

NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD

IN THE MATTER OF

Northwest Territories Power Corporation

General Rate Application for the Test Years

2006/07 and 2007/08

- Argument -

Submitted on behalf of:

TOWN OF INNUVIK
HAMLET OF FORT SIMPSON
HAMLET OF FORT LIARD

(The Thermal Generation Communities)

June 18, 2007

TABLE OF CONTENTS

1.	Introduction.....	3
2.	Affiliate Transactions and Code of Conduct.....	4
a)	General.....	4
b)	Lack of transparency in affiliate transactions.....	4
c)	Need for a proper affiliate code of conduct.....	7
d)	Comparison with other Crown Corporations.....	8
e)	Exemption for Smaller Utilities.....	9
f)	NTPC's position that its cost tracking procedures are adequate.....	11
g)	Allocation of NTPC's Inter-Affiliate Code Implementation Costs.....	12
h)	Process and Timing to finalize NTPC's Inter-Affiliate Code of Conduct.....	13
3.	Generation Sources other than Diesel.....	15
4.	Fuel Pricing in Inuvik.....	19
5.	Fuel Efficiency Rating for Town of Inuvik.....	21
6.	Capital Additions.....	24
7.	Fuel Stabilization Funds.....	25
a)	System-wide FSF Rider versus community-specific rider.....	25
b)	Using Forecast versus Actual Heat Rates in FSF.....	26
8.	Station Losses.....	28
9.	Pension Costs.....	31
10.	Employee Future Benefits Liability and Ultimate Removal Costs.....	32
11.	Sales Forecast.....	35
12.	Fort McPherson New Plant.....	41
13.	GAAP vs. Regulatory Accounting.....	45
14.	Necessary Working Capital.....	48
15.	Wholesale Sales Contracts.....	51

1. Introduction

This Argument is submitted on behalf of the Thermal Generation Communities (TGC) whose participants, for purposes of this proceeding, include the Town of Inuvik, the Hamlet of Fort Simpson and the Hamlet of Fort Liard.

The following submissions cover the majority of issues identified by the TGC and discussed either in IR Responses or at the hearing. Silence on any issue should not be construed as agreement with the positions or recommendations of any other party in this proceeding.

2. Affiliate Transactions and Code of Conduct

a) General

NTPC owns the following four non-utility affiliates:

NWT Energy Corporation Ltd., under the authority of the Northwest Territories Power Corporation Act, financed the Dogrib Power Corporation in 1996 for the construction of a 4.3 MW hydro facility. The NWT Energy Corporation (03) Ltd. has three operations: the operation, management and shared ownership of one residual heat project in Fort McPherson, the development of business opportunities outside the regulated business including development of hydroelectric projects and an investment in Deze Energy Corporation Ltd. a company involved in the expansion of the Taltson hydro system, started in 2006. Sahdae Energy Ltd. began operations in 2005. Its mandate is to pursue a hydro development project on the Great Bear River to provide power to the potential Mackenzie Valley pipeline. 5383 NWT Ltd. is an inactive company.¹

Under the new Hydro Corporation Act, NTPC will become a subsidiary of the NWT Hydro Corporation, the objects of which “relate generally to the generation, supply and sale of electricity in the Northwest Territories, with one object pertaining specifically to the Twin Gorges Hydroelectric Generating Facility on the Taltson River.”²

b) Lack of transparency in affiliate transactions

The TGC filed evidence expressing concern there was a lack of transparency to adequately gauge and test the nature and extent of affiliate transactions and whether, in fact, customers of NTPC are subsidizing the operations of NTPC’s non-regulated operations. As both Sahdae Energy Ltd. and NWT Energy Corporation (03) Ltd.³ have hydro projects which dwarf the 4.3 MW Dogrib Power dam financed by NWT Energy Corporation, it is quite conceivable NTPC, as the parent

¹ X7, Response TGC.NTPC-6 (a)

² Bill 4, NWT Hydro Corporation Act, Summary.

³ X7, Response HC.NTPC-1 (b) (the 2005/06 audited consolidated financial statements (page 12, “Discussion of Objectives and Strategies for 2005/06”) indicates that Sahdae Energy Ltd. hydro project on the Great Bear River is 126 MW and NWT Energy Corporation (03) Ltd.³ hydro project on the Taltson River is 36 MW.

corporation, will be required to devote significantly more time and resources to assist its subsidiaries in becoming fully operational.

NTPC appears to have some internal processes intended to monitor inter-affiliate costs:

As part of the annual budgeting process, the Corporation budgets for both the regulated operations and the non-regulated operations. The operational subsidiaries (NTEC(03) and Aadrii) provide their budgets to NTPC to consolidate. NTPC prepares budgets for the remaining subsidiaries based on expected operations for the budget year. The Corporation reports to its Board of Directors on regulated operations as well as consolidated operations on a quarterly basis. The Revenue Requirement applied for in the Corporation's Application does not include costs related to non-regulated operations.⁴

NTPC goes on to describe the manner in which direct charges and overheads are allocated to the various non-regulated operations. Notably, none of these processes are evident in the 2006-08 GRA filing, nor to our knowledge have these processes or the resulting charges to/from affiliates, been specifically approved by the Board in the past. NTPC will not even provide financial statements of the affiliates on the grounds this "information is not relevant to this proceeding."⁵

In its Rebuttal Evidence, NTPC identified some \$1.51 million of "shared services" in its 2005/06 financials as follows:

"In the Corporation's 2005/06 financial statements, there were:

- \$0.6 million in operating and administration expenses related to non-regulated operations;
- \$0.8 million in labour and related costs charged to non-regulated activities;
- \$0.01 million in shared services associated with non-regulated activities including computer usage, financial reporting & management services; and
- \$0.1 million in net interest expenses related to non-regulated debt.⁶

While it identified the above-noted shared services amounts as pertaining to its non-regulated operations in 2005/06, NTPC did not provide the relevant amounts for the Test Years 2006/07 and 2007/08. It simply states the Test Year Revenue Requirements do "not include costs related

⁴ X12, NTPC Rebuttal Evidence, page 4

⁵ X7, Response TGC.NTPC-6 (b)

⁶ X12, NTPC Rebuttal Evidence, page 6

to non-regulated operations.”⁷ The TGS submit the “trust me” approach is inconsistent and inappropriate with the standards required of a utility operating in a regulated environment.

Transparency in parent/subsidiary operations and interactions is clearly missing from the current 2006-08 GRA both in respect of direct charges as well as for shared services. As well, there is absolutely no evidence of the drivers used to allocate NTPC’s shared services costs. For example, were some portion of rent is charged to one or more of the affiliates, it might be reasonable to expect the use of square feet as a driver for rent as a shared service. Even if the shared services cost amounts allocated to non-regulated operations are properly removed from the 2006-08 Test Year Revenue Requirements, the complete absence of information and evidence concerning these allocations or related cost drivers makes any verification of these allocations impossible.

As a public utility, NTPC must bear the onus to demonstrate the costs charged or payable to the non regulated operations are quantifiable, based on appropriate cost drivers and above all, transparent and reasonable under the circumstances. The TGC accordingly submit the Board direct NTPC to file, at its next GTA, details of all amounts it incurs in respect of non-regulated operations, the basis of these amounts (direct charges as opposed to using allocation factors), all relevant allocation drivers, as well as all amounts included in the Revenue Requirement with respect to costs incurred by non regulated operations. To the extent it uses a shared services model to allocate these inter-affiliate charges, it should also provide an excel-based model to help understand the allocation to/from affiliates. In our submission, the level of detail required to understand affiliate charges will become even more important as Sahdae and NTEC (03)’s hydro operations become operational as it can be expected that more resources of the parent NTPC will be utilized. As well, while the full impacts of the newly created NWT Hydro Act are not fully evident at this time, it is reasonable to expect there will be even more inter-affiliate transactions than today.

Summary: -

⁷ X12, NTPC Rebuttal Evidence, page 4

As NTPC's affiliates Sahdae Energy Ltd. and NWT Energy Corporation (03) Ltd. have significant hydro projects on the board, NTPC, as the parent, will have to devote significantly more time and resources to assist these subsidiaries in becoming fully operational. While NTPC appears to have some internal processes to keep a track on the inter-affiliate costs, none of these processes are evident in the 2006-08 GRA filing, nor been specifically approved by the Board in the past. As well, while the full impacts of the newly created NWT Hydro Act are not fully evident at this time, it is reasonable to expect there will be even more inter-affiliate transactions than today.

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.

c) Need for a proper affiliate code of conduct

The TGC filed evidence demonstrating the need for a proper code of conduct governing inter-affiliate transactions modelled after the ATCO Group code of conduct, approved by the AEUB in Decision 2003-040. In the TGC's view, a consistent application of a NTPC code of conduct and associated code-compliant reporting of financial results has the potential to reduce hearing time and 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.⁸

NTPC disagrees with the need for an inter-affiliate code of conduct. The sections that follow provide NTPC's position and the TGC's comments.

⁸ X10, Evidence of Mr. Merani, page 4

d) Comparison with other Crown Corporations

NTPC makes the point that its cost tracking procedures as between regulated and non-regulated operations are similar to those of Newfoundland and Labrador Hydro and Manitoba Hydro, which are specifically “reviewed and accepted by the regulator”⁹. The TGC submits this response uses a very narrow, selective sample of crown corporations in Canada. NTPC has not provided any evidence of the inter-affiliate codes for other crown corporations such as Ontario Hydro, Quebec Hydro or BC Hydro.

Further, we submit while the NWT PUB may have, in the past, implicitly approved these allocation methods and the resulting costs in the past, there has been no explicit approval analogous to that provided by the regulators of the two crown corporations cited by NPTC. The TGC evidence on the record in these proceedings warrants the adoption of a more formalized inter-affiliate code of conduct which would establish principles and guidelines related to transfer pricing and other matters governing all inter-affiliate transactions.

