \$193,000 included again as a component of the plant rebuild costs, to be a credible explanation of the costs comprising the net capital additions in relation to the Fort McPherson plant. Accordingly, the Board directs NTPC, as part of its refiling, to reduce the opening plant balance for 2006/07 by \$193,000 being that portion of the rate base addition for the Fort McPherson plant that has not been explained nor demonstrated to be a prudent expenditure by NTPC.

3.1.3 Bluefish Generating Station

NTPC added the Bluefish generating station to rate base in 2004/05. The purchase price plus the cost of capital works amounts to \$12.603 million. In support of the Bluefish addition to rate base, NTPC stated as follows:

“In response to BR.NTPC-9, the Corporation noted that at the time of the purchase, the Bluefish purchase was estimated to have a positive impact for ratepayers with a net-present value of \$38.1 million. Since that time, the economics of the purchase have been affected by a number of factors,

most notably increases in the price of diesel fuel, offset by actual and forecast capital improvement costs that are higher than was anticipated at the time of the Bluefish purchase. As a result of these factor, an updated project economic assessment was presented in BR.NTPC-9, which indicates that the net present value benefit to ratepayers is now expected to be \$51.4 million (2005\$) – an increase of 35 per cent from the forecast at the time of the project permit application.

In summary, the Bluefish project was a prudent acquisition that is providing benefits to customers today and will continue to provide benefits into the future. No intervenor submitted evidence to suggest that the costs of the project were not reasonable. The Corporation submits that the project should be approved as part of the rate base for the test years.” (NTPC Argument, p. 48, // 8 - 20)

Views of the Board

The Board considers the purchase of the Bluefish hydro plant to be prudent and approves the inclusion of the plant in rate base in 2004/05.

3.1.4 Snare Rapids Plant Upgrade

NTPC added \$3.838 million in 2005/06 and proposed the addition of \$1.305 million in 2007/08 to rate base with respect to the Snare Rapids plant upgrade. In support of the Snare upgrade additions to rate base, NTPC stated as follows:

“The Snare Rapids Plant upgrade was reviewed and approved by the Board in Decision 8-2004. The project permit application included NTPC’s proposed budget of \$4.984 million, which was specifically noted as being a “budget level” estimate and not an “engineering pre-design” estimate. The GRA forecast costs are \$0.159 million higher and include capital costs of \$3.838 million in 2005/06 and forecast costs of \$1.305 million in 2007/08 for total project capital costs by the end of the test period of \$5.143 million. A breakdown of the costs included in the \$3.838 million portion of the project was provided in response to HC.NTPC-60(a).

The Corporation submits that the project costs included in the test period are reasonable and should be approved.” (NTPC Argument, p. 49, // 15 - 23)

Views of the Board

The Board notes none of the interested parties raised any concerns respecting the Snare upgrade additions. The Board considers the Snare Rapids plant upgrade additions to be prudent and approves the inclusion of the plant in rate base as proposed.

3.1.5 Aklavik Power Plant

NTPC proposed the addition of \$5.298 million with respect to a new modular power plant in Aklavik to rate base in 2007/08. NTPC indicated the existing plant was originally built in 1976. Since that time, the community has developed in the area around the plant. With this increased development, there have been complaints from local residents related to plant noise and air emissions. As a result, the Corporation indicated it has received support from the Aklavik Council to relocate and build a new modular power plant outside the town property.

The project permit for the modular power plant at Aklavik was approved at \$4.9 million in Decision 11-2006. The Board notes the forecast costs are higher than the project permit estimate by \$398,000 or about 8%. The Board also notes the project cost estimate was increased from \$3.5 million to \$4.9 million at the time the project permit application was submitted to the Board. At that time, NTPC indicated the increased costs are attributable partly to delays from the original schedule due to ongoing consultations with the community and due to deployment of the Corporation’s engineering staff to address the fire at Fort

McPherson. (Decision 11-2006; p. 4) The Board notes that although the project permit application contemplated addition of the unit to rate base in 2006/07, the Corporation is now proposing to add the plant to rate base in 2007/08.

Views of the Board

The Board is concerned by the significant cost overruns noted at the time of the project permit application and the additional adverse cost variance between the project permit amount and the forecast addition for 2007/08. The Board considers some of the cost increases resulted from unforeseen circumstances, which resulted in delays in the completion of the unit, and the Board is not convinced the customers of Aklavik should bear the entire cost risk resulting from these delays. Accordingly, the Board considers the carrying costs and overheads associated with delays due to unforeseen community consultations and deployment of the Corporation's engineering staff to address the fire at Fort McPherson should be shared between the Corporation's shareholder and the customers of Aklavik.

The Board directs NTPC, in its Phase 1 refiling, to reduce the cost of the Aklavik plant addition by 50% of the cost increase resulting from the delays. The costs to be included for the 50% risk sharing adjustment are overheads and Allowance for Funds Used During Construction ("**AFUDC**") resulting solely from the delays in completion of the plant caused by the unforeseen length of time spent on community consultations and the fire at Fort McPherson.

3.2 Fort Liard Distribution Upgrade

NTPC proposed to add \$900,000 to rate base in 2007/08 in the community of Fort Liard. NTPC indicated this project consists of upgrading the plant voltage from 600 volts to 4,160 volts. This increase in voltage capacity is required to meet any future load growth that may occur due to increased oil and gas activity in the area.

TGC argued that since this project is not expected to go ahead during the 2007/08 test year, the corresponding costs should be removed from rate base:

“However, in Response TGC.NTPC-58, NTPC indicated there was uncertainty as to when the expected growth in oil and gas activity would materialize; further, at hearing, NTPC confirmed this project is not anticipated to proceed.

Based on the foregoing, the TGC submit this project, with a forecast cost of \$900,000 in 2007/08 should be removed from rate base. It is not clear what load growth is exactly included in the 2007/07 forecast for Fort Liard; obviously, if the capital project is removed, the TGC expect any associated load forecast should be removed as well, and NTPC should be directed to provide this information.” (TGC Argument, p. 24)

NTPC submitted it is not appropriate to recognize this one change in the capital forecast without regard to offsetting other projects.

“...TGC argues for removal of this one project to reflect actuals despite having sought no evidence at any time in regards to the dynamic changes in the capital plan, the reprioritization that has occurred during the year and the offsetting other projects that have been changed or added to the plan on an actual basis that were not forecast.

Under a future forward test year regulatory framework, the utility’s forecasts leading forward from the date of filing are the appropriate basis for developing and testing the revenue requirement. To the extent they are

available, some actual results can aid in the testing of the reasonableness of the forecasts, but it is simply not appropriate to substitute those actuals for the utility's forecast. Were that to be the case, the form of regulation would be more akin to retrospective regulation with an assured earning of a fair net income and return, which is not the regulatory framework in NWT or any other Canadian jurisdiction." (NTPC Reply, p.3. // 7 - 17)

Views of the Board

The Board notes the Corporation appears to have recognized the forecast sales based on which the plant upgrade was predicated would not materialize at the time of the filing of the Application.

"NTPC has forecast the load to reflect the latest information at the time of filing concerning the impact of oil and gas activity which is lower than when this project was first identified." (TGC.NTPC-58(c))

The Board is of the view that it was likely that the Corporation would have known the project would not proceed at the time of the filing of the GRA. Therefore in order to be consistent with the determination of the sales forecast, the Corporation's forecast plant upgrade should also be excluded from rate base additions in 2007/08. The Board directs NTPC, in its refiling, to exclude the capital addition related to the plant upgrade amounting to \$900,000 from rate base additions for Fort Liard in 2007/08.

3.3 Working Capital

The Corporation's calculation of necessary working capital for the test years is set out in Schedules 5.8 and 5.9 of the Application. One of the components of working capital is the allowance of cash working capital. The purpose of allowing cash working capital is to recognize the time lag that occurs between when payments for expenses are made and when the corresponding revenues are

received. The cash working capital was estimated on the basis of a lead lag study carried out by the Corporation.

The TGC expressed concern that the revenue lag days in the lead lag study were unduly high because they were estimated on the basis of the maximum time allowed for payment of bills before penalties are imposed:

“The TGC submit NTPC’s assumption all customers pay on the “maximum allowable time for payment prior to interest charges” may be over-stating the revenue lags to the extent customers pay their bills prior to the date interest charges commence. To this end, the Board should direct NTPC to incorporate, in its next GRA, a proper sampling of bill payments from various sources (industrial, wholesale, NWT Housing Association, Territorial Subsidy and Domestic/Commercial/Street Lighting) in order to properly assess the actual number of days it takes on average for customers to pay bills. To the extent payments received after the due date attract interest and/or late payment penalties, the Corporation should also address why such payments should be included in this sample for purposes of conducting the lag associated with revenue collection.” (TGC Argument, p. 48)

The TGC also expressed concern that the expense items comprising the cash working capital do not reflect the corresponding net lag days associated with that expense item. TGC submitted the Board should direct NTPC, in its refiling, to provide a computation of its cash working capital for the Test Years using the net lead or lag associated with each expense item.

Views of the Board

The Board agrees with TGC that the use of the maximum number of days before penalties are imposed to estimate the revenue lag is unrealistic. Accordingly, the Board directs the Corporation to estimate the revenue lag based on sampling the

number of days it takes for recovery of revenues, on average, from customers, for the next GRA.

The Board also agrees with TGC that each item of expense in the cash working capital calculation should reflect its corresponding lead or lag. This is to recognize the changes in the relative proportions of expenses included in the cash working capital calculation from year to year. Accordingly, the Board directs NTPC to provide, in its refiling, a computation of its cash working capital for the Test Years using the net lead or lag associated with each expense item.

4. RETURN ON RATE BASE

4.1 Cost of Debt

NTPC calculated the effective cost of long-term debt using the following formula:

$$\text{Effective Cost of Long Term Debt} = (I + AFC - SFE) / (DWAD - UFC - SFI)$$

Where:

I= Interest on Daily Weighted Average Long Term Debt

AFC= Amortization of Financing Costs

SFE= Sinking Fund Earnings in the year

DWAD= Daily Weighted Average Debt Principal

UFC= Unamortized Financing Costs

SFI= Sinking Fund Investment

The resulting debt rates proposed by NTPC for the two test years are as follows:

2006/07	10.532%
2007/08	10.927%

The calculation of the effective cost of long-term debt is provided in Schedule SM 3 of Exhibit 3 from the Technical Workshop. NTPC also provided a detailed continuity schedule of the sinking fund balance for each of the sinking fund debt instruments in Exhibit 4 Table NTPC.TWU-15. Further details respecting sinking fund investment terms were provided in HC.NTPC-23.

The HC in its filed evidence disagreed with NTPC's proposal to include sinking fund earnings and the sinking fund investment as part of the effective cost of long-term debt calculation. HC expressed the view the sinking fund earnings as

well as the sinking fund balance should be excluded from the calculation of the effective cost of long-term debt.

“Our recommendation is that the Board adopt the method of calculation prescribed by the Board in Alberta for this purpose, which considers no sinking fund earnings in the calculation. Further, we recommend that the resulting embedded cost of debt be used by NTPC for all its calculations, including but not restricted to AFUDC, working capital and capital lease. We recommend the method prescribed by the Board in Alberta because of the inequities in the current formula used by NTPC to calculate the cost of debt with sinking funds that are due to the formula’s construction and because the costs that are generated from the current formula explode as the debentures approach maturity. ...” (Ex.8, p, 107)

The HC also recommended the Board consider some cost sharing with respect to certain sinking fund debentures, namely, the \$20 million debenture issued in March 1989 with a coupon of 11%, the \$15 million debenture issued in June 1991 with a coupon of 11.125% and the \$20 million issued in March 1992 with a coupon of 10.75%. HC indicated cost sharing with the shareholder would be appropriate since these debentures did not include a call feature and the Corporation’s sinking funds investment policy prior to the proclamation of Bill 9 which permitted more diversified investments in the sinking fund, did not conform to best practice.

“Yes, we would recommend that the Board consider some cost sharing between the rate payers and shareholders of NTPC that recognizes the ongoing excessive costs associated with the three earlier debentures with sinking funds and with earlier management of the investment policy of the sinking fund in addition to our recommendations at page 107. The reason for the former is that these debentures did not conform to “best practice” because they did not include a call feature, and the reason for the latter is that the earlier investment policy did not conform to the principles of “prudent portfolio” management because the portfolio of investments was not well diversified and could have achieved a higher return with about the same risk.” (Ex.8, p.108)

The HC submitted that it is appropriate to examine the terms of the sinking fund issues in this proceeding since the Corporation did not specifically request the current sinking fund treatment until the 2001/02/03 GRA and then it was implicitly approved as part of a 01/03 Settlement.

“NTPC implies that each of the sinking fund issues was subject to Board review and approval, and from that perspective, it would be unfair to revisit the terms and conditions of bonds that were issued up to 17 years ago. It should be noted that while the Board approves the purposes of the bond or debenture at the time of issue, it typically defers approval of the specific terms and conditions, and in this case the regulatory treatment of debentures with sinking fund provisions, to the next GRA. NTPC did not specifically request the current sinking fund treatment until the 2001/02/03 GRA and then it was implicitly approved as part of a negotiated settlement.” (HC Reply, p.10)

The HC also argued that, since NWT Energy Corporation (a more risky non-regulated entity) could issue debentures without sinking funds, NTPC could have issued debentures either without sinking funds or with less onerous sinking fund provisions. (HC Reply, p.9)

NTPC stated that the effective cost of long term debt formula recommended by the HC would put the utility's return on equity at risk, a risk for which the utility has never been compensated.

With regard to the effective cost of long term debt calculations where sinking fund investments are involved, NTPC indicated its proposed calculation is consistent with that used in four other jurisdictions.

“...There are four jurisdictions in Canada (other than the Northwest Territories) with Crown utilities regulated on a rate base/rate of return basis and whose capital structures include sinking fund debt (with offsetting sinking fund assets). The utilities and the jurisdictions are: BC Hydro (British Columbia Utilities Commission), NB Power Transmission

Corporation (New Brunswick Board of Commissioners of Public Utilities), Hydro Québec Distribution and TransÉnergie (Régie de l'Énergie de Québec), and Newfoundland and Labrador Hydro (Newfoundland and Labrador Board of Commissioners of Public Utilities). All four of these utilities calculate their embedded cost of debt using the same methodology as NTPC. In three of these jurisdictions (British Columbia, Québec, and Newfoundland and Labrador), the propriety of the embedded cost of debt calculation has not been questioned. In New Brunswick, the methodology was explicitly reviewed by the regulator in 2003 and found to be appropriate." (Ex.12 McShane Rebuttal, p.10 – 11, // 289 - 302)

With regard to the inequities referred to by HC concerning the debt rate formula, NTPC stated the calculated rate is primarily a function of the fact that (1) the specific debt issue is very close to maturity and thus the amount of the net proceeds (the denominator of the formula) is very small since the sinking fund was virtually fully funded in 2005/2006; (2) the projected earnings on the related sinking fund reflect the fact that the issue is to be retired shortly and thus the related investments have been immunized, i.e., their duration is similar to the remaining term to maturity of the debt; and (3) interest rates happen to be at a relatively low level at present compared to 1989 when the 11.0% issue was made. (Ex.12 McShane Evidence, p.7)

With regard to the prudence of the terms under which the three debentures referred to above were issued, the Corporation stated at the time the sinking fund debentures were issued (1989-1998), NTPC was a virtually unknown quantity from a creditworthiness perspective, and was issuing relatively small amounts of debt, and thus there would have been very few potential investors for NTPC's long-term debt. While its debt carried a guarantee from the Government of the Northwest Territories, neither NTPC nor the government itself had a credit rating.

With regard to HC's view that the Corporation failed to follow best practice in the management of the sinking fund, NTPC indicated the investments allowed under

the *Financial Administration Act* (“**FAA**”) prior to Bill 9 were substantively the same as those in which the sinking funds of other government-owned electric utilities continue to be invested. None of these entities invest the sinking funds designed to retire debt securities in equities, as NTPC has been permitted to do under the provisions of Bill 9.

Views of the Board

The Board considers sinking fund investments, together with earnings on such investments, are put in place in order provide some or all of the cash flow required to retire the corresponding sinking fund debt when it becomes due for payment. The funds transferred to the sinking fund are no longer available to the Corporation since they are set aside specifically for the purpose of retiring the debt. Therefore, to the extent earnings on sinking fund investments do not match the corresponding debt rate there is either a cost or benefit to the Corporation as a result of the investment in the sinking fund until such time as the sinking fund debt instrument is retired.

The Board notes the average sinking fund debt rate exceeds the average sinking fund return by about 6% in each of the two test years as shown below.

Debt Interest Rate Vs Sinking Fund Return						
\$000						
		Debt Principal		Sinking Fund Investment		
		Mid Yr 06/07	Mid Yr 07/08	Mid Yr 06/07	Mid Yr 07/08	
1	11% Debt Mar 9/89	11.000%	20000	20000	19191	20830
2	11.126% debt Jun 6/91	11.125%	15000	15000	9087	10199
3	10.750% Debt May 28/92	10.750%	20000	20000	10434	11880
4	8.700% Debt Feb 27/96	8.410%	8700	8700	261	446
5	6.330% Debt Oct 27/98	6.330%	10000	10000	1150	1504
6	Total		73700	73700	40122	44858
			Debt Interest		Sinking Fund Earnings	
7	11% Debt Mar 9/89		2200	2200	553.00	602.00
8	11.126% debt Jun 6/91		1669	1669	453.00	507.00
9	10.750% Debt May 28/92		2150	2150	524.00	594.00
10	8.700% Debt Feb 27/96		732	732	12.00	21.00
11	6.330% Debt Oct 27/98		633	633	50.00	67.00
12	Total		7383	7383	1592	1791
13	Average Interest Rate/Sinking Fund Return		10.018%	10.018%	3.968%	3.993%
14	Difference between debt rate and sinking fund return				6.050%	6.026%
15	Carrying cost of sinking fund investments [L6*L14]				2427	2703

As shown in the above table, the difference between the average debt interest rate and the sinking fund return times the sinking fund balance constitutes the carrying cost to the Corporation of the sinking fund investments. This cost could also be a benefit if the earnings on sinking fund investments exceed the average debt rate in any given year. The Board notes the Corporation's proposed formula is designed to reflect the carrying cost of sinking fund investments in the effective cost of long-term debt for the two test years. On the other hand, the effective cost of debt formula recommended by HC does not recognize the carrying cost of sinking fund investments since it ignores both sinking fund earnings and sinking fund investments in the debt rate formula.

The terms of sinking fund investments are governed by the corresponding debt covenants. In the Board's view, the carrying costs associated with sinking fund investments are part of the cost of borrowing under a sinking fund debt instrument. Therefore the Board finds it appropriate to provide for recovery of

sinking fund carrying costs or benefits, as the case may be, in the effective cost of debt formula.

Notwithstanding the above finding, the Board observes that instability in the effective cost of debt can be caused by variations in sinking fund returns from year to year. The annual average sinking fund investment returns for NTPC are shown in the following table:

Average Sinking Fund	
Earnings %	
2003	6.17
2004	6.52
2005	5.52
2006	9.72
2007	3.97
2008	3.99
Average	5.98

Note: 2003-06 from X8; P104

The Board notes the relatively low sinking funds returns in 2006/07 and 2007/08 are partly the result of immunizing the investments associated with the \$20 million debenture debt issued in March 1989, in anticipation of the retirement of the debt in March 2009. These relatively low sinking fund returns have the effect of increasing the effective cost of long-term debt in the two test years.

The Board considers a normalized sinking fund return based on the average returns over the 6 year period shown above, rather than each test year's forecast return, would provide for stability in the effective cost of long term debt from year to year. The Board also notes from the term sheets for the \$20 million 8.41% debenture debt issued February 1996 and the \$10 million 6.33% debenture debt issued October 1998, that the expectation for the long term average return on sinking fund investments associated with these two debentures is 6%. The Board

considers therefore that a 6% return reflects a reasonable estimate of expected and realized long-term average returns on sinking fund investments and would provide for a more stable effective cost of long-term debt calculation over time. Further the Board considers basing the sinking fund return on a long term average sinking fund return would avoid potential windfall gains or losses to the Corporation which could be the case if the sinking fund returns were based on specific test year forecasts. Accordingly, for the purposes of these proceedings, the Board directs NTPC to use a 6% sinking fund return for each of the test years for purposes of calculating the effective cost of long-term debt.

The Board notes the HC's argument that this is the first time the treatment of debt costs including sinking funds is being proposed by NTPC in the context of a proceeding other than the 01/03 Settlement and therefore it is appropriate to review the terms of the sinking fund debenture issues although they were issued several years ago. However, the Board considers the prudence of the terms of each issue should be examined based on evidence surrounding the specific circumstances of each issue. Given the passage of time since the debenture issues were made, the Board considers the evidence before it is insufficient to assess what the potential impacts on debenture debt rates would have been, had they been issued with call features and/or without sinking fund provisions and/or with less stringent sinking fund requirements. Therefore, the Board is not persuaded by the HC's recommendations that there should be a risk sharing adjustment on certain sinking fund debentures or that the terms of certain debenture issues including the sinking fund provisions should be re-examined in these proceedings.

In addition to the sinking fund treatment, the Board notes NTPC has calculated the debt interest and debt balance on a daily weighted average basis. Since the mid year convention is used for determining the rate base, the Board considers

the debt balance and debt interest should also be calculated on a mid year basis in order to be consistent.

The Board, therefore, directs the Corporation to calculate its effective cost of long term debt as follows in its refiling:

$$\text{Effective Cost of Long Term Debt} = (I + AFC - SFE) / (MAD - UFC - SFI)$$

Where:

I= Interest on Mid Year Average Long Term Debt

AFC= Amortization of Financing Costs

SFE= Sinking Fund Earnings in the year based on long term average return of 6%

MAD= Mid Year Average Debt Principal

UFC= Unamortized Financing Costs

SFI= Sinking Fund Investment

4.2 Capital Lease

NTPC proposed a cost rate for the Snare Cascades capital lease of 9.69% in 2006/07 and 9.70% in 2007/08. NTPC indicated the capital costs that the Corporation incurs with respect to the lease represent the Dogrib Power Corporation's ("**DPC**") costs of financing comprised of DPC's cost of debt raised to finance the construction of the project (9.6% on 93.26% of DPC's capital structure) and a return on DPC's equity position in the project (NTPC's allowed return on equity less 0.25% on 6.74% of DPC's capital structure).

DPC's cost of debt financing, in turn, reflects the actual cost rate of borrowing from NWT Energy Corporation an amount of \$22.9 million under a loan agreement between the two parties. To provide the debt financing to DPC, NWT Energy Corporation issued three series of debentures as follows:

Date of Issue	Amount of Issue	Due Date	Coupon Rate
May-95	\$8 million	May-25	10.00%
Oct-95	\$8 million	Oct-25	9.75%
Sep-96	\$9 Million	Sep-26	9.11%

The weighted average cost of the debt that was issued by NWT Energy and loaned to DPC was 9.6%. The 9.6% average cost of debt incurred by DPC is the same 9.6% rate that is included in the calculation of the capital cost of the lease that is part of NTPC's revenue requirement.

The \$22.9 million loan is being amortized and repaid by DPC to NWT Energy Corporation in monthly installments of \$195,068 over a period of 30 years.

The HC expressed the view the NTPC could have borrowed at a lower rate than its unregulated subsidiary NWT Energy Corporation at the point in time the lease arrangement was entered into. This would have lowered the cost of the loan to the DPC. In turn, this would have lowered the cost of the lease to the NTPC. HC's expert witness noted that NTPC's calculation uses weights of 6.74% equity and 93.26% debt while the standard approach is to employ a debt weight of 100%. Further, the HC expert witness noted that if the cost of the lease is to include an equity component then the cost of equity should be lowered by more than 25 basis points to capture the lower risk of the lease. (Ex.8, p. 110 - 111; HC Reply, p.13)

NTPC submitted reviewing the terms of the DPC agreement 10 years after it was entered into would constitute retroactive ratemaking.

"...As stated in Board Decision 1-97 (January 14, 1997), the Board "examined the evidence before it and agrees with the parties that the above interest rates are reasonable for this portion of the capital structure.

The Board approves lease interest rates of 10.063% and 10.044% for the Test Years 1996/97 and 1997/98 respectively.” In my view, a retrospective reconsideration of the prudence of the capital lease arrangement entered into by NTPC more than 10 years ago constitutes retroactive ratemaking.” (Ex.12 McShane Rebuttal, p.22, // 614 - 620)

NTPC indicated the cost of borrowing on the debt issued by NWT Energy Corporation to finance the loan to DPC is consistent with borrowing costs on B++ debenture debt at the time of issue.

“Nevertheless, a comparison of the yields on the NWT Energy debentures to yields prevailing on outstanding long-term B++ rated Canadian utility bonds at the time the NWT Energy debt issues were made and the funds were loaned to DPC provides a clear indication that the cost of the debt component of the capital lease was reasonable.” (Ex.12 McShane Rebuttal, p.22, // 622 - 626)

NTPC noted that in the event of a disallowance of the capital lease costs, the power acquisition agreement between DPC and the Corporation provides that DPC will pay to the Corporation the amount of the disallowed costs.

“Were the Board to adopt the recommendations of Drs. Kryzanowski and Roberts, it is important to note the impacts that would arise. The Power Acquisition Agreement between the DPC and NTPC provides that the DPC will pay to NTPC the amount of all Disallowed Costs. Under that agreement, “Disallowed Costs” means amounts payable by NTPC under the agreement which the Board does not permit NTPC to recover in its rates, tolls and charges. The lease was structured to ensure that regulatory risk for recovery of the costs of the project from ratepayers was a risk that DPC bore, not NTPC. Ultimately, it is DPC that would be directly and adversely impacted were the Board to accept HC’s recommendations. ...” (Ex.12 NTPC Rebuttal, p.3, // 31 - 37)

In its reply argument, the HC submitted that the DPC capital lease arrangements were a three part commercial arrangement and all parties were aware of the contractual risks associated with strict application of their commercial arrangement.

“...Furthermore, this is a three-way commercial arrangement that involved two interrelated entities (NTPC and NTEC), as well as two nonregulated parties (NTEC and DPC), and where all parties supposedly were aware of the contractual risks associated with the strict application of their commercial arrangement. Thus, Drs. Kryzanowski and Roberts do not recommend any changes to the commercial agreement between NTPC, NTEC and Dogrib nor do they recommend that the terms of that agreement be violated.” (HC Reply, p.13)

Views of the Board

The Board considers the time for raising issues concerning the prudence of the DPC lease financing rate was the 1996/97/98 GRA when the inclusion of the DPC hydro plant in rate base and the related financing arrangements were examined and agreed to by interested parties. The Board does not consider a retrospective review of the long-term debt rate or the cost structure of the lease financing arrangement, approved in a previous proceeding, to be conducive to maintaining a climate of regulatory certainty in the NWT. Therefore, the Board does not accept the HC’s recommendation that the debt financing rate reflected in the DPC capital lease be reviewed and reset.

The Board directs NTPC to include a capital lease rate that reflects, for the equity portion of lease financing, the equity rate of return approved by the Board in this Decision less 25 basis points, in its refiling application.

The Board notes the value of the annual lease payments to DPC over the 65 years is financially equivalent to DPC’s cost of capital. The lease payments by NTPC to DPC include depreciation based on a 65-year amortization of the lease and carrying costs on the unamortized balance of the lease reflecting 93.26% debt at 9.6% interest and 6.74% equity at the allowed rate of return on equity minus 25 basis points. DPC’s cost of financing the lease, on the other hand, is based on 93.26% debt owed to NWT Energy at 9.6% interest which is being

repaid over 30 years and 6.74% equity at the allowed rate of return on equity minus 25 basis points. Since the 9.6% debt to NWT Energy is being repaid by DPC over 30 years, the cash flow profile of the lease payments by NTPC to DPC differs from the cash flow profile of DPC's debt repayments to NWT Energy. Given this mismatch in cash flow profiles, the Board considers there may be potential for DPC to reduce its cost of capital by substituting some of the higher cost debt included in its capital structure with lower cost debt as the 9.6% debt is being amortized over 30 years. The Board directs NTPC to address the potential for better matching the carrying cost of the lease to DPC with the cost of the lease to NTPC over the 65-year term of the lease, at the next GRA.

4.3 Capital Structure

The NTPC proposed capital structure for the two test years is as follows:

	2006/07	2007/08
Common Equity	45.53%	48.59%
Long Term Debt	44.53%	41.65%
Capital Lease Obligation	10.86%	10.61%
No Cost Capital	-0.92%	-0.85%
	100.00%	100.00%

The above capital structures reflect the Corporation's forecast capital structures, as opposed to deemed capital structures, in each of the test years.

In support of the proposed capital structure, Ms. McShane, expert witness for NTPC, stated NTPC would need a more conservative capital structure compared with a typical investor owned utility, in order to achieve a similar debt rating in light of its small size, higher business risks and non taxable status. Ms. McShane stated that in her opinion, a common equity ratio in the range of 45-50% would

be adequate to allow NTPC to achieve a BBB rating on a stand-alone basis and NTPC's actual equity ratios are forecast to be in that range. Ms. McShane defined a benchmark utility as an A-rated utility and indicated NTPC's risk would remain higher than that of the benchmark which would suggest an incremental equity risk premium is required for NTPC. (Ex 12; McShane Evidence, p.18)

Among the business risks the utility is exposed to, Ms. McShane discussed market risks, supply and physical risks as well as regulatory risks.

With respect to market risks Ms. McShane stated the reliance on a small number of cyclical industries with a sparse population results in a higher level of market risk.

