

**NORTHWEST TERRITORIES POWER CORPORATION
2006/2007/2008 GENERAL RATE APPLICATION – PHASE I REFILING**

**ARGUMENT OF THE CITY OF YELLOWKNIFE, THE TOWN OF HAY RIVER
AND THE TOWN OF FORT SMITH (“HYDRO COMMUNITIES”)**

October 23, 2007

BROWNLEE LLP
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INTRODUCTION

This Argument is submitted on behalf of the City of Yellowknife, the Town of Hay River and the Town of Fort Smith (“the Hydro Communities” or “HC”). The interests of each of these communities are generally aligned. The Northwest Territories Power Corporation (“NTPC”) filed its 2006/2007/2008 Phase I General Rate Application Refiling with the Northwest Territories Public Utilities Board (“the Board”) on October 1 and 5, 2007. The Hydro Communities consider that the refiling does not fully meet the Board’s Directions in a number of instances as discussed in the following sections. The HC will only address those concerns which they raised in Argument under the applicable Board Directive as provided in the refiling.

Directives 5 and 6

The Board directed NTPC, in its Phase I refiling, to use a 6% sinking fund return for each of the test years for purposes of calculating the effective cost of long-term debt. The Board’s formula to calculate the long-term effective cost of debt was set out at page 26 of Decision 13-2007. NTPC provided details of the long-term debt calculation in HC.NTPC-1b).

It is not clear how NTPC calculated the Sinking Fund Earnings in the test years based on long term average return of 6% (SFE). However, the HC submit that to be consistent with the use of mid-year balances for long term debt and sinking fund balances, not to mention rate base, SFE should be calculated by applying the 6% average return to the mid-year balance of sinking funds. The HC have recalculated the SFE for the years 2006/07 and 2007/08 using the 6% average return and the mid