As well, we submit the design of an appropriate inter-affiliate code of conduct for NTPC should be based on a broader study of other jurisdictions as noted by TGC:

Again, as I mentioned before, it needs to match what other provinces and jurisdictions have done in terms of codes as well. So NTPC may be doing all that it thinks it has to do, but unless you've taken a comprehensive look at all of the other codes of conduct in other jurisdictions, you may not know that you're missing something.¹⁰

Based on the foregoing, the TGC submit the Board should direct NTPC to 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

Summary: -

⁹ X12, NTPC Rebuttal Evidence, page 6, L36-37

¹⁰ Tr. Vol. 3, page 31, L16-22

NTPC supports its inter-affiliate charges methods (cost tracking procedures) by suggesting these methods are similar to those of Newfoundland and Labrador Hydro and Manitoba Hydro. However, NTPC has not provided any evidence of the inter-affiliate codes for other crown corporations such as Ontario Hydro, Quebec Hydro or BC Hydro. Any design of inter-affiliate transactions should be based on a broader study of the code in place in other jurisdictions. Based on the evidence on the record in these proceedings, 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.

e) Exemption for Smaller Utilities

NTPC also appears to suggest that it is a much smaller utility than any of the ATCO Group regulated affiliates and therefore should be exempt from the requirements implicit in the ATCO Code recommended by the TGC.

The TGC do not agree there need to be exceptions for “smaller” utilities. In Alberta, for example, a small natural gas utility, AltaGas Utilities Inc., received approval from the AEUB for its code of conduct¹¹, which was modelled based on the ATCO Group Affiliate Transactions and Code of Conduct approved in AEUB Decision 2003-040. AltaGas Utilities is much smaller than NTPC and is still required to follow the code of conduct¹².

The proposed exemption for smaller entities is also absent from the application of Generally Accepted Accounting Principles (GAAP). This issue was addressed by the TGC witness:

¹¹AEUB Order 2004-416 dated December 1, 2004. [Source: <http://www.eub.ca/docs/documents/orders/utilities/2004/u2004-416.pdf>]

¹² AltaGas Utilities Inc. has filed for a 2007 Revenue Requirement of \$37.533 million excluding the cost of gas, whereas NTPC has filed for a 2007/08 Revenue Requirement of \$66.479 million, excluding the cost of fuel [X2, Schedule 3.1, L19 less L12

....my familiarity, of course, is with the accounting side, so in the accounting literature often we've talked about small gap (sic GAAP) versus large gap (sic GAAP) and the CICA, it doesn't draw any distinction between small gap (sic GAAP) and large gap (sic GAAP).

.....So, if you have a regulated utility, whether it's the size of NTPC or whether it's ten (10) times its size, it doesn't matter, in my view.

What matters is the fact that customers need some assurance -- I'm sure the Board needs that, too -- that there's some transparency in these transactions; that there's checks and balances to ensure that the customers' rates are reasonable and -- and at a level where we think or we can make that assessment as to the prudence of the costs and the allocation of those costs as between utility and non-utility.¹³

The contention that smaller utilities should somehow be exempted from the provisions of a code of conduct necessitates the NWT PUB to apply a different standard for smaller utilities, although NTPC is the largest utility in the NWT. As a regulated utility, the principles applicable to the determination of a Revenue Requirement for a smaller regulated utility are no different than that for a larger regulated utility. In order to provide transparency in costs allocated to/from affiliates, the TGC submit there really is no option other than fully compliant with a properly constituted affiliate code of conduct approved by the NWT PUB. As noted by the TGS witness at the hearing:

So, I'm not suggesting that what NTPC is doing is not correct. They may be absolutely following the share services in a model that they know internally, but nobody outside of the company seems to know.

My suggestion to you, sir, was that -- again, we're talking about checks and balances and principles and codification of those principles in a document -- my suggestion to you, sir, is that the primary concern being transparency can only be addressed through a satisfactory set of principles that the Board has identified and the utility's following and that everybody around that is a stakeholder -- customers, government, other parties -- know that those principles are being followed consistently from year to year.¹⁴

Summary:-

Any suggestion that a formalized inter-affiliate code of conduct not apply to a 'small' utility like NTPC should be rejected. Utilities much smaller than NTPC in Alberta are also required to adhere to such a code. As a regulated utility, the principles applicable to the determination

¹³ Tr. Vol. 3, pages 24-25

¹⁴ Tr. Vol. 3, pages 28-29

of a Revenue Requirement for a smaller regulated utility are no different than that for a larger regulated utility.

f) NTPC's position that its cost tracking procedures are adequate

NTPC takes the position that in the two Canadian crown electric utilities, Newfoundland and Labrador Hydro and Manitoba Hydro, the “cost tracking guidelines are far simpler than those in the ATCO Group code of conduct.”¹⁵ It appears to suggest that as the tracking of costs as between regulated and non-regulated operations in these two jurisdictions is similar to that used by NTPC, there is no need for any changes.

However, NTPC was not able to elaborate on what specific aspects of the ATCO Inter-Affiliate Code of Conduct were unnecessarily complex or irrelevant. The TGC submit that if a much smaller Alberta gas utility, Alta Gas Utilities, is able to comply with an affiliate code that is structured and based on the ATCO code, there is no rationale why NTPC cannot do so likewise. As noted later in this Argument, NTPC has a new parent, the NWT Hydro Corporation which will bring about yet another layer in the corporate structure, with another set of affiliate transactions. All these factors warrant the need for a formalized affiliate code of conduct to ensure transparency, as noted earlier, and ensure transfer pricing is based on Board-approved principles.

The TGC provided further details¹⁶ with respect to transfer pricing. In essence, the ATCO affiliate code requires transfer pricing to be based on “cost recovery” except for services to/from “for profit” affiliates. While NTPC may not have any “for affiliate” affiliates at the present time, it is quite conceivable the creation of the new parent, NWT Hydro Corporation, may be set up as a “for profit” entity. As such, the TGC submits any affiliate code of conduct should take into account not only the current circumstances, but should also address the future.

¹⁵ X12, NTPC Rebuttal Evidence, page 6, L31-34

¹⁶ X11, Response BR.TGC-1 (b)

Summary: -

NTPC suggests its cost tracking guidelines are far simpler than those in the ATCO Group code of conduct, but does not elaborate on what specifically in the ATCO Inter Affiliate Code of Conduct it found was not simple. If utilities much smaller than NTPC are able to comply with an affiliate code that is structured and based on the ATCO code, there is no rationale why NTPC cannot do so likewise. The creation of the NWT Hydro Corporation will bring about another layer in the corporate structure, with another set of affiliate transactions. These factors all warrant the need for a formalized affiliate code of conduct to ensure transparency and ensure transfer pricing is based on Board-approved principles.

g) Allocation of NTPC's Inter-Affiliate Code Implementation Costs

During the hearing¹⁷, counsel for NTPC broached the issue of whether any portion of the additional costs arising from the implementation of the affiliate code of conduct should be borne by hydro customers, considering this is a proposal advanced by TGC. Other than to agitate the intervenors representing the hydro communities, the TGC question NTPC's motivation as to why it would ask a Phase 2 cost allocation question in the context of a Phase 1 proceeding. NTPC is well aware of the past (and current) strongly held difference in views of the thermal/hydro customers as far as rate-averaging is concerned. For NTPC to further inflame these divergent views and to attempt to cause a further schism between intervenors in a Phase 1 proceeding, all in an attempt to bolster its position, is unfortunate.

In any event, there is no evidence on the record as to what, if any, additional costs may arise if and when the NTPC's inter-affiliate code of conduct is finalized. Nor is there any evidence of the impact on rates (if any) arising from such implementation costs. The Board should therefore ignore any insinuations left on the record by NTPC.

¹⁷ Tr. Vol. 3, Page 35, L14-24

Summary:-

Any suggestion by NTPC that the implementation costs associated with the adoption of an affiliate code of conduct should be borne only by thermal communities should be rejected. First, this is a Phase 2 cost allocation issue, and secondly, there is no evidence on the record as to the amount of costs, if any, associated with the implementation of NTPC's inter-affiliate code of conduct, nor is there any evidence of the impact on final rates.

h) Process and Timing to finalize NTPC's Inter-Affiliate Code of Conduct

The TGC evidence recommended "NTPC provide no later than its next GTA, its own comprehensive code of conduct and a compliance plan, modelled after the ATCO Group code of conduct."¹⁸

However, at the hearing, the TGC was advised of the newly created NWT Hydro Corporation, which will own 100% of NTPC. This revised corporate structure creates a substantial change from the facts available and known to the TGC as at the date it filed evidence. Considering it might be another five years before NTPC files its next GRA¹⁹, the TGC submits there exists a need for an earlier deadline for the completion and filing of the inter-affiliate code of conduct.²⁰

Further, as noted in the hearing, the TGC propose a separate proceeding to deal with the inter-affiliate code of conduct, preferably one based on a collaborative approach as between NTPC, Board staff, customer representatives²¹, as well as interested stakeholders. In our view, such a proceeding should be convened as soon as possible in 2007.

¹⁸ X10, Evidence of Mr. Merani, page 5, L25-27

¹⁹ The most recent GRA was for 2001/03 test years; hence the current 2006/09 GRA represents a 5-year lag.

²⁰ Tr. Vol. 3, page 68, L12-19

²¹ Tr. Vol. 3, Page 68, L5-11

Summary:-

At the hearing, parties were made aware of the creation of the new entity, the NWT Hydro Corporation, which will own 100% of NTPC. This fact creates a substantial change from the facts known to the TGC as at the date it filed evidence. Considering it might be another five years before NTPC files its next GRA, 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. Generation Sources other than Diesel

The TGC filed evidence on the need to incent NTPC to undertake projects in thermal communities that would replace diesel as the primary fuel of choice²². In his opening statement, the TGC witness states:

In the Hydro Communities, NTPC has done an impressive job of displacing diesel fuel with hydro in recent years. However, other than in Inuvik where diesel has in large part been replaced by natural gas, precious little has been done to wean the communities off their diesel-dependency and the related escalating costs. With the growing interest in Canada in the need to curb greenhouse emissions, increased funding amounts are available from all levels of government for projects displacing thermal with “green” energy. As the market in carbon trading evolves in Canada, proceeds from such trading will provide an additional benefit to green projects²³.