“...While the outlook is one of strong growth in the near to medium term, the reliance of the NWT on a small number of cyclical industries, in conjunction with the sparse population, results in a higher level of market risk for NTPC relative to the typical Canadian utility which operates in a more diverse economic environment with higher population density.” (Ex. 2, Appendix B, McShane Evidence, p. 12, // 323 - 327)

Ms. McShane indicated NTPC faces an inherently higher level of risk relative to other integrated Canadian electric utilities with respect to supply and physical risks.

“With respect to supply and physical risks, NTPC faces an inherently higher level of risk relative to other integrated Canadian electrical utilities. The level of risk is in large part a function of the severe climate, the vast geographic expanse and rugged terrain of the service area, and the lack of a system grid to connect the communities served.” (Ex.2, Appendix B, McShane Evidence, p.12, // 329 - 333)

Ms. McShane indicated the regulatory environment in the NWT has been even-handed in its approach and the use of rate stabilization funds mitigates risks.

“With respect to regulatory risk, the regulatory environment in the NWT has been even-handed in its approach. The authorization and maintenance of the rate stabilization funds, which mitigate risks beyond the control of the utility, are an indication of that even-handedness.” (Ex.2, Appendix B, McShane Evidence, p.13, // 354 - 357)

With regard to financial risks, Ms. McShane indicated in comparison to the interest coverage ratios of the major Canadian electric utilities, NTPC’s 2003/2004 to 2005/2006 average of 1.7 times interest coverage ratio has been considerably weaker. The average (pre-tax) interest coverage for the major Canadian electric utilities with rated debt over the same period was 2.5 times. She indicated a key reason for the difference is the taxability of the major Canadian utilities because the income tax allowance provides a cushion that enhances interest coverage ratios.

Drs. Kryzanowski and Roberts, expert witnesses for the HC, recommended a deemed equity ratio of 42% for the two test years. The HC summarized the expert witnesses view with respect to business risk as follows:

“In summary, NTPC’s business risk is at an acceptable level with regard to the major factors causing business risk for a regulated electric utility in Canada. Drs. Kryzanowski and Roberts base this assessment on their view that the regulatory process and prudent management practices will combine to mitigate the potential risks discussed in their evidence. Two further favorable factors are the lack of competition and reliance on hydro generation which shields the company from the risk of rising energy prices. On the other side of the ledger, NTPC is smaller than the sample companies investigated by Drs. Kryzanowski and Roberts and faces challenges due to the geography of its service area. On balance, the Hydro Communities’ view is that the business risk faced by NTPC is somewhat higher than that faced by the average integrated electric company or the average utility in Canada. ...” (HC Argument, p. 42)

Drs. Kryzanowski and Roberts formed four estimates of the appropriate equity ratio for NTPC. The first two benchmarks represent measures of the average common equity ratio for utilities in Canada. The third benchmark captures equity

ratios deemed appropriate for utilities of above-average risk by the Alberta Energy and Utilities Board. The fourth benchmark measures the equity levels approved for NTPC by this Board in the past.

The witnesses indicated that the benchmark equity ratios all fall in a range of 38% - 43%. Based on the analysis of the business risk faced by NTPC, the witnesses assessed NTPC's business risk as somewhat higher than that of the average shareholder-owned electric utility in Canada. Drs. Kryzanowski and Roberts considered a 42% equity ratio, just below the top end of the range, would be sufficient to result in a stand alone bond rating of BBB for NTPC.

With regard to NTPC's non-taxable status and its impact on coverage ratios and financial risks alluded to by Ms. McShane, the HC stated although bond rating agencies pay attention to ratios, there is no formula which translates ratios into bond rating. Considerable judgment comes into play. Simply having a key ratio (interest coverage, for example) below a certain level is not by itself grounds for a downgrade in practice. (HC Argument, p.47)

Views of the Board

The Board notes the expert witnesses' view that NTPC's business risk is higher (McShane) or somewhat higher (Kryzanowski and Roberts) than that of an average risk utility. The Board also notes Ms. McShane's view that the Corporation's non-taxable status has an impact on its coverage ratios and therefore the financial risk. The Board considers that although the coverage ratios do not necessarily dictate bond ratings, it would appear that the rating agencies include coverage ratios, among other factors, in their rating considerations and, to that extent, coverage ratios would appear to be relevant to the determination of capital structure for NTPC.

The Board notes NTPC's effective cost of long term debt somewhat exceeds the requested cost rate on equity. The Board sees this as an atypical cost structure because, for a typical utility, the cost of debt is generally less than the cost rate on equity. [Schedule 3.5] The relatively high debt cost appears to be largely the result of reflecting sinking fund earnings and investments in the effective cost of long term debt for NTPC and it would appear this situation may continue for some time until a substantial portion of the sinking fund debt instruments are retired. In the Board's view, any consideration of the appropriate capital structure for NTPC for the test years must take into account the reality of the presence of high cost debt in the capital structure since it has an impact on coverage ratios. The Board notes the capital structure recommendations of the HC witnesses reflect an equity ratio taking into consideration NTPC's business risks only. However, in the Board's view the Corporation's financial risk, as measured by indicators such as the coverage ratios, is also a relevant consideration in establishing an appropriate capital structure. The Board notes the HC calculated the coverage ratios excluding lease finance costs. (BR.HC-2) In the Board's view, the lease finance costs are a fixed contractual obligation by NTPC to DPC and should therefore be included in the calculation of coverage ratios.

For the purposes of this Decision, the Board accepts the capital structure proposed by NTPC as it appears to give due recognition to the relatively high cost of debt in relation to cost of equity in 2006/07 and 2007/08 and results in an acceptable level of interest coverage ratios for the test years.

The Board considers, with the eventual retirement of the high cost sinking fund debt, the coverage ratios and the financial risk of the utility would likely improve. Therefore, the capital structure accepted by the Board should not be viewed as solely reflecting NTPC's business risks but rather as one that takes into account NTPC's particular circumstances with respect to high cost debt.

4.4 Fair Return On Equity

NTPC requested allowed returns on equity of 10.5% and 10.75% for test years 2006/07 and 2007/08 respectively. Ms. McShane filed expert testimony supporting the NTPC proposed returns on equity. Drs. Kryzanowski and Roberts, who filed evidence on behalf of the HC, recommended returns on equity of 6.75% for 2006/07 and 7.20% for 2007/08.

Ms. McShane used the equity risk premium method; the discounted cash flow method and the comparable earnings test to estimate the returns on equity applicable to a benchmark utility as follows:

“Ms. McShane’s recommended returns on equity are based on the application of five different tests, three risk premium tests, the discounted cash flow test and the comparable earnings test. Ms. McShane used these tests to develop a fair return on equity for a benchmark Canadian utility, that is, a utility which, in light of its business and financial risks, would be able on a stand-alone basis, to achieve debt ratings in the A category. The returns on equity applicable to a benchmark utility would be approximately 10.0% for 2006/07 and 10.25% for 2007/08. A summary of the results of the tests applied by Ms. McShane (as updated in her Rebuttal Evidence, Ex. 12) are set out in the table below.

	Equity Risk Premium (ERP)
Test Year 2006/07	9.5%
Test Year 2007/08	9.75%
Discounted Cash Flow	9.0-9.5%
Comparable Earnings	12.0%”

(NTPC Argument, p.41, // 35 – p. 42, // 10)

Ms. McShane added a 50 basis points risk premium to the returns on equity applicable to the benchmark utility to reflect NTPC’s higher risk in relation to the benchmark utility and came up with recommended returns on equity for NTPC of 10.50% for 2006/07 and 10.75% for 2007/08.

Drs. Kryzanowski and Roberts relied primarily on the equity risk premium test for their recommended returns. However, Drs. Kryzanowski and Roberts used the DCF Test to provide additional estimates of the Market Equity Risk Premium using both historical and forward-looking estimates of dividends and dividend growth at the market level.

Comparable Earnings (“CE”) Test

The HC argued the results of the CE test should be given no weight in the determination of a fair return for the Corporation because the method is devoid of scientific merit, lacks theoretical underpinnings and suffers from substantive implementation difficulties.

“Drs. Kryzanowski and Roberts point out that the basic problem is that there is neither a theoretical underpinning nor any empirical support for the comparable earnings approach to estimating a regulated fair rate of return for a utility. As an *ad hoc* approach to estimating a regulated fair rate of return, there are no agreed-upon rules for deciding upon how the Comparable Earnings Test should be implemented. They not only review 11 problems encountered in implementing a Comparable Earnings Test in their evidence but they illustrate the net effect of these problems by calculating the performance of the sample of 20 low risk Canadian industrials used by Ms. McShane over the 1994-2005 period to calculate accounting ROEs. They find that her sample outperforms the S&P/TSX Composite in that it not only has a higher mean return but also less risk. Thus, Ms. McShane has used a sample that has outperformed the S&P/TSX Composite over her test period both in terms of realized return and risk. Thus, Drs. Kryzanowski and Roberts recommend that the Board should not apply any weight to the Comparable Earnings evidence submitted by Ms. McShane. The method is not only devoid of scientific merit and theoretical underpinnings but its substantive implementation difficulties make it unsuitable to play a role in the determination of a fair rate of return for a utility.” (HC Argument, p. 36)

Ms. McShane responded in detail to the HC's criticism of the CE test in her rebuttal evidence. (Ex.12 McShane Rebuttal) In essence, Ms. McShane's view as to the usefulness of the CE test may be summarized as follows:

"...Regulation relies on an original cost rate base construct, or convention, rather than the market values to which the "scientific" cost of attracting capital tests apply. The comparable earnings test measures comparable returns measured in a manner compatible with the regulatory construct for measuring the equity investment in a utility, that is, on the basis of original cost. The cost of attracting capital tests do not." (Ex.12 McShane Rebuttal, p. 54, // 1581 - 1586)

Discounted Cash Flow ("DCF") Test

The HC submitted the DCF tests are unreliable when applied to specific firms in the same industry because of circularity problems and due to subjectivity in analysts' growth forecasts.

"Ms. McShane also generates DCF estimates of a fair return on equity for a sample of U.S. gas and electric distributors. Due to a number of disadvantages, including circularity, discounted cash flow (DCF) tests are unreliable when applied to specific firms in the same industry." (HC Argument, p. 35)

In response, Ms. McShane submitted circularity is mitigated by using a sample of companies instead of the specific company and subjectivity is addressed by using a consensus growth forecast.

"...However, circularity is mitigated by (a) using samples of companies, not the specific company to which the DCF test is being applied and (b) using the consensus of growth forecasts for the companies in the samples. With regard to the second, the use of the available consensus of analysts' earnings forecasts for the growth component eliminates the possibility that the results are colored by an analyst's own subjective views

of what the regulator should allow.” (Ex.12 McShane Rebuttal, p. 44, // 1299 – p. 45, // 1305)

Equity Risk Premium (“ERP”) Test

The benchmark equity return estimates under the ERP test provided by Ms. McShane are as follows:

	McShane	
	2006/07	2007/08
Risk free rate	4.25%	4.50%
Market equity risk premium	6.50%	6.50%
Beta	65% to 70%	65% to 70%
Equity risk premium	4.75%	4.75%
Allowance for financing flexibility	0.50%	0.50%
Benchmark utility return	9.50%	9.75%

The estimates for equity returns under the ERP test provided by the Drs. Kryzanowski and Roberts are as follows:

	Kryzanowski & Roberts	
	2006/07	2007/08
Risk free rate	4.20%	4.65%
Market equity risk premium	4.90%	4.90%
Beta	50.0%	50.0%
Equity risk premium	2.45%	2.45%
Allowance for financing flexibility	0.10%	0.10%
Benchmark utility return	6.75%	7.20%

The significant differences between the two sets of estimates are explained by differences in the estimates included for the market equity risk premium (“**MERP**”), the beta value (which is a measure of the risk of an average risk utility stock relative to the market) and the allowance for financing flexibility

Ms. McShane indicated her 6.5% market equity risk premium estimate recognizes the expected value of the equity market return developed from historic values in conjunction with the current and forecast low levels of interest rates.

“Based on the analysis of the historic risk premiums, primarily in Canada and the U.S., with focus on the arithmetic averages and with consideration given to trends in the equity and government bond markets in both countries, a reasonable estimate of the expected value of the equity market risk premium at the forecast levels of long-term government bond yields is approximately 6.5%. The 6.5% estimate of the equity market risk premium explicitly recognizes the expected value of the equity market return developed from historic values in conjunction with the current and forecast low levels of interest rates.” (Ex. 2, Appendix B, McShane Evidence, p.33, // 900 - 907)

The HC witness expressed several concerns with Ms. McShane’s forecast MERP.

“In contrast, Ms. McShane uses the historic average MERP for Canada, the U.S. and the U.K. over the period 1947-2006 to obtain an estimate of the MERP going forward of 6.5%. Her estimate is inappropriately high for four reasons. First, the chosen time period results in an inflated estimate of the going-forward likelihood of achieving the high realized returns on equities and low realized returns on bonds that followed World War II. This period begins with rapid economic growth due to pent up demand from the war period and administered low interest rates. Using the mean gives an equal weight to each year in this early period. Second, minimal or no weight is placed on the declining trend of MERPs for the three markets over this time period. Third, no adjustments are made for differences in risks across the market proxies used to calculate the MERP in the different countries. Fourth, no adjustments are made for the effect of equity re-valuations over this period of time unless one believes that price-to-dividend multiples will exhibit a similar three-fold increase over the next 60 years.” (HC Argument, p. 30 - 31)

In her rebuttal evidence, Ms. McShane responded to the first 3 concerns of the HC. First, with regard to the time period chosen for the analysis, Ms. McShane stated as follows:

“...It would be inappropriate to “cherry pick” the post World War II period. Equally, it could be argued that other sub-periods are not representative of future expectations and whose inclusion or exclusion might inflate or deflate the estimate of the expected long-term forward looking returns or risk premium...” (Ex.12 McShane Rebuttal, p.38, // 1131 - 1134)

Ms. McShane explained that observed risk premiums have declined because the achieved returns on long-term Canada bonds reflect historic yields that were much higher than they are expected to be and the significant capital gains that have occurred since long Canada bond yields began to decline.

“..The reason that the observed risk premiums have declined is because the achieved returns on long-term Canada bonds reflect (1) historic yields that were much higher than they are expected to be; and (2) the significant capital gains that have occurred since long Canada bond yields began to decline....” (Ex.12 McShane Rebuttal, p. 40, // 1191 - 1194)

With regard to the HC’s view, no adjustments have been made for the market proxies used because Ms. McShane did not consider such adjustments were needed.

“With respect to the benefits of international diversification, one of the principal reasons for investing abroad is the opportunity to earn similar or higher returns than available in the domestic market while bearing similar or lower risk. From this perspective, there is no rationale for concluding that the returns and risk premiums that Canadian investors would anticipate from investing abroad would be reduced from those anticipated from domestic markets only. (Ex.12 McShane Rebuttal, p. 42, // 1236 - 1241)

Ms. McShane explained one of the reasons for difference between her estimate of market equity risk premium and Drs. Kryzanowski and Roberts' estimate relates to the weight given to the arithmetic versus geometric averages in the estimation of historic market risk premiums. Drs. Kryzanowski and Roberts gave more weight to geometric averages based on their finding that historically returns have been mean reverting. Mean reverting essentially means that low returns can be expected to be followed by high returns, so that investors can reasonably expect that, over time, returns will return to some long term average. Therefore, the estimate of the required future equity risk premium should take into account the predictability of future returns as indicated by the mean reversion, by giving some weight to the historic compound, or geometric, return.

Drs. Kryzanowski and Roberts indicated they had conducted a number of tests of robustness of their MERP estimate and conclude that it should not be increased from their estimate of 4.9%.

With respect to the beta values, the difference between the McShane approach and that of Drs. Kryzanowski and Roberts relates mainly to the fact Ms. McShane adjusted her raw beta estimates upwards to provide a better correlation between utility risk and return.

“Using adjusted betas can mitigate the deficiencies in “raw” betas. Adjusting betas entails moving betas above and below the market mean of 1.0 toward the market mean. The adjustment that is used by the major commercial suppliers of betas uses a formula that gives approximately two-thirds weight to the stock's own beta and one-third weight to the market mean beta of 1.0. Use of adjusted betas implicitly recognizes that “raw” utility betas are not adequate explainers of utility returns. For example, “raw” betas do not capture utilities' interest rate sensitivity. The objective of the relative risk adjustment is to predict the investors' required return. Adjusted betas provide a better correlation between utility risk and return than “raw” betas.” (Ex. 2, Appendix B McShane Evidence, p. 38, // 1031 - 1040)

Drs. Kryzanowski and Roberts disagreed with the upward adjustment of raw betas recommended by Ms. McShane.

“...McShane uses the Value Line method to adjust her betas upwards when she should not. Drs. Kryzanowski and Roberts provide various rationales in Sections IV and VI of their evidence why the beta of an average-risk (never mind low-risk) utility should not be adjusted towards one. Not only is it logically inconsistent to assume that the average beta of a mature industry is equivalent to that of the overall market but empirical findings upon which this adjustment is based reveal that individual betas revert to the sample mean, which in the case of an average-risk utility is itself. Drs. Kryzanowski and Roberts also demonstrate why the interest-rate sensitivity rationale for using a variant of the adjusted beta method for utilities is flawed and is based on a misunderstanding of asset pricing theory and empirical tests. Since Ms. McShane basically uses the sample average utility beta as her beta estimate for a low-risk utility benchmark, no upward adjustment is needed to offset the tendency of the beta of a specific utility to regress to that same sample average utility beta...” (HC Argument, p. 32)

Drs. Kryzanowski and Roberts explained why in their view adjustment of beta’s for interest rate sensitivity is not necessary.

“...Over the long run, we would expect the average return on long Canada’s to be equal to the yield on long Canada’s (the proxy for the risk-free rate in rate of return settings). This is because our expectation is that rates would fluctuate randomly so that returns would be above yields to maturity in some periods and below them in others. Thus, while it is true that utility returns are sensitive to interest rates, it is not true that interest rate risk will have a positive risk premium over the long run. (Ex. 8; p. 83)

With respect to the financing flexibility allowance of 50 basis points recommended by Ms. McShane, Drs. Kryzanowski and Roberts noted the Board should consider the excess returns earned by utility investors when establishing the financing flexibility add-on to the return on equity (“**ROE**”) in this rate hearing.

“...In other words, providing generous rates of return allowances to enhance the financial integrity and flexibility of these utilities (without requiring these utilities to establish a reserve account to capture these insurance premiums) just over-compensates investors given the high dividend payout practices of many Canadian utilities. Drs. Kryzanowski and Roberts do not recommend the establishment of such a reserve account. Instead, they recommend that the Board consider the excess returns earned by utility investors when establishing the financing flexibility add-on (or kicker) to the ROE in this rate hearing...” (HC Argument, p. 38)

Additional Risk Premium on Benchmark Return Estimates

Ms. McShane recommended an additional 50 basis points risk premium on the returns on equity applicable to the benchmark utility to reflect NTPC's higher risk in relation to the benchmark utility. In her view, NTPC would be a BBB rated utility at the proposed capital structure and therefore she indicated an additional risk premium is required on the basis of cost of debt differentials between a BBB rated utility and a benchmark A rated utility.

“The estimation of the difference in return that would be warranted for NTPC's higher business risks is in part a matter of professional judgment, but should be constrained by factual support. Ms. McShane's direct evidence demonstrates that the difference in the cost of debt as between a utility with debt ratings in the A category and a utility whose debt is rated in the BBB category is approximately 0.60%. The difference in the cost of debt between an A rated benchmark utility and a BBB rated utility (which NTPC would be on a stand-alone basis) serves as a proxy for the incremental return that an equity investor would require to invest in NTPC. On the basis of cost of debt differentials, Ms. McShane's incremental equity risk premium of 0.50% for the Corporation should be viewed as the minimal differential return required relative to a benchmark utility. Her proposed differential is fully consistent with the 0.60% differential adopted by the Board in respect of the allowed return for NUL in Decision 9-2006 (March 2006).” (NTPC Argument, p. 45, // 13 - 23)

Drs. Kryzanowski and Roberts did not agree that an incremental risk premium on the benchmark return is required because in their view Ms. McShane's estimated

benchmark returns would have the effect of rewarding NTPC twice for the same incremental risk that is already reflected in the capital structure of an average-risk utility.

“When she estimates the risk premium, she incorrectly uses a sample or an industry index, which is really for an average and not low-risk utility. Recognizing her error, Drs. Kryzanowski and Roberts challenged her view that an incremental equity risk premium is required. Such an equity risk premium would have the effect of rewarding NTPC twice for the same incremental risk that is already reflected in the capital structure of an average-risk utility.” (HC Reply, p. 21)

Views of the Board

The Board notes the CE method provides a measure of the actual realized returns on the book value of comparable risk securities. In this regard the CE test differs from other tests such as the equity risk premium test, which attempt to measure the expected return on the market value of securities. In an original cost rate base jurisdiction where the fair return is established on the basis of the book value of assets, the awarded returns must reflect investors' expectations of market returns on comparable risk securities. These expectations of market returns cannot, in the Board's view, be measured by the book returns of comparable risk securities because of differences between the book values and market values. Rather, the investors' expectations are appropriately measured in relation to the market value of comparable risk securities. In the Board's view the CE method fails to meet this requirement. Therefore the Board will not give any weight to the CE method in determining the fair return on equity.

The Board notes the DCF test, similar to other tests, has certain drawbacks. However, in view of the mitigating factors referred to by Ms. McShane, the Board

considers it appropriate to consider the DCF test among other tests in determining the fair rate of return on equity.

The Board notes NTPC's submission that based on the British Columbia Utilities Commission's ("**BCUC's**") automatic adjustment mechanism, the market equity risk premium would be much closer to Ms. McShane's 6.5% than Drs. Kryzanowski and Robert's 4.9%.

"The most recent regulatory determination of the market risk premium was in 2006 by the British Columbia in which, having heard all the evidence, concluded that the market risk premium was 5.8% at a long-term Canada bond yield of 5.25%. The forecast yield on long Canada bonds in this proceeding is considerably lower than 5.25% (4.5% and 4.65% for 2007/08 by Ms. McShane and Drs. Kryzanowski and Roberts respectively). Based on the BCUC's automatic adjustment mechanism, which, similar to those used by other Canadian regulators, is premised on an inverse relationship between interest rates and risk premiums, the indicated market risk premium at a 4.5% to 4.65% long Canada yield would be higher than 5.8%, much closer to Ms. McShane's 6.5% than Drs. Kryzanowski and Roberts's 4.9%." (NTPC Reply, p. 29, // 25 - 33)

The Board notes NTPC's submission that the risk premium looking forward should be higher than the historic values when bond market returns are expected to be lower.

"...Ms. McShane's Rebuttal evidence pointed out that Drs. Kryzanowski and Roberts acknowledged that there has been no material change in the equity market return. If equity market returns are approximately the same, but bond market returns are expected to be lower, then it follows that the risk premium looking forward should be higher than the historic values." (NTPC Reply, p. 29, // 10 - 14)

The Board considers Drs. Kryzanowski and Roberts' estimated market equity risk premium to be downwardly biased since the witnesses do not appear have given

recognition to market equity risk premium increases resulting from lower prospective bond market returns, compared to the historic period.

The Board, having reviewed the foregoing, considers a market equity risk premium of 6% to be appropriate under current long-term interest rate conditions.

The Board also considers Ms. McShane's adjusted beta values to be on the high side when viewed in relation to the raw beta estimates based on observations during a relatively stable interest rate environment such as the 30 month periods, January 2003 to June 2005 and July 2003 to December 2005. (Ex.12 McShane Evidence, p.36, Table 7)

The Board notes Drs. Kryzanowski and Roberts' view that beta values need not be adjusted for interest rate risk because interest rate risk will not result in a positive risk premium over the long run. However, the beta estimates provided by the witnesses in Schedule 4.10 of Exhibit 8 show wide variations in beta values for each 5-year period analyzed. This indicates inference of average beta values from such wide dispersions in beta values may not produce reliable results.

The Board considers a 50 basis point addition for financing flexibility is consistent with similar allowances awarded in other jurisdictions and is appropriate in order to maintain the financial integrity of the utility. The Board is not persuaded that past excess earnings need to be considered in assessing the appropriateness of an allowance for financing flexibility for a utility that is regulated on a forward test year basis. Under forward test year regulation, there is an expectation the probability of actual returns being higher or lower than the allowed return is about the same.

The Board notes Ms. McShane's view that the proposed capital structure would result in a BBB rating for the Corporation. The Board notes the high cost of debt in NTPC's capital structure and considers the 50 basis points upward adjustment recommended by Ms. McShane is reasonable under the circumstances to compensate for the relatively high financial risk of the utility.

Although the Board has accepted an upward adjustment to the equity return estimates as noted above, in future proceedings, the Board would prefer to see all of the business risk adjustment reflected in the capital structure rather than in the capital structure as well as in the return on common equity.

The Board notes NTPC filed its Application in November of 2006, about eight months into the first test year. Since the Corporation would have had knowledge of actual events pertaining to a substantial part of the first test year, the Board considers the Corporation's forecast risks were mitigated to some extent. Therefore the Board considers it reasonable to reduce the allowed rate of return on equity for 2006/07 by 40 basis points to recognize this risk reduction.

Having considered the ERP test and the DCF test and the factors discussed above, the Board determines the fair rate of return on equity to be 8.60% for 2006/07 and 9.25% for 2007/08.

For purpose of calculating the return component of the DPC lease payments, the Board does not consider the 40 basis point reduction in NTPC's return on equity for 2006/07 noted above should apply because this is a specific adjustment applicable to NTPC's particular circumstances in 2006/07. Accordingly, the Board directs NTPC to use fair returns on equity of 9.00% for 2006/07 and 9.25% for 2007/08 in order to calculate the DPC lease payments in the Phase 1 refiling.

5. PRODUCTION FUEL AND PURCHASED POWER

NTPC produces power using two fuels, diesel and natural gas, and also purchases power for resale in Norman Wells.

NTPC is seeking the Board's approval for \$17.150 million and \$17.848 million in production fuel and purchased power expenses in 06/07 and 07/08, respectively. These amounts represent increases of \$2.635 million and \$3.333 million, respectively, from the \$14.515 million approved in the 01/03 Settlement.

Of the \$17.150 million forecast in 06/07, \$0.511 million will be expensed to the hydro water stabilization funds so only \$16.639 million is included in the 06/07 revenue requirement.

Of the \$17.848 million forecast in 07/08, \$0.425 million will be expensed to the hydro water stabilization funds so only \$17.423 million is included in the 07/08 revenue requirement.

NTPC has been attempting to reduce the fuel expenses with two notable projects being the addition of a third gas engine in Inuvik and the purchase of the Bluefish Generating Station. These efforts have allowed NTPC to offset approximately half of the fuel price impact on a Corporate-wide basis.

Three issues were raised by the interveners on this matter:

- 1) Diesel and natural gas engine fuel efficiencies;
- 2) Losses and station service; and
- 3) Fuel Pricing in Inuvik

These three issues are addressed by the Board in Sections 5.1, 5.2 and 5.3. Subject to the Board's directions in these three sections and in Section 10.1.1 concerning the water stabilization fund, NTPC's proposed production fuel and purchased power expenses forecast for 06/07 and 07/08 are approved by the Board.

5.1 Fuel Efficiencies

The topic of fuel efficiencies, for diesel in all communities and natural gas in Inuvik, was pursued by the TGC.

5.1.1 Diesel

Diesel efficiency data which has been provided over the course of this review is compiled in Table 5.1. The data is drawn from the Phase 1 Application (Schedules 2.1, 2.2 and 2.3, Schedules 3.3.1 and 3.3.2 and Appendix A) and information request responses (BR.NTPC-6, TGC.NTPC-20 and TGC.NTPC-32).

Table 5.1 – Diesel Plant Efficiency (kWh/L)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Yellowknife	3.698	Not Provided	3.776	3.797	3.844	3.500	3.500
Behchoko	3.000	Not Provided	Not Provided	Not Provided	Not Provided	3.250	3.250
Fort Resolution	Not Provided	Not Provided	NA	NA	3.459	3.459	3.459
Fort Smith	3.440	Not Provided	3.259	3.323	3.177	3.277	3.277
Hydro	3.673	Not Provided	Not Provided	3.779	3.725	3.458	3.442
Wha Ti	3.147	Not Provided	3.624	3.654	3.778	3.711	3.711
Gameti	3.464	Not Provided	3.539	3.254	3.259	3.398	3.398
Lutsel K'e	3.793	Not	3.751	3.792	3.772	3.778	3.778

		Provided					
Fort Simpson	3.763	Not Provided	3.749	3.774	3.713	3.755	3.755
Fort Liard	3.665	Not Provided	3.764	3.709	3.636	3.725	3.725
Wrigley	3.617	Not Provided	3.645	3.413	3.386	3.525	3.525
Nahanni Butte	2.311	Not Provided	2.407	2.440	2.594	2.511	2.511
Jean Marie River	2.520	Not Provided	2.589	2.591	2.907	2.749	2.749
Inuvik	3.450	3.579	3.603	3.693	3.524	3.635	3.635
Norman Wells	Not Provided	Not Provided	0.000	3.277	3.506	3.414	3.414
Tuktoyaktuk	3.581	Not Provided	3.733	3.680	3.622	3.697	3.697
Fort McPherson	3.381	Not Provided	NA	NA	3.609	3.609	3.609
Aklavik	3.428	Not Provided	3.570	3.421	3.299	3.475	3.475
Deline	3.471	Not Provided	3.475	3.591	3.515	3.546	3.546
Fort Good Hope	3.556	Not Provided	3.565	3.606	3.507	3.576	3.576
Tulita	3.587	Not Provided	3.660	3.591	3.616	3.634	3.634
Paulatuk	3.397	Not Provided	3.464	3.508	3.481	3.492	3.492
Sachs Harbour	3.281	Not Provided	3.168	3.242	3.073	3.189	3.189
Tsiigehtchic	3.279	Not Provided	3.556	3.525	3.506	3.537	3.537
Colville Lake	2.414	Not Provided	2.864	2.773	3.081	2.957	2.957
Ulukhaktok	3.579	Not Provided	3.560	3.552	3.675	3.616	3.616
Diesel	3.502	Not Provided	Not Provided	3.551	3.546	3.596	3.599
Overall	3.575	3.654	Not Provided	3.636	3.559	3.587	3.592

With 4 exceptions, on a community-by-community basis the 06/07 and 07/08 forecast fuel efficiencies are based on the approach agreed to in the 01/03 Settlement which calculates the forecast efficiency based on the last 3 years of actual efficiency, weighted 3 for the highest efficiency year, 2 for the middle efficiency year and 1 for the lowest efficiency year.