NTPC appears to have a number of projects on the board that could potentially be used to displace part of the diesel generation in several communities, but characterizes these projects as considered uneconomic or unreliable at this time²⁴. However, the TGC suggest with the continuing increases in fuel prices, as well as the significant interest shown by all levels of government to invest in “green” projects, it is no longer sufficient for NTPC to wait for an opportunity to knock on its doors. It can no longer sit back and operate under the “rate base/rate of return” modus operandi where it gets compensated by simply building rate base that uses diesel fuel only. As long as the current system of regulation allows for full recovery of all costs, in our view NTPC has little incentive to push for alternate source of energy generation.

With respect, NTPC should show genuine concern as to what type of fuel is used to source generation for thermal communities. The TGC recommend that NTPC aggressively seek out all federal and other funding sources²⁵ that would accelerate the replacement of diesel generation to an alternate source of energy. As well, there is significant discussion in the industry today about

²² X10, Evidence of Mr. Merani, pages 6-8

²³ Tr. Vol. 3, page 11

²⁴ X7, Response TGC.NTPC-7 (a)

²⁵ Please see discussions of funding sources at X10, page 7. X7, Response TGC.NTPC-7 (a) and Tr. Vol. 1, pages 269-270

the potential for earning “greenhouse credits”; while the market for these credits is not fully developed at this point²⁶, the current greenhouse gas control regime will clearly result in CO2 credits (arising from displacement of thermal fuel) which will result in positive cash flows to NTPC and may, with the aid of federal and other funding for “green” projects, make projects that would otherwise be uneconomic to be economic.

However, given the stated position of NTPC, unless there is a clear direction from the Board for NTPC to pursue these funding opportunities and greenhouse credits aggressively, customers in thermal communities will continue to be left with inaction from NTPC. A typical example of its reluctance to be proactive is illustrated in the following response to the question of how the recent federal funding announcements may impact the manner in which NTPC delivers energy in the thermal communities:

Considering the very recent announcement by the Government of Canada regarding the launch of its ecoENERGY program, it is premature for NTPC to comment on the availability of additional funds or initiatives that will be available under this program. According to Minister Lunn, "The new Initiative is a focused, integrated approach built on key priorities that include carbon dioxide sequestration, clean coal, clean oil sands production and renewable energy. Priorities will be further developed with provinces and industry partners through consultations."

In his speech unveiling the program, the Prime Minister indicated that "the first component of the initiative, ecoENERGY for Renewable Power, will invest \$1.48 billion to boost Canada's supply of clean electricity from renewable sources like wind, biomass, small hydro and ocean energy. A ten-year incentive program will be established to fund eligible projects to be constructed over the next four years."

Given the timeframe outlined by the Prime Minister it is unlikely that there will be any impact on the Corporation or its customers during the test years. The same can be said for other parts of the program which are aimed at emission reduction.

Rather than a positive and forward directed stance that the NTPC will take the required steps to obtain such funding during the Test Years, it simply concludes there will be no funding in this period. To further understate the problem, it states the “NWT greenhouse emissions represent approximately 0.3 percent of Canada’s emissions; and, of that, industry and transportation represent approximately 75 percent of that number.” These statistics are of no comfort to

²⁶ See further discussion at Tr. Vol. 2, Page 23 where NTPC quantifies the cost of these credits to be about \$15/tonne. As well, NTPC states there may be market for “private deals”.

customers who seek lowering of costs because of the high diesel fuel costs, and know the potential exists to lower costs by alternative forms of generation. Notwithstanding the overall negative approach which appears to drive its inaction in this matter, NTPC has nevertheless obtained a grant of \$650,000 from the Eco-Energy program, with these funds “earmarked for mini-hydro projects in Lutsel K’e and Wha Ti.”²⁷

Based on all of the foregoing, the TGC recommend NTPC file periodic reports with the Board to document what efforts have been undertaken to obtain external sources of capital in order to kick start some of the numerous alternatives to diesel generation listed in Response TGC.NTPC-9 (c) (iii), and any other alternative projects that may be considered. As well, in these reports, NTPC should provide documentation concerning any recent developments in respect of greenhouse gas credits that may result from the development of these alternative energy projects in thermal communities, or credits that NTPC may be entitled from initiatives undertaken in the past. Any such projects that are undertaken before the next GRA should be included in a deferral account, and savings passed on to customers in the next GRA.

Summary: -

NTPC has a number of projects under consideration that could potentially be used to displace part of the diesel generation in several communities. However, it appears as long as the current system of regulation allows for full recovery of all costs, NTPC has little incentive to push for alternate source of energy generation. NTPC should aggressively seek out all federal and other funding sources to accelerate the replacement of diesel generation to alternate sources of energy. As well, the potential to sell or otherwise transfer “greenhouse credits” will result in positive cash flows to NTPC and may, with the aid of federal and other funding for “green” projects, make projects that would otherwise be uneconomic to be economic. NTPC should be provided with a clear direction to aggressively pursue these funding opportunities and greenhouse credits.

²⁷ Tr. Vol. 1, page 270

NTPC should be directed to file periodic reports with the Board as to what efforts it has undertaken to obtain external sources of capital in order to initiate some of the alternatives to diesel generation listed in Response TGC.NTPC-9 (c) (iii), and any other alternative projects that may be considered. As well, NTPC should document in these reports any recent developments in respect of greenhouse gas credits it may earn with the development of these alternative energy projects in thermal communities. Any such projects that are undertaken before the next GRA should be included in a deferral account, and savings passed on to customers in the next GRA.

4. Fuel Pricing in Inuvik

With respect to natural gas generation in Inuvik, NTPC indicated “the contract gas price is indexed to diesel fuel”²⁸. As rationale for the nexus of gas pricing to diesel, it provided the following:

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.”²⁹

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.”³⁰

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 Inuvik³¹, 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.

²⁸ X7, Response TGC.NTPC-9 (b); further, at Tr. Vol. 2, page 29, NTPC indicated gas prices in Inuvik are “tied to the change in the Edmonton rack price, but only 50% of that change.”

²⁹ X7, Response TGC.NTPC-18 (a)

³⁰ Tr. Vol. 2, Pages 33, L13-15

³¹ Tr. Vol. 2, page 31, L19-21

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.

Summary:-

NTPC's reluctance to review the terms of the contract on a bilateral basis is difficult to understand as any cost or savings that arise from the use of an alternative index is to the account of customers in Inuvik, not the shareholder. The Board should 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 a more favourable end-result to customers in Inuvik. This will avoid the need to wait, as NTPC asserts, for the 15-year contract term to expire.

5. Fuel Efficiency Rating for Town of Inuvik

NTPC has used a gas efficiency rating of 3.399 Kwh/cubic meter for the Inuvik for both test years 2006/07 and 2007/08. This rating gives no weight to the newly installed third gas engine in 2006/07; instead the 3.399 Kwh/cubic meter is based on weighted average actual experienced gas efficiency rates for 2003-04, 2004-05 and 2005-06³². The TGC filed evidence and recommended that the Inuvik gas heat rate should be increased by 5% based on the following factors:

- 6.99% improvement in diesel efficiency at the new plant in Normal Wells
- 6.70% improvement in diesel efficiency at the new plant in Fort McPherson
- 5.60% increase in fuel efficiency rating for Fort Providence upon installation of a new diesel engine
- 3.600 Kwh/Cubic meter being the recommended manufacturer's test rating.³³

As background for the variance between the assumed or forecast gas efficiency rate and the actual rate for 2002/03 NSA, NTPC explained:

The natural gas efficiency of 3.600 kW.h/m³ presented in the 2002/03 negotiated settlement was based on the manufacturer's factory test rating since the Corporation had no actual data to base a gas efficiency forecast on. The 3.429 kW.h/m³ takes into account three years of operational experience and represents the actual gas efficiency rating for the Inuvik gas engines.³⁴ {Emphasis added}

However, at the hearing, NTPC corrected the above IR Response; it did, for the 2002/03 GRA, have “two (2) years of actual experience with the gas generation engines in Inuvik and those two (2) years of actuals were relied on in coming up with an estimated fuel efficiency.”³⁵ In other words, the 3.600 Kwh/cubic meter was based on 2 years actual data: 3.510 for 1999/2000, and 3.650 for 2000/01³⁶.

³² Based on the 3:2:1 weighting factors approved in the 2001/03 GRA; see also Response BR.NTPC-6 (a).

³³ X10, Evidence of Mr. Merani, pages 13-14

³⁴ X7, Response TGC.NTPC-20

³⁵ Tr. Vol. 1, page 31-32

³⁶ Tr. Vol. 2, page 20, L2-5

NTPC went on to state that the manufacturer's test rating is significantly higher than the 3.600 Kwh/cubic meter provided for in Response TGC.NTPC-20.

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.³⁷

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 meter³⁸
- 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 processes³⁹, 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.

³⁷ Tr. Vol. 2, page 20, L14-22

³⁸ X7, Response TGC.NTPC-20

³⁹ Tr. Vol. 2, page 28, L6-8

- 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.⁴⁰

Summary:-

The fuel efficiency rate for the Inuvik gas engines should be increased in each of the Test Years from 3.399 Kwh/cubic meter to 3.569 Kwh/cubic meter to properly account for the installation of the new gas engine in Inuvik in 2006/07, and to reflect the most recent historical performance data available on the record.

⁴⁰ X12, page 15

6. Capital Additions

a) Project 2065057

In 2007/08, NTPC forecasts the replacement of gensets with modulars in Fort Liard:

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. In addition, the community has expressed an interest in utilizing the residual heat from the plant. The current plant cannot accommodate this due to restrictions in floor space. The new modular plant will also provide the community with residual heat options.⁴¹

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 hearing⁴², 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.

Recommendation: -

Considering NTPC evidence that Project 2065057 in Fort Liard is not anticipated to proceed, the \$900,000 planned expenditure 2007/08 should be removed from rate base. Any associated load forecast should be removed as well, and NTPC should be directed to provide this information.

⁴¹ X7, NTPC 2006/08 GTA, Appendix C, page C-42

⁴² Tr. Vol. 2, page 112

7. Fuel Stabilization Funds

a) *System-wide FSF Rider versus community-specific rider*

The Fuel Stabilization Fund (FSF) operates such that any rider is applied on an across-the-board basis. That is, while the fuel rates reflected in the rates set in a GRA are based on the costs (landed costs, delivery costs, service charges and fuel tax) specific to each diesel community, the rider resulting from the FSF operates via a “postage-stamp” mechanism. The TGC filed evidence recommending the application of the FSF rider on a community-specific basis, consistent with the manner in which rates are initially set in a GRA⁴³. The following is a brief of the arguments advanced in this evidence:

- 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 community⁴⁴; 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.

⁴³ X10, Evidence of Mr. Merani, pages 9-11

⁴⁴ See for example, X12, NTPC Rebuttal Evidence, page 13, Table 1

Summary:-

While the fuel rates reflected in the rates set in a GRA are based on the costs (landed costs, delivery costs, service charges and fuel tax) specific to each diesel community, the rider emanating from the FSF operates using a postage-stamp concept. The Board should direct NTPC to compute the FSF rider on a community-specific basis, consistent with the manner in which rates are initially set in a GRA.

b) Using Forecast versus Actual Heat Rates in FSF

The TGC also filed evidence recommending the use of actual heat rates when NTPC files its FSF reconciliation. Currently, NTPC uses the Board-approved heat rate approved in the last GRA (i.e. using the 2001/03 heat rates, which are now some 5 years old) to compute the volume of fuel required for purposes of the FSF. This creates a theoretical fuel requirement, and has no connection to the actual fuel requirement except perhaps by coincidence. As explained by TGC witness:

Secondly, sir, our -- we've taken the position that there is a fundamental disconnect in that the -- the calculation that you see on Table 1 takes into account approved effic -- pardon me, an approved efficiency or heat rate that dates back to the last time the Board approved it in the context of a rate application.

So, as we've seen, almost without exception, that as each year goes on and there's new additions to engines and capital and these engines tend to be more efficient, we've seen an improvement in heat rate year over year, sir.

So what this calculation basically does is it provides an inherent benefit to the shareholder in terms of ratcheting the efficiency at a previously approved heat rate whereas the facts -- facts suggest that the efficiencies are improving year over year.

So there -- there isn't a built in bias, if I can call it that, that -- that results in customers overpaying the proper cost of fuel because my view is that when you're looking at a true-up mechanism, sir, you ought to look at what it costs the company on an actual basis and what the customers have paid.

So the first part of that equation being what it costs the company, if you're going to include an approved efficiency factor, which was approved in the last rate application, I think what you've got is a theoretical value of the product and the volume of the product.

I'm suggesting rather than using a theoretical value, you use the actual, so tho – those are the -- it's a two (2) pronged issue for me, sir.⁴⁵

To illustrate, Table 1 of NTPC's rebuttal evidence⁴⁶ calculates fuel costs for the month of September 2006, by reference to the "approved efficiency" in the 2001/03 GTA. Assuming the forecast efficiency for 2006/07 was the actual efficiency, there would be 22,948 litres of less fuel required. Assuming an average cost of fuel of 87.50 cents/litre (per Schedule 3.3.1, L26), there would be a savings to customers of \$20,080 for the month of September 2006. On an annualized basis, there would be reduced fuel volumes of 299,077 litres, or savings to customers of \$261,692. [299,077 L * \$0.875]⁴⁷

Hence, the amounts collected through the FSF rider by virtue of fixing the fuel efficiency rate at the last GRA level results in customers paying to the NTPC a significant and on-going cost for a volume of diesel fuel that it did not consume while generating electricity.

Further, the TGC submit there is no real incentive lost on NTPC if the actual heat rate is used in the FSF computations. In fact, the actual heat rates are what they are, and there is not much NTPC can do improve upon the forecast heat rates, as the latter is simply based on the weighted average of the last three years of actual data.⁴⁸

Summary:-

The use of the last 2001/03 heat rates, which are now some 5 years old, to compute the volume of fuel required for purposes of the FSF, creates a theoretical fuel requirement and has no connection to the actual fuel requirement except by coincidence. 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.

⁴⁵ Tr. Vol. 2, pages 76-77

⁴⁶ X12, NTPC Rebuttal Evidence, page 13

⁴⁷ See Appendix 1 of TGC Argument

⁴⁸ See also X7, Response BR.NTPC-3 (a)

8. Station Losses

NTPC has set an acceptable station loss target to be 5% of plant generation. It states:

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.⁴⁹

While 5% has been set as an appropriate target, there does not appear to be any factual or logical basis for this specific target.. NTPC states:

I can't really speak to whether 5 percent is an appropriate target or not....The Power Corporation with our operations staff decided that let's pick a number and try to achieve that and 5 percent seemed to be a -- a reasonable target to try to achieve and as you can see from the graph, most of Northwest Territories Power Corporation's facility actually fall under that. We've achieved that number and we will continue to work to reduce those numbers even further, if we can, where it makes economic sense to do so.

I don't know that we're going to go in and spend hundreds of thousands of dollars to achieve five thousand dollars (\$5,000) in savings, so, at some point in time you get to the law of diminishing returns.⁵⁰

A review of the evidence⁵¹ indicates station losses percent for 2005/06 vary from a low of about 1% in Colville Lake to a high of about 13% in Jean Marie River. Compared to the 1990/91 baseline data provided, it is also evident NTPC has made some significant progress in the reduction of both the absolute amount of station losses in certain specific communities and the overall average station losses as illustrated in the following table:

⁴⁹ X7, Response TGC.NTPC-13 (a), page 14

⁵⁰ Tr. Vol. 2, pages 44-45

⁵¹ X7, Response TGC.NTPC-13 (a), page 14

NTPC Summary of Changes in Station Service %

Community	1990-91	2005-06	Reduction	%
Deline	9.9%	2.0%	-7.9%	-80%
Aklavik	17.0%	4.0%	-13.0%	-76%
Fort Good Hope	5.5%	3.0%	-2.5%	-45%
Fort Liard	2.0%	1.0%	-1.0%	-50%
Fort McPherson	7.0%	4.0%	-3.0%	-43%
Fort Simpson	4.0%	3.0%	-1.0%	-25%
Holman	2.0%	2.5%	0.5%	25%
Inuvik	18.0%	5.5%	-12.5%	-69%
Jean Marie River	19.0%	13.0%	-6.0%	-32%
Lutsel K'e	11.0%	6.0%	-5.0%	-45%
Nahanni Butte	6.5%	4.5%	-2.0%	-31%
Paulatuk	10.5%	4.0%	-6.5%	-62%
Rae Lakes	9.5%	8.0%	-1.5%	-16%
Sacs Harbour	4.9%	5.1%	0.2%	4%
Tsiigehtchic	10.0%	3.0%	-7.0%	-70%
Tuktoyaktuk	7.0%	5.1%	-1.9%	-27%
Tulita	7.5%	5.2%	-2.3%	-31%
Wha Ti	15.5%	2.0%	-13.5%	-87%
Wrigley	4.5%	3.0%	-1.5%	-33%
	9.0%	4.4%	-4.6%	-51%

Note: Percentages 1990/91 and 2005/06 are approximated from the table provided in Figure 8 of Response TGC.NTPC-13 (a), Page 14

The TGC understand NTPC’s concern respecting the additional costs that may be required to achieve further, but potentially marginal reductions in station service costs. However, it is not clear why or how NTPC can achieve station losses of 2% or less in the communities of Deline, Fort Liard and Wha Ti, but not in other communities. The TGC note NTPC has undertaken several specific initiatives to reduce station service losses such as the installation of residual heat systems, implementation of the use of “jacket water heating off the operating engine to heat our other engine” and the installation of “variable frequency drives on exhaust fans”⁵² The evidence does not clearly indicate to what extent these initiatives have lowered the station service losses noted in the above table. However, the fact remains that NTPC has achieved significant reductions in station service losses since the 1990/1991 period.

⁵² Tr. Vol. 2, page 46-47

Based on the actual reductions in station service losses experienced at several plants since 1990/91, it is clear the stated target rate of 5% was arbitrary and much too high. As these station losses come down from the arbitrarily set 5% rate, there should be a new target rate set closer to its actual experience. NTPC too appears to recognize this:

We've made tremendous strides in -- in trying to reduce our station service and we will continue to -- to try to do that. As these numbers come down, we will probably look at this again and -- and perhaps reset it again trying to make it another stretch number.⁵³

There appears to be little reason why NTPC cannot or should not attempt to achieve reductions in station losses in the range of 1-2% actually experienced at several plants. To this end, the TGC recommend that Board direct TGC to provide evidence at its next GRA why it cannot, and has not been able to, reduce station losses at all other plants to a target of the 1-2% actual loss experience. Obviously, if this target is uneconomic for a particular community, NTPC should provide a fully supported cost benefit analyses demonstrating the excess of costs over benefits. Further, to the extent it is able to reduce station service loss ratios below those approved in this GRA, the TGC recommend the Board direct the set up of a deferral account 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.

Summary: -

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.

⁵³ Tr. Vol. 2, page 48, L16-19

9. Pension Costs

One of the reasons for the increase in the 2006/07 and 2007/08 Revenue Requirements, compared to the 2001/03 Revenue Requirement is attributed to the termination of the credit to mitigate the increase in pension costs effective March 31, 2005. NTPC explained:

The derivation of the pension credit resulted from changes in Federal legislation that increased the employer's contribution into the Public Service Superannuation Plan (PSSP) from a matching 1:1 contribution to 1:2.14 times the employee's contribution. This change was effective April 1, 2000 however, for the interim period between April 1, 2000 and March 31, 2005 a contribution agreement with the GNWT paid for the incremental change in PSSP funding amounts. The Corporation got verbal communication indicating the PSSP funding would terminate at March 31, 2005 and the GNWT would not extend the funding agreement. For reference, a copy of the last interim funding agreement for 2004/05 is attached.⁵⁴

NTPC has received a pension credit amount of \$669,000 in 2002/03, \$931,000 in 2003/04 and \$595,000 in 2004/05. According to NTPC, the 2001/03 Revenue Requirement did not include any amounts for pension costs as "there was an offsetting revenue, so, the net impact in our last General Rate Application was zero." Assuming the credit amounts received in 2002-03 to 2004/05 offset the related pension costs, the TGC submit NTPC's treatment appears to be appropriate. The TGC also note NTPC did receive PUB-approval in respect of the pension costs once the pension credits were terminated.