The 4 exceptions to this method of forecasting efficiencies are:

Yellowknife: With the addition of Bluefish and the reduced mining loads, generation at the Jackfish plant has been significantly reduced. Jackfish will primarily be used as a standby plant. Standby plants usually have lower efficiencies than primary plants as a result of fuel being used to warm-up and cool down the engines but with no power being produced. As a result, NTPC does not believe that Jackfish will achieve its historic efficiencies. The 3.500 kWh/L is an operational estimate for Jackfish's new status as a standby plant.

Fort Resolution: The plant is new so the only year of actual efficiencies (05/06) is used for 06/07 and 07/08.

Norman Wells: The plant has only 2 years of actual efficiencies so those 2 years were taken as representative of the actual plant efficiency with a weighting of 3 for the highest efficiency and 2 for the lowest.

Fort McPherson: The plant is new so the only year of actual efficiencies (05/06) is used for 06/07 and 07/08.

NTPC does not apply any weighting to new engines installed in the test years (unless it is for a new plant), nor does it make any adjustments for any decreased efficiency for older engines. NTPC also provided its view that in the future it is likely that new engines will be less efficient due to requirements to meet new emissions standards.

The TGC pursued questioning on the fuel efficiency issue but this questioning was not driven by differences with NTPC over the fuel efficiency data that was provided. The TGC was primarily concerned with bolstering arguments being put forward by the TGC with regards to 1) altering the forecast efficiencies of the Inuvik natural gas engines, which will be dealt with later in this section; and 2) the

use of actual fuel efficiencies for the fuel stabilizations funds, which will be dealt with in Section 12.2 of this decision.

The TGC, in Undertaking 13, had requested an explanation from the NTPC as to the impact of changing fuel efficiencies (01/03 Settlement to 06/07 forecasts) on the overall costs of diesel fuel. NTPC's response explained that the change from the 02/03 to the 06/07 diesel efficiencies was responsible for a \$122,000 decrease in diesel expense on a corporate-wide basis.

The TGC did not directly address the diesel fuel efficiency issue in either its argument or reply. In its argument, NTPC submitted that *"its fuel efficiency forecasts for the test years are reasonable and should be approved."*

Views of the Board

The Board approves of the alternative methods for calculating the forecast fuel efficiencies for Yellowknife, Fort Resolution, Norman Wells and Fort McPherson.

The Board notes that there are 4 communities (Nahanni Butte, Jean Marie River, Sachs Harbour and Colville Lake) with fuel efficiencies, which are substantially lower than the other communities; however no detailed explanation has been provided justifying this situation. The Board directs NTPC at the next GRA to provide a detailed analysis as to 1) why the fuel efficiencies in Nahanni Butte, Jean Marie River, Sachs Harbour and Colville Lake are so low; and 2) what NTPC has done and will do to improve the fuel efficiencies in these 4 communities.

The Board notes that unlike other aspects of the GRA, the 07/08 fuel efficiency forecasts do not incorporate the 06/07 forecasts. Given the generally upward

trend in fuel efficiencies, it is the Board's view that calculating the 07/08 forecasts without including the 06/07 forecasts could result in customers forgoing a year's worth of fuel efficiency improvements. Since this matter was not fully canvassed as part of these proceedings the Board does not consider it appropriate to make any adjustments in this regard for the purposes of these proceedings. However, the Board directs NTPC to give due weight to the first test year forecast fuel efficiencies in order to calculate the second test year fuel efficiency forecasts, in the next GRA.

It is the Board's view that the analysis of this issue would have been simplified had the data shown in Table 5.1 been provided in such a format as part of the Phase 1 application. The Board directs NTPC, in the next GRA, to provide an updated version of Table 5.1 that includes the forecast and actual diesel efficiencies for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

5.1.2 Natural Gas in Inuvik

Gas efficiency data in Inuvik, which has been provided over the course of this review, is compiled in Table 5.2. The data is drawn from the Phase 1 Application (Schedule 2.3, Schedules 3.3.1 and 3.3.2) and information request responses (BR.NTPC-6 and TGC.NTPC-20).

Table 5.2 – Inuvik Gas Plant Efficiency (kWh/m³)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Gas Efficiency	3.600	3.429	3.389	3.391	3.409	3.399	3.399

The 01/03 Settlement set the gas efficiency at 3.600 kWh/m³. This was based on 2 years of actual experience with the 2 engines that had been installed in Inuvik in 1999.

Gas consumption is forecast to rise considerably as a result of the installation of a third gas unit in Inuvik in 2006. A 28.7% increase in gas consumption is forecast for 2006/07 and 1.3% for 2007/08. However, gas efficiency is forecast to be steady across the two test years at 3.399 kWh/m³. This forecast is based on energy generation of 95% gas and 5% diesel as opposed to the historical average of 76% gas and 24% diesel.

In its evidence, the TGC took issue with NTPC's forecast gas efficiency. The TGC suggested that the addition of the third engine in Inuvik should result in an increase in the gas efficiency. The TGC suggested an efficiency increase of at least 5% is appropriate and that, based on a 5% improvement, the fuel costs for Inuvik should be reduced by \$177,000 in 2006/07 and \$179,000 in 2007/08.

In its rebuttal, the NTPC provided the following evidence to support its proposed gas efficiency.

"Mr. Merani's evidence suggests that an increase to the fuel efficiency rate for Inuvik is warranted. He appears to arrive at this conclusion by relying on two factors:

- the forecast efficiency is lower than the manufacturer's stated test efficiency rating; and
- because replacing diesel engines in other communities has resulted in improved fuel efficiency.

In the Corporation's view neither of these factors is a valid reason for adjusting the forecast gas plant efficiency in Inuvik.

The manufacturer's efficiency rating is seldom, if ever, achievable in practice. Actual operating conditions influence the efficiency achieved. The forecast fuel efficiencies used to calculate fuel expense reflect the overall efficiency of all units in a plant. The plant efficiencies are impacted by the operating loads; the efficiency of individual units; how the units are dispatched; and percentage loading on the individual engines. Also, fuel efficiencies calculated by the manufacturer do not include fuel consumed during unit start-up and cool down periods. It is therefore not reasonable to adjust the forecast gas plant efficiency based on the manufacturer's rated efficiency. Rather, the more accurate measure of fuel efficiency is to consider recent historical performance of the actual unit when available and, if not available, recent historical performance of similar units at the same generation plant.

Mr. Merani's evidence cites instances where replacing older diesel engines with newer diesel units improved the fuel efficiency at the plant. In the Corporation's view, comparing the efficiency improvements observed as a result of replacing older diesel engines with newer diesel engines to the installation of the 3rd gas genset in Inuvik is not a reasonable basis to suggest that the gas plant efficiency in Inuvik should be adjusted.

Newer diesel engines typically have electronic controls and/or electronic fuel injection – where the primary target is to produce as much power as possible while utilizing the least amount of fuel. This contrasts with the much older technology typically being replaced in diesel plants. In these situations fuel efficiency often is observed to improve. However, it should be noted that this may not continue to be the case in the future as current diesel technology has largely maximized fuel efficiency to the extent possible. Further, it should be noted that diesel engine manufacturers are in many cases faced with competing design objectives of fuel efficiency and reduced emissions. In some newer diesel engines, fuel efficiency is actually lower than previous technologies, in order to maximize emissions reduction objectives.

By contrast, the new natural gas genset in Inuvik is only 4-5 years newer than the existing natural gas gensets (it was manufactured in 2001). The new unit has the same engine control system/fuel system and the same efficiency ratings as the other 2 units. The 3rd gas genset was not justified based on improving efficiency but rather on displacing consumption of diesel fuel. In the Corporation's view there is no reasonable basis to expect that the 3rd gas genset will materially affect the gas plant efficiency in Inuvik. (Ex. 12 NTPC Rebuttal, p. 14, // 30 – p. 15, // 35)

Undertaking 9 at the hearing requested NTPC to provide the 2 years of actual data that was relied upon in setting the fuel efficiency to 3.600 kWh/m³ in the 01/03 Settlement. NTPC reported that for 1999/2000, the actual gas efficiency was 3.51 kWh/m³ and for 2000/2001, it was 3.65 kWh/m³.

Undertaking 10 requested the manufacturer's rated efficiencies for the gas engines. NTPC's response was:

“MR. STEPHEN KERR: The manufacturer's rated efficiencies for the Inuvik gas engines. At 50 percent load the efficiency is 3.7 kilowatt hours per metre cubed. At 75 percent load, 4.01 kilowatt hours per metre cubed. At 100 percent load, 4.23 kilowatt hours per metre cubed.

And these efficiencies are based on one (1) hour of continuous operation at those loads, but it does not take into consideration any fuel consumed to warm up or cool down the engine.” (Tr. Vol. II, p. 20, // 13 - 22)

This explanation for Undertaking 10 was questioned by the TGC.

“MR. AZAD MERANI: Before I go on to my cross, just a quick question on the undertakings.

Mr. Kerr, you mentioned the Inuvik gas engine had an efficiency rating depending on the percent loading; that was the manufacturer's recommended ratings.

Are you able to tell me what the engines are running at on an actual basis? Are they fairly close to 100 percent or thereabouts?

MR. STEPHEN KERR: Subject to check, I would say no. The Inuvik gas engines are -- they would follow the load in Inuvik, so I would say rarely are these engines base loaded.

MR. AZAD MERANI: Certainly not 50 percent; you'd say it would be higher than 50, close to 75 percent or so?

MR. STEPHEN KERR: Again, something to check. They probably operate somewhere between 50 and 75 percent, again, depending on the load.” (Tr. Vol. II, p. 27, // 16 – p. 28, // 8)

In its argument, NTPC suggested that the Board should disregard the TGC suggestions of a 5% improvement in gas efficiency and provided the following explanation.

“Fuel efficiency for the Town of Inuvik is forecast in the Application at 3.399 kW.h/m³ for both test years. As discussed in section 4(b) above, that forecast is based on a weighted average of the past three years’ actual plant efficiencies and no adjustment was made for the third Inuvik gas engine installed in 2006/07.

Mr. Merani has suggested that “...there is no doubt the addition of the third engine in Inuvik should result in an increase in the gas efficiency. This review of changes in efficiency associated with a new plant or engine suggests an efficiency increase of at least 5% is appropriate.”

The evidence does not support Mr. Marani’s suggestion. The third Inuvik gas engine is not likely to have a better fuel efficiency than the existing gas gensets that are only 4 to 5 years older. Further, manufacturer’s fuel efficiency ratings are not useful for GRA forecasts. As Mr. Kerr noted, manufacturer’s ratings “...are based on one (1) hour of continuous operation at those loads, but it does not take into consideration any fuel consumed to warm up or cool down the engine.” Clearly the manufacturer’s fuel efficiency ratings do not reflect real world conditions, which a GRA forecast is intended to mirror, and should not be applied in this case.

Consequently, a 3.399 kW.h/m³ forecast fuel efficiency for the Town of Inuvik is reasonable and the Board should disregard Mr. Merani’s suggestion. (NTPC Argument, p. 69, // 7 – 22)

In its argument, the TGC restated its position as follows:

“The TGC submit the recommendations in its evidence to increase Inuvik’s gas efficiency rating for the Test Years 2006/07 and 2007/08, by 5%, from 3.399 Kwh/cubic meter to 3.569 Kwh/cubic meter, remain valid for the following reasons:

- As noted in the TGC evidence, when a new engine is installed (for example, in Fort Providence), or when a new plant is installed, we

generally see an increase in fuel efficiency rate; this increase has been in the range of 5.60% to 6.99%

- Contrary to the evidence filed in TGC.NTPC-20, the 2002/04 has heat rate was filed based on actual experienced gas heat rates of between 3.510 Kwh/cubic meter in 1999/2000 and 3.650 Kwh/cubic meter in 2000/01
- The actual gas heat rate in 2002/03 was 3.429 Kwh/cubic meter
- At 50% loading, the manufacturer’s test heat rate is 3.700 Kwh/cubic meter whereas as 75% loading, it is 4.010 Kwh/cubic meter; considering these engines run at about 50 to 75% loading, and taking into account the consumption of fuel during the warming up and cooling down processes, the recommended revised rate of 3.569 Kwh/cubic meter appears reasonable.
- The simple average of the above noted heat rates is 3.529 Kwh/cubic meter $[(3.510+3.650+3.429)/3]$, significantly higher than the 3.399 Kwh/cubic meter used in the GRA.
- Using the weighting of 3:2:1 for the data available, a rate of 3.565 Kwh/cubic meter is obtained:

Year	Heat Rate	Weighting	Weighted HR
1999-00	3.5100	2	7.02
2000-01	3.6500	3	10.95
2002-03	3.4290	1	3.429
Total	10.5890	6	21.399
Simple Average	3.5297		
Weighted Average			3.5665

- The use of the most recent data available on the record is appropriate as acknowledged by NTPC:

Rather, the more accurate measure of fuel efficiency is to consider recent historical performance of the actual unit when available and, if not available, recent historical performance of similar units at the same generation plant. ” (TGC Argument, p. 22 – 23)

The TGC and NTPC both discussed this issue further in their reply arguments.

Views of the Board

It is the Board's view that the TGC has not justified why NTPC should use actual gas efficiencies from 99/00, 00/01 and 02/03 when there is more recent (03/04, 04/05 and 05/06) actual data available for use. Similarly, the Board is not convinced that the 3rd gas engine in Inuvik will produce efficiencies substantially different than first two engines given the young age of the first two engines. It is the Board's view that the improved diesel efficiencies achieved when older engines have been replaced by newer engines is not comparable to the situation in Inuvik with the addition of a 3rd gas engine.

The Board approves of the forecast gas efficiencies for 06/07 and 07/08.

In keeping with the Board's direction on diesel efficiencies, the Board directs NTPC to give due weight to the first test year gas efficiency forecasts in order to calculate the second test year gas efficiencies, in the next GRA.

The Board is also concerned about two other issues.

Drop in Efficiency: For 1999/2000, the actual gas efficiency was 3.51 kWh/m³ and for 2000/2001, it was 3.65 kWh/m³. Since that time the efficiency has been substantially lower at about 3.4 kWh/m³. NTPC has not provided a satisfactory explanation as to why the gas efficiency has decreased from the first two years of operation. The Board directs NTPC, at the next GRA, to provide an analysis as to why the recent gas efficiency has dropped substantially from 99/00 and 00/01.

Manufacturer's Rating: As acknowledged by NTPC, the gas engines generally operate in the range of 50% to 75% of capacity. The manufacturer's efficiency ratings at these loads are 3.7 kWh/m³ and 4.01 kWh/m³, respectively, which is

substantially higher than NTPC's forecast of 3.399 kWh/m³. While the Board can accept that the actual operation of the engines can differ from the manufacturer's ratings, the magnitude of the discrepancy is of concern to the Board. The Board directs NTPC, at the next GRA, to provide a detailed analysis as to why the actual gas efficiencies are so much lower than the manufacturer's ratings.

It is the Board's view that the analysis of this issue would have been simplified had the data shown in Table 5.2 been provided in such a format as part of the Phase 1 application. The Board directs NTPC, in the next GRA, to provide an updated version of Table 5.2 that includes the forecast and actual gas efficiencies for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

5.2 Losses and Station Service

5.2.1 Losses

Loss data which has been provided over the course of this review is compiled in Table 5.3. The data is drawn from the Phase 1 Application (Schedules 2.1, 2.2 and 2.3, and Schedules A.1 to A.27) and information requests (TGC.NTPC-32 and HC.NTPC-9(g)).

Table 5.3 – Losses (MWh and % of Generation)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Behchoko	Included in Snare System figures						
Dettah	Included in Snare System figures						
Snare	10,920	11,691	7940	10,490	8314	6642	7579
	5.2%	5.6%	3.9%	4.6%	4.2%	3.4%	3.9%
Fort Resolution	Included in Taltson System figures						

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Fort Smith	Included in Taltson System figures						
Taltson	4225	7252	5912	8670	5591	6742	6818
	6.7%	11.2%	9.6%	13.2%	8.7%	10.2%	10.2%
Hydro	15,144	Not Provided	Not Provided	19,160	13,905	13,384	14,397
	5.5%	Not Provided	Not Provided	6.5%	5.3%	5.2%	5.5%
Wha Ti	116	Not Provided	Not Provided	111	113	135	135
	6.2%	Not Provided	Not Provided	6.5%	6.6%	7.8%	7.8%
Gameti	39	Not Provided	Not Provided	39	59	43	42
	4.1%	Not Provided	Not Provided	4.0%	5.9%	4.4%	4.3%
Lutsel K'e	94	Not Provided	Not Provided	80	79	90	92
	6.2%	Not Provided	Not Provided	5.0%	5.0%	5.6%	5.6%
Fort Simpson	433	260	456	408	460	446	453
	5.4%	Not Provided	Not Provided	5.1%	5.8%	5.5%	5.5%
Fort Liard	258	498	170	251	232	254	244
	7.0%	Not Provided	Not Provided	8.8%	8.4%	9.0%	9.0%
Wrigley	58	Not Provided	Not Provided	32	55	45	41
	7.0%	Not Provided	Not Provided	4.1%	7.5%	6.2%	6.1%
Nahanni Butte	21	Not Provided	Not Provided	41	22	37	35
	5.2%	Not Provided	Not Provided	10.4%	5.4%	9.4%	9.4%
Jean Marie River	19	Not Provided	Not Provided	57	58	63	65
	7.0%	Not Provided	Not Provided	17.3%	19.0%	19.0%	19.0%
Inuvik	2020	1929	584	1221	1318	1854	1880
	7.0%	Not Provided	Not Provided	4.0%	4.3%	6.0%	6.0%
Norman Wells	515	Not Provided	Not Provided	1256	1232	1121	1157
	7.0%	Not Provided	Not Provided	14.0%	13.7%	12.4%	12.4%
Tuktoyaktuk	303	Not Provided	Not Provided	452	404	480	485
	7.0%	Not Provided	Not Provided	10.0%	9.2%	10.6%	10.6%
Fort McPherson	174	Not Provided	Not Provided	170	160	146	144
	4.9%	Not Provided	Not Provided	4.9%	4.7%	4.2%	4.2%
Aklavik	102	Not Provided	Not Provided	92	123	158	158
	3.6%	Not Provided	Not Provided	3.1%	4.2%	5.7%	5.7%
Deline	182	Not Provided	Not Provided	251	230	242	243
	7.0%	Not Provided	Not Provided	9.2%	8.5%	9.1%	9.1%
Fort Good Hope	60	Not Provided	Not Provided	145	187	153	154
	2.3%	Not Provided	Not Provided	4.9%	6.6%	5.4%	5.4%
Tulita	112	Not Provided	Not Provided	197	170	181	183
	5.3%	Not Provided	Not Provided	8.8%	7.8%	8.3%	8.3%
Paulatuk	69	Not Provided	Not Provided	107	69	109	112
	7.0%	Not Provided	Not Provided	7.5%	5.1%	8.2%	8.3%
Sachs Harbour	38	Not Provided	Not Provided	70	68	42	41
	3.6%	Not Provided	Not Provided	7.1%	7.1%	4.5%	4.5%
Tsiigehtchic	47	Not Provided	Not Provided	62	47	55	57
	6.1%	Not Provided	Not Provided	7.4%	5.6%	6.6%	6.6%
Colville Lake	15	Not Provided	Not Provided	49	35	54	55
	7.0%	Not Provided	Not Provided	15.5%	11.0%	16.2%	16.3%
Ulukhaktok	133	Not Provided	Not Provided	119	111	104	110
	7.0%	Not Provided	Not Provided	6.1%	5.5%	5.5%	5.5%
Thermal	4808	Not Provided	Not Provided	5208	5232	5813	5886
	6.3%	Not Provided	Not Provided	6.5%	6.5%	7.2%	7.2%
Overall	19,953	24,807	Not Provided	24,367	19,137	19,197	20,283
	5.7%	Not Provided	Not Provided	6.5%	5.6%	5.7%	5.9%

In the 01/03 Settlement, losses had been capped at 7%. Forecast losses for 06/07 and 07/08 represent the full uncapped losses on each system and are calculated as a rolling average of losses over the previous five years.

Overall the total forecast corporate-wide losses for 06/07 and 07/08 are approximately the same as the 01/03 Settlement. A slight increase in losses from 06/07 to 07/08 is due to modest sales growth.

According to NTPC, the Taltson system experiences substantial losses due to the long and lightly-loaded transmission system. This has a mitigating effect on overall loss reduction, however since the losses on Taltson are supplied by surplus hydro, there is no net cost to the losses on that system.

Outside of Taltson, NTPC asserts that losses have declined in both absolute and relative terms since the 01/03 Settlement which reflects NTPC's continuing efforts to reduce the overall level of line losses. However some communities still have losses higher than 7% despite NTPC's best efforts to reduce loss levels.

According to NTPC, the losses in the thermal communities are now confirmed by over a decade of experience. They are not anomalies and should be included in the calculation of the revenue requirement.

In BR.NTPC-5(a), NTPC provided the following explanation as to why losses are high in some communities.

"The following communities have forecast losses as a percentage of generation to be greater than 7% for the two test years: Wha Ti, Fort Liard, Nahanni Butte, Jean Marie River, Norman Wells, Tuktoyaktuk, Deline, Tulita, Paulatuk, and Colville Lake.

Metering problems have been identified in Jean Marie River, Nahanni Butte and Colville Lake and steps have been taken to correct these problems.

Losses represented in Appendix A include losses from distribution transformers, conductors and the residual difference between metered generation and metered consumption. Factors that impact losses include, metering accuracy, conductor size relative to load, transformer size relative to load, distance from the source of generation to the delivery point.

As these communities have grown, customer loads are getting further from the generation source and the loads on feeders are increasing. In particular, Norman Wells and Tuktoyaktuk, losses are negatively impacted by the significant distance from the generation source. In addition, historical assets were not necessarily built with a view to reduce losses however as these assets are changed out over time, the Corporation considers current and future loads in assessing the best match for voltage, conductor and transformers in order to reduce future losses.

No other cost effective steps or investigations have been identified at this time to reduce losses.”

NTPC provided further explanation in its argument.

“Except for Taltson, the Corporation’s line losses as a percentage of sales have declined from 6.01% to 4.95% since the last GRA. In the case of Taltson, percentage losses are high reflecting the unavoidable characteristics of substantial and lightly loaded transmission, and in any event do not drive costs in the Revenue Requirement as they are served by surplus hydro.

BR.NTPC-5 requested NTPC to provide an explanation as to communities where losses were higher than 7%. The 10 communities listed reflect basically the same communities that have had losses in the higher end of the range going back to the Board’s Decision 9-93 and that investigations have been done over a long period of time on these communities. While generic approaches that can be employed to reduce line losses (such as reconductoring or voltage conversion) are expensive and not practical in these cases, “[n]o other cost effective steps or investigations have been identified at this time to reduce losses”. Consequently, NTPC submits that the line losses indicated in the GRA are a reasonable, valid and justified

cost of operating its systems, and as such should be approved the Board as part of calculating the NTPC's Revenue Requirement.

Ms. Goucher noted in her opening comments an error in the calculation of the line losses for Norman Wells. The Corporation proposes that this error be corrected (line losses reduced and consequently Revenue Requirement reduced) in its final GRA refiling. (NTPC Argument, p. 10, // 4 – 20)

As stated at the hearing, NTPC expects that the Norman Wells losses will be reduced from the 12.4% in the application to about 10%.

Views of the Board

Losses are comprised of two components: electrical losses and non-electrical losses, a major part of which is unbilled energy at year-end. The Board considers if there is variation in the cycle meter reading dates, the amount of unbilled energy may vary from year to year.

The Board is of the view that electrical loss data is similar to the use of fuel efficiency data in that both data sets are measurements of the efficiency of a particular portion of the electrical system. Given that both data sets are efficiency measures, it is the Board's view that electrical losses can and should be forecast with the 3-year 3:2:1 weighting procedure used for fuel efficiency forecasts.

While the 3-year 3:2:1 weighting system is preferred by the Board for dealing with electrical losses, the Board recognizes that this method might not be suitable for application to non-electrical losses. As well, the Board recognizes that there is insufficient evidence in this proceeding to effectively separate electrical losses and non-electrical losses.

The Board directs that, in the next GRA, NTPC is to include an examination of the pros and cons of separating losses into its two components (electrical losses and non-electrical losses) which would allow the electrical losses to be forecast using the same method as for fuel efficiencies while non-electrical losses could still be forecast using the 5-year rolling average method.

While the forecast 06/07 and 07/08 corporate-wide losses are approximately the same as the 01/03 Settlement, in the absence of many of the actual 02/03 losses, it is not possible for the Board to determine if any meaningful improvements in losses have been made by NTPC in many of the communities.

That being said, the Board is not satisfied with the level of effort or the results achieved by NTPC in reducing the high losses in some communities. While the high losses in Jean Marie River and Colville Lake might not be anomalies, the Board does not consider losses of 19.0% and 16.3% to be reasonable.

As part of the 01/03 Settlement, the Board approved a 7% cap on losses. It is the Board's view that the continuation of this cap is necessary to protect consumers in high loss communities. The Board directs NTPC, as part of its Phase 1 refiling, to apply a 7% cap on losses.

It is the Board's view that the analysis of this issue would have been simplified had the data shown in Table 5.3 been provided in such a format as part of the Phase 1 application. The Board directs NTPC, in the next GRA, to provide an updated version of Table 5.3 that includes the forecast and actual losses for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

5.2.2 Station Service

Station service data, which has been provided over the course of this review, is compiled in Table 5.4. The data is drawn from the Phase 1 Application (Schedules 2.1, 2.2 and 2.3, and Schedules A.1 to A.27) and information requests (TGC.NTPC-32 and HC.NTPC-9(g)). The station service as a percentage of generation was calculated by the Board from the information provided in these same sources where total generation was provided.

Table 5.4 – Station Service (MWh and % of Generation)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Behchoko	Not Provided						
Dettah	Not Provided						
Snare	5828	5619	5991	7006	6291	5982	6137
	2.8%	2.7%	2.9%	3.1%	3.2%	3.1%	3.1%
Fort Resolution	Not Provided	Not Provided	Not Provided	104	111	111	111
	Not Provided	Not Provided	Not Provided	3.7%	4.1%	4.1%	4.2%
Fort Smith	2660	916	833	788	690	690	690
	9.0%	4.1%	3.8%	3.5%	3.2%	3.2%	3.2%
Taltson	2660	2182	1924	1037	1665	1665	1665
	4.2%	3.4%	3.1%	1.6%	2.6%	2.5%	2.5%
Hydro	8488	Not Provided	Not Provided	8044	7956	7647	7802
	3.1%	Not Provided	Not Provided	2.7%	3.0%	3.0%	3.0%
Wha Ti	32.6	Not Provided	Not Provided	23	23	23	23
	1.8%	Not Provided	Not Provided	1.3%	1.3%	1.3%	1.3%
Gameti	52	Not Provided	Not Provided	64	85	85	85
	5.5%	Not Provided	Not Provided	6.6%	8.6%	8.7%	8.7%
Lutsel K'e	103	Not Provided	Not Provided	87	96	96	96
	6.8%	Not Provided	Not Provided	5.5%	6.1%	6.0%	5.9%
Fort Simpson	320	261	302	263	231	231	231
	4.0%	Not Provided	Not Provided	3.3%	2.9%	2.8%	2.8%
Fort Liard	56	61	44	45	33	33	33
	1.5%	Not Provided	Not Provided	1.6%	1.2%	1.2%	1.2%
Wrigley	30	Not Provided	Not Provided	24	27	27	27
	3.6%	Not Provided	Not Provided	3.1%	3.7%	3.7%	4.0%
Nahanni Butte	36	Not Provided	Not Provided	28	33	33	33
	8.7%	Not Provided	Not Provided	7.1%	8.0%	8.4%	8.8%
Jean Marie River	37	Not Provided	Not Provided	31	31	31	31
	13.5%	Not Provided	Not Provided	9.5%	10.2%	9.3%	9.1%
Inuvik	1422	1607	1687	1783	1612	1612	1612
	4.9%	Not Provided	Not Provided	5.8%	5.2%	5.2%	5.1%
Norman Wells	152	Not Provided	Not Provided	67	101	101	101
	2.1%	Not Provided	Not Provided	0.7%	1.1%	1.1%	1.1%

Tuktoyaktuk	208	Not Provided	Not Provided	198	226	226	226
	4.8%	Not Provided	Not Provided	4.4%	5.2%	5.0%	4.9%
Fort McPherson	231	Not Provided	Not Provided	23	153	153	153
	6.5%	Not Provided	Not Provided	0.7%	4.5%	4.4%	4.5%
Aklavik	102	Not Provided	Not Provided	127	117	117	117
	3.6%	Not Provided	Not Provided	4.4%	4.0%	4.2%	4.2%
Deline	88	Not Provided	Not Provided	58	56	56	56
	3.4%	Not Provided	Not Provided	2.1%	2.1%	2.1%	2.1%
Fort Good Hope	139	Not Provided	Not Provided	126	76	76	76
	5.3%	Not Provided	Not Provided	4.3%	2.7%	2.7%	2.6%
Tulita	172	Not Provided	Not Provided	127	122	122	122
	8.1%	Not Provided	Not Provided	5.6%	5.6%	5.6%	5.5%
Paulatuk	86	Not Provided	Not Provided	50	53	53	53
	8.7%	Not Provided	Not Provided	3.5%	3.9%	4.0%	3.9%
Sachs Harbour	97	Not Provided	Not Provided	104	96	96	96
	9.1%	Not Provided	Not Provided	10.5%	9.9%	10.3%	10.6%
Tsiigehtchic	39	Not Provided	Not Provided	44	39	39	39
	5.1%	Not Provided	Not Provided	5.2%	4.7%	4.7%	4.5%
Colville Lake	35	Not Provided	Not Provided	4	2	2	2
	15.8%	Not Provided	Not Provided	1.3%	0.6%	0.6%	0.6%
Ulukhaktok	13371	Not Provided	Not Provided	68	62	62	62
	3.7%	Not Provided	Not Provided	3.5%	3.1%	3.3%	3.1%
Thermal	3511	Not Provided	Not Provided	3344	3274	3274	3274
	4.6%	Not Provided	Not Provided	4.1%	4.1%	4.1%	4.0%
Overall	11,999	11,164	Not Provided	11,387	11,231	10,921	11,076
	3.4%	Not Provided	Not Provided	3.1%	3.3%	3.2%	3.2%

The forecast overall 06/07 station service has decreased from the 01/03 Settlement, both in absolute terms and as a percentage of sales. There has been a material increase however at the Jackfish diesel plant. The remaining communities are forecast by NTPC to achieve stable station service loads or reductions compared to 02/03.