Summary:-

Considering the net zero amounts included in the customer rates from the 2001-03 GRA in respect of pension costs, and assuming the subsequent pension-related credits offset the related costs in the intervening years, the TGC submit NTPC's treatment appears to be appropriate.

⁵⁴ X7, Response TGC.NTPC.15 (a&b)

10. Employee Future Benefits Liability and Ultimate Removal Costs

The 2001/03 GRA NSA set up a deferral account for Employee Termination Costs. NTPC explained:

The Negotiated Settlement required NTPC to effectively reflect the recorded liability for employee future benefits (referred to as termination costs) as at March 31, 2001 as a source of no-cost capital. In addition, the settlement required NTPC to record the liability as a "deferral account" to the benefit of ratepayers, and to use this deferral account to pay for costs incurred in respect of employee termination. The deferral account was to have a \$0 annual appropriation at that time, until such time as the then existing balance was drawn down. Due to Generally Accepted Accounting Principles, NTPC is not able to record the employee future benefits liability as a deferral account. Instead, it is required to record a mathematically equivalent approach of recording an Employee Future Benefits liability per the CICA Handbook, and an offsetting Employee Future Benefits Regulatory Asset, to which NTPC charges or credits all appropriations to the Employee Future Benefits liability. The net balance between the two accounts is effectively the same as if a deferral account had been established.⁵⁵

Adjustments to the amounts included in the 2001/04 NSA

The TGC note there exist two major adjustments to the Employee Future Benefit Deferral account. The first is to decrease this account by \$250,000 in 2003/04 and the other is to increase this account in 2006/07 by \$450,000. NTPC explained:

At the time of the 2001/03 GRA Negotiated Settlement, only the Employee Future Benefits amounts as identified in NTPC's Annual Report were addressed. However, NTPC also maintained two other accounts that were not considered at that time:

1) A separate liability for employee future benefits that was recorded as a \$0.250 million liability in other accounts. This amount was transferred in to the overall regulated Employee Future Liability in 2003/04, crediting the net "ratepayer funds" account with the full \$0.250 million.

2) An "Ultimate Removal" liability (\$0.495 million at March 31, 2006) which was not part of the negotiated settlement. NTPC proposes to transfer this amount in to the credit

⁵⁵ X2, NTPC 2006/08 GRA. Page 6-53

of the ratepayer amounts for 2006/07. The ultimate removal provision fits within the definition of the employee future benefits (it represents the costs of moving employees out once their employment is over), however the 2001/03 GRA had costs in revenue requirement related to transfers to this liability, so NTPC determined it was fairer to ratepayers to maintain this account separate until the present GRA. Note that if the Board does not approve incorporating the ultimate removal provision into the Employee Future Benefits provision, revenue requirement will need to be increased to address forecast appropriations to the Ultimate Removal account.⁵⁶

The TGC has reviewed the foregoing and concurs with the proposed NTPC adjustments.

Forecast 2006/07 and 2007/08 Draw-down amounts

A review of the evidence suggests customers will only be liable for the current liability associated with the ultimate removal costs which, at best, is a guesstimate of the number of employees who will terminate employment with NTPC during the test years⁵⁷. For example, there is no consistency in the amount of actual expenses charged to the Employee Future benefits Deferral Account balance⁵⁸ as noted in the following table:

2001/02	\$274,000
2002/03	\$205,000
2003/04	\$106,000
2004/05	\$44,000
Average 4-years	\$157,250

NTPC proposes to draw down the Employee Future benefits Deferral Account by \$353,000 in 2005/06, \$165,000 in 2006/07 and \$88,000 in 2007/08. However, to the extent NTPC cannot forecast, with any degree of accuracy, the number of employees, or the nature and extent of entitlement, terminating their services in these years, the TGC submits the draw-down should only reflect actual expenses approved by the Board at NTPC’s next GTA. To that end, the 2005/06 estimate, and the 2006/07 Test Year forecasts, should be regarded as only placeholder

⁵⁶ X7, Response TGC.NTPC-52 (b)

⁵⁷ Tr. Vol. 2, page 55, L1-15

⁵⁸ X2, NTPC 2006/08 GRA, Page 6-55, Table 6.7

amounts at this time. In our view, the “pay-as-you-go”⁵⁹ philosophy can only make sense based on the actual incurred expenses for this account, considering the difficulty in estimating the number of staff who will terminate their employment with NTPC in the Test Years, as well as their position and tenure with the Company.

Negative balances in no-cost capital reflect the current negative balance in the Reserve for Injuries and Damages (discussed in further detail in the response to Directive 2 from Decision 1-2002 set out in Chapter 6) offset to some degree by the Employee Future Benefits net liability (as set out in Chapter 6, section 6.2), which is treated as no-cost capital pursuant to the 2001/03 GRA Phase I Negotiated Settlement. [Page 3-19]

Summary: -

- (i) ***The proposal to decrease the “customer-provided funds” in the Employee Future Benefit Deferral account by \$250,000 in 2003/04 and increase this account in 2006/07 by \$450,000 appears reasonable.***

- (ii) ***Given the difficulty associated with forecasting the number of employees who may terminate their services on a forecast basis, or the nature and extent of entitlement, terminating their services, the draw-down should only reflect actual expenses submitted for Board review for reasonableness at NTPC’s next GTA. To that end, the 2005/06 estimate, and the 2006/07 Test Year forecasts, should be regarded only as placeholder amounts at this time.***

⁵⁹ Tr. Vol. 2, page 56, L5-10, NTPC states: “In the last negotiated settlement, customers expressed an interest in not funding, if you like, that liability as the employees worked for the Corporation but instead doing it on a pay-as-you-go basis will -- building it into revenue requirement at the time the employees leave.”

11. Sales Forecast

a) 2006/07 Load and Sales Forecast

When asked to comment on changes in actual versus the sales and revenue forecasts approved in the 2001/02 and 2002/03 Test Years, NTPC indicated there can be a number of factors influencing consumption. With respect to thermal communities, NTPC states:

Due to a lack of economies of scale in the Thermal Communities, very small changes can have a material impact on the year over year results. The Corporation has communities that are so small the entire community consumes less energy than a single General Service customer in some of the larger communities. A few houses not constructed or not occupied can have a noticeable effect on sales. As noted in the attached tables, for 2001/02 and 2002/03, none of the larger communities (those with more than 500 customers) had customers classes with variances over about 10%, and most were well under 5%. The very small communities however are much more difficult to forecast to the same degree of precision.⁶⁰

At the hearing, NTPC confirmed the preparation of forecasts for thermal communities poses a “massive challenge”:

So, when you get down to some of these very small communities, it is a -- it is a massive challenge to try to get a forecast that -- that will -- will -- will hold up and -- and at the end of the day, it's -- it's generally not even possible to meet the kind of -- of accuracy test that a large utility would use.⁶¹

NTPC provided the total variance (sum of Residential, GS and Street Lights) was negative 0.5% in 2001/02 and 0.6% in 2002/03⁶². However, the individual Thermal communities exhibit significant differences. When we include Inuvik with the Thermal Communities, the attached Appendix 1, shows the variances range as follows:

2001/02	+44.1% to -12.5%
2002/03	+41.8% to -19.0%

⁶⁰ X7, Response BR.NTPC-4 (a)

⁶¹ Tr. Vol. 2, page 59

⁶² X7, Response BR.NTPC-4 (a), Table BR.NTPC.4 (a) (iii) Thermal Communities

2003/04 +58.2% to -17.1%⁶³

As well, an interesting observation from the data in Appendix 1 of this Argument suggests the number of communities with sales higher than FC increases in 2002/03 and in 2003/04:

	2001/02	2002/03	2003/04
Communities with sales > FC	9	10	13
Communities with Sales < FC	11	10	7
Total	20	20	20

Accordingly, while in the aggregate, the total variances for Thermal Communities do not appear materially out from the forecast levels with respect to the 2001/02 and 2002/03 Test Years, there are some material forecasting errors at the community level. As rates are set on a community level, the magnitude of such forecasting errors raise significant questions as to whether the rates at the community level are just and reasonable.

For example, we note that the sales variance for Colville Lake was 44.4%, that is, sales were under-forecast by 44.1% in 2001/02. If one assumes, for illustrative purposes, the community cost of service for Colville Lake is \$150,000, excluding fuel costs, then a total forecast sales of 170,000 Kwh in 2001/03 would result in the average rate of 88.23 cents/Kwh; however, if the sales had been closer to the actual level of 245,000 Kwh, the average rate would have been 61.22 cents/Kwh (assuming no change in costs of service of \$150,000); that is, the average rates were higher for Colville Lake by about 27 cents/Kwh, or 30.6%.

In its calculations, NTPC has incorporated the actual sales results to the end of July 2006 i.e. for the first 4 months of 2006/07 Test Year⁶⁴. However, data for the first 6 months (i.e. to September 30, 2006) suggest an increase in actual (not normalized) sales of 1.4% over the corresponding period ended September 30, 2006. Based on discussions at the hearing, NTPC provided actual (unaudited) sales for 2006/07 to be 72,351 Gwh⁶⁵, compared to the forecast of 71,517 Mwh⁶⁶, an increase overall of some 834

⁶³ In Appendix 1 of the TGC Argument, for 2003/04, the forecast sales are assumed to be the same as the 2002/03 as the rates in 2003/04 were based on the most recent Test Year 2002/03.

⁶⁴ X7, Response BR.NTPC. 4 (d), page 20 of 23. Tr. Vol. 2, page 59-60

⁶⁵ X32, Response to Undertaking at Tr. Vol. 2, page 75

⁶⁶ X2, NTPC 2006/08 GRA, Schedule 2.3, L23

Mwh or 1.17%. It appears based on a review of the method of forecasting sales for thermal communities, only a few of these communities are forecast using normalized sales data⁶⁷. This was further confirmed at the hearing as follows:

If you look to BR-4, though, page 22 to 23, in particular, it goes through customer class by customer class, community by community, what type of forecast was used. In some of those cases a weather normalized regression trend was used.

In some communities a non-weather normalized trend was used; in some communities a different method was used, like the Fort Smith example I gave earlier, which simply took the data from one (1) month -- well, from last year, the same month of the previous year and it inflated it by 1 percent. It -- it -- it's not normalized, it doesn't incorporate weather it incorporates the fact that Fort Smith's load is generally flat.