With the decreased use of the diesel engines at Jackfish, the residual heat from the engines is no longer sufficient to provide heat to the plant. Surplus hydro is now used to heat the plant with electric heaters. It is NTPC's position that the higher station service at Jackfish through the use of surplus hydro is a benefit to ratepayers as it avoids the use of more expensive heating oil.

The station service forecasts are set equal to the station service for the previous year with adjustments made where needed based on specific knowledge of plant

requirement changes. The rationale for this approach is that station service normally doesn't change unless there are material changes in a plant's systems or structure.

As for station service targets, NTPC explained its approach in the Corporation 2005/06 Greenhouse Gas Report, which was attached to TGC.NTPC-13(a).

"By diligently monitoring facility statistics, NTPC is able to identify sites where station service requirements are in excess of acceptable levels. NTPC set a target for each facility to achieve and maintain a station service less than or equal to 5% of its total generation. NTPC will continue to monitor station service and work to reduce it at the seven plants still exceeding the 5% target while maintaining all other site station service percentages below the target." (TGC.NTPC-13(a) attachment, p. 14)

The Greenhouse Gas Report also described NTPC's approach and techniques for reducing station service.

"NTPC is continuously investigating ways to reduce its own consumption of power. Some of the equipment and design improvements utilized to reduce station service at our plants include:

- replacement of in-plant electric space heating with residual heat from engine jacket water systems;
- replacement of engine electric block heaters with residual heat circuits that utilize jacket water heat from operating engines;
- replacement of inefficient lighting;
- installation of separate lighting circuits so that only specific lights are on at certain times;
- installation of variable frequency drives on radiators; and
- installation of photo sensors on all outside lighting.

Station service reductions have also come through the education and resulting heightened awareness of plant personnel. Small measures are highlighted, such as turning off lights when plants are unattended, turning heaters down or off when not required, and ensuring that any pipes or other equipment that require heat tracing during winter months are shut-off

during spring and summer months.” (TGC.NTPC-13(a) attachment, p. 13 - 14)

NTPC states that it has significantly reduced station service as a percentage of generation over the last several years. It will continue to monitor station service and work to reduce it where cost effective.

At the hearing, the TGC questioned NTPC on why the station service target was set at 5%. NTPC responded that 5% was simply chosen by the operations staff as a reasonable target given the range of actual station service that was being used in the various communities.

“MR. AZAD MERANI: ...

You -- you really don't have any -- any better explanation for why 5 percent is more appropriate than a lower number? You just picked it because that was the target that you guys thought was a reasonable target?

MR. STEPHEN KERR: The -- I guess you -- you are correct. Five percent was a number that the Power Corporation, its operation staff set...” (Tr. Vol. II, p. 48, // 2 – 11)

When asked by the TGC why some of the smaller communities had station service in excess of the 5% target, NTPC responded that there is certain amount of station service inherent in all of the plants but the only specific reason provided was that Jean Marie River has an office that is separate from the power plant and that uses electric heat. NTPC then reverted to a discussion of what it has done to reduce station service rather than providing direct answers to the question that had been asked.

The TGC questioned NTPC on what it would do if the Board were to establish a target lower than 5%.

“MR. STEPHEN KERR: I guess for the Power Corporation to try to achieve something -- some target, arbitrary target, that would be imposed would probably take a lot of money and investment, particularly, in some of the older plants to try and go in and retrofit those facilities; that would mean fairly significant capital dollars in some place for probably minimal return.

So I'll -- for us to undertake that, we could certainly attempt it, but at the end of the day I'm not sure it would be in the best interest of our customers.” (Tr. Vol. II, p. 49, // 11 – 21)

TGC summarized its views on this matter in its argument.

“NTPC’s target station service loss ratio of 5% is arbitrary and unrealistic; since 1990/91, it has been able to achieve a reduction in the overall average station service losses from 9.0% to 4.4% in 2005/06, a reduction of some 51%. NTPC should provide evidence, at its next GRA, as to why it cannot, and has not been able to reduce station service losses to 1-2% of total generation experienced in several communities in 2005/06. Further, to the extent it is able to reduce station service loss ratios below those approved in this GRA, a deferral account should be set up to allow any savings, net of any incremental costs not included in the 2006/07 and 2007/2008 Revenue Requirements, to be flowed through to customers in the next GRA.” (TGC Argument, p. 30)

NTPC submitted in its argument that:

“No evidence was submitted by any intervenor challenging NTPC’s station service or line loss forecasts. Consequently, NTPC submits that the station service, line losses and overall load forecast provided in Chapter 2 and Appendix A of the Application is reasonable and should be approved by the Board.” (NTPC Argument, p. 11, // 29 – 32)

In its reply, NTPC directly addressed the recommendations from the TGC. On lowering the 5% target, NTPC cautions that there are limited economic opportunities to improve station service. NTPC also opposes the creation of a station service deferral account due to the hypothetical nature of potential station service projects and also due to the fact that station service projects are a normal

component of NTPC costs with investments in capital improvements to reduce station service loads capitalized as with any other capital asset.

Views of the Board

The Board is of the view that station service data is similar to the use of fuel efficiency data in that both data sets are measurements of the efficiency of a particular portion of the electrical system. Given that both data sets are efficiency measures, it is the Board's view that they can and should be forecast in a similar manner. NTPC explains that station service forecasts are set equal to the station service for the previous year with adjustments made where needed based on specific knowledge of plant requirement changes. However, NTPC does not provide any justification for using this procedure as opposed to an alternative such as the 3-year 3:2:1 weighting procedure already used for fuel efficiency forecasts.

The Board directs NTPC that, in its Phase 1 refiling, station service is to be calculated using the same procedure used for fuel efficiencies. Forecast station service is to be calculated using 3 years of actual data with a weighting of "3" given to the lowest station service year, a weighting of "2" given to the middle station service year and a weighting of "1" given to the highest station service year. Consistent with its directions respecting fuel efficiencies, the Board directs NTPC to give due weight to the first test year station service forecasts in order to calculate the second test year station service forecasts, in the next GRA.

While the forecast 06/07 and 07/08 corporate-wide station service is a slight improvement over the 01/03 Settlement, in the absence of many of the actual 02/03 amounts, it is not possible for the Board to determine if any meaningful improvements have been made by NTPC in many of the communities over this

time period. Over the longer term, however, it is apparent that significant improvements have been made in station service levels.

While the Board is encouraged by the improvements made in station service, the Board is still concerned that, in some communities, station service is still too high. In particular, the Board finds that station service levels in Gameti, Nahanni Butte, Jean Marie River and Sachs Harbour are unreasonably high.

Given the high station service in some communities, it is the Board's view that a station service percentage cap is necessary to protect consumers in these communities. The Board directs NTPC, in its Phase 1 refiling, to apply a 5% cap on station service as a percentage of generation.

It is the Board's view that the analysis of this issue would have been simplified had the data shown in Table 5.4 been provided in such a format as part of the Phase 1 application. The Board directs NTPC, in the next GRA, to provide an updated version of Table 5.4 that includes the forecast and actual station service for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

With the imposition of the station service percentage cap, the Board does not see any need to create a station service deferral account. However, the Board does direct NTPC to provide a more detailed analysis of station service levels and potential reductions at its next GRA.

5.3 Fuel Pricing in Inuvik

The TGC expressed concern with the 15-year contract that NTPC has for the supply of natural gas in Inuvik. Specifically, the TGC is concerned that the contract indexes the price of natural gas to local diesel prices rather than world gas markets. The NTPC provided an explanation in its response to TGC.NTPC-18(a).

“The terms of the natural gas agreement dictate that the price be based on the Edmonton average unbranded regular diesel price as seen in Bloomberg Oil Buyers Guide. This is because natural gas price indices have no relevance to the gas system in Inuvik, as there is no way of getting the gas from Inuvik to a North American market. The value of gas in Inuvik is as a displacement to diesel fuel, and as a result diesel-linked pricing is the appropriate benchmark for both NTPC and the vendor.”

In its Argument, the TGC provided the following analysis and recommendation.

“NTPC also states it cannot change the index to an AECO-C or NYMEX gas price index because the contract with the Town of Inuvik is for a 15-year term, and “so changing the rules or underlying principles of the contract at this point is not an option. However, at renewal time we would be open to those discussions.”

The TGC submits NTPC’s reluctance to review the terms of the contract on a bilateral basis is difficult to understand. As the price paid for natural gas, whether tied to a diesel index or gas index, is eventually part of the Fuel Stabilization Fund for Inuvik, there should be no impact on the Corporation’s bottom line. That is, any cost or savings that arise from the use of an alternative index is to the account of customers in Inuvik, not the shareholder.

As to NTPC’s argument that a gas pricing index is irrelevant because of a lack of physical connection, the TGC submit to the extent the objective is to set a reasonable price, physical connection is an irrelevant consideration. What is relevant is that gas prices be tied to a gas index;

there is no evidence that gas prices have any nexus to the world diesel prices.

As such, the TGC submit the Board direct the Corporation to commence discussions with the Town of Inuvik with a view of determining if the use of a gas price index such as the AECO-C or NYMEX, can provide benefits (in terms of cost savings, or additional stability) to customers in Inuvik. In our view, as long as two parties are willing and agreeable, any contractual arrangement can be changed; hence, there is no need to wait, as NTPC asserts, for the 15-year contract term to expire.” (TGC Argument, p. 19 – 20)

The NTPC responded to this recommendation in its reply.

“The TGC requests that the Board direct the Corporation to commence discussions with the Town of Inuvik respecting the use of another gas price index. That request is supported by the statement that “...the contract with the Town of Inuvik is for a 15-year term...” and the TGCs’ apparent misunderstanding that the Town of Inuvik is a party to the Inuvik Gas Sale Agreement. The Town of Inuvik is not, in fact, a party to that agreement. Rather, the Inuvik Gas Sales Agreement is an agreement among Ikhil Resource Ltd., Altagas Marketing Inc. and IPL Holdings Inc., and the Corporation.

Recognizing the actual counterparties to the Inuvik Gas Sale Agreement, the TGC request amounts to a suggestion that the Corporation should break a contract negotiated in good faith among the above noted parties. That suggestion is simply unreasonable, particularly in the context of a contract that has provided substantial benefits to the Town of Inuvik. For example, the Inuvik Gas Sales Agreement has enabled savings related to the Inuvik 3rd engine of over \$200,000 in 2006/07 alone. While Ms. Goucher agreed to consult with the Town of Inuvik at the time the agreement is up for renewal, any suggestion that NTPC should break the contract prior to renewal is untenable and should be summarily dismissed by the Board.” (NTPC Reply, p. 16, // 9 – 23)

Views of the Board

The Board does not agree with NTPC’s characterization that the TGC recommendation would require the NTPC to “break a contract”. As pointed out

by the TGC, the parties to a contract can review the terms of the contract and could potentially agree to alter them. This is simply a review which could lead to an amendment. Furthermore, it is clear that the TGC reference to the Town of Inuvik was a mistake which does not detract from their argument.

However, while the TGC is correct that changing the indexing mechanism for the price of Inuvik gas would not impact NTPC's bottom-line, if the ratepayers are to receive a benefit from the renegotiation of this contract then it would be the bottom-line of the other contractual parties that would necessarily be negatively impacted. The Board has no evidence of any consideration which could convince the other contractual parties to agree to a change to the contract at this point.

The Board is satisfied with the NTPC commitment that it will examine this issue in the negotiations for the next contract to replace the current 15-year contract.

6. OPERATION AND MAINTENANCE EXPENSES

The operation and maintenance expenses from the previous GRA to the current GRA forecasts are shown in Table 6.1. The data was obtained from Table 3.3 and Schedules 3.1 and 3.2 revised May 16th.

Table 6.1 – Operation and Maintenance Expenses (\$000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	13,982	14,540
Thermal	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	17,002	17,904
Overall	25,780	Not Provided	Not Provided	27,780	28,014	30,984	32,444

NTPC is seeking Board approval for operation and maintenance expenses of \$30.984 million in 06/07 and \$32.444 million in 07/08. Less corporate donations of \$0.103 million in 06/07 and \$0.103 million in 07/08, the operation and maintenance expenses included in the revenue requirement each year is \$30.881 million and \$32.341 million, respectively.

The 4 components of operation and maintenance expenses are:

- Salaries and Wages
- Non-Production Fuel
- Supplies and Services
- Travel and Accommodation

Intervenors raised various issues with respect to these 4 components and these issues are discussed in detail in Sections 6.1, 6.2, 6.3 and 6.4.

Subject to the Board’s directions in Sections 6.1 to 6.4, NTPC’s proposed operation and maintenance expenses for inclusion in the 06/07 and 07/08 revenue requirement are approved by the Board.

6.1 Salaries and Wages

NTPC is seeking approval for its salaries and wages forecast expenses of \$17.730 million for 06/07 and \$18.552 million for 07/08.

Table 6.2 summarizes the total salaries and wages data provided in the Application (Table 3.3 and Schedules 3.1 and 3.2 revised May 16th) and subsequent material (HC.NTPC-42 and Table BR.NTPC-10(a) revised May 19th).

Table 6.2 – Salaries and Wages (\$000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	6,531	Not Provided	7,403	7,832
Thermal	Not Provided	Not Provided	Not Provided	8,499	Not Provided	9,967	10,720
Overall	14,696	15,569	Not Provided	15,030	16,543	17,370	18,552

The salaries and wages expense includes all pay for full time and casual employees as well as related benefits. The \$2.674 million increase from the 01/03 Settlement to the 06/07 forecast is a result of increases required by the collective agreements as well as changes in staff complement. Major components of the increase are:

Safety and Environmental Legislation (\$0.293 million) – Legislative requirements has forced the addition of three positions.

Bluefish (\$0.409 million) – The addition of the Bluefish Generating Station has increased salaries and wages.

Apprenticeship Program (\$0.278 million) – NTPC has undertaken an apprenticeship program by adding three new line positions and two journeyman supervisors. The program will be expanded by another \$0.633 million in 07/08 by adding two apprentice mechanics and two apprentice electricians.

Job Evaluation (\$0.261) – Implementing a new job evaluation program required an increase in salaries and wages.

Outside of these 4 factors, the salaries and wages increase from the 01/03 Settlement to the 06/07 forecast is \$1.433 million or 2.4% average annual growth per year. NTPC attributes this residual growth to wage information and the tight labor markets.

The interveners raised concerns with 4 aspects of the salaries and wages expense:

1. Operational Savings from Bluefish
2. Benefits from Automatic Meter Reading (“AMR”)
3. At-Risk Compensation
4. Apprentice Salaries

These four issues are addressed by the Board in the following sections.

NTPC’s salaries and wages forecasts for 06/07 and 07/08 are approved by the Board subject to the Board directions in Sections 6.1.2 and 6.1.3.

6.1.1 Operational Savings from Bluefish

NTPC purchased the Bluefish Generating Station in 2002. The benefits expected by NTPC included avoided diesel generation, reduced future diesel engine

replacement at the Jackfish Lake plant, and an increased ability to meet future load growth on the Snare-Yellowknife system.

NTPC states that while Bluefish has resulted in significant reduced overall costs with large savings in diesel fuel use being offset somewhat by increases by the operating and capital costs of Bluefish. In the area of salaries and wages, Bluefish's forecasts are \$0.409 million for 06/07 and \$0.423 million for 07/08.

The difference between what was forecast for Bluefish at the time of purchase and the forecast for the 2 test years was explored in BR.NTPC-9. The Project Permit forecast salaries and wages for 02/03 and 03/04 as \$0.262 million so the 06/07 and 07/08 forecasts represent \$0.147 million and \$0.161 million increases, respectively. The explanation provided for these increases is:

“Salaries are analyzed as a group since variations in the allocations of salary costs between labour accounts are a result of a lack of working experience when the project permit was completed in managing the labour needed between operations and maintenance and regular time, overtime or casuals, as well as in managing the Bluefish labour requirements with those at Snare and Jackfish. Compared to the project permit projections, salaries have increased by \$145,000. This is a result of more work required than originally expected to maintain the facility coupled with average labour cost increases over the period between 2003/04 and 2006/07.” (BR.NTPC-9, p. 1 of 6)

In HC.NTPC-13(g), the HC requested the salaries and wages for Jackfish, Bluefish and Snare for 02/03 through 07/08. NTPC provided the following table:

	2004/05	2005/06	2006/07	2007/08
	Actual	Actual	Forecast	Forecast
Jackfish	1,598	1,515	1,646	1,882
Snare	1,057	1,195	1,230	1,271
Bluefish	74	358	409	423
Totals	2,729	3,068	3,284	3,576

Note: the costs for General & Administration are not tracked separately between Bluefish, Jackfish and Snare, therefore they are all included with costs for Jackfish

The HC pursued this line of questioning at the hearing and again in their argument. The basic thrust of the HC position is that the purchase of the Bluefish Generating Station should have provided reductions in salaries and wages at Jackfish due to the reduced need for diesel generation. When questioned by the HC, NTPC responded that personnel, and therefore their salaries, are deployed across the Snare, Bluefish and Jackfish system on an as-needed basis. Since specific positions are not dedicated to Snare, Bluefish or Jackfish, NTPC cannot provide the information requested by the HC. Across the combined system, the number of positions has been relatively constant with 41 (04/05), 39 (05/06), 39, (06/07) and 41 (07/08). The HC's evaluation of this information was summarized in its argument:

"...NTPC was requested to provide the positions represented by the salary costs in HC.NTPC-13(g) to determine whether the operating savings as a result of the Bluefish purchase had materialized. NTPC advised that it was unable to make that distinction and could only advise that the number of positions across the Snare system for 2004/05 onward including the two test years were 41, 39, 39 and 41 respectively and that the number of operator positions at Jackfish had been reduced by 5. That information does not demonstrate any labor savings as a result of the Bluefish purchase because those FTE's include system operators for the thermal communities as well." (HC Argument, p. 16)

Given that the information provided by NTPC did not permit a clear calculation of salaries and wages reductions at Jackfish due to Bluefish, the HC recommendation to the Board is:

"...The Hydro Communities submit absent any demonstrated savings in operating expenses as a result of the Bluefish purchase, the Board should

maintain Jackfish salaries ... at the 2005/06 levels shown in HC.NTPC-13(g)..." (HC Argument, p. 17)

The NTPC countered in its reply:

"It is clear that at the time of the project permit application, the feasibility of the project did not hinge on achieving any non-diesel fuel operating expense savings. Rather, the project was and continues to be justified on basis of avoided diesel fuel and engine replacement costs. This is clearly demonstrated in the attachment to BR.NTPC-29(k), which indicates that the only variable (meaning O&M, Salaries and Wages, and Supplies and Services) savings from Bluefish included in the project permit application economics was based on 2.5 cents per diesel kW.h displaced. This savings reflects the costs of overhauls and other related savings, such as oil changes at the Jackfish units, which would have otherwise been part of NTPC's revenue requirement over time. In short, in contrast to Hydro Communities' assertions, the purchase of Bluefish was not predicated on saving in Salaries and Wages and Supplies and Services at Jackfish. Despite this, Ms. Goucher noted that the purchase of Bluefish, in combination with changes to the industrial loads on the Snare-Yellowknife system, has allowed NTPC to reduce Jackfish plant operators by five positions, a benefit in excess of those assumed at the time of the Bluefish purchase.

...

The reduction in salaries and wages related to the Bluefish acquisition requested by the Hydro Communities is arbitrary, unsupported by the evidence and should be rejected by the Board. The Corporation addressed this issue in its Written Argument at page 13 and has provided considerable evidence to support the increases in operations and maintenance costs in the test years over the 2005/06 levels. The Corporation submits that these costs are reasonable and should be approved." (NTPC Reply, p. 11)

Views of the Board

The Board agrees with NTPC that the Bluefish purchase was not predicated upon, and might not result in, demonstrated operational savings in salaries and

wages at Jackfish. While such savings can and should be sought by NTPC whenever feasible, the Board is satisfied that the salaries and wages forecasts provided by NTPC do not require an adjustment by the Board. The Board will not act upon the recommendation from the HC to maintain the Jackfish salaries and wages at 05/06 levels.

6.1.2 Benefits from Automatic Meter Reading (“AMR”)

Appendix C of the Phase 1 GRA described 4 AMR projects:

Date	Location	Project Number	Description	Cost
2004/05 Actual	Norman Wells	3045049	Turtle Meter Reading Conversion	\$107,000
2005/06 Actual	Fort Smith	2015157	Turtle Meter Reading Conversion	\$206,000
2006/07 Forecast	Fort Simpson	2055090	Turtle Meter Reading Conversion	\$150,000
2007/08 Forecast	Ops Support	9905021	Turtle Meter Reading Conversion	\$200,000

The Norman Wells, Fort Smith and Fort Simpson projects converted all customers in these communities to meters for the Hunt Technologies Turtle AMR System. NTPC stated that the previous meter system was time-consuming and inefficient and that the technical support had been discontinued. The new meter system allows NTPC to better utilize line personnel. The projects were undertaken for cost savings.

The 2007/08 project, which is listed under Ops Support, is intended to ensure that a funding allocation is in place to enable the continuation of this conversion project in one or two more communities. NTPC is undertaking a review to determine which communities are the most suitable to upgrade.

The Fort Smith project is noted in a couple of locations (Table NTPC.TWU-9 and Table HC.NTPC-64) as being “Partial Close Out”, indicating that the actual cost is higher than the 2005/06 actual of \$206,000 listed in Appendix C.

For the Fort Simpson project, the alternatives are listed in Table NTPC.TWU-8a as being:

- 1) Do Nothing
- 2) Contract meter reading locally
- 3) Convert meters to the Turtle System

NTPC provided additional details on their projects in BR.NTPC-29(m).

“In 1996/97 NTPC undertook research and investigated the emerging technologies related to Automatic Meter Reading (AMR). The Hunt Technologies AMR system (Turtle) utilized Power Line Carrier (PLC) to transfer data. This meant that NTPC's existing distribution system could be utilized instead of 3rd party communications (i.e. telephone lines). In this way, the Corporation would eliminate the cost of telephone charges to download information or interrogating the system. The meters could be read remotely without driving or walking the community routes with a radio system.

At that time, the only other PLC based AMR system was TWACS or DCSI, which was much more expensive than the Hunt Technologies system. Other considerations were:

- Hunt Technologies superior design of substation interface between the reading collector and meter transmitter
- Hunt Technologies could also supply all NTPC's meter needs while others could only supply domestic energy meters
- Hunt Technologies also had water meter transmitters and NTPC was supplying water to the Town of Inuvik at that time. This also provides the Corporation with the flexibility of potentially offering water meter reading services to other communities in the future.

To date, the installation and utilization of this system has been a success. It has reduced time required to read meters, improves accuracy of meter reads, and reduces administrative time for data entry and significantly reduces billing errors which improves customer relations. Finally, the Turtle meters free up line personnel to take on more meaningful and productive work.

Prior to the utilization of the AMR system, meter reading costs were approximately \$30-\$35 per meter per year (depending upon the community). With the AMR system, meter reading costs are \$2.00 - \$2.50 per meter.”

Both the HC and the TGC questioned NTPC on this issue at the hearing. These exchanges were summarized by NTPC in its argument.

“In 1996/97 NTPC undertook research and investigated the emerging technologies related to Automatic Meter Reading (“AMR”). The Hunt Technologies AMR system (Turtle) used Power Line Carrier to transfer data. This meant that NTPC’s existing distribution system could be utilized instead of 3rd party communications. To date, the installation and utilization of the system has been a success. It has reduced time required to read meters, improves accuracy of meter reads, and reduces administrative time for data entry and significantly reduces billing errors which improves customer relations.

The Board requested more information on studies undertaken to justify the Norman Wells AMR project in 2004/05, the Fort Smith AMR project in 2005/06 and the Fort Simpson AMR project forecast for 2006/07. In BR.NTPC-29(m) NTPC provided a series of net-present value analyses that showed all of the projects had positive net present value under the assumptions both at the time the projects were proposed and using current cost variables.

During the hearing, the TGC’s consultant requested more detail with respect to the net present value analysis undertaken for the Fort Simpson AMR project. The Corporation responded to this request in Undertaking No. 15. Counsel for the Hydro Communities also asked whether there was any reduction in staff levels related to meter reading or administrative data entry, to which Ms. Goucher replied that “...installation of the automatic Turtle meter reading system has allowed us to utilize our line persons for other line-related work, as opposed to meter reading.”

The evidence demonstrates that the AMR projects have improved the efficiency of the Corporation’s operations and have a net benefit to customers. However, this does not mean that staff positions can be reduced or eliminated as a result of the projects. The Corporation submits

that costs related to the AMR projects are reasonable and should be approved. (NTPC Argument, p. 51, *ll.* 22 – p, 52, *ll.* 8)

As described in its argument, the HC were concerned that there has been no change in the Fort Smith NTPC staff levels as a result of installing the new AMR with the net result being a rate base addition of \$206,000 but no operating savings. The HC argued that if the project is added to rate base then labor costs in Fort Smith should be reduced by \$35,000/year so that there is no net impact upon the rate payers due to this project.

In its reply, the NTPC urged the Board to disregard the HC recommendation. NTPC stated that a portion of Fort Smith lineman costs will not be allocated to Fort Smith in the Phase 2 GRA. As well, the elimination of technical support for the previous system necessitated that a new system be installed. The chosen system also provides greater accuracy and reduces billing errors.

In its reply, the HC proposed an alternative recommendation to that provided in its argument.

“At page 52, NTPC asserts that the AMR projects have improved the efficiency of the Corporation’s operations and have a net benefit to customers. This statement assumes there were benefits which is not true. The net present value analysis in BR.NTPC-29(m) indicates a 10-year net present value of \$75,000. However, as noted at pages 18-19 of the HC Argument, there are no labor savings because linemen have been redeployed to other areas. The Hydro Communities reiterate that if the \$206,000 net rate base addition is approved, then labor costs should be reduced by \$35,000 per year so that customers are indifferent. Alternatively, the project should be excluded from rate base until such time as the \$35,000 of labor savings can be demonstrated.” (HC Reply, p. 23)

Views of the Board

The Board is concerned that it does not have complete and accurate analyses of the costs and benefits of these AMR projects as reflected in the application, which includes the impact on community operating expenses.

The HC argues that NTPC “*assumes there were benefits which is not true*”. While the Board does not agree that the asserted benefits have been proven to not be true, the Board does believe that the asserted benefits have not been completely and accurately quantified. By not incorporating the effect of the redeployed linemen (along with justification for this redeployment) in the filed material, it is not possible for the interveners or the Board to properly assess and test the assertions being made by NTPC.

While the HC was only advancing its arguments on behalf of Fort Smith, the Board notes that this issue of redeployment of linemen appears to affect all of the AMR projects. Given that NTPC is asserting that a benefit of these projects are the allocation of linemen costs to outside of the community in which they are based, the economic analyses and cost tracking provided by NTPC should be completed from the perspectives of both NTPC and the specific communities in which these projects have been completed/proposed.

The Board is prepared to approve the addition of these four AMR projects (Project Numbers 3045049, 2015157, 2055090 and 9905021) to NTPC’s rate base. However, pending this approval, the Board directs NTPC, as part of the Phase 1 refiling, to provide complete and accurate analyses of the costs and benefits of these projects that incorporate the reasons for and the effects of the redeployment of the linemen. These analyses are to be provided both from the perspective of the individual communities and NTPC.

6.1.3 At-Risk Compensation

There was no mention of at-risk compensation in the Phase 1 Application. At-risk compensation was first mentioned on the record on page 42 of NTPC's 2005/06 Annual Report, which was submitted as an attachment to HC.NTPC-1. At-risk compensation falls under the responsibilities of the NTPC's Board of Director's Compensation Committee. The following description is from the Annual Report.

"The compensation committee should be responsible for:

- (a) reviewing and approving corporate goals and objectives relevant to CEO compensation, evaluating the CEO's performance in light of those corporate goals and objectives, and determining (or making recommendations to the board with respect to) the CEO's compensation level based on this evaluation;
- (b) making recommendations to the board with respect to non-CEO officers and director compensations, incentive-compensation plans and equity-based plans; and
- (c) reviewing executive compensation disclosure before the issuer publicly discloses this information."

According to the Annual Report, the Compensation Committee should be composed entirely of independent directors. The members of the committee at that time were:

1. Peter Allen – Committee Chairman and Board Member
2. Richard Nerysoo – Board Chairman
3. Leon Courneya – President and CEO

The at-risk compensation system was described in detail in BR.NTPC-10(b&c).

“NTPC's Senior Management (SM) Salaries and At-Risk (performance based component) are set by the Board of Director's Governance and Compensation Committee (Committee) and approved by the Board of Directors with the assistance of outside consultants. NTPC's SM salaries are set in comparison to a group of utilities selected by the Committee as the organizations which NTPC competes with for staff.

The Committee retains Towers Perrin HR Services to perform a detailed survey every 3 years of a group of utilities to compare NTPC Senior Management compensation to for salary and incentive plans. The last detailed survey was prepared in March 2004. In years between detailed surveys an informal review is done to ensure there have been no material changes to Senior Management compensation in the intervening years.

The Corporation cannot release the details of the study as it is considered proprietary information of Towers Perrin. The Committee adopted the process of setting SM salaries based on being within 10% (plus or minus) of the 50th percentile. The survey compares total target cash compensation (salary, plus incentive plan/at risk). The method for setting the salary component of SM salaries has not changed since it was adopted. The comparability of the different sizes (revenues) of the companies in the survey is increased through the use of regression analysis.

The results of the last detailed survey in 2004 found that the President's & CEO's total compensation (salary and incentive) were within the target range. The survey also found that while the salaries for the Directors' positions were within the target range the incentive component of Director's compensation was, in general, below the target range.

The last informal survey completed in November 2006 indicated that at the President & CEO's annual salary increase were competitive with the market the Director level annual salary increases were typically below the competitive market and that NTPC's short term target incentive opportunities were below the competitive market.

The Corporation's incentive plan is considered at risk compensation. The At-Risk plan covers all management and excluded positions currently includes approximately 40 positions. Effective April 1, 2007 excluded employees will no longer be eligible for At-Risk (they will receive overtime instead) and the number of positions in the plan will be approximately 30.

Currently there are 3 components to the plan. For each position's eligible pool, 50% of the potential amount is based on net income targets, 25% is based on the achievement of individual objectives and 25% is based on the achievement of operational targets.

Employees under the plan are eligible to earn At-Risk compensation up to 15% of their salary (excluded and Managers), up to 20% of their salary (Directors), up to 30% of their salary (Vice Presidents) and up to 40% for the President & CEO. The system supports achievement of results by setting financial and operational targets. Performance measurement targets are set for system availability, debt/equity ratio, efficiencies, operating cost per kwh generated, customer service (based on external survey), staff turnover, safety (accident severity, lost time accidents, lost time days), MWh generated per hours worked, hazardous materials spills, employee satisfaction (based on external survey).

Management and excluded employees compensation packages are based on the same principles/objectives as the Senior Management Compensation with the exception of how the salary ranges are determined. Excluded and middle management employees positions have been evaluated using the Hay Methodology of job evaluation.

In order to ensure the Corporation remains compliant with equal pay for work of equal value legislation under the Public Service Act, salary ranges are based on the formulas used to determine the bargaining unit salary scale. Excluded employees and Managers do not currently receive overtime. At-Risk compensation is provided in part to recognize an employee for the extra time and effort employees put in to achieve Corporate and individual objectives. Effective April 1, 2007 excluded employees' compensation package is being adjusted to be similar to that of bargaining unit employees. Excluded employees will be eligible to receive overtime and other leave entitlements provided to unionized employees to ensure compliance with equal pay for work of equal value legislation. Management employees will continue to receive at-risk compensation and are not entitled to overtime. At-Risk payments are non-pensionable.

The Corporation does not have a long-term incentive plan.”

Table BR.NTPC-10(a) provided the following at-risk compensation amounts:

- 2002/03 GRA Forecast \$586,000

- 2002/03 Actual \$608,000
- 2004/05 Actual \$547,000
- 2005/06 Actual \$595,000
- 2006/07 GRA Forecast \$540,000
- 2007/08 GRA Forecast \$558,000

The Community of Behchoko suggested in its letter that a clear bonus structure, as well as performance benchmarks tied to levels of service, should form part of the executive compensation model and that the model should be publicly available.

In its argument, NTPC submitted that, given the evidence on the record, its forecast salary and wage expenses in the test years, including at-risk compensation, are reasonable and necessary, and should be approved.

The HC argued that since the Towers Perrin review is considered proprietary and was not filed before the Board, no evidentiary value can be placed on whether or not the total target cash compensation is within 10% of the 50th percentile as adopted by the Governance and Compensation Committee. Nor can any weight be attributed to the informal internal reviews, the last of which was conducted in November 2006, as they are directly linked to the Towers Perrin review.

During HC questioning at the hearing, NTPC confirmed that the 50% of the potential amount that is based on net income targets is based on the rate of return on equity on the regulated business. In argument, the HC took the following position:

“...Although the Hydro Communities are not opposed to incentive pay, this component is of primary concern because it results in and is motivated

almost exclusively by benefits to shareholders rather than benefits to customers. This component of the at-risk pay provides perverse incentives to staff, in that cutting service levels may be used to improve the bottom line. For example, deferring maintenance, deferring brushing or charging an engine overhaul or repair to a deferral account may improve the bottom line to the benefit of shareholders and management through at-risk compensation, but customers would be faced with higher costs in the future. Any costs related to improvement of net earnings should be borne by the shareholders who will benefit, not by customers.” (HC Argument, p. 21 – 22)

Although it did not cite any decisions, the HC asserted that the Alberta Energy and Utilities Board has consistently disallowed that portion of at-risk or variable pay that is related to or is a function of earnings.

The HC submitted that the achievement of higher earnings will not necessarily translate to improved efficiency to customers and in fact may well have the opposite effect and therefore the 50% of at-risk pay that is a function of net income targets should be excluded from the revenue requirement. Accordingly, the HC submitted that salaries and wages should be reduced by \$270,000 and \$279,000 respectively in the test years.

For the 25% of at-risk compensation based on individual objectives, the HC seemed to express some concern that these objectives could also relate to financial performance but did not provide any recommendations to the Board.

For the 25% based on operational objectives, the HC consider that for the most part, these objectives would primarily be to the long-term benefit of customers.

NTPC replied that that the Towers Perrin study was not provided because Towers Perrin refused the Corporation’s request to file it in this proceeding. In

NTPC's view, however, there is sufficient evidence on the record for the Board and that the HC claim regarding the Towers Perrin study should be disregarded.

Regarding the HC's recommendation that the 50% of at-risk compensation related to net income be disallowed, the NTPC responded as follows.

"Regarding the Hydro Communities speculation about managements' actions, it is important to recognize that net income objectives are balanced with personal objectives that ensure an on-going benefit to customers by maintaining service levels (through, among other things, efficiency gains, customer satisfaction and employee satisfaction) or avoided costs (such as avoided labour disputes in the event that a collective bargaining agreement is not reached)..." (NTPC Reply, p. 13, // 1 - 5)

NTPC went on to state the following.

"Further, if NTPC's managers strive to ensure earnings objectives are met (which by necessity means some combination of lower costs due to efficiencies, or higher revenues), it is in fact customers who will benefit in longer run from lower rates than would otherwise be required, or avoided rate increases and deferred rate cases.

In any event, there is no evidence on the record to suggest that NTPC employees act in the manner described by the Hydro Communities to impair customer service to the benefit of the shareholder. If the Hydro Communities' speculation were true, one would see the performance targets not being met. For example, if management cut costs related to maintenance programs, one would expect problems with safety, reliability, customer service and employee satisfaction. That has not been the case.

There is evidence, however, that the actual amounts paid out by the Corporation as part of the at-risk compensation program have typically been higher than the amounts included in the Corporation's revenue requirement. This means that a portion of the actual costs of the at-risk compensation program is in fact already borne by the shareholder and not by ratepayers. Further, at-risk compensation avoids having to pay overtime – the avoided cost of paying overtime instead of at-risk

compensation for all positions excluding the Officers of the Corporation is estimated at \$425,000.

Lastly, while the Hydro Communities states that the “[t]he Alberta Energy and Utilities Board has consistently disallowed that portion of at risk or variable pay that is related to or is a function of earnings” and lists a number of public utilities, it does not provide any references to regulatory authorities in support of its claim.

NTPC is a regulated entity that must submit its revenue requirement to the review of the PUB and intervenors. The costs included with respect to the at-risk compensation program are typical of such programs for other utilities, are reasonable and should be approved.” (NTPC Reply, p. 14, // 11 - 34)

TGC stated in its reply that it was in agreement with the position taken by the HC in its argument.

Views of the Board

The objective of the Towers Perrin review was to compare NTPC’s executive compensation program to other utilities, with NTPC’s Governance and Compensation Committee having established a total target cash compensation that is within 10% of the 50th percentile of the other utilities. The Board agrees with the HC that since the Towers Perrin review is not in evidence before the Board, the Board cannot apply any weight to the review when making its decision.

However, the HC has not provided any recommendations or evidence for the Board to use in evaluating the target established by NTPC. The HC does not dispute the 10% of the 50th percentile as being a suitable target for NTPC. Nor did the HC provide any evidence on other utilities’ compensation programs. As noted by the HC during questioning, Towers Perrin has provided information in

several proceedings in Alberta. It is the Board's view that the HC could have filed this information from other proceedings before the Board.

It is the Board's view that it has no evidence or reason upon which to dispute the NTPC's total target cash compensation range of 10% of the 50th percentile as being acceptable for NTPC.

While the range is not in dispute, what is in dispute is which party should pay for the at-risk compensation: the shareholders or the ratepayers. It is the view of the Board that any at-risk compensation that is included in the revenue requirement should result in clear benefits to customers.

The Board notes that under the Corporation's at-risk compensation program, 50% of the potential compensation amount is based on net income targets, 25% is based on the achievement of individual objectives and 25% is based on the achievement of operational targets.

The 50% of NTPC's at-risk compensation, which is based on net income, is based on the return on equity of the regulated business. The Board agrees with the HC that the potential exists for management to improve net income, and hence increase at-risk compensation, in manner that is detrimental to the ratepayers and exclusively to the benefit of the shareholders.

While NTPC argues that there is no evidence of this occurring, the Board is of the view that no such evidence is necessary for the Board to take action as it is the compensation model that is at question, not any specific actions of management. It is the Board's view that an at-risk compensation model that allows for actions that benefit the shareholders, but not the ratepayers, is not appropriate in NTPC's regulated business.

The Board is also concerned that the 50% based on net income sets up a no-win situation for ratepayers and a no-lose situation for the shareholders.

- 1) If the net income targets are met, that is a benefit to the shareholders and the at-risk compensation is paid out of money collected from the revenue requirement. However, there is no certainty that there was any benefit for the ratepayers.
- 2) If the net income targets are not met, the at-risk compensation is not paid but the shareholders retain those dollars collected for that purpose from the ratepayers.

Both ways, the shareholders come out ahead and the ratepayers come out behind.

The Board is also concerned about the entire at-risk compensation program based upon NTPC's statement in the following exchange.

“MR. TOM MARRIOTT: ...What happens to money that is budgeted for this program but not paid out in a given year?”

MS. JUDITH GOUCHER: The **amounts paid out have typically always been higher than what's included in rates**, so I have no knowledge of what would have occurred had the amounts not have been paid out other than it would have been a -- been an expense not incurred.” (emphasis added) (Tr. Vol. I, p. 167, ll. 11 - 20)

It is the view of the Board that if the ratepayers are to contribute to an at-risk compensation program for senior management, then that compensation should truly be “at-risk” by setting sufficiently demanding targets that are not routinely met. If, as stated by Ms. Goucher, the amounts paid out are always higher than budgeted in the rates, then where is the risk for the senior management from the

perspective of the ratepayers? If the targets are being set so low as to ensure that the at-risk compensation is always being paid then the Board fails to see where the incentive lies for management to strive to improve performance. Apparently, the at-risk compensation program is merely base pay in another form.

The Board considers the at-risk compensation to be included in revenue requirement should result in clear benefits to customers. Therefore, in addition to giving weight to achievement of operational targets and individual objectives, consideration may also be given to designing the program to incent efficient planning and execution of capital projects, efficient management of the deferral accounts such as the overhaul deferral account and achievement of safety, reliability and customer satisfaction targets. The Board recognizes some of these targets might presently be part of the operational or individual targets. However, the Board considers greater transparency with respect to the operation of these incentive schemes would be useful in future proceedings.

The Board is also concerned that NTPC has exhibited questionable corporate governance by including Mr. Leon Courneya, the President and CEO and the only non-independent Director, as a member of the Governance and Compensation Committee. This Committee is responsible for evaluating the CEO's performance and approving the at-risk compensation model and payments to the CEO and other senior management. As noted by NTPC in its Annual Report, this Committee should be exclusively made up of independent directors however Mr. Courneya for some reason is a member of the Committee.

In light of its various concerns, the Board directs NTPC to:

- 1) Remove the 50% net income component of its at-risk compensation program from the revenue requirement calculations for NTPC's regulated business. For 06/07, the amount is \$270,000 and, for 07/08, the amount is \$279,000;
- 2) Ensure that the Governance and Compensation Committee is exclusively made up of independent directors; and
- 3) Undertake a comprehensive review of the at-risk compensation program; make any necessary changes in light of the concerns expressed by the Board and report back to the Board in the next Phase 1 GRA.

6.1.4 Apprentice Salaries

NTPC views the apprenticeship program as key to ensuring that the Corporation has qualified, highly skilled employees in these positions at a time when workers in these fields are in high demand.

TGC.NTPC-36 identifies that 6 line positions were added in 04/05, 1 line position in 06/07, two journeyman supervisors in 06/07 and 2 apprentice mechanics and 2 apprentice linemen in 07/08.

As already mentioned, the apprenticeship program has driven a \$0.278 million increase in salaries and wages from the 01/03 Settlement to the 06/07 forecast. A further \$0.633 million is required for the 07/08 forecast.

According to TGC.NTPC-36, the 4 new apprentice positions in 07/08 will cost \$490,000 with another \$112,000 required for the two journeyman supervisors that were added in 06/07.

In its argument, the HC took issue with the \$490,000 required in 07/08 for the 4 new apprentice positions. HC stated:

“However, NTPC did note that it was adding 4 apprentice positions in 2007/08 at a cost of \$490,000 for salaries and benefits. Based on the average union salary of \$71,800, the Hydro Communities consider this amount (average of \$122,500) is apparently an error and should conservatively be reduced to \$71,800 per position, a reduction in salaries and wages of \$203,000.” (HC Argument, p. 15)

The TGC stated in its reply that it agreed with the argument presented by the HC on salaries and wages.

NTPC responded to the HC recommendation in its reply:

“Counsel for the Hydro Communities reviewed the forecast of \$122,500 on average for the four apprentice positions with Ms. Goucher, who indicated it was not an error. While the average base salary for a union employee is indeed \$71,800 for 2007/08, this figure does not include other aspects of the total salaries and wage costs, including fringe benefits (\$26,600 average per FTE) and overtime (\$7,300 average per FTE). Overtime costs are higher than average for the apprentice positions as they are deployed across the entire NTPC system, often on short notice for unscheduled periods in response to system emergencies. The Hydro Communities’ analysis also ignores that apprentice positions will receive greater benefits due to higher than average location differentials due to being based in more remote communities. Consequently, the Hydro Communities’ recommendation does not fairly reflect the costs of providing four apprentice FTE positions and should be dismissed by the Board.” (NTPC Reply, p. 10, // 10 – 20)

Views of the Board

The Board finds that NTPC has provided a satisfactory explanation for the seemingly high 07/08 forecast cost for the 4 apprentice positions. The Board will not act on the HC recommendation to reduce the forecast 07/08 salaries and wages for these 4 positions.

6.2 Non-Production Fuel

The non-production fuel expenses from the previous GRA to the current GRA forecasts are shown in Table 6.3. The data was obtained from Table 3.3 and Schedules 3.1 and 3.2 revised May 16th.

Table 6.3 – Non-Production Fuel Expenses (\$000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	448	69	247	252
Thermal	Not Provided	Not Provided	Not Provided	477	393	484	494
Overall	588	Not Provided	Not Provided	925	461	730	745

NTPC is seeking Board approval for non-production fuel expenses of \$0.730 million in 06/07 and \$0.745 million in 07/08. The increases (\$0.142 million and \$0.157 million, respectively) over the 01/03 Settlement reflect the pressures of higher fuel prices.

The interveners did not raise issues with respect to non-production fuel.

Views of the Board

The Board has not identified any issues to warrant deviating from NTPC’s forecasts for 06/07 and 07/08. NTPC’s forecast non-production fuel expenses for 06/07 and 07/08 are approved by the Board for inclusion in the revenue requirement.

6.3 Supplies and Services

NTPC is seeking Board approval for its supplies and services forecast expenses of \$10.889 million for 06/07 and \$11.091 million for 07/08.

Table 6.4 summarizes the total supplies and services data provided in Table 3.3 and Schedules 3.1 and 3.2 revised May 16th.

Table 6.4 – Supplies and Services (\$000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	5,482	5,581
Thermal	Not Provided	Not Provided	Not Provided	Not Provided	Not Provided	5,266	5,368
Overall	8,587	Not Provided	Not Provided	10,120	9,189	10,748	10,948

The supplies and services expenses include the costs for maintaining the plants and equipment and include such costs as supplies, freight, contractors, professional development and administration. There is a \$2.161 million increase from the 01/03 Settlement to the 06/07 forecast. Major components of the increase are:

Insurance and the RFID – The Corporation’s cost for external insurance and self-insurance via the Reserve has increased substantially.

Bluefish – The addition of the Bluefish Generating Station has increased supplies and services.

Brushing – NTPC has increased its brushing efforts to reflect a normal annual level of brushing work.

Computer Licensing – This is largely due to new annual licensing costs replacing one-time costs that were previously capitalized.

Satellite and Communication Costs – The Corporation has required increased telecommunication and bandwidth requirements since 02//03.

Outside of these 5 factors, the increase in supplies and services from the 01/03 Settlement to the 06/07 forecast is less than the rate of inflation.

The interveners raised concerns with 2 aspects of the supplies and services expense:

1. Transmission and Distribution Brushing
2. Operational Savings from Bluefish

These two issues are addressed by the Board in the following sections.

NTPC's supplies and services expense forecasts for 06/07 and 07/08 are approved by the Board subject to the Board directions in Sections 6.3.1 and 6.3.2.

6.3.1 Transmission and Distribution Brushing

In recognition that brushing is an essential component of maintaining the reliability of transmission and distribution systems, NTPC proposes to significantly increase its brushing expenses, as compared to 2002/03, to reflect a

normalized annual level of brushing work. In TGC.NTPC-38(e), NTPC clarifies that in referring to an annualized level of brushing, NTPC meant that it has attempted to set brushing budgets for each area at a level that is generally representative of the typical average annual level of effort required to address all brushing requirements in a timely fashion.

In BR.NTPC-12, NTPC provided descriptions of its 03/04, 04/05 and 05/06 actual brushing activities and its 06/07 and 07/08 forecast brushing activities. NTPC also provided two tables (BR.NTPC-12(b).1 and 2) that showed its 01/02 and 02/03 forecast costs, its 04/05 and 05/06 actual costs and its 06/07 and 07/08 forecast costs.

The data in BR.NTPC-12 was supplemented with the 01/02, 02/03 and 03/04 actual costs by Undertaking 7. Table 6.5 provides a summary of the brushing expenses.

Table 6.5 – Brushing Expenses

	Transmission	Distribution	Total
2001/02 Forecast	\$114,000	\$79,000	\$193,000
2001/02 Actual	\$8,000	\$10,000	\$18,000
2002/03 Forecast	\$116,000	\$80,000	\$196,000
2002/03 Actual	\$33,000	\$11,000	\$44,000
2003/04 Actual	\$17,000	\$129,000	\$146,000
2004/05 Actual	\$207,000	\$71,000	\$278,000
2005/06 Actual	\$130,000	\$16,000	\$146,000
2006/07 Forecast	\$213,000	\$180,000	\$393,000
2007/08 Forecast	\$217,000	\$184,000	\$401,000

When the HC questioned NTPC regarding its brushing policy, NTPC responded as follows.

“MR. TERENCE COURTOREILLE: Historically the Corporation would conduct its brushing requirements on an as-and when-needed basis.

Recently, however, the Corporation undertook an internal evaluation of its brushing requirements and the forecast numbers that you see proposed for the test years in this table would represent what we're proposing as our minimum brushing requirements on an annual basis.

MR. TOM MARRIOTT: And can you explain what those are? Is it -- is it quite a complicated series of steps or is it something that you could describe at a high level? Like, I'm looking for perhaps a brushing cycle, something along those lines.

MR. TERENCE COURTOREILLE: It's certainly more defined for the transmission line. For the areas that have road access, we would brush on a rotating annual basis every five (5) to six (6) years. For those areas that do not have road access, we would brush on an annual rotating basis every twelve (12) years.

MR. TOM MARRIOTT: Okay. And is there no set time for distribution?

MR. TERENCE COURTOREILLE: Distribution is not as structured because a lot of our plants have very little sp -- particularly the plant -- the plants in the northern part of the territory, would have very little brushing requirements. So, in regards to those plants, we're still brushing on an as and when-needed basis.

In the southern communities where vegetation growth is much more rapid, we're proposing an annual budget of sixty thousand dollars (\$60,000) per year for the Dehcho region and an additional sixty thousand dollars (\$60,000) per year for the North Slave Region.” (Tr. Vol. I, p, 155, // 6 – p. 156, // 15)

The HC summarized the brushing data and provided its views in its argument.

“... it is noteworthy that NTPC's rates had provided for \$115,000 per year for the period 2001/02 through 2005/06, but it only expended \$79,000 per year on average or 32% below forecast for transmission. NTPC's rates provided for \$80,000 per year for the period 2001/02 through 2005/06 but it only expended \$47,400 per year on average or 40% below forecast for

distribution. It is apparent from the above table that NTPC is catching up in the test years for not maintaining brushing activities over the last 5 years. This has all the attributes of yet another retroactive deferral account.

NTPC advised that it did not have a written brushing policy and historically conducted its brushing “on an as when and needed basis” although it recently undertook an internal evaluation of its brushing requirements to determine its forecast for the test years. While there is no evidence to dispute the test years forecast per se, NTPC should not be compensated twice for the same work. Clearly, NTPC did not maintain its brushing program since the last GRA and is now faced with a serious catch up situation.

NTPC under spent by \$185,000 on transmission and by \$163,000 on distribution over the last 5 years. Assuming the forecast test year expenditures are now in fact required to bring brushing up to standard, the normalized annual brushing over the 7 year period will have been approximately \$92,000 per year for transmission and \$86,000 for distribution. On this basis, the Hydro Communities submit that transmission brushing should be reduced by \$121,000 and \$125,000 in the test years and distribution brushing should be reduced by \$94,000 and \$98,000 in the test years to ensure that NWTTPC is not compensated twice for the same work.” (HC Argument, p. 19)

NTPC responded to the HC in its reply.

“Clearly the forecast brushing expenses for the test years are intended only to reflect normal annualized amounts for brushing requirements and are not in any way to address a “serious catch up situation” for previous years. The appropriate basis for regulatory review is the level of costs forecast to be incurred in the test years, in this case to maintain a standard annual brushing requirement. The only evidence is that NTPC has forecast 2006/07 and 2007/08 brushing costs based on what will normally be required annually over the long-term to maintain an appropriate and safe brushing program. As a result, the Hydro Communities’ speculation regarding a “serious catch up situation” is incorrect. The Board should reject the Hydro Communities’ recommendation and approve the Corporation’s forecast brushing requirements.” (NTPC Reply, p. 15, // 11- 19)

TGC stated in its reply that it was in agreement with the position taken by the HC in its argument.

Views of the Board

The Board is concerned about the large discrepancy from 01/02 to 05/06 between revenue collected by NTPC for brushing and the actual brushing expenditures. The Board calculates this discrepancy to be \$345,000.

The HC argues that NTPC under-spent on brushing from 01/02 to 05/06 and that the increased brushing expenditures forecast for 06/07 and 07/08 are a result of NTPC now being in a catch-up situation. The HC assert that NTPC should not now be compensated for work for which it has already been compensated.

NTPC argues that the increase in brushing expense for the test years is not because it is in a catch-up situation. NTPC asserts that its proposed brushing expenditures in 06/07 and 07/08 accurately reflect the necessary level of normalized annual brushing and is not a result of under-spending in 01/02 to 05/06.

The Board finds the characterization of the situation to be beside the point. NTPC has either 1) under-spent \$345,000 from 01/02 to 05/06 or 2) over-collected \$345,000 in 01/02 to 05/06. Either way, the ratepayers paid \$345,000 for brushing services that they did not receive and the Board finds this to be unacceptable.

As there is no evidence to the contrary, the Board accepts NTPC's argument that the forecast expenditures of \$393,000 for 06/07 and \$401,000 for 07/08 represent the necessary, normalized level of brushing on a go-forward basis.

Accepting NTPC's argument on this point effectively means that NTPC over-collected \$345,000 from the ratepayers from 01/02 to 05/06.

The Board directs NTPC, in its Phase 1 refiling, to calculate its total 06/07 and 07/08 supplies and services expenses using its forecast brushing expenditures of \$393,000 for 06/07 and \$401,000 for 07/08.

The Board directs NTPC, in its Phase 1 refiling, to propose a procedure for returning to the ratepayers over a 3-year period the \$345,000 that was over-collected by the Corporation for brushing over the 01/02 to 05/06 period. To be clear, the refunded \$345,000 is to be obtained from NTPC's non-regulated cash flow, not by reducing the test year brushing expenditures.

The Board recognizes that there will be year-to-year fluctuations in what is spent on brushing. However, to ensure that such a situation does not occur again and also to capture NTPC's assertion that the normalized brushing expenditure represents the minimum required annually, the Board directs NTPC that, commencing with the 06/07 test year, NTPC's 3-year rolling average actual brushing expenditures must be no less than 10% below the 3-year rolling average forecast brushing expenditures. NTPC's 5-year rolling average actual brushing expenditures must be no less than equal to the 5-year rolling average forecast brushing expenditures.

6.3.2 Bluefish Supplies and Services

NTPC purchased the Bluefish Generating Station in 2002. The benefits expected by NTPC included avoided diesel generation, reduced future diesel

engine replacement at the Jackfish Lake plant, and an increased ability to meet future load growth on the Snare-Yellowknife system.

NTPC states that while Bluefish has resulted in significantly reduced overall costs with large savings in diesel fuel use being offset somewhat by increases by the operating and capital costs of Bluefish. In the area of supplies and services, the 06/07 and 07/08 forecasts are \$0.277 million and \$0.282 million (Table BR.NTPC-9), respectively.

The difference between what was forecast for Bluefish at the time of purchase and the forecast for the 2 test years was explored in BR.NTPC-9. The Project Permit forecast supplies and services for 02/03 and 03/04 as \$0.146 million so the 06/07 and 07/08 forecasts represent \$0.131 million and \$0.136 million increases, respectively. The two primary reasons given by NTPC for these increases are:

1. Initially significant work had to be undertaken in order to meet safety requirements and to improve operational efficiencies. On an on-going basis, more work is required than originally expected to maintain the facility. This also accounts for the increased use of contractors as well.
2. The Bluefish project permit did not specifically identify the impact of Bluefish on the Corporation's insurance costs. For the purposes of budgeting in 06/07 and 07/08, Bluefish has been allocated \$96,000 of NTPC's insurance costs.

In HC.NTPC-13(l), the HC requested the supplies and services expenses for Jackfish, Bluefish and Snare for 02/03 through 07/08. NTPC provided the following summary:

	2004/05 Actual	2005/06 Actual	2006/07 Forecast	2007/08 Forecast
Jackfish	1,882	1,722	2,189	2,225
Snare	497	532	746	761
Bluefish	65	280	254	259
Totals	2,445	2534	3,189	3,244

Note: The costs for General & Administration are not tracked separately between Bluefish, Jackfish and Snare, therefore they are all included with costs for Jackfish

It appears to the Board that the 06/07 and 07/08 forecasts for Bluefish in the above table are in error and should be approximately \$0.277 million and \$0.282 million, respectively, to be consistent with Table BR.NTPC-9. These corrected figures would also be consistent with the 05/06 actual expense of \$0.280 million. However, NTPC's response to NUL.NTPC-15(b) further confuses the issue.