This -- this table, I think if you'll go through it, you'll find that it's probably the...minority of communities that use the weather normalized data and the regression analysis to ultimately forecast.⁶⁸

Given the fact NTPC uses normalized sales for only a few of the thermal communities, the difficulty inherent in forecasting load forecast and sales in the thermal communities, the sensitivity of rates set for these communities to inaccurate load forecasts, and further the demonstrated material errors in prior years between actual and GRA forecast sales per community as demonstrated in Appendix 1 of this Argument, the TGC submit it is reasonable to increase the 2006/07 load forecast by the observed 1.17% increase in the actual sales, as noted above, on an across-the-board basis. Hence, the total 2006/07 load FC for each thermal community should be increased by 1.17% such that in the aggregate, the resulting 2006/07 load FC is increased from 71,517 Mwh to 72,351 Mwh.

b) 2007/08 Load and Sales Forecast

With respect to the reasonableness of the 2006/07 sales forecast, many of the same comments noted above apply equally to the 2007/08 load and sales forecast for the thermal communities. Accordingly, the same 1.17% increase recommended for 2006/07 load and sales forecast should be equally applicable for 2007/08. The TGC therefore recommend the 2007/08 test year, NTPC sales forecast be increased from 72,304 Mwh to 73,150 Mwh, or by 846 Mwh or 1.17%.

⁶⁷ X7, Response BR.NTPC-4 (s), pages 22-23

⁶⁸ Tr. Vol. 2, page 73-74

As well, we note there appears to be a consistent overall downward bias in the 2007/08 sales per customer in most of the thermal communities, as shown in Appendix 2 of this Argument. For example, we note for Residential customers, 13 out of 21 communities exhibit a reduction in the sales/customer. Likewise, for General Service, 12 out of 21 communities exhibit a reduction in the sales/customer.

NTPC suggests not much turns on the forecast number of customers and we should rather look at the total load forecast.

Mr. Chairman, the -- the simple answer is, the average use per customer, it goes down in those years because the load forecast, which is looking at the overall sales that you'll see in the first row of that table, indicates loads doing what they do in each of these communities; in the case of Fort Simpson, remaining relatively flat during those test years, increasing just slightly...and that's used as the numerator in the measure of the sales per customer.

The denominator is the number of customers. And the number of customers used in this table -- first from what we recall, is the year-end number of customers. But of course, it will vary during any given month of year; you'll have customers connecting and disconnecting. And the customers, particularly at -- at year-end, which is in March, will - - will audit --tend to, in some of these communities, be a little bit higher than the average number of customers during the year because in the winter there are a -- a few more customers that tend to connect than -- than occur in the summer.

It's not -- it -- it's not because the Corporation has any particular basis for -- for forecasting at -- on -- on that line, that trend. It's just simply that the customer forecasts are developed using a -- a different method or a different system than the load forecasts and the customer count forecasts.

The customer number forecasts do not receive anywhere near the same level of -- of attention because very, very little of the Corporation's costs or revenues hinge on the difference between say one (1) -- one (1) or two (2) customers in these communities. But a lot hinges on the sales in these communities within one (1) or two (2) percent, because most of the revenues developed are developed out of energy revenues.⁶⁹

The TGC submit the average use per customer should provide the Board with a useful tool to assess the reasonableness of the total forecast sales. While NTPC may not place much attention on the customer number forecasts, it is not possible to forecast total load in a vacuum; that is, load is a function of sales per customer and the number of customers forecast for a year.

⁶⁹ Tr. Vol. 2, page 77-78

The TGC is not suggesting a further adjustment to the 1.17% increase proposed above for 2007/08 over the amount forecast by NTPC. In our view, this adjustment 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. However, the TGC submits the Board should direct NTPC to provide, at its next GTA, 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.

Summary: -

- a) *NTPC acknowledges forecasting for thermal communities can be a “massive challenge”. While the overall variances in sales forecast for all of the thermal communities does not appear too large, the variances of actuals over prior year GRA forecasts, on a community-by-community level are material, ranging from a low of -12.50% to a high of +58.2%. For each of the thermal communities, the Board should direct NTPC to increase its 2006/07 sales by 1.17%, being the actual overall 2006/07 sales increase over forecast. Use of actuals is appropriate considering NTPC utilizes normalized sales for only a few of the thermal communities, and reflects the difficulty inherent in forecasting sales for thermal communities, and will avoid the material variances experienced in prior test years summarized in Appendix 1 of this Argument. NTPC should therefore, in its Refiling, reflect an increase in the 2006/07 load FC from 71,517 Mwh to 72,351 Mwh by increasing the sales forecast in each of the thermal communities by 1.17%.*

- b) *NTPC should increase its total sales forecast for 2007/08 by 1.17% as well, for the same reasons as noted above for 2006/07. This will counteract, in part, the bias evident in NTPC’s forecast i.e. for most communities NTPC has reflected a reduction in the average sales/customer. While NTPC de-emphasises the importance of the average use per customer, this metric provides the Board with a useful tool to assess the reasonableness of the total forecast sales since load is a function of sales per customer and the number of customers forecast for a year. The Board should direct NTPC to*

provide, at its next GTA, a comprehensive assessment of the annual changes in the sales per customer and address whether NTPC should be using average, as opposed to year-end number of customers.

12. Fort McPherson New Plant

NTPC's application for approval of a project permit pursuant to section 54 of *the Act* for a major capital project to replace the generating plant at Fort McPherson that was completely destroyed by fire on January 19, 2004 was approved in Decision 6-2004. The Board stated:

The Board recognizes the prudence of the expenditures and the cost recovery will be subject to examination at the time of the hearing of NWTPC's next General Rate Application. However, the Board is required to consider, among other matters the impact on rates pursuant to Section 54.(4) of the Act, prior to NWTPC undertaking the project. Accordingly, the Board considers any approval of the Application should be subject to the condition that NWTPC provides *all relevant cost information respecting the project that would have been provided in the normal course for project applications*, including the rate impact, as soon as such information can be reasonably assembled and in any event no later than completion of the design stage of the new plant.⁷⁰ {Emphasis added}

While it forecast replacement costs to be in the range of \$5.5 to 7.0 million⁷¹, the actual cost to rebuild the Fort McPherson power plant in 2004 was \$9.816 million⁷². NTPC also decided to add some \$2.911 million in betterments that were not covered by insurance, bringing the total re-build cost to some \$12.727 million. This re-build was initially financed by short-term debt and later converted to long-term debt along with other corporate requirements. NTPC estimates a 20% increase in rates due to the addition of the plant.⁷³

A number of issues arise from manner in which NTPC handled the replacement or re-build of this plant which may have an impact on other thermal communities in the future faced with the prospect of a plant re-build in similar circumstances.

⁷⁰ Decision 4-2006, page 3

⁷¹ Decision 4-2006, page 2

⁷² X7, Per Response TGC-NTPC-34 (a), the actual cost of the re-build was \$7.996 million, plus: (i) initial response to restore power \$1.023 million, (ii) Debris Removal \$0.638 million (iii) Claims Prep at \$0.066 million and Inventory Replacement at \$0.093 million, for a total of \$9.816 million.

⁷³ X2, NTPC 2006/08 GRA, pages 6-25 to 6-27; X7, Response TGC-NTPC-34 (a),

Given the sheer magnitude of the cost of the re-build, and the extent of cost overruns from the \$5.5 to \$7.0 million forecast, the expectation would be for NTPC to provide some evidence its costs were reasonably and prudently incurred. When posed with the specific question to provide evidence “costs incurred in the plant re-build were prudently incurred”, it stated:

The Corporation has not calculated the cost to re-build the Fort McPherson Plant using replacement cost indices. The fire that completely destroyed that plant on January 19, 2004 left the residents of Fort McPherson without power. Although the Corporation was successful at *restoring power to the community within 10 hours of the fire*, there was an urgent requirement to replace the plant as soon as possible. The urgent nature in which this plant needed to be replaced caused the Corporation to deviate from *its typical planning, procurement and construction cycle for a new power plant, which takes approximately 2-3 years*. Rather, the Corporation purchased the components of the plant on an *invitational tender basis instead of public tenders* with accelerated response requirements from companies. In some cases the Corporation purchased components directly from *known and reputable suppliers without any tendering due to time constraints*. As a result of these efforts, the Corporation had procured, constructed and commissioned the new Fort McPherson power plant within 12 months of the January 19, 2004 fire.

The Corporation also took into consideration the *end date of insurance coverage for temporary power supply (11 months coverage) which would have cost customers approximately \$50,000 per month until the new plant was completed*.

This accelerated strategy to re-build the Fort McPherson Plant was proposed to the Board in the Fort McPherson Project Permit Application filed on February 20, 2004. The project permit was approved by the PUB in Decision 4-2006⁷⁴. {Emphasis added}

It appears from the foregoing NTPC was primarily motivated to complete the power plant and the minimizing the resulting costs were of secondary concern. The TGC is concerned NTPC has provided little evidence costs to re-build were prudently incurred.

- The PUB direction in Decision 6-2004 was for NTPC to provide “all relevant cost information respecting the project that would have been provided in the normal course for project applications, including the rate impact, as soon as such information can be reasonably assembled and in any event no later than completion of the design stage of the new plant.”⁷⁵ First, it is not evident NTPC provided any information to the PUB upon the

⁷⁴ X7, Response TGC.NTPC-24 (h); it appears reference to Decision 4-2006 should be to Decision 6-2004 dated March 8, 2004

⁷⁵ Decision 6-2004, page 3

completion of the design stage of the new plant. Next, the nature and extent of the information filed in the current 2006/08 GRA is not, in our view, sufficient to discharge the onus or burden of proof required of NTPC to demonstrate prudence. For example, it will not even provide the cost to re-build the Fort McPherson Plant using replacement cost indices. Such information would have been a useful tool to assess the total costs it now submits for plant re-build.

- While the insurance for temporary power was expected to lapse in 11 months after the fire, it did have an option to renew and extend this coverage. Even if such insurance could be renewed, given the stated NTPC goal of “restoring permanent power to the community was perhaps a greater consideration and definitely trying to do that in a timely manner.”,⁷⁶ this extended insurance option may not have been considered, and additional and unnecessary costs incurred.
- While NTPC states it could not “sit there and go through weeks of tendering processes”,⁷⁷ it is also not clear why an expedited tendering process at some level and for certain of the plant components was not undertaken.