The HC pursued this line of questioning at the hearing and again in their argument. The basic thrust of the HC position is that the purchase of the Bluefish Generating Station should have provided reductions in supplies and services at Jackfish due to the reduced need for diesel generation. When questioned by the HC, NTPC responded that there were three primary reasons why the Jackfish supplies and services expenses have increased despite the decreased generation:

- 1) General and administration expenses for Snare, Bluefish and Jackfish are all included in the Jackfish supplies and services;
- 2) The change to the RFID required a budget be established for events between the old threshold of \$5000 and the new threshold of \$100,000; and
- 3) Increases to computer licensing costs.

The HC's evaluation of this information was summarized in its argument:

"HC.NTPC-13(l) provided a breakdown of supplies and services for each the Jackfish, Snare and Bluefish generating facilities. Again, rather than a decrease in operating expenses, supplies and services are forecast to increase. It appears that the Jackfish supplies and services include far more than just the supplies and services required for the operation of Jackfish (i.e. collection of bad debts, long service awards, termination costs, general and administration for the entire Snare/Yellowknife system, administration for the region). Again, it is impossible to determine from HC.NTPC-13(l) whether there have been any savings in supplies and services as a result of the Bluefish purchase." (HC Argument, p. 16 – 17)

Given that the information provided by NTPC did not permit a clear calculation of salaries and wages reductions at Jackfish due to Bluefish, the HC recommendation to the Board is:

"...The Hydro Communities submit absent any demonstrated savings in operating expenses as a result of the Bluefish purchase, the Board should maintain Jackfish salaries and supplies and services at the 2005/06 levels shown in ... HC.NTPC-13(l)." (HC Argument, p. 17)

The NTPC countered in its reply:

"It is clear that at the time of the project permit application, the feasibility of the project did not hinge on achieving any non-diesel fuel operating expense savings. Rather, the project was and continues to be justified on basis of avoided diesel fuel and engine replacement costs. This is clearly demonstrated in the attachment to BR.NTPC-29(k), which indicates that the only variable (meaning O&M, Salaries and Wages, and Supplies and Services) savings from Bluefish included in the project permit application economics was based on 2.5 cents per diesel kW.h displaced. This savings reflects the costs of overhauls and other related savings, such as oil changes at the Jackfish units, which would have otherwise been part of NTPC's revenue requirement over time. In short, in contrast to Hydro Communities' assertions, the purchase of Bluefish was not predicated on saving in Salaries and Wages and Supplies and Services at Jackfish. Despite this, Ms. Goucher noted that the purchase of Bluefish, in

combination with changes to the industrial loads on the Snare-Yellowknife system, has allowed NTPC to reduce Jackfish plant operators by five positions, a benefit in excess of those assumed at the time of the Bluefish purchase.” (NTPC Reply, p. 11, // 8 – 20)

Views of the Board

The Board agrees with NTPC that the Bluefish purchase was not predicated upon, and might not result in, demonstrated operational savings in supplies and services at Jackfish. While such savings can and should be sought by NTPC whenever feasible, the Board is satisfied that the supplies and services forecasts provided by NTPC do not require an adjustment by the Board. The Board will not act upon the recommendation from the HC to maintain the Jackfish supplies and services at 05/06 levels.

The Board directs NTPC to reconcile the 06/07 and 07/08 Bluefish supplies and services forecasts shown in Tables BR.NTPC-9 and HC.NTPC-13(l) and described in NUL.NTPC-15(b). NTPC is to adjust the Bluefish supplies and services forecasts as needed to account for any errors in their information request responses.

6.4 Travel and Accommodation

NTPC’s travel and accommodation expense includes all the travel, accommodation and meal costs associated with staff travel for operational and professional development purposes.

Table 6.6 summarizes the travel and accommodation data provided in Table 3.3, Schedules 3.1 and 3.2 revised May 16th and Undertaking 8.

Table 6.6 – Travel and Accommodation (\$000s)

	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Hydro	Not Provided	Not Provided	Not Provided	685	714	851	876
Thermal	Not Provided	Not Provided	Not Provided	1,020	1,107	1,284	1,323
Overall	1,939	1,594	Not Provided	1,705	1,821	2,135	2,199

NTPC's forecast for 06/07 is \$2.135 million, which represents an increase of \$0.196 million from the 01/03 Settlement. That increase represents about an average annual increase of 2.4%, which is approximately equal to overall inflation. The 07/08 forecast of \$2.199 million is a further increase of \$0.064 million (3%) over the 06/07 forecast.

Both the TGC and the HC requested that the travel and accommodation expense be broken out into operations versus professional development and training (TGC.NTPC-39(c), HC.NTPC-13(o) and Undertaking #8). This is shown in Table 6.7.

Table 6.7 – Travel and Accommodation Separated into Accounts (\$000s)

	01/02 Actual	02/03 Settlement	02/03 Actual	03/04 Actual	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Operations	1,735	Not Provided	1,497	Not Provided	1,552	1,774	1,786	1,840
PD and Training	103	Not Provided	97	Not Provided	154	87	349	359
Total	1,838	1,939	1,594	Not Provided	1,706	1,861	2,135	2,199

The Board notes that there is a discrepancy of \$40,000 in the 05/06 actual provided by Schedules 3.1 and 3.2 as compared to TGC.NTPC-39(c).

The Board also requested a break-down of the travel and accommodation expenses but according to Head Office versus Plants. NTPC provided the following data in its reply to BR.NTPC-13. This is shown in Table 6.8.

Table 6.8 – Travel and Accommodation – Head Office vs. Plants (\$000s)

	04/05 Actual	05/06 Actual	06/07 Forecast	07/08 Forecast
Plants	1,411	1,474	1,665	1,715
Head Office	294	347	470	484
Total	1,705	1,821	2,135	2,199

The 06/07 and 07/08 forecasts for Plants and Head Office are broken out further in SM-5 and Tables NTPC.TWU-13(a) and (b) according to Hydro vs. Thermal and also into the individual plants.

An additional breakdown of the travel and accommodation expense into its components is provided in Table BR.NTPC-8.

NTPC justified the increases from 04/05 to 06/07 in its reply to BR.NTPC-8.

“Increases from 2004/05 to 2005/06 reflect overall higher travel costs as well as the full year impact of the addition of Bluefish to the system. From 2005/06 to 2006/07 increases reflect two factors outside of inflation: First, additional amounts are included to address additional costs that will arise in O&M expenses as a result of the changes to the RFID policy, as noted above. An additional factor in the increase is related to increased training requirements discussed above under Administration.”

The increase in the travel budget in the test years due to the change in the RFID is \$100,000/year. NTPC does not quantify the increase in travel due to the increased training requirements.

The TGC questioned NTPC about the controls that are in place to minimize these expenses. NTPC provided the following response to TGC.NTPC-39(b):

“In order to ensure that travel and accommodation costs are properly contained the Corporation has a number of controls in place. The first control is during the budget process where travel expenses are reviewed by Senior Management against historical travel and in consideration of

other lower cost options (e.g. video conference, conference call, telephone interviews). Employees are encouraged to combine travel for different purposes where possible (e.g. community meetings, plant visits, medical travel, etc.). Supervisory approvals are required for all travel and additional approval is required for certain types of travel (e.g. Human Resources approves medical travel, Senior Management approves travel outside of NWT). Travel claims are reviewed and signed by Supervisors to ensure that low cost travel options are selected (e.g. economy airfares, direct routing, government rates for accommodation and rental vehicles) and that costs are supported by receipts. Travel expenses are subject to regular review by the Internal and External Auditors.”

In its argument, the HC provided its analysis and recommendation to the Board.

“The travel and accommodation related to operations appears reasonable to the Hydro Communities. Although NPC identified environmental training (including fuel handling) and safety training (under emerging WCB regulations), it is still difficult to fathom close to a 200% increase in professional development travel and accommodation over the \$113,000 average of actual costs in the three prior years shown in the table above. Under the circumstances, the Hydro Communities submit that no more than a doubling of the \$113,000 average professional development costs should be allowed, that is \$226,000 per test year.” (HC Argument, p. 20)

NTPC countered this recommendation in its reply.

“The Hydro Communities’ comment, however, fails to acknowledge the difficulty in tracking professional development travel costs versus operational travel costs as the Corporation will often schedule operational meetings and professional development events for the same trip, thus minimizing overall travel costs. Consequently, the Corporation’s travel and accommodation forecasts should be evaluated having regard to the total budgeted expense, as opposed to individual components. In total, despite major increases in industry travel costs since 2001/03, including fuel surcharges, and the fact that apprentice positions require more travel and accommodation expenses because they are used system wide, the Corporation has kept the growth in travel and accommodation budgets to approximately 2.4% per year – well within the level of simple inflation. As a result, the Corporation submits that there is sufficient evidence on the record for the Board to be satisfied that the travel and accommodation

forecasts in the test years are reasonable and therefore should be approved.” (NTPC Reply, 15, // 31 – p. 16, // 7)

The TGC stated in its reply that it agreed with the recommendation of the HC.

Views of the Board

The Board finds NTPC’s referral to a 2.4% annual average increase since 02/03 to be unhelpful given that this figure is calculated based upon the 01/03 Settlement, not the 02/03 actual. Using the 02/03 actual as the base year figure, the Board calculates that the actual annual average increase in the travel and accommodation expense is 7.6%, which the Board finds to be excessive. However, the Board recognizes that the 06/07 forecast also includes two new cost drivers that were not present in earlier years: the change in the RFID and increased training due to regulatory requirements.

While NTPC has quantified the impact of the change in the RFID as \$100,000/year, it has unfortunately not quantified the impact of the increased regulatory training, which is cited as the other major cost driver.

Assuming a range of \$50,000 to \$100,000/year for the increased regulatory training and using the \$100,000/year identified by NTPC for the change in the RFID, the Board calculates the annual average increase absent these 2 cost drivers to be in the range of 5.0% to 5.6%, which, while still high, is reasonable over that time period.

The Board approves NTPC’s 06/07 and 07/08 forecast travel and accommodation expenses.

7. AMORTIZATION

7.1 Fixed Assets Amortization

NTPC requested approval of amortization expenses (net of customer contributions) of \$9.568 million and \$10.115 million in 2006/07 and 2007/08 respectively for fixed assets.

NTPC used the same rates as accepted in the 01/03 Settlement. However, NTPC indicated the amortization true up from the negotiated settlement has ended.

NTPC explained why it did not complete a depreciation study for the test years:

“NTPC began but did not complete a depreciation study. NTPC did full depreciation studies for the last two GRA's which provided detailed reviews of asset lives and site restoration costs. Utilities do not normally do full depreciations studies for every GRA.

The current GRA requires a large increase to deal with fuel price increases, loss of credits, investment, regulation and inflation. The preliminary work on the depreciation study was indicating the need for additional increases due to depreciation and NTPC did not want to apply for any potential increases at the same time as the other increases and not without a more thorough review of the study results and more information on how Asset Retirement Obligations (ARO) recommendations of the Canadian Institute of Chartered Accountants (CICA) will impact depreciation rates, true ups, equity and the Revenue Requirement.

The various methods of dealing with the new ARO's have the potential to have a material impact on NTPC's GRA and depreciation rates depending on whether the recommendations of the CICA are followed or ignored for rate making purposes or whether the Board approves NTPC's proposal in

the GRA or whether the Board approves another approach to for dealing with ARO's.

Once the question of how ARO's will be handled NTPC will complete a new depreciation study reflecting newer historical information, updated site restoration information and the approved ARO treatment." (NTPC Argument, p. 21, // 3 - 22)

Views of the Board

The Board notes there could be differences between regulatory requirements and reporting requirements. The procedures and rules concerning depreciation accounting for regulatory purposes are long established. Therefore, in the Board's view any new CICA reporting requirements need not deter NTPC from completing a depreciation study based on established procedures and rules in a timely fashion.

The Board accepts NTPC's proposed amortization of fixed assets subject to the comments in Section 7.2 of this Decision.

7.2 Reserve for Future Removal and Site Restoration

The amount included in the accumulated amortization with respect to future removal and site restoration is set out in BR.NTPC-16 for each asset category.

In response to a Board directive in Decision 1-2002 to provide an updated estimate of soil remediation costs, including an estimate of the costs that are considered recoverable from the Federal Government, NTPC indicated it has completed an updated soil remediation assessment, based on estimated volumes of impacted soil and unit costing of remediation for similar projects carried out in northern Canada. NTPC stated the estimated soil remediation cost

was \$12.959 million in 2005 based on a study conducted by Biogenie in January 2006. A copy of the study was provided in Exhibit 4 and Undertaking #6.

NTPC submitted in regards to estimates of the costs considered to be recoverable from the Federal Government, NTPC has pursued Canada in regards to the commitments of the Acquisition Agreement. However NTPC indicated the Corporation has not been successful with those discussions.

The Corporation submitted it does not expect any recoveries and may risk undermining the discussions/negotiations by providing speculation at this point in time. Any recoveries that NTPC secures will be credited against the Net Salvage Reserve, and will ultimately go to lower the amounts ratepayer would otherwise pay to that reserve for site restoration. (Ex. 2, p. 6-2, 6-3)

NTPC indicated the recording of future removal of assets and site clean up costs was supported by Generally Accepted Accounting Principles (“GAAP”), and approved by the Board as part of the Corporation’s periodic depreciation reviews. Changes to GAAP in the last few years now require the recording of a liability only in cases where there is a “legal obligation” for the asset disposal or site clean up and to reverse to equity any other retirement obligations liabilities.

NTPC submitted to ensure fair intergenerational allocation of costs (that customers are paying for the cost of the assets they are using, including costs of disposing these assets and restoring the facility sites) as well as smoother rates, NTPC would like to continue with its past practice of maintaining a liability (the Reserve for Future Removal and Site Restoration) for the removal and clean up of all its assets regardless of legal obligations or otherwise. (Ex. 2, p. 3-12, 3-13)

The HC submitted the Corporation was directed to provide an updated estimate of soil remediation costs including an estimate of the costs that are considered recoverable from the Federal Government, at the time of its next GRA. NTPC filed an updated soil remediation estimate of \$12.959 million in 2005 dollars. NTPC has included an annual appropriation of \$600,000 per year for Future Removal and Soil Remediation. The study indicated that approximately 90% of the costs related to the period when Northern Canada Power Corporation ("**NCPC**") was owned by the Federal Government.

The HC submitted they expect the Corporation to continue to monitor and pursue funding from the Federal Government for the soil remediation that they are responsible for. (HC Argument, p. 23)

In its reply submission, the Corporation undertook to continue to monitor the situation and pursue the Federal Government further should there be new developments or programs. NTPC submitted the Corporation's efforts with respect to recovering funding from the federal government have been prudent and reasonable to date. NTPC stated the Board and Hydro Communities can take comfort from the Corporation's commitment for future monitoring of the issue. (NTPC Reply, p. 21)

The adequacy of the current balance to deal with these anticipated future costs is at the present time uncertain. This is part of the assessment underway over the next number of years with respect to NTPC's current depreciation rates, reserve for future removal balances and treatment of Asset Retirement Obligations as they relate to regulatory accounting and rate setting.

Views of the Board

The Board notes the accumulated site restoration component included in accumulated amortization is as follows:

	2004/05	2005/06	2006/07	2007/08
	\$000	\$000	\$000	\$000
Accumulated reserve for site restoration	37154	37780	38853	39967

Source: BR NTPC 16 Table 1

The Board considers that although there might be other costs related to site restoration in addition to soil decontamination, there appears to be a very large difference between the accumulated reserve for site restoration as of fiscal year end 2004/05 of \$37.154 million and the estimated cost of soil decontamination, in the sum of \$12.959 million in 2005 dollars, as per the Biogenie study. The Board notes NTPC's evidence at the time of the 2001/02 and 2002/03 GRA that the estimate of negative salvage for diesel plant site restoration, excluding soil remediation costs, was in the vicinity of \$12.9 million. (Decision 1-2002; p. 6)

The Board notes NTPC's view that the adequacy of the current balance in the accumulated reserve to deal with anticipated future costs is at the present time uncertain. However, the Board is concerned by the significant and growing gap between the potential amount required for site restoration including soil remediation as reflected in the Biogenie study and as per the evidence referred to in Decision 1-2002, and the accumulated balance in the reserve for site restoration. The Board notes from the above table \$1.073 million in 2006/07 and \$1.114 million in 2007/08 will be added to the reserve for site restoration, thereby contributing to the gap between the potential amount required for site restoration and the accumulated balance in the reserve for site restoration. The Board notes the Corporation has not had an opportunity to respond to this perspective on the

accumulated balance in the reserve for site restoration. The Board, therefore, directs NTPC to provide, as part of the refiling, an assessment of the significant and growing gap between the accumulated balance in the reserve for site restoration and the estimated site restoration costs in light of the above discussion and propose a cap to the accumulated reserve balance until such time as studies on the adequacy of the current balance can be completed. In this regard, the Board estimates if the accumulated reserve is capped at the 2005/06 year end level, amortization expense would be reduced by \$1.073 in 2006/07 and \$1.114 million in 2007/08.

NTPC is directed to complete the assessment of the adequacy of the current balance in the accumulated reserve to deal with NTPC's share of anticipated future costs for site restoration including soil remediation and reflect this assessment in the amortization rates at the time of the next GRA.

The Board accepts NTPC's request to maintain the reserve (the Reserve for Future Removal and Site Restoration) for the removal and clean up of all its assets regardless of legal obligations or otherwise until an assessment of the adequacy of the current balance in the accumulated reserve to deal with NTPC's share of anticipated future costs for site restoration including soil remediation is completed.

7.3 Amortization of Deferred Charges

NTPC set out details of each of the deferral account amortizations in BR.NTPC-21.

7.3.1 Overhaul Deferral Account

The Corporation requested permission to set the annual appropriation for overhauls at \$1.693 million. A continuity schedule of the overhaul deferral account since March 31, 2004 was provided in BR.NTPC-21.

Views of the Board

The Board accepts the overhaul deferral account forecast as proposed.

7.3.2 Water Licensing Fee Deferral Account

Due to increasing uncertainty related to the costs and terms of water licenses, NTPC proposed to establish a new deferral account for water licensing fee. A continuity schedule of the water licensing fee deferral account is provided in HC.NTPC-15 Table 3.

The HC did not object to the establishment of a water licensing fee commencing in 2006/07. However, the HC submitted that NTPC should not be able to recover through the deferral account any deferred water license fees from prior years when the water license fee deferral was not in existence:

“...The costs that NTPC incurred for water licensing fees between rate cases are no different than any other unplanned maintenance expenses or any other unbudgeted expense. This is the very reason that utilities receive a risk premium. Utilities should not be allowed to add to their earnings without scrutiny and then apply for retroactive recovery of such expenses. There is no evidence before the Board to demonstrate that such unplanned expense would have been allowed in the years when the expenses regarding water license fees were incurred. For that matter, NTPC admits that \$0.04 million was included in the 2002/03 revenue requirement. The Hydro Communities submit that the Board should

specifically deny the \$611,000 (sic) of retroactive expenses related to water license fees incurred prior to the two test years as a matter of principle...” (HC Argument, p. 58)

NTPC submitted deferral and amortization of water licensing fees has been accepted in the past. (NTPC Reply, p. 18) What is being proposed in this application is an approach designed to address the increasing uncertainty over the cost and term of a license. Accordingly, NTPC proposed to amortize the forecast water license fees to 2021/2022 of \$1.551 million and an opening unamortized balance of \$0.634 million over 16 years. (HC.NTPC-15)

Views of the Board

Noting that the deferral account treatment of water license fees is designed to address uncertainty over the cost and term of each license and since amortization of water license fees has been accepted in the past, the Board accepts NTPC's proposed deferral account treatment for water license fees.

7.3.3 Job Evaluation

NTPC incurred \$256,000 in 2003/2004 and 2004/05 in order to carry out a job evaluation study following incorporation of the Equal Pay for Equal Value legislation into the public service act. NTPC proposed to treat the cost of this study as a deferred cost and amortize it over a period of 5 years for the reason the expenditure has enduring benefits beyond the year of expenditure.

The HC took exception to the proposed inclusion of the annual amortization portion of the job evaluation costs in the amount of \$61,000, in the test year revenue requirements since NTPC did not have prior Board approval to treat these costs as a deferral account. The HC submitted it is just like any other

unbudgeted expense between rate cases and this is the very reason that utilities receive a risk premium. (HC Argument, p. 55)

NTPC stated the Job Evaluation System is properly treated as a deferred cost since it meets the accounting definition of an asset; i.e., it provides long-term or enduring benefits (the previous study related to job evaluation was in 89/90). The deferred cost is amortized over a five-year period. (BR.NTPC-16(c))

Views of the Board

Given the significance of the amount, its enduring benefits beyond a single year and noting the expenditure was the result of a legislative requirement, the Board considers the capitalization and amortization of the job evaluation study expenditure over a period is appropriate. The Board therefore accepts NTPC's proposed deferral account treatment of the job evaluation study expenditure.

In order to address the concerns of HC that the ability to defer certain expenditures should not result in changing the risk assumptions made at the time the fair return on rate base was established, the Board directs NTPC to file a written policy with regard to the criteria that are to be used to determine the eligibility of expenditures for deferral account treatment, at the time of the refiling.

8. DEFERRAL ACCOUNTS

8.1 Reserve for Injuries and Damages (“RFID”)

In response to a Board Directive from Decision 1-2002, NTPC filed a proposed policy with respect to the charges to the RFID. NTPC also requested to increase the annual appropriation to the RFID from \$485,000 per year to \$670,000 per year.

The HC submitted the proposed policy still leaves events that are uninsured or uninsurable to the discretion of NTPC. The HC submitted that these higher impact uninsurable or uninsured events must meet a higher test or degree of scrutiny. The HC also submitted that the only practical solution appears to be to defer disposition of these higher impact events until the next GRA and, if considered appropriate, appoint a qualified independent individual to determine whether the event truly meets the test of “accidental.” (HC Argument, p. 57)

NTPC stated that the charges to the RFID are reviewed in detail at each GRA, and as such the Board currently retains full jurisdiction to review all reserve charges as it sees fit. The Hydro Communities’ recommendation to have each and every charge reviewed by a third party, and defer confirmation of the charges until such review has occurred, is unreasonable, unnecessary and cannot practically be implemented. (NTPC Reply, p. 20)

Views of the Board

The Board considers all charges to the reserve will be subject to review by the Board and interveners at the next GRA. The Board expects the Corporation to

maintain the necessary records to facilitate full scrutiny of the costs and details of the circumstances relating to each accidental event giving rise to a claim against the reserve.

Having reviewed the proposed policy and the continuity schedule of the RFID account, the Board approves the RFID policy as filed and the increase in the annual appropriations from \$485,000 per year to \$670,000 per year.

8.2 Employee Future Benefits

The employee future benefits deferral account was established in the context of the 01/03 Settlement. The settlement contemplates actual employee termination payments would be charged to this account on a pay as you go basis.

Table 6.7.of the Application shows the changes in this account since March 31, 2001:

	\$000
Credit balance as at March 31,, 2001	889
2001/02 Expense	-274
2002/03 Expense	-205
2003/04 Expense	-106
2003/04 Adjustment	250
2004/05 Expense	-44
2005/06 Expense (Forecast)	-353
Credit balance as at March 31, 2006	157
Transfer in ultimate removal portion	495
Revised balance as at March 31, 2006	652
2006/07 Expense (Forecast)	-165
2007/08 Expense (Forecast)	-88
Credit balance as at March 31, 2008	399

With respect to the \$250,000 adjustment shown above, NTPC stated this relates to amounts that had been previously recognized in other accounts which fit the

appropriate definition of this account. These amounts were therefore consolidated into this account.

With respect to the \$495,000 transfer, NTPC stated the amount was included in NTPC's 2001/03 revenue requirement. This amount has since been appropriated from net income.

The TGC indicated it has reviewed the above adjustments and concurs with the NTPC proposals. (TGC Argument, p. 33)

Views of the Board

The Board accepts the NTPC proposed balances for employee future benefits deferral account for inclusion as a component of no cost capital.

9. SALES AND REVENUE FORECAST

The sales forecast by customer class is provided in Schedule 2.1 of NTPC's application. Appendix A to the application shows the sales forecast by customer class by community.

9.1 Industrial Sales Forecast

The HC recommended the Giant mine sales included under the industrial sales forecast in Yellowknife should be increased considering the recorded sales in the last two quarters of 2006/07:

“...However, the preliminary actual Giant Mine sales for 2006/07 were 4,988 MWh as compared to the forecast of 4,113 MWh for 2006/07 and 3,781 MWh for 2007/08. Although NTPC had forecast the Giant Mine care and maintenance sales to level out at about 315 MWh per month for the last two quarters of 2006/07, that forecast proved to be pessimistic and instead averaged about 416 MWh and there is no discernible downward trend to 315 MWh per month. The average for 2006/07 also was 416 MWh per month. The Hydro Communities submit that, based on the best available information up to the time of the application and to the time of the hearing, it appears that 4,988 MWh for each of test years 2006/07 and 2007/08 would be a reasonable forecast for the Giant Mine care and maintenance sales. The forecast energy and billing demand units should both be increased for purposes of determining revenues.” (HC Argument, p. 8)

NTPC submitted the higher sales recorded in the last two quarters of 2006/07 reflects a one-time experience related to high water levels in winter that were not expected by NTPC or the mines. (NTPC Reply, p. 7)

Views of the Board

The Board considers it appropriate to review recorded sales in order to test the forecast assumptions used; however, the Board does not consider it appropriate to substitute actual results for forecasts on a selective basis. With regard to the forecast assumptions, the Board notes NTPC's view the higher recorded sales in the last two quarters of 2006/07 is a one time event and might not be repeated. The Board concludes therefore that the forecast assumptions used by NTPC in regard to sales to the Giant mine are appropriate.

The Board accepts NTPC's industrial sales forecast as proposed.

9.2 Retail Sales Forecast

The Corporation's load forecasting approach is a balance of two broad methods:

- **"Top-down"** assessment of the activities and plans underway in a community, such as statistics from the GNWT capital spending plans, NWT Housing Corporation plans, and known developments occurring in a community such as construction activity and forecasts provided by other third parties (e.g. NUL, mines, etc). The Corporation's loads are also reviewed by its Operations and field personnel.
- **"Bottom-up"** analysis of loads experienced over the previous period up to 10 years, including two regression methods - one that is simply based on 10 year load patterns (called the "trend" analysis), and one that is based on weather-normalized loads. The regression is not a simple calculation, but rather a methodology that provides outputs of monthly loads." (BR.NTPC-4, p. 20 of 23)

Fort Smith

For Fort Smith, NTPC indicated it had used the top down approach to arrive at the sales forecasts.

HC expressed concern the forecast of sales for the community of Fort Smith were understated when compared with the normalized actual sales in prior years:

“Based on the various pieces of information provided, the Hydro Communities have compiled the following summaries of actual and forecast sales per customer (BR.NTPC-4 and Schedule A.8) and HDD (Exhibit 34) for Fort Smith since 2001/02:

	<u>Residential</u>	<u>General Service</u>	<u>HDD</u>
2001/02A	10660	53660	7120
2002/03A	10640	52300	7733
2003/04A	10310	51280	7058
2004/05A	10470	55390	7726
4 Year Ave	<u>10520</u>	<u>53140</u>	<u>7409</u>
2005/06A	9690	53330	6294
2006/07F	9370	52410	7439 (30 Year Normal)
2007/08F	9270	53120	7439 (30 Year Normal)

It is obvious from the above that 2005/06 was an extremely mild year in terms of HDD (15% less HDD than the 30 year average) and that the average sales per customer were also well below the preceding 4 year average (residential sales 8% below 4 year average). The HDD in those 4 years were close to the 30-year average. To use this year as the base upon which to add 1% defies logic...” (HC Argument, p. 10)

The HC submitted that the use of the four year average sales per residential and general service customer times the forecast number of customers should be used for the 2006/07 and 2007/08 sales forecasts. HC recommended residential sales per customer should be increased to 10,520 kWh per forecast customer for each test year and general service sales should be increased to 53,140 kWh per forecast customer. (HC Argument, p. 10 – 11)

NTPC explained sales per customer in Fort Smith may be declining for reasons other than heating degree days. NTPC considered conservation may be a factor in the decline:

“...Sales are indicated by the Hydro Communities to be low in 2005/06 consistent with the warm winter. However, other clearly material factors are impacting the residential sales forecast. For example, 2005/06 sales per customer (at 9.69 MW.h) were below 2003/04 levels (at 10.310 MW.h) by 6.40% at a time when the heating degree days (“HDD”) were down by 12.14% (from 7058 to 6294). The correlation, however, does not hold in other cases, such as 2002/03 compared to 2001/02 which indicates a year with HDD 8.6% lower (7120 versus 7733) but results in sales per customer that are 0.2% higher (10.660 MW.h versus 10.640 MW.h). In short, the Hydro Communities’ simplified analysis with respect to HDD does not bear out.

In contrast the evidence in this proceeding with respect to Fort Smith is that sales continue to materially decline, whether due to conservation efforts or population declines, such that July 2006 was the second lowest month of sales in Fort Smith for the last ten years. The HC Argument appears to try to dismiss this fact by indicating that it is clearly not related to HDDs. In this respect, the Hydro Communities are correct because HDDs will not affect loads in July, however, it also serves to clearly illustrate how many other factors are driving loads in this community and the degree of downward rate driver that this combination represents – a fact that is dismissed out-of-hand by the Hydro Communities. (NTPC Reply, p. 8, // 9 - 35)

Fort Resolution, Behchoko and Dettah

Fort Resolution, Behchoko and Dettah are communities where NTPC indicated it had used the top down approach to arrive at the sales forecasts.