The TGC recognize the Board in Decision 6-2004 approved the expedited sole source or invitational tendering as opposed to a public tender process. However, as noted earlier, there is little or no evidence demonstrating prudence of the costs incurred to re-build the plant. NTPC’s “trust me” approach is obviously in clear violation of the specific directives of the PUB to be provided with evidence as to the prudence of these expenditures.

Based on all of the foregoing, the TGC submit there should be at least a 10% disallowance of costs incurred to re-build the Fort McPherson plant.

Summary:-

A number of issues of concern arise with respect to the rebuild of the Fort McPherson Plant. First, there is very little evidence on the significant difference between the forecast replacement

⁷⁶ Tr. Vol. 2, page 84

⁷⁷ Tr. Vol. 2, page 83

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. For example, it was requested, but did not provide the cost to re-build the plant using replacement cost indices. It appears NTPC was primarily motivated to complete the power plant; minimizing costs were of secondary concern. Contrary to the direction in Board Decision 6-2004 to provide “all relevant cost information... no later than completion of the design stage of the new plant”, it appears no such information was provided at this time.

Next, NTPC does not appear to have considered the option to renew the insurance for temporary power; it did have an option to renew and extend this coverage but appears to have decided against this option. Additionally, it is also not clear why an expedited tendering process at some level and for certain of the plant components was not undertaken. Based on all of the foregoing, the TGC submit there should be at least a 10% disallowance of costs incurred to re-build the Fort McPherson plant.

13. GAAP vs. Regulatory Accounting

NTPC uses a number of regulatory conventions and treatments of revenues and expenses which may not be consistent with the recommendations of the CICA Handbook. It request Board approval to specifically allow it to carry on its regulatory accounting in the manner approved by the NWT PUB. To this end, it states:

The above Revenue Requirement reflects treatment of various expenses consistent with normal regulatory practice and “test year” normalization. At the time of the 2001/03 GRA Phase I Negotiated Settlement, the CICA Handbook considered industry practice for rate-regulated companies as a primary source of generally accepted accounting principles (GAAP) as opposed to the standard GAAP used by non-rate regulated companies. In the intervening years there have been a number of significant changes in Canadian GAAP as a result of the Canadian Institute of Chartered Accountant’s (CICA) project for creating more specific guidelines for rate regulated companies. One of these changes has been the removal from the CICA Handbook of industry practice as a primary source of GAAP for rate-regulated companies. As a result of these changes a rate regulated company, such as NTPC, is allowed to continue recording those assets and liabilities created through regulation as regulated assets and liabilities only if they are specified by the company’s regulator and appropriately disclosed in the financial statements.

The Corporation is striving to maintain the same accounting treatment for its regulated reporting and its external reporting in order to minimize the impact to customers of extreme changes in rates as a result of recovering these costs over a single year and to reduce intergenerational cross subsidization. Consequently, the Corporation would like to continue with its current deferral treatment of these costs for both regulatory and financial statements. GAAP currently allows the Corporation to record regulator approved accounting treatments for assets and liabilities, therefore the Corporation is seeking approval and clarification from the Board for consistent accounting and regulatory treatments of the following items:⁷⁸

In its May 16, 2007 Update, NTPC again addressed this issue as follows:

Accounting Provisions: There are a number of new provisions in Canadian Generally Accepted Accounting Principles that could be inconsistent with the way NTPC has maintained its regulatory accounts as approved by the PUB. NTPC seeks approval and confirmation from the PUB to maintain these funds as per established practice, for the benefit of ratepayers.⁷⁹

⁷⁸ X2, NTPC 2006/08 GRA, page 3-20, 3-21

⁷⁹ X13, NTPC GRA Revisions dated May 16, 2007, page 7-8

The TGC supports the position advanced by the Corporation and encourages the Board to provide specific approval to maintain the regulatory accounts, which may not be in accordance with GAAP inasmuch as industry practice is no longer used in the CICA Handbook as a primary source of GAAP. In our view, the NWT PUB sets the Corporation's Revenue Requirement considering, amongst other things, a proper balancing of the interests of customers and the shareholder for example, by approving collection of expenses over a period of years to smooth rates or avoid potential rate spikes. On the other hand, the objectives of GAAP are more to ensure consistency in treatment of a particular item across all companies, so that users of financial statements can make appropriate investment, credit and similar decisions. Users must also be able to determine the amounts and net cash inflows to make these decisions.

Hence, in the TGC's view, the objectives of a regulator and CICA Handbook do not necessarily correspond and thus slavish adherence to CICA Handbook principles may be quite inappropriate in a regulatory setting. Strict compliance with GAAP has the potential to deprive the NWT Board from exercising its discretion in the setting of just and reasonable rates by matching the recovery of costs from customers over a different time frame than GAAP may require. To this end, we note with approval that NTPC is making submissions, in concert with the CEA, in response to the proposed harmonization of Canadian GAAP with the International Financial Reporting Standards⁸⁰.

In order to avoid a significant change in the timing of collection of the various deferral accounts previously approved by this Board⁸¹, and avoid the potential for rate spikes, the TGC supports NTPC's request for the PUB confirmation to maintain these funds as previously approved.

Summary:-

With the removal of references to industry practice as a source of GAAP, the TGC supports NTPC's proposal for the Board to provide specific approval to maintain the previously

⁸⁰ Tr. Vol. 2, page 86-87

⁸¹ As identified and described in X2, NTPC 2006/08 GRA, page 3-21 to 3-26

approved regulatory accounts even though these practices may not be in compliance with GAAP. In setting the Corporation's Revenue Requirement, the Board considers a proper balancing of the interests of customers and the shareholder, for example by approving collection of expenses over a period of years to smooth rates or avoid potential rate spikes. The objectives of a regulator and CICA Handbook do not necessarily correspond and thus slavish adherence to CICA Handbook principles may be quite inappropriate in a regulatory setting. In order to avoid a significant change in the timing of collection of the various deferral accounts previously approved by this Board, and avoid the potential for rate spikes, the TGC supports NTPC's request for the PUB confirmation to maintain these funds as previously approved.

14. Necessary Working Capital

a) General

NTPC's lead lag study reflects a reduction in the revenue lag from the 45.08 days approved in the 2001/03 GRA to 36.25 days in the current GRA. Offsetting this reduction is an increase in the net lag days for payment of operating expenses from 31.21 days to 26.86. Hence, the net lag used for lead lag study has decreased from 13.87 days to 9.39 days⁸².

b) Revenue Lag

NTPC states:

For the 2001/03 GRA the revenue lags were based on a sample of bills analyzed for the lead-lag study. For the current GRA, the Corporation has calculated the revenue lags assuming that all bills are paid within the timeframe allowed by the Corporation's terms and conditions of service.⁸³

The TGC submit NTPC's assumption all customers pay on the "maximum allowable time for payment prior to interest charges"⁸⁴ 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.

⁸² X7, Response TGC.NTPC-46 (b), Table 5; X13, May 16, 2007 Update to 2006/08 GRA

⁸³ X7, Response TGC.NTPC-46 (d)

⁸⁴ X7, Response TGC.NTPC-46 (b), Table 6

c) Use of Aggregate Net Lag Days

Rather than calculating the net lag associated with each expense items, NTPC adopts the practice of taking the total lag in revenues (36.25 days), subtracting the total weighted average lag days associated with all expenses (26.86 days), and applies the net lag days (9.39 days) to the year end balances of: Salaries and Wages, Fuel and Lubricants, Supplies and Services and Travel and Accommodation. It states:

The calculation of the cash-working capital requirement in Schedules 5.6 through 5.9 is based on the net-lag days for all revenues and expenses rather (i.e. revenue lag days less expense payment lag days) rather than separately calculating a net lag day figure for each expense type. This is consistent with the methodology used in the 2001 103 General Rate Application and approved by the Board⁸⁵.

The TGC submit NTPC's method does not result in a proper matching of the revenue lag to the expense lag associated with each expense item. It makes the very simplistic assumption that all of NTPC's expenses are paid on average 9.39 days after date of incurrence.

For example, NTPC uses a net lag of 9.39 days for Fuel and Lubricants expense and arrives at a cash working capital amount of \$477,000. In fact, there is a net lead for this expense item of 8.75 days as the lag in payment is 45.0 days and the lag in revenue is 36.25 days. Similarly there is a net lead for Supplies and Services of 8.75 days and for insurance, the net lead is 143 days. The Board should direct NTPC, in its refiling, to provide a computation of its cash working capital for the Test Yeas using the net lead or lag associated with each expense item.

Summary: -

- a) 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. NTPC should be directed to incorporate, in its next GRA, a proper sampling of bill payments from various sources to arrive at the actual number of days it takes on average for customers to pay bills.*

⁸⁵ X7, Response TGC.NTPC-46 (e)

b) NTPC's method of using the net lag of 9.39 days carries with it a simplistic assumption that all of NTPC's expenses are paid on average 9.39 days after date of incurrence. For Fuel and Lubricants, Supplies and Services and Insurance, rather than a net lag, there exists a net lead. 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.

15. Wholesale Sales Contracts

NTPC states it provides power on a wholesale basis to Northland Utilities (YK) Ltd. in Yellowknife and to Northland Utilities (NWT) Ltd. in Hay River and area. In fact, there has never been a wholesale contract with BUK (YK) and the agreement with NUL (NWT) “was signed with the Northern Canada Power Commission in 988 and expired in 1998”⁸⁶.

NTPC states:

The 2001/03 Negotiated Settlement provided that NTPC and its two wholesale customers NUL(NWT) and NUL (YK) would enter into negotiations towards putting in place a long-term supply agreement for each wholesale customer. The Corporation has pursued discussions with each of the wholesale customers. At this time, no long term supply agreements have been entered into⁸⁷.