The HC submitted that the same rationale as for Fort Smith should be applied to sales in Fort Resolution. Sales per residential customer would increase from 6,580 and 6,510 kWh per customer to 6,720 kWh per customer. The HC submitted the 4-year average for Fort Resolution general service customers is

only marginally higher than the NTPC forecast and thus no change appears necessary for the general service class. (HC Argument, p. 11)

HC expressed concern that as with the Fort Smith and Fort Resolution Sales Forecasts, 2005/06 residential sales for Behchoko and Dettah appear to be down due to the extremely mild year in terms of HDD and that the average sales were also well below the preceding 4 year average (4.3% and 2.1% respectively for Behchoko and Dettah).

In light of these observations, the Hydro Communities submitted that four year average sales per residential customer times the forecast number of customers should be used for the 2006/07 and 2007/08 sales forecasts. HC submitted Residential sales per customer should be increased to 7,135 kWh per forecast residential customer in Behchoko for each test year and to 8,045 kWh per forecast residential customer in Dettah for each test year. The HC noted the general services sales forecasts do not appear to be unreasonable. (HC Argument, p. 14)

NTPC submitted there is a fundamental flaw in the Hydro Communities' overall analysis, which overextends the type of HDD correlation that might exist on a larger and more diverse load population as compared to the extremely small centers. (NTPC Reply, p. 9)

Thermal Communities

TGC noted since NTPC uses normalized sales for only a few thermal communities and considering the difficulties involved in preparing accurate sales forecasts for these communities, the Board should adjust up the sales forecasts

for thermal communities by 1.17% being the percent by which actual sales for thermal communities exceed the forecast in 2006/07. (TGC Argument, p. 37)

The TGC submitted the average use per customer should provide the Board with a useful tool to assess the reasonableness of the total forecast sales. The TGC noted a consistent overall downward bias in the 2007/08 sales per customer in most of the thermal communities. TGC submitted a 1.17% upward adjustment to sales in 2007/08 should cater for whatever bias is built into the 2007/08 sales/load forecast arising from a downward trend in the sales/customers observed in most of the thermal communities. The TGC submitted the Board should direct NTPC to provide, at its next General Rate Application, a comprehensive assessment of the annual changes in the sales per customer and address whether NTPC should employ average, as opposed to year-end number of customers. (TGC Argument, p. 38 – 39)

NTPC submitted that simply because preliminary actuals are now available (and TGC appears to prefer those results), there is no reason for the Board to reject NTPC's reasonable GRA forecasts.

NTPC submitted the 1.17% adjustment bears no linkage whatsoever to 2007/08 forecasts, as it is not based on any values arising from that year, and as such the TGC recommendation with respect to 2007/08 should be dismissed by the Board. (NTPC Reply, p. 5)

NTPC submitted, while sales per customer multiplied by total number of customers may be the methodology utilized by some utilities, it is not utilized by NTPC. Rather, the Corporation's sales forecast is done in aggregate for each customer class and community solely based on the total sales in kWh. (NTPC Reply, p. 6)

Views of the Board

The Board notes that, due to certain data limitations, regression analysis for both trend and weather normalized conditions are not always used. Instead alternative methods of forecasting based on averages of consumption from the same month in previous years or averages of the most recent month's consumption are used.

“...In each case, the regression analyses for both trend and weather-normalized conditions are run, and the fit assessed for reasonableness. However, data limitations are often encountered due to the small size of the communities (for example, in certain billing cycles, no consumption will be recorded for a given month and double consumption the following month, due to meter read cycles varying for example from on the order of 28 days to 35 days for practical reasons - if only a few customers are out of cycle, this can materially affect the usefulness of the monthly data for regression-type analysis). As a result, NTPC also considers other alternative methodologies, such as:

- straight-line growth
- averages of consumption from the same month in previous years
- averages of the most recent month's consumption.

Each of these methodologies will be used in certain cases in order to ensure the "bottom-up" analysis results in loads that are consistent with the "top-down" assessment by the field personnel familiar with the communities.” (BR.NTPC-4, p. 21 of 23)

The Board notes NTPC’s difficulty in forecasting monthly sales given the small size of several communities and the concern that if a few customers are out of cycle, this can materially affect the usefulness of the monthly data for regression-type analysis. The Board considers that while these might be concerns, they are nevertheless not insurmountable.

The Board considers that while the bottom up and top down approaches described above are consistent with prudent forecasting practice, the Board is

concerned by the lack of complete explanations or support for the load forecast assumptions used for certain communities as reflected in Table BR.NTPC-4(d). The Board notes NTPC's analytical methods do not consider normalized average use per customer. The Board considers normalized average use per customer to be a useful forecasting tool, among others, because it takes into consideration the impact of changes in customer numbers on the sales forecast. It can also provide indications of trend in customer usage and usage patterns.

The illustration provided by HC in relation to Fort Smith is an example of how a four-year average of average use per customer may be used to test the forecast sales. The use of historical averages could be useful particularly if a single year use per customer might not be accurate as a result of out of cycle metering issues. The Board also notes TGC's views on the use of average use per customer in forecasting sales in future proceedings.

The Board considers NTPC should consider historical normalized average use per customer, among other methods, in determining its sales forecast for residential and general service customers by community. The historical normalized average annual use should be averaged over the most recent four years if there are out of cycle metering issues. The Board directs NTPC, as part of its Phase 1 refiling, to adjust the Test Year sales forecasts by community having regard to historical normalized average use per customer and any other relevant factors considered in the top down and bottom up approaches. The Board also directs NTPC to reflect any consequential impacts of any changes in sales forecasts on fuel costs and any other second order impacts, in the refiling.

The Board directs NTPC to consider among other forecasting techniques normalized average use per customer, for purposes of future GRA filings.

9.3 Revenue Uncertainty Due to Material Load Additions

The Hydro Communities submitted that there is sufficient uncertainty surrounding the potential increases and treatment of incremental revenues to NTPC prior to the next GRA from new mining loads or the diamond mines and through corporate restructuring such that a deferral account to capture these incremental revenues and any related costs is warranted. The HC submitted the potential for these incremental revenues should be considered not just over the term of the Test Years in this Application but over the next 5 years, which is the interval since NTPC's last GRA. (HC Argument, p. 6)

HC also submitted that Northland Utilities (NWT) Limited should continue to be supplied by hydro power from the existing Taltson Hydro Plant facilities in preference to new customers to be served by the proposed non-regulated NTHC. HC submitted this may require the negotiation of a new wholesale power supply if that situation arises. (HC Argument, p. 7)

In reply, NTPC submitted the timing of any new mining load is simply not known at this time and certainly beyond the Test Years. Further, NTPC stated the Corporation requires a rate schedule to be approved by the Board for new mining load. In the event that NUL were to serve a new mine load, the Corporation would be back before the Board on its own accord or at the direction of the Board if NTPC's incremental wholesale revenues were material and changed its level of earnings to the extent that its rates were no longer appropriate. (NTPC Reply, p. 4)

Views of the Board

The Board recognizes the potential for significant changes in the costs and revenues of the Corporation if significant new loads were to develop. The Board therefore considers a mechanism is required to review and assess the impact of these changes in the Corporations rates. Accordingly, the Board directs NTPC to provide to the Board and to all interested parties a report on the costs and revenues associated with new industrial, mining or wholesale loads, or load increases, that would have a material impact on its level of earnings and/or rates. This information should be provided at the time when the Corporation becomes aware of such load increases. For the purpose of initiating the report, the Board considers net revenue increases exceeding \$500,000 to be material.

The Board recognizes HC's concern respecting the potential for conflict of interest with respect to the allocation of hydro power output from the Taltson facility between NTPC and NTHC. The Board has addressed this matter in the context of the Corporation's code of conduct, under Section 12.1 of this Decision.

9.4 Miscellaneous Revenue

Miscellaneous revenues consist of items such as pole rentals, connection charges, contract work, building and equipment rentals, and connect and disconnect charges.

The HC submitted revenues from contract work are forecast to reduce from the 4-year actual average of \$239,000 to \$170,000. The HC noted NTPC's explanation that the average was being skewed by \$120,000 of contract revenues in Yellowknife in 2004/05.

The HC submitted that given the overall difficulty of forecasting contract work revenues in advance, the actual amounts from the previous 4 years adjusted for the one identified anomaly is the best estimate for these revenues. HC submitted reducing the \$120,000 of contract work in Yellowknife in 2004/05 to a more normal \$30,000, results in an average of \$215,000 of contract work as compared to the \$170,000 forecast by NTPC.

NTPC noted HC's recommendation that miscellaneous revenues for both contract work and customer connections should be forecast using a four-year average of the most recent actuals adjusted for anomalies. NTPC estimated that using that methodology results in forecast miscellaneous revenues of \$914,000 for 2006/07 and \$817,000 for 2007/08. The Corporation indicated it accepts that methodology and the resulting forecasts. (NTPC Reply, p. 32)

Views of the Board

In view of NTPC's concurrence with the HC's proposed method of forecasting miscellaneous revenues, the Board directs NTPC to reflect the revised forecast of miscellaneous revenues in its Phase 1 refiling.

9.5 Impact of Wholesale Contracts on Revenues

The TGC noted that while NUL(YK) has a demand rate of \$8.10/KVA for wholesale primary service, there is no corresponding demand charge for NUL (NWT). TGC was concerned if a different set of rates were established as part of the Phase 2 proceedings and in particular a demand charge were instituted for NUL (NWT) the overall revenues could change. In this regard, TGC stated:

“...These are obviously matters for a Phase 2 proceeding. However, to the extent the absence of contracts with these two large wholesale customers affects the level of rates from these customers it may be a Phase 1 matter. To this end, the TGC recommend the Board direct NTPC to provide, in its Phase 1 GRA Refiling, an assessment of the impact on revenues were a contract signed with the each of the two wholesale customers.” (TGC Argument, p. 51 – 52)

In its reply, NTPC submitted TGC appears to be under the misapprehension that entering into wholesale contracts with NUL will impact rates. That is simply not the case. NTPC submitted there are currently no bulk power agreements in place with NUL(YK) and NUL(NWT). NTPC submitted wholesale rates have historically been and will continue to be set by the Board regardless of whether wholesale contracts are ultimately negotiated with NUL. (NTPC Reply, p. 48)

Views of the Board

The Board notes that if the wholesale rate levels or structure were to change as a result of the Phase 2 proceeding or as a result of any contractual arrangements with wholesale customers, the Board will be privy to the revenue impacts of such changes at the time. Accordingly the Board considers no action is required with respect to this matter at this time.

10. STABILIZATION FUNDS

NTPC proposed to continue and maintain its fuel and water stabilization funds, all as active funds. This includes five fuel stabilization funds (Norman Wells, Inuvik, Taltson, Snare-Yellowknife and Diesel communities) and two water stabilization funds (Snare-Yellowknife and Taltson). Subject to the comments below, the Board accepts NTPC's proposed stabilization funds as proposed.

10.1 Water Stabilization Funds

10.1.1 Snare-Yellowknife Water Stabilization Fund

The Snare-Yellowknife water stabilization fund has historically operated on the basis of 177 Gwh as the long term average for hydro generation on the Snare Yellowknife system. In this Application, NTPC requested an increase in the long term average generation to 220 Gwh to reflect the addition of the Bluefish generating plant in 2004/05 (Bluefish as 42.5 GW.h per year and the remaining Snare at 177.5 GW.h per year).

Risks Covered by Water Stabilization Fund

The HC expressed concern that the Snare-Yellowknife water stabilization fund should not have to absorb diesel fuel cost risks associated with hydro or transmission outages:

“...all diesel generation is automatically run through the Water Stabilization Fund, which was never the intent. In 2005/06, NTPC charged \$112,000 to the Fund as a result of work on the Snare Rapids Upgrade and a further \$161,000 as result of the tower failure on the Rae Transmission Line. As a

consequence of the change in 2001/02/03, the Fund operates more like a Fuel Stabilization Fund (volume only) which removes all risks associated with hydro or transmission outages..." (HC Argument, p. 24)

NTPC submitted the Corporation's proposed treatment of diesel fuel expenses for the Snare-Yellowknife and Taltson systems is transparent, consistent with the operating rules of the stabilization funds agreed to by the parties to the 1995/98 Phase 1 Negotiated Settlement and results in the Corporation fairly recovering diesel fuel costs required to maintain safe and reliable service to its customers.

NTPC submitted in the event the Board would prefer an alternative treatment of diesel fuel costs related to unavailability of hydro generation or transmission facilities in the future – along the lines of those suggested by the Hydro Communities, the Corporation should be allowed to consider how it might reasonably implement such a consideration and propose an alternative treatment at a later date. (NTPC Reply, p. 42)

Long Term Average Generation

The HC submitted that the impact of capital additions to the Bluefish plant on the long term average generation of the plant should be addressed by NTPC before the Bluefish generation impacts the water stabilization.

"In BR.NTPC-19, NTPC was asked to comment on increases to the 42.5 GWh as a result of capital projects at Bluefish. NTPC indicated that the focus of projects to date has been on the safety and condition of Bluefish and not on enhancing the output because the system still had excess hydro capacity. In summary, NTPC indicated that any increases in output would have no impact on test year revenue requirements due to the forecast load being below the 220 GWh system capability. When asked when NTPC would suggest the Board address the Bluefish generation for purposes of the Water Stabilization Fund, NTPC indicated that it would do so following the capital projects that increase output and when the system

needs hydro power. Although it has no impact today, the Hydro Communities submit that NTPC be required to address the long term output of Bluefish at the time of its next GRA in order to ensure there is a forum to test the long-term output in advance of when the Water Stabilization Fund needs to be updated.” (HC Argument, p. 25)

NTPC indicated the Corporation will revisit the long-term average output of Bluefish when it becomes a material consideration in the development of the Corporation’s Revenue Requirement. (NTPC Argument, p. 62)

Views of the Board

The Board considers the purpose of a stabilization account is to mitigate the utility’s risk for items that are difficult to forecast and where the impacts of variances from forecasts can be significant. In this instance the intent of the water stabilization fund is to mitigate the risk of the availability of the hydro resource for power generation. Given this intent, there does not appear to be a valid reason to insulate NTPC from risks associated with incidents that are not directly related to the availability of the hydro resource.

The Board notes costs associated with hydro plant or transmission outages are generally considered part of the utility’s risk. Including such costs and associated risks in the water stabilization account could potentially weaken the utility’s incentive to efficiently manage its generation and transmission outages. The Board therefore, concurs with the HC that it would be appropriate to not include the diesel costs associated with generation and transmission outages in the water stabilization account. However, the Board considers the benefits of an approach designed to isolate different risks must be balanced against the administrative costs of implementing it. Therefore, the Board directs NTPC to propose in its refiling, a cost effective approach to excluding the costs and risks associated with generation and transmission outages from the water stabilization

account, having regard to the administrative costs involved, and to reflect these proposals, in the refiling.

The Board agrees with the HC that the long-term average generation from Bluefish should be determined as soon as it is practical to do so and before the Bluefish generation impacts the water stabilization fund. Equally, the Board considers given the length of time since the long-term average generation for the Snare system was established this matter should also be revisited on a timely basis. Accordingly, the Board directs NTPC to address the long-term average Bluefish and Snare generation at the time of the next GRA or earlier if the Corporation's forecasts indicate the water stabilization fund might be impacted in any given year.

10.1.2 Taltson Water Stabilization Fund

NTPC proposed to reactivate the Taltson water stabilization fund in order to maintain a parallel fund with the Snare water stabilization fund.

The HC submitted that the level of the surplus hydro available on the Taltson River is still so large that there is no need to establish a fund to deal with water variance from year to year. Therefore, the proposal to reactivate this fund appears to be nothing more than an attempt to further reduce the Corporation's risks.

The HC submitted that the rationale provided for reactivating the Taltson water stabilization fund is not compelling and NTPC's request should be denied. However, should the Board decide to approve this fund, the balance at March 31, 2006 should be deemed to be zero consistent with the fact the fund was deemed to be inactive in the 01/03 Settlement.

NTPC submitted formally reactivating the Taltson stabilization fund with a zero opening balance in the 2006/07 test year is reasonable and should be approved by the Board. NTPC indicated any need to address the related “triggers” for the fund to determine when any refund or riders are required could be suitably addressed during the Corporation’s Phase 2 proceeding.

Views of the Board

The Board is not convinced that there is a need to reactivate the Taltson water stabilization fund at this time given the surplus hydro situation on the Taltson system. However, if this situation is expected to change, NTPC should make an application to reestablish the fund at that time and request approval of the triggers for charges or credits to the fund. Accordingly, the Board directs NTPC to file an application to reactivate the Taltson water stabilization fund when the circumstances surrounding surplus hydro on the Taltson system change, as a result of which NTPC forecasts a need to reestablish the fund.

10.2 Fuel Stabilization Funds

10.2.1 Separate Fuel Stabilization Funds by Community

NTPC operates a single fuel stabilization fund for all diesel communities except for Norman Wells (purchased power) and Inuvik (gas stabilization) for which separate funds are maintained because of the difference in fuel cost causation factors applicable to these latter two communities. The TGC expressed concern that the use of a single fuel stabilization fund and single rider to pass through fuel cost changes for diesel communities is contrary to the premise of community

based rates upon which the base rates for each community are established. The TGC submitted that separate fuel stabilization funds should be maintained for each of the communities with separate fuel stabilization riders for the following reasons:

- “Management of a fairly major component of the Revenue Requirement at the time of true-up on a postage stamp basis is inconsistent with the community-based rate making approved by the Board.
- The FSF rider has the impact of averaging fuel efficiencies and delivery costs. Hence, even if there is no difference in the landed cost, the fact that delivery/shipping costs vary significantly as between communities, a common rider results in the cross subsidization. That is, communities with higher delivery/shipping costs are being subsidized by those with lower delivery/shipping costs.
- While the TGC proposal would require a need to develop and maintain riders by community, this is a reality NTPC must live under its presently approved community-based rates. NTPC currently maintains all the information to provide riders by community; hence, development of community-specific FSF riders and implementation of the same should not, in our view, result in an undue additional expense or effort.
- Customer comprehension will be enhanced by a community specific FSF rate rider, not diminished as suggested by NTPC.” (TGC Argument, p. 25)

NTPC indicated the cost of tracking the fuel stabilization fund balance by community would be material.

“...the Fuel Stabilization Fund has not been tracked on this basis and the history of costs by community cannot be broken out in the fund. Even on a go-forward basis there would be difficulties applying certain common costs, such as fuel hedge costs and credits, on an individual community

basis. The costs involved in preparing regulatory filings, responding to information requests, and tracking and reconciling riders would be material while providing relatively few cost-tracking benefits. The Corporation has not included any such costs in its test year forecasts and would otherwise charge such costs to the regulatory deferral account. Further, community-by-community riders for fuel cost changes would be complicated to implement and monitor (including the process to turn on/turn off the riders by month for every community), would decrease customer comprehension with respect to the funds and would violate the basic premise for the funds as a collective “insurance” as they were designed in the 1995/98 GRA Negotiated Settlement, with involvement from diesel communities...” (NTPC Reply, p. 43, // 21 – 32)

Views of the Board

The Board agrees with the TGC that under community based rates, the fuel riders should follow the community costs as closely as possible. The Board notes the increase or decrease in fuel costs that are passed through to customers via the fuel rider would be approximately the same incremental costs per kWh for each community resulting from a common change in the reference price for crude oil. However, given the differences in fuel efficiencies by community as well as differences in station service and line losses by community, the fuel riders to pass through a given cost change can vary by community. For example, a community with a relatively low average fuel efficiency would require a higher fuel rider compared with one with a relatively high fuel efficiency in order to pass through a given cents per kWh increase or decrease in fuel costs. The present fuel stabilization rider mechanism does not recognize these differences by community.

The Board notes NTPC’s concern respecting material costs for maintaining separate fuel stabilization accounts by community. However, the Board considers the premise of community based rates can be maintained if the change in fuel cost following a change in the reference price of oil can result in different fuel

riders for each community based on the forecast efficiencies and station service/losses for that community. Since the change in the fuel cost on a per kWh basis could be expected to be approximately the same for all communities, there will be no requirement to maintain separate fuel stabilization accounts by community. The reconciliation of revenues and costs recorded in the fuel stabilization account could be carried out as at present using a single fund. The Board directs NTPC to consider these comments and propose a procedure for determining future fuel stabilization riders triggered by fuel price changes as part of the refiling.

10.2.2 Use of Forecast Vs Actual Fuel Efficiencies

NTPC indicated fuel efficiencies are forecast for the test years based on the last three years of actual efficiency, weighted 3 for the highest of the past three years, 2 for the middle efficiency year and 1 for the lowest efficiency of the three years. (Ex 2, p. 2-8, Footnote 8)

TGC submitted that for purposes of calculating the fuel stabilization rider, actual fuel efficiencies rather the forecasts should be used:

“...As newer engines are installed, any resulting improvement in heat rates is not recognized in the calculation of fuel volumes to the detriment of customers. NTPC should therefore be directed to use actual heat rates in the computation of the FSF Rider.” (TGC Argument, p. 27)

NTPC suggested the TGC recommendation would have minimal impact. (NTPC Reply, p. 43)

Views of the Board

The Board considers it appropriate to establish fuel efficiencies on a prospective basis after giving effect to any known changes in fuel efficiencies for the test period such as resulting from the addition of a new generating unit. The Board considers this approach would preserve the utility's incentive to improve efficiencies and is consistent with forward test year regulation. The Board also considers use of forecast efficiencies in the fuel rider calculation would be consistent with the use of forecast efficiencies in the establishment of base rates. Accordingly, the Board accepts NTPC's current practice of using forecast fuel efficiencies for the purpose of determining fuel riders.

11. TERMS AND CONDITIONS OF SERVICE

NTPC proposed a number of changes to its Terms and Conditions of Service “(TCS)”. The proposed changes are approved with the exception of those noted in the following sections.

After the completion of the Phase 2 GRA, NTPC is directed to amend its terms and conditions of service in accordance with the Board’s decisions and to file a copy of the amended terms with the Board. The Corporation should also take steps to advise its customers that the terms and conditions of service have been changed and make arrangements to provide a copy of the revised document to any customer who requests one.

11.1 Application for Service

There was an addition proposed to Section 4.1 (paragraph 4), which would allow NTPC to refuse service to an applicant because a customer in arrears resides at and might continue to reside at the applicant’s premises.

Views of the Board

This amendment attempts to make the applicant assume some responsibility for the debt of the previous customer when there may be no legal relationship between these parties. The Board is not convinced that this is an appropriate provision to be included in the TCS and does not approve its inclusion.

11.2 Limitation of the Corporation's Liability

NTPC proposed a replacement of Section 13.2 by a limitation clause which would prevent any claim for loss, injury or damages brought more than 180 days after the date of the occurrence of the incident which resulted in the loss. The intended effect of this clause is to bar any liability if the claim is made after the 180 day limitation period.

Views of the Board

In the Board's view, such clauses belong in customer service agreements where the likelihood of notice to the customer is greater.

After questioning in the hearing, NTPC withdrew this proposed limitation period but it should be noted that the Board does not believe that it has the jurisdiction to establish a limitation of actions through the terms and conditions of service which varies from the limitations set out in the NWT *Limitations of Actions Act*, R.S.N.W.T 1988, c. L-8.

NTPC proposed further changes with respect to the text of Section 13.2 in its reply argument. Since this proposed limitation provision will affect all of the Corporation's customers, the Board does not consider it appropriate to approve a change advanced for the first time in reply argument. The Board therefore directs the Corporation to include this proposed change in its Phase 2 filing in order to give interveners and customers the opportunity to respond to it.

11.3 Indemnity

The Corporation proposed the addition of a new indemnity clause in Section 14.1. This proposed change would require a customer to indemnify the Corporation against certain risks.

Views of the Board

The Board is of the view that such arrangements are best included in customer service agreements where proper notice of the risk assumed by the customer can be given. This amendment is not approved.

11.4 Maximum Investment Policy

NTPC requested approval of revised Maximum Corporation Investment levels of \$1,500 per residence, \$750/unit for multiple unit residential dwellings and \$250/anticipated kW for General Service customers.

NTPC stated that the proposed changes were determined to be reasonable after having reviewed the (i) current corporate investment rates used by other utilities, (ii) NTPC's current costs to connect new customers and (iii) a net present value analysis of the costs and revenues associated with connecting new customers. Based on that review, NTPC submitted the proposed corporate investment rates are comparable to other utilities, materially less in most sample cases than the costs for hooking up new customers and within levels that can be accommodated for an increase, respectively.

Views of the Board

The Board has reviewed the proposed investment levels and accepts them for purposes of this Decision.

11.5 Standby Interconnection Guidelines

NTPC requested approval of standby interconnection guidelines applicable to any customer who seeks to receive standby service or otherwise self-generate all or a portion of their power while connected to NTPC's distribution system.

Based on comments received at the Technical Workshop, the Corporation withdrew its proposed standby rate design principles until the Phase 2 portion of this proceeding.

The Standby Interconnection Guidelines are set out in Attachment 2 of Chapter 6 of the Application. NTPC indicated the guidelines were prepared in conjunction with Northland Utilities Ltd., allow customers to better evaluate self-generation options and are required by the Corporation for safe and reliable service in the event that standby service is provided.

Views of the Board

The Board notes none of the parties raised any issues respecting the guidelines. The Board has reviewed the guidelines and approves them on an interim basis for purposes of this Decision. The Board will examine the guidelines together with associated rates at the time of the Phase 2 proceedings and consider final approval at that time.

12. OTHER MATTERS

12.1 Code of Conduct

The NTPC has 4 wholly owned subsidiaries:

1. NWT Energy Corporation Ltd.
2. NWT Energy Corporation (03) Ltd.
3. Sahdae Energy Ltd.
4. 5383 NWT Ltd.

With the recent creation of the Northwest Territories Hydro Corporation (“**NTHC**”), NTPC has itself become a wholly owned subsidiary with NTPC’s common shares being held by the NTHC.

Without access to the financial statements for these 5 affiliated companies, the TGC is concerned that it is not possible to:

- Gauge the size and results of the affiliates operations;
- Determine the amounts due to/from the NTPC; or
- Assess how the affiliates are being financed and their source of financing.

The TGC is concerned by the lack of transparency and states in its evidence:

“Without adequate checks and balances to ensure transactions with affiliates are transparent and will not impair the operations of the regulated entity, having the NTPC affiliates engaged in operations similar to those provided by the regulated arm can be problematic. ... Clearly, the activities undertaken by NTPC’s affiliates are in competition to the

activities engaged in by NTPC. Therefore, it is appropriate for safeguards to be put in place to ensure the resources of the regulated arm, if used, are properly priced and all such revenues are recorded in the books of the regulated operations.” (Ex. 10, p. 3, // 20 – p. 4, // 7)

The TGC recommends that NTPC be required to develop a comprehensive code of conduct to govern its transaction with its affiliates. The rationale provided by the TGC is:

“... A properly structured code of conduct will ensure:

- a) regulated operations do not subsidize the non-regulated operations undertaken by the Corporation;
- b) non-regulated subsidiaries do not subsidize the regulated operations;
- c) confidentiality of customer information is protected; and
- d) no preferential access to utility services is provided to the non-regulated operations.

Further, a consistent application of the code of conduct and associated code-compliant reporting of financial results also has the potential to reduce hearing time.

Currently, NTPC appears to provide, on a cost basis, a wide array of services to its subsidiaries, including purchasing, IT support, accounting and commitment of senior management time. In my view, this confers a significant benefit to the non-regulated businesses as these services should be offered on the basis of Fair Market Value (FMV) (i.e. pricing should be no different than if NTPC were providing such services to independent third parties).” (Ex. 10, p. 4, // 18 – p. 5, // 6)

The TGC recommends that NTPC is to provide, no later than its next GRA, its own comprehensive code of conduct. The TGC suggests that it could be modeled after the ATCO Group code of conduct. NTPC should also provide sufficient information to determine the exact nature and extent of the types of services provided to affiliates by NTPC, the market prices associated with these services, as well as the method of determining such transfer pricing, the costs of

NTPC senior management time charged to the affiliates and details of all overheads charged for services to affiliates.

The TGC provided substantially more information elsewhere in this process that can be found at the following locations:

- Response to BR.TGC-1
- Hearing Transcripts - Volume 3, Page 13 - Line 4 to Page 52 – Line 14
- Hearing Transcripts – Volume 3, Page 67 – Line 5 to Page 71 – Line 11
- TGC Argument Pages 4-14
- TGC Reply Pages 3-9

As a result of learning about the creation of the NTHC by Bill 4 during the course of this proceeding, the TGC updated the recommendation provided in its evidence to a three-part recommendation:

1. The Board should direct NTPC to adopt a more formalized inter-affiliate code of conduct which would establish principles related to transfer pricing and other matters governing all inter-affiliate transactions.
2. The Board should direct NTPC to file its inter-affiliate code of conduct as soon as possible in 2007, based on a collaborative approach as between NTPC, Board staff, customer representatives, as well as interested stakeholders.
3. The Board direct should NTPC to file, at its next GTA, details of all amounts it incurs in respect of non-regulated operations, basis of these amounts (direct charges as opposed to using allocation factors), allocation

drivers, as well as all amounts included in the Revenue Requirement with respect to costs incurred by non-regulated operations.

The HC is also concerned about Bill 4. The HC explained its concerns in its argument.