While NTPC has had discussions with the two wholesale customers, it refuses to provide any details of these discussions:

The discussions between NTPC and NUL(YK) Ltd and NUL(NWT) Ltd were undertaken on a without prejudice confidential basis and therefore NTPC is not able to disclose the nature or specific timing of those discussions. Discussion between the parties has been ongoing since 1998. Over the years a number of in person meetings were held as well as written exchanges of information. The last exchange between the parties regarding purchase power agreements was October 2005.⁸⁸

It is not clear why NTPC cannot enter into suitable long-term contractual agreements with the two wholesale customers. The fact that these discussions or negotiations have been on-going for close to 10 years now suggests neither NTPC nor the wholesale customers are in any hurry to conclude a deal.

The TGC note, for example, while NUL (YK) has a demand rate of \$8.10/KVA for wholesale primary service, there is no corresponding demand charge for NUL (NWT). These are obviously

⁸⁶ X7, Response TGC.NTPC-23 (a)

⁸⁷ X2, NTPC 2006/08 GRA, page 6-59

⁸⁸ X7, Response TGC.NTPC-49 (a)

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.

Summary: -

It is not clear why NTPC cannot enter into suitable long-term contractual agreements with its two wholesale customers. The fact that these discussions or negotiations have been on-going for close to 10 years now suggests neither NTPC nor the wholesale customers are in any hurry to conclude a deal.

The TGC note, for example, while NUL (YK) has a demand rate of \$8.10/KVA for wholesale primary service, there is no corresponding demand charge for NUL (NWT). 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.

**NORTHWEST TERRITORIES POWER CORPORATION
2006-07 and 2007-8 General Tariff Application**

**TCG Argument June 18, 2
Appendix 1**

Sales (MWH) Variance 2001/02, 2002/03 and 2003/04 Actual Vs. FC

Line No.	Plant No.	2001-2002			2002-2003			2003-2004			
		FC	Actual	Variance	FC	Actual	Variance	FC	Actual	Variance	
1	104	Wha Ti	1,572.0	1,427.0	-9.2%	1,713.0	1,478.0	-13.7%	1,713.0	1,446.0	-15.6%
2	105	Gameti	840.0	843.0	0.4%	851.0	889.0	4.5%	851.0	898.0	5.5%
3	110	Lutsel K'e	1,303.0	1,231.0	-5.5%	1,322.0	1,380.0	4.4%	1,322.0	1,417.0	7.2%
4	205	Fort Simpson	7,142.0	6,808.0	-4.7%	7,256.0	7,106.0	-2.1%	7,256.0	7,205.0	-0.7%
5	206	Fort Liard	3,077.0	2,916.0	-5.2%	3,368.0	2,728.0	-19.0%	3,368.0	2,792.0	-17.1%
6	207	Wrigley	745.0	777.0	4.3%	748.0	725.0	-3.1%	748.0	721.0	-3.6%
7	208	Nahanni Butte	352.0	308.0	-12.5%	357.0	314.0	-12.0%	357.0	325.0	-9.0%
8	209	Jean Marie River	218.0	237.0	8.7%	218.0	239.0	9.6%	218.0	258.0	18.3%
9	301	Inuvik	24,167.0	23,454.0	-3.0%	25,409.0	26,238.0	3.3%	25,409.0	27,513.0	8.3%
10	305	Tuktoyaktuk	3,810.0	3,712.0	-2.6%	3,840.0	3,825.0	-0.4%	3,840.0	4,170.0	8.6%
11	306	Fort McPherson	3,193.0	3,344.0	4.7%	3,165.0	3,358.0	6.1%	3,165.0	3,235.0	2.2%
12	307	Aklavik	2,607.0	2,542.0	-2.5%	2,599.0	2,570.0	-1.1%	2,599.0	2,600.0	0.0%
13	308	Deline	2,280.0	2,739.0	20.1%	2,330.0	2,272.0	-2.5%	2,330.0	2,451.0	5.2%
14	309	Fort Good Hope - Summer	2,458.0	2,387.0	-2.9%	2,409.0	2,482.0	3.0%	2,409.0	2,553.0	6.0%
15	310	Tulita	1,780.0	1,740.0	-2.2%	1,838.0	1,773.0	-3.5%	1,838.0	1,794.0	-2.4%
16	311	Paulatuk	847.0	1,100.0	29.9%	839.0	1,190.0	41.8%	839.0	1,183.0	41.0%
17	312	Sachs Harbour	909.0	865.0	-4.8%	926.0	872.0	-5.8%	926.0	877.0	-5.3%
18	313	Tsiigehtchic	672.0	688.0	2.4%	679.0	724.0	6.6%	679.0	774.0	14.0%
19	314	Colville Lake	170.0	245.0	44.1%	170.0	236.0	38.8%	170.0	269.0	58.2%
20	315	Ulukhaktok	1,653.0	1,779.0	7.6%	1,692.0	1,819.0	7.5%	1,692.0	1,829.0	8.1%
		Totals	59,795.0	59,142.0	-1.1%	61,729.0	62,218.0	0.8%	61,729.0	64,310.0	4.2%
		Min			-12.5%			-19.0%			-17.1%
		Max			44.1%			41.8%			58.2%

**NORTHWEST TERRITORIES POWER CORPORATION
2006-07 and 2007-8 General Tariff Application**

**TCG Argument June 18, 2007
Appendix 2**

Sales per Customer (MWH) - Residential

Line No.	Plant No.	2004-05 Actual	2005-06 Actual	2006-07 Forecast	2007-08 Forecast	Increase (Decrease) over Prior Year		
						2005-06 Over 2004-05	2006-07 Over 2005-06	2007-08 Over 2006-07
1	104 Wha Ti	6.71	6.44	6.54	6.46	(0.27)	0.10	(0.08)
2	105 Gameti	5.81	5.53	5.54	5.53	(0.28)	0.01	(0.01)
3	110 Lutsel K'e	6.26	5.65	5.88	5.91	(0.61)	0.23	0.03
4	205 Fort Simpson	5.91	5.64	5.88	5.82	(0.27)	0.24	(0.06)
5	206 Fort Liard	5.92	5.90	6.12	6.07	(0.02)	0.22	(0.05)
6	207 Wrigley	5.33	5.19	5.33	4.96	(0.14)	0.14	(0.37)
7	208 Nahanni Butte	4.09	5.02	4.40	4.39	0.93	(0.62)	(0.01)
8	209 Jean Marie River	5.40	4.77	5.53	5.47	(0.63)	0.76	(0.06)
9	301 Inuvik	6.75	6.62	6.30	6.23	(0.13)	(0.32)	(0.07)
10	304 Normal Wells	7.84	7.61	7.77	7.86	(0.23)	0.16	0.09
11	305 Tuktoyaktuk	6.49	6.18	6.38	6.48	(0.31)	0.20	0.10
12	306 Fort McPherson	5.64	5.66	5.53	5.45	0.02	(0.13)	(0.08)
13	307 Aklavik	5.51	5.53	5.12	5.10	0.02	(0.41)	(0.02)
14	308 Deline	5.66	5.78	5.54	5.47	0.12	(0.24)	(0.07)
15	309 Fort Good Hope	6.36	6.24	6.46	6.49	(0.12)	0.22	0.03
16	310 Tulita	6.34	6.48	6.29	6.33	0.14	(0.19)	0.04
17	311 Paulatuk	6.29	6.01	5.59	5.51	(0.28)	(0.42)	(0.08)
18	312 Sachs Harbour	4.43	4.98	4.99	5.02	0.55	0.01	0.03
19	313 Tsiigehtchic	4.75	4.97	5.19	5.33	0.22	0.22	0.14
20	314 Colville Lake	4.24	4.36	4.05	4.00	0.12	(0.31)	(0.05)
21	315 Ulukhaktok	5.32	5.52	5.19	5.47	0.20	(0.33)	0.28
Average Increase (Decrease) in Sales/Customer						(0.05)	(0.02)	(0.01)

Sales per Customer (MWH) - General Service

1	104 Wha Ti	26.35	23.72	22.24	20.31	(2.63)	(1.48)	(1.93)
2	105 Gameti	19.19	17.07	18.21	17.55	(2.12)	1.14	(0.66)
3	110 Lutsel K'e	18.36	18.80	17.97	17.56	0.44	(0.83)	(0.41)
4	205 Fort Simpson	27.11	26.95	29.14	30.06	(0.16)	2.19	0.92
5	206 Fort Liard	26.14	26.26	25.92	25.31	0.12	(0.34)	(0.61)
6	207 Wrigley	11.68	9.98	11.27	10.34	(1.70)	1.29	(0.93)
7	208 Nahanni Butte	12.16	11.08	10.20	8.77	(1.08)	(0.88)	(1.43)
8	209 Jean Marie River	7.20	6.31	7.15	7.11	(0.89)	0.84	(0.04)
9	301 Inuvik	40.00	39.96	39.90	40.44	(0.04)	(0.06)	0.54
10	304 Normal Wells	34.16	32.74	33.03	34.17	(1.42)	0.29	1.14
11	305 Tuktoyaktuk	19.94	19.80	20.58	20.54	(0.14)	0.78	(0.04)
12	306 Fort McPherson	25.72	25.06	26.32	26.05	(0.66)	1.26	(0.27)
13	307 Aklavik	17.62	17.33	16.08	15.92	(0.29)	(1.25)	(0.16)
14	308 Deline	21.58	21.82	21.72	22.13	0.24	(0.10)	0.41
15	309 Fort Good Hope	25.43	25.77	25.59	26.04	0.34	(0.18)	0.45
16	310 Tulita	14.81	13.48	13.76	13.54	(1.33)	0.28	(0.22)
17	311 Paulatuk	18.88	18.73	17.55	18.17	(0.15)	(1.18)	0.62
18	312 Sachs Harbour	24.96	22.16	22.48	21.15	(2.80)	0.32	(1.33)
19	313 Tsiigehtchic	14.42	13.32	13.22	13.64	(1.10)	(0.10)	0.42
20	314 Colville Lake	9.94	11.76	12.65	13.41	1.82	0.89	0.76
21	315 Ulukhaktok	19.06	19.36	18.69	19.47	0.30	(0.67)	0.78
Average Increase (Decrease) in Sales/Customer						(0.63)	0.11	(0.09)

Source: X13, 2006-08 GRA, Schedule A (updated May 16, 2007, and as per Response TGC.NTPC-26 (h))