“...Section 36 of Bill 4 calls for an addition to Section 2 of the Public Utilities Act whereby that Act would “not apply to the supply and sale of energy generated by the Twin Gorges Hydroelectric Generating Facility on the Taltson River and any expansion of, addition to or replacement of that Facility, and distributed over transmission lines that have not been constructed on the day this section comes into force.” The Public Utilities Act would continue to apply to generation from that facility distributed to customers in and near Enterprise, Fort Resolution, Fort Smith, Hay River and the Hay River Reserve. In short, Bill 4 calls for the existing generation and distribution facilities to continue to be regulated and any expansion facilities to be non-regulated.

This raises several questions. The existing Taltson Hydro Plant includes facilities that would be considered common to it and any expansion facilities such as upstream storage, spillways, other infrastructure and water licenses for example. It is unclear how the costs associated with these common facilities would be shared between the regulated and unregulated operations. Credits from the non-regulated to the regulated operations or adjustments to the rate base would be alternatives.

If a new transmission line is constructed to connect the pilot project or fully reopened mine at Pine Point such as proposed by Tamarlane Ventures Inc., are the sales regulated or unregulated?

How would the revenues from the sale of excess hydro from the existing Taltson Hydro Plant to either the Pine Point pilot/expansion or to the diamond mines be treated?” (HC Argument, p. 5 – 6)

The HC supported the TGC’s recommendation on the need for a code of conduct. In its argument, the HC stated that “*Customers require assurance that the regulated operation of the utility is not subsidizing non-regulated affiliates...*”.

In its reply, the HC went on to state that “...*the need for a formalized code is increasing in concert with new initiatives and Developments including, most notably, Bill 4 and the creation of the Northwest Territories Hydro Corporation as the new corporate parent of NTPC.*”

NTPC’s position was that adequate checks and balances exist in NTPC’s current procedures to ensure that affiliate transactions are correctly and fairly recorded. The Corporation provided a detailed description of its inter-affiliate cost tracking procedures. NTPC’s views on this issue were expressed at various points in this proceeding:

- NTPC Rebuttal Evidence Pages 4 to 9
- Hearing Transcripts – Volume 1, Page 222 – Line 16 to Page 247, Line 19
- NTPC Argument Pages 65 to 68
- NTPC Reply Pages 44 and 45

In its reply, NTPC summed up its position as follows:

“The Corporation’s Written Argument sets out the detailed “checks and balances” and discusses the procedures which it follows when implementing those checks and balances. The Corporation does not oppose codification of its inter-affiliate cost tracking measures and is prepared to make such a filing, based on its review of other applicable jurisdictions, with the Board. It is important to note, however, that a code of conduct in the nature of the ATCO Group code is not relevant (except for the inter-affiliate transfer pricing and cost tracking measures) because the ATCO Group’s operating environment, unlike NTPC’s operating environment, consists of non-regulated generation and retail functions. As NTPC’s regulatory resources will be occupied with the preparation and prosecution of its 2006/08 Phase II GRA over the short term and running parallel proceedings would not be practical, the Corporation suggests that a filing date eight months following a final Phase II decision would be appropriate.” (NTPC Reply, p. 44, *ll.* 24 – p. 25, *ll.* 2)

Views of the Board

NTPC's affiliates are becoming involved in increasingly complex and large projects that the Board needs to ensure do not negatively impact upon the regulated ratepayers. Additionally, the creation of the NTHC has exacerbated the already complex relationship that NTPC has with its multiple affiliates.

The Board agrees with the TGC that the NTPC is in need of a comprehensive code of conduct. Given that it is the regulated utility, NTPC, which is typically providing services to its non-regulated subsidiaries (and now potentially its non-regulated parent), merely codifying the Corporation's current cost-tracking measures will not provide the level of transparency and assurance of market-based transactions that is required to protect the regulated ratepayers.

Given the level of concern from the interveners in relation to the passage of Bill 4 and the creation of the NTHC, the Board has undertaken a review of Bill 4 and its implications for NTPC and the regulated ratepayers.

A major effect of Bill 4 was the creation of a new Section 2.1 in the *PUA*. Section 2.1 states:

- 2.1.** (1) This Act shall apply to the supply and sale of energy generated by the Twin Gorges Hydroelectric Generating Facility on the Taltson River and any expansion of, addition to or replacement of that Facility, and distributed to customers in and near Enterprise, Fort Resolution, Fort Smith, Hay River and the Hay River Reserve.

- (2) This Act shall not apply to the supply and sale of energy generated by the Twin Gorges Hydroelectric Generating Facility on the Taltson River and any expansion of, addition to or replacement of that Facility, and distributed to customers over transmission lines that have not been constructed on the day

this section comes into force, unless those lines connect with and branch off transmission lines that had been constructed before that day.

Section 2.1(2) has the effect of creating a single facility, which is both regulated and unregulated at the same time. This will potentially make the regulatory process more complex and difficult due to the Board's requirement to ensure that the unregulated customers are not being subsidized in any way by the regulated customers. Regulated vs. unregulated costs for capital, head office, operations and maintenance, amortization and depreciation, fuel supply, etc. will need to be carefully untangled and closely scrutinized.

Section 2.1(2) does not seem to consider the potential customers north of this new development, which are not industrial. For example, if a deal were made to supply hydro power to Lutsel k'e with a transmission line off the new main transmission line to the diamond mines, it would appear that this transmission line would also be unregulated even though it is providing service to a regulated community. Without a defined franchise area, it is unclear if there is even any obligation to serve these other potential customers.

Section 2.1(2) applies partially based on the time of construction of transmission lines and might have the effect of taking new lines constructed in the existing hydro zone out of Board jurisdiction. Again, the effect could be to have an unregulated transmission line providing service to a regulated community.

While the new Section 2.1 of the *PUA* only refers to the expansion of the Taltson facility, it is clear that the mandate of the NTHC encompasses much more than that single project as Section 5 of Bill 4 states:

5. (1) The objects of the Corporation are:

(a) to generate, transform, transmit, distribute, deliver, sell and supply electricity on a safe, economic, efficient and reliable basis;

(b) to undertake programs to conserve electricity;

(c) to ensure a continuous supply of electricity adequate for the needs and future development of the Northwest Territories; and

(d) to undertake any other activity authorized by the Executive Council.

(2) In addition to the objects referred to in subsection (1), it is an object of the Corporation to facilitate the expansion of, addition to or replacement of the Twin Gorges Hydroelectric Generating Facility on the Taltson River, and to participate in the supply and sale of electricity generated by that Facility.

(3) The Corporation may, with the approval of the Executive Council, establish one or more subsidiaries of the Corporation to carry out its objects.

Not only is there the possibility of additional affiliates being created under Section 5(3), it is the Board's view that Bill 4 places NTPC into direct competition with its own parent company for new power customers. The effect is that there will be a conflict of interest created for the Board of Directors and Senior Management of the two Corporations from the perspective of protecting the interests of the regulated ratepayers. For example, if an opportunity for acquiring a significant new power customer was to arise, would NTPC or NTHC be allowed to pursue the opportunity? How would this decision be made? Where would the interests of the regulated customers be considered and protected in this process?

A decision by the Board and management of the two companies to forgo an opportunity (such as providing power to the diamond mines or other large

industrial customers) for NTPC in favor of NTHC could have significant negative repercussions for regulated customers.

As part of its rationale against requiring a code of conduct, NTPC asserted that NTPC's operating environment does not include non-regulated generation and retail functions. The Board disagrees. With the creation of the NTHC, the NTPC operating environment clearly now does include non-regulated generation and retail functions with all the complexity that that entails.

While the Board is not in favor of running parallel proceedings, it is the view of the Board that the development of an NTPC code of conduct cannot wait until the next GRA or even the conclusion of Phase 2 of this GRA. The Board directs NTPC to:

1. By the end of January 2008, file with the Board a formalized inter-affiliate code of conduct which would establish principles related to pricing and other matters governing all transactions with the Corporation's parent, other affiliates and non-regulated operations.
2. As part of its next Phase 1 GRA, file with the Board details of all transactions with the Corporation's parent, other affiliates and non-regulated operations, including details of how the transfer pricing is determined (fair market value, allocated costs), the allocation drivers used, as well as identification of all amounts included in the Revenue Requirement with respect to costs or revenues related to parent, other affiliate and non-regulated operations.
3. By the end of November 2007, file with the Board a detailed policy that explains how the interests of the regulated ratepayers will be protected in

relation to decisions by the Board and Senior Management regarding the operations of NTPC and NTHC. In particular, the Board expects a detailed explanation as to how it will be decided which of the two companies will pursue new generation and sales opportunities and how the interests of the regulated ratepayers will be protected in that decision-making process.

12.2 Generation Using Sources Other Than Diesel

The TGC is recommending that the Board require NTPC to take a more aggressive approach to developing generation sources other than diesel. In its evidence, the TGC stated the following:

“Customers expect NTPC to take an aggressive and proactive position in pursuit of whatever external funding is available for any green projects that may serve to reduce the dependence on diesel fuel and capitalize on the touted environmental benefits. To this end, NTPC should file quarterly reports of all its efforts to obtain funding from all levels of government to kick start projects to deliver electrical energy from ‘green’ sources and replace diesel fuel thermal power generation. NTPC should also report on any available private and/or public funding for projects using and exploiting renewable, and/or low-emission energy sources and comment on the viability of such endeavors. Finally, I recommend NTPC also be directed to report on the status of each of the renewable projects noted in TGC.NTPC-9 (c) (iii), pages 4 to 6, as noted above, as well as any other feasible, renewable projects with external funding.” (Ex. 10, p. 8, // 10 – 20)

In its response to BR.TGC-2(b), the TGC clarified its reasons for requesting quarterly reporting by NTPC.

“The objective in recommending the filing of quarterly reports is to provide the Board and stakeholders with a sense of how proactive and aggressive NTPC has been in the pursuit of federal and territorial funding available for green power. As the Board has broad general and supervisory powers, as

well as a mandate to ensure prudent acquisition of capital property when first devoted to public use (s. 49 of *Public Utility Act*), the Board may as a result of a review of such quarterly filings direct NTPC to conduct further study, or direct to undertake or not to undertake such projects.

The TGC recognize that approval of capital projects is typically in the context of a GRA; however, given the limited amount of environmentally focused funding, and the many demands placed by various parties for such funding, it may not be appropriate to wait until the filing of the next GRA to seek approval of such projects. As well, we note that NTPC currently has a significant number of potential “green projects” on the table (see TGC Evidence, page 8), which may only proceed if there is some external federal/territorial funding to defray the total costs of these projects. Absent the requested oversight in the form of quarterly reporting, and given the natural incentive for a utility to increase rate base in order to increase its return, there is no real incentive for NTPC to incorporate a “green portfolio” as part of its overall resource planning.”

NTPC responded in its rebuttal evidence by stating that there are hurdles with regards to the economic and technical viability of alternative energy projects and that it is NTPC’s view that such projects are better pursued by private business and government rather than a Crown Corporation, such as NTPC, as business and government typically have an easier time accessing third-party funding for alternative energy projects. NTPC concluded by stating:

“...To the extent that Mr. Merani’s proposition would require NTPC to aggressively pursue alternative energy funding beyond its current efforts and report quarterly on its efforts to the PUB, NTPC does not have sufficient resources to fulfill this request. NTPC maintains that the current level of effort to acquire third party funding either directly or through assisting communities to obtain funding is appropriate and that quarterly reporting on these efforts would be done at the expense of using resources to successfully acquire funding. If Customers in the diesel communities determine that this is a high priority, NTPC would be willing to amend its 2006/08 rate application to include a position to aggressively and proactively pursue alternative energy funding and make reports to the Board on a full time basis.” (Ex. 12, p. 10, // 40 – p. 11, // 3)

NTPC added to this statement in its argument.

“Absent consensus from NTPC’s customers that additional resources should be applied to seeking out and reporting on third party funding for alternative energy projects, the Corporation submits that its current program is reasonable and nothing further is required from the Board.” (NTPC Argument, p. 69, // 3 – 5)

The TGC discussed this issue at length in its argument and reply leading to the following summary of the TGC position:

“NTPC’s opposition to take any steps to seek out funding for alternate modes of electricity generation that would wean the thermal communities of their diesel-dependency and reduce fuel costs is contrary to its Vision Statement, and in our view, contrary to its obligation to demonstrate the projects it undertakes from amongst the various alternatives reflect the least short-term and long-term negative environmental impacts. NTPC’s argument that it requires additional resources is not plausible given that it has successfully undertaken alternate energy projects in the past without a requirement for additional resources and external funding.

Given the availability of federal and other external funding sources in respect for renewable energy, and the growing societal concerns respecting CO₂ emissions from the use of thermal fuels, NTPC needs to incorporate in its resource planning options a consideration of all of the costs, including impacts of carbon emissions. The Board should direct NTPC to:

- i. file quarterly reports of all its efforts to obtain funding from all levels of government to kick start projects that deliver electrical energy from ‘green’ sources and replace diesel fuel thermal power generation;
- ii. report on any available private and/or public funding for projects that use and exploit renewable, and/or low-emission energy sources and comment on the viability of such endeavors; and
- iii. report on the status of each of the renewable projects noted in TGC.NTPC-9 (c)(iii), pages 4 to 6 as well as any other feasible, renewable projects with external funding.

In addition, any GHG credits NTPC becomes entitled to as a result of undertaking renewable energy projects prior to the next GRA, or credits earned from prior such projects, should be recorded in a deferral account for disposition at the next GRA.” (TGC Reply, p. 14)

The NTPC position is summarized in its reply as follows:

“While the TGCs’ concerns around alternative energy and climate change is laudable, the TGC fails to recognize that the Corporation shares those concerns and is taking reasonable and prudent measures to address the matter. Consequently, there is no need for the Board to accept the TGCs’ recommendations that (i) NTPC be provide with a clear direction to aggressively pursue these funding opportunities and greenhouse credits and (ii) file periodic reports with the Board to document efforts to obtain external sources of capital for the pursuit of alternative projects and developments in climate change credits. Further, as noted in the Corporation’s Rebuttal Evidence, “[i]f Customers in the diesel communities determine that this is a high priority, NTPC would be willing to amend its 2006/08 rate application to include a position to aggressively and proactively pursue alternative energy funding and make reports to the Board on a full time basis.”

For the reasons discussed in section 4(c) above and in NTPC’s Written Argument, the Board should also disregard the TGCs’ recommendation that alternative energy projects undertaken before the next GRA be included in a deferral account.” (NTPC Reply, p. 46, // 23 – p. 47, // 3)

Views of the Board

The Board shares the TGC’s concerns with regards to the high cost of power in the diesel communities and supports the development of projects that would alleviate the burden on these communities.

While the Board notes that there have been some large successes by NTPC in lowering its diesel usage, such as the natural gas engines in Inuvik and the purchase of Bluefish, the Board is concerned with the lack of progress in the majority of the small, isolated diesel communities.

The Board is also concerned by the NTPC's apparent willingness to forego some projects in favor of allowing its non-regulated affiliated companies to take the lead with little to no justification being provided to the Board. The Board recognizes there are risks related to the economic and technical viability of certain alternative energy projects and notes NTPC's view that such projects are better pursued by private business and Government rather than a Crown Corporation, such as NTPC. However, the Board notes that NTPC was able to manage such risks in the past through appropriate business arrangements with third parties such as the DPC with respect to the development of hydro on the Snare River. Assuming risk considerations can be addressed through appropriate business arrangements as in the past, the Board expects NTPC to take the lead in aggressively pursuing, from a least cost planning perspective, alternative energy, demand side management and energy efficiency project opportunities while ensuring that project decisions are made in the best interests of NTPC's regulated ratepayers rather than NTPC's affiliates.

The Board finds that requiring NTPC to provide regular reporting on its efforts in the areas of alternative energy, demand side management and energy efficiency projects should not create an undue hardship for NTPC, particularly given that the Board expects the production and evaluation of such reports should be part of NTPC's own internal processes. The Board would, however, be satisfied with biannual reports rather than the quarterly reports recommended by the TGC.

The Board directs NTPC to provide the Board with biannual reports that discuss the following:

1. The efforts and progress of NTPC and its affiliates in pursuing alternative energy, demand side management and energy efficiency projects;

2. Justification for any projects being pursued by NTPC's affiliates rather than NTPC;
3. Funding programs that are, or will be, available and any efforts and progress by NTPC and its affiliates in obtaining funding.

In light of the currently underdeveloped market for the valuation and trading of greenhouse gas emissions, the Board will not act on the TGC recommendation that NTPC create a deferral account to capture the benefits of GHG reductions.

12.3 Accounting Provisions

NTPC indicated there are a number of new provisions in Canadian GAAP that are in effect since the 2001/03 GRA or are emerging and may be in effect over the next few months or years. NTPC indicated, in order to be proactive in addressing the implications for rate regulation, the Corporation is seeking approval and confirmation from the Board to continue to account for various regulatory assets and liabilities consistent with past practice and Board approvals.

The specific accounts referred to by NTPC in this context are

- The rate stabilization funds
- The overhaul deferral account
- Regulatory hearing costs deferral account
- Amortization of financing costs
- Reserve for injuries and damages
- Snare Cascades deferral account
- Employee future benefits deferral account
- Deferred revenues related to customer contributions to aid in the acquisition of property, plant and equipment

- Other regulated assets, comprised of capital studies waiting for capital asset construction or determined not feasible
- The water licensing deferral account
- The treatment of deferring future costs over a period of time, where costs incurred in one year have a longer term benefit to customers and are significant in magnitude (eg. job evaluation)
- Maintaining a liability for the Future Removal for Site Restoration for the removal and clean-up of all its assets regardless of legal obligations or otherwise

The Board confirms the above accounts should be maintained in accordance with past practice and Board approvals and as approved in this Decision.

13. SUMMARY OF BOARD DIRECTIONS

Phase 1 Refiling

1. The Board directs NTPC, in its Phase 1 refiling, to reduce the opening plant balance for 2006/07 by \$193,000 being that portion of the rate base addition for the Fort McPherson plant that has not been explained nor demonstrated to be a prudent expenditure by NTPC.
2. The Board directs NTPC, in its Phase 1 refiling, to reduce the cost of the Aklavik plant addition by 50% of the cost increase resulting from the delays. The costs to be included for the 50% risk sharing adjustment are overheads and Allowance for Funds Used During Construction (“**AFUDC**”) resulting solely from the delays in completion of the plant caused by the unforeseen length of time spent on community consultations and the fire at Fort McPherson.
3. The Board directs NTPC, in its Phase 1 refiling, to exclude the capital addition related to the plant upgrade amounting to \$900,000 from rate base additions for Fort Liard in 2007/08.
4. The Board directs NTPC, in its Phase 1 refiling, to provide a computation of its cash working capital for the test years using the net lead or lag associated with each expense item.
5. The Board directs NTPC, in its Phase 1 refiling, to use a 6% sinking fund return for each of the test years for purposes of calculating the effective cost of long-term debt.

6. The Board directs NTPC, in its Phase 1 refiling, to calculate its effective cost of long term debt as follows:

$$\text{Effective Cost of Long Term Debt} = (I + AFC - SFE) / (MAD - UFC - SFI)$$

Where:

I= Interest on Mid Year Average Long Term Debt

AFC= Amortization of Financing Costs

SFE= Sinking Fund Earnings in the year based on long term average return of 6%

MAD= Mid Year Average Debt Principal

UFC= Unamortized Financing Costs

SFI= Sinking Fund Investment

7. The Board directs NTPC, in its Phase 1 refiling, to include a capital lease rate that reflects, for the equity portion of lease financing, the fair returns on equity of 9.00% for 2006/07 and 9.25% for 2007/08 less 25 basis points.
8. The Board directs NTPC, in its Phase 1 refiling, to use a fair rate of return on equity of 8.60% for 2006/07 and 9.25% for 2007/08.
9. The Board directs NTPC, in its Phase 1 refiling, to apply a 7% cap on losses.
10. The Board directs NTPC, in its Phase 1 refiling, to calculate forecast station service using the same procedure used for fuel efficiencies. Forecast station service is to be calculated using 3 years of actual data with a weighting of "3" given to the lowest station service year, a weighting of "2" given to the middle station service year and a weighting of "1" given to the highest station service year.
11. The Board directs NTPC, in its Phase 1 refiling, to apply a 5% cap on station service as a percentage of generation.

12. The Board directs NTPC, in its Phase 1 refiling, to provide complete and accurate analyses of the costs and benefits of the AMR projects that incorporate the reasons for and the effects of the redeployment of the linemen. These analyses are to be provided both from the perspective of the individual communities and NTPC.

13. The Board directs NTPC, in its Phase 1 refiling, to remove the 50% net income component of its at-risk compensation program from the revenue requirement calculations for NTPC's regulated business. For 06/07, the amount is \$270,000 and, for 07/08, the amount is \$279,000.

14. The Board directs NTPC, in its Phase 1 refiling, to calculate its total 06/07 and 07/08 supplies and services expenses using its forecast brushing expenditures of \$393,000 for 06/07 and \$401,000 for 07/08.

15. The Board directs NTPC, in its Phase 1 refiling, to propose a procedure for returning to the ratepayers over a 3-year period the \$345,000 that was over-collected by the Corporation for brushing over the 01/02 to 05/06 period. To be clear, the refunded \$345,000 is to be obtained from NTPC's non-regulated cash flow, not by reducing the test year brushing expenditures.

16. The Board directs NTPC, in its Phase 1 refiling, to reconcile the 06/07 and 07/08 Bluefish supplies and services forecasts shown in Tables BR.NTPC-9 and HC.NTPC-13(l) and described in NUL.NTPC-15(b). NTPC is to adjust the Bluefish supplies and services forecasts as needed to account for any errors in their information request responses.

17. The Board directs NTPC, in its Phase 1 refiling, to provide an assessment of the significant and growing gap between the accumulated balance in the

reserve for site restoration and the estimated site restoration costs in light of the above discussion and propose a cap to the accumulated reserve balance until such time as studies on the adequacy of the current balance can be completed.

18. Board directs NTPC, in its Phase 1 refiling, to file a written policy with regards to the criteria that are to be used to determine the eligibility of expenditures for deferral account treatment.
19. The Board directs NTPC, in its Phase 1 refiling, to adjust the test year sales forecasts by community having regard to historical normalized average use per customer and any other relevant factors considered in the top down and bottom up approaches. NTPC is to reflect in the refiling any consequential impacts of any changes in sales forecasts on fuel costs and any other second order impacts.
20. The Board directs NTPC, in its Phase 1 refiling, to reflect the revised forecast of miscellaneous revenues.
21. The Board directs NTPC, in its Phase 1 refiling, to propose a cost effective approach to excluding the costs and risks associated with generation and transmission outages from the Snare-Yellowknife water stabilization fund, having regard to the administrative costs involved, and to reflect these proposals, in the refiling.
22. The Board directs NTPC, in its Phase 1 refiling, to consider these comments and propose a procedure for determining future fuel stabilization riders triggered by fuel price changes.

Phase 2 Application

23. The Board directs NTPC, in its Phase 2 application, to include this proposed change to Section 13.2 of the Terms and Conditions of Service to give interveners and customers the opportunity to respond to it.

Next Phase 1 GRA

24. The Board directs NTPC, in its next Phase 1 GRA, to estimate the revenue lag based on sampling the number of days it takes for recovery of revenues, on average, from customers.

25. The Board directs NTPC, in its next Phase 1 GRA, to address the potential for better matching the carrying cost of the lease to DPC with the cost of the lease to NTPC over the 65-year term of the lease.

26. The Board directs NTPC, in its next Phase 1 GRA, to provide a detailed analysis as to 1) why the fuel efficiencies in Nahanni Butte, Jean Marie River, Sachs Harbour and Colville Lake are so low; and 2) what NTPC has done and will do to improve the fuel efficiencies in these 4 communities.

27. The Board directs NTPC, in its next Phase 1 GRA, to give due weight to the first test year forecast fuel efficiencies in calculating the second test year forecast fuel efficiencies.

28. The Board directs NTPC, in its next Phase 1 GRA, to provide an updated version of Table 5.1 that includes the forecast and actual diesel efficiencies for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

29. The Board directs NTPC, in its next Phase 1 GRA, to give due weight to the first test year forecast gas efficiency in calculating the second test year forecast gas efficiency.
30. The Board directs NTPC, in its next Phase 1 GRA, to provide an analysis as to why the recent gas efficiency has dropped substantially from 99/00 and 00/01.
31. The Board directs NTPC, in its next Phase 1 GRA, to provide a detailed analysis as to why the actual gas efficiencies are so much lower than the manufacturer's ratings.
32. The Board directs NTPC, in its next Phase 1 GRA, to provide an updated version of Table 5.2 that includes the forecast and actual gas efficiencies for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.
33. The Board directs NTPC, in its next Phase 1 GRA, to include an examination of the pros and cons of separating losses into its two components (electrical losses and non-electrical losses) which would allow the electrical losses to be forecast using the same method as for fuel efficiencies while non-electrical losses could still be forecast using the 5-year rolling average method.
34. The Board directs NTPC, in its next Phase 1 GRA, to provide an updated version of Table 5.3 that includes the forecast and actual losses for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.

35. The Board directs NTPC, in its next Phase 1 GRA, to give due weight to the first test year forecast station service in calculating the second test year forecast station service.
36. The Board directs NTPC, in its next Phase 1 GRA, to provide an updated version of Table 5.4 that includes the forecast and actual station service for 06/07 and 07/08, the forecasts for the test years in the next GRA, and the actuals for the intervening years.
37. The Board directs NTPC, in its next Phase 1 GRA, to provide a more detailed analysis of station service levels and potential reductions.
38. The Board directs NTPC, in its next Phase 1 GRA, to undertake a comprehensive review of the at-risk compensation program, make any necessary changes in light of the concerns expressed by the Board and report back to the Board.
39. The Board directs NTPC, in its next Phase 1 GRA, to complete the assessment of the adequacy of the current balance in the accumulated reserve to deal with NTPC's share of anticipated future costs for site restoration including soil remediation and reflect this assessment in the amortization rates.
40. The Board directs NTPC, in its next Phase 1 GRA, to consider, among other forecasting techniques, the use of normalized average use per customer.
41. The Board directs NTPC, in its next Phase 1 GRA or earlier, to address the long-term average Bluefish and Snare generation if the Corporation's

forecasts indicate the water stabilization fund might be impacted in any given year.

42. The Board directs NTPC, in its next Phase 1 GRA, to file with the Board details of all transactions with the Corporation's parent, other affiliates and non-regulated operations, including details of how the transfer pricing is determined (fair market value, allocated costs), the allocation drivers used, as well as identification of all amounts included in the Revenue Requirement with respect to costs or revenues related to parent, other affiliate and non-regulated operations.

Other Directions

43. The Board directs NTPC, in its dealings with contractors, to establish prudent contractual arrangements including the reasonable provisions for insurance and guarantees of proper workmanship and materials that a prudent owner would require.

44. The Board directs NTPC to ensure that the Governance and Compensation Committee is exclusively made up of independent directors.

45. The Board directs NTPC that, commencing with the 06/07 test year, NTPC's 3-year rolling average actual brushing expenditures must be no less than 10% below the 3-year rolling average forecast brushing expenditures. NTPC's 5-year rolling average actual brushing expenditures must be no less than equal to the 5-year rolling average forecast brushing expenditures.

46. The Board directs NTPC to provide to the Board and to all interested parties a report on the costs and revenues associated with new industrial, mining or

wholesale loads, or load increases, that would have a material impact on its level of earnings and/or rates. This information should be provided at the time when the Corporation becomes aware of such load increases. For the purpose of initiating the report, the Board considers net revenue increases exceeding \$500,000 to be material.

47. The Board directs NTPC to file an application to reactivate the Taltson water stabilization fund when the circumstances surrounding surplus hydro on the Taltson system change, as a result of which NTPC forecasts a need to reestablish the fund.
48. The Board directs NTPC, after the completion of the Phase 2 GRA, to amend its terms and conditions of service in accordance with the Board's decisions and to file a copy of the amended terms with the Board. The Corporation should also take steps to advise its customers that the terms and conditions of service have been changed and make arrangements to provide a copy of the revised document to any customer who requests one.
49. The Board directs NTPC, by the end of January 2008, to file with the Board a formalized inter-affiliate code of conduct which would establish principles related to pricing and other matters governing all transactions with the Corporation's parent, other affiliates and non-regulated operations.
50. The Board directs NTPC, by the end of November 2007, to file with the Board a detailed policy that explains how the interests of the regulated ratepayers will be protected in relation to decisions by the Board and Senior Management regarding the operations of NTPC and NTHC. In particular, the Board expects a detailed explanation as to how it will be decided which of the two companies will pursue new generation and sales opportunities and how

the interests of the regulated ratepayers will be protected in that decision-making process.

51. The Board directs NTPC to provide the Board with biannual reports that discuss the following:

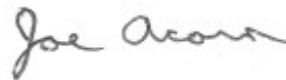
1. The efforts and progress of NTPC and its affiliates in pursuing alternative energy, demand side management and energy efficiency projects;
2. Justification for any projects being pursued by NTPC's affiliates rather than NTPC;
3. Funding programs that are, or will be, available and any efforts and progress by NTPC and its affiliates in obtaining funding.

14. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. The Board directs NTPC to provide to the Board and interested parties a Phase 1 refiling reflecting the findings and directions in this Decision within 30 days of this Decision.
2. The Board directs NTPC to provide as part of the Phase 1 refiling a working model, in Excel format, of all GRA schedules relating to the establishment of rate base, return, revenue requirement, revenues and revenue deficiencies and all relevant supporting schedules.
3. Nothing in this Decision or Order shall bind, affect or prejudice this Board in its consideration of any other matter or question relating to Northwest Territories Power Corporation.

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



**Joe Acorn
Chairman**

DATED August 29, 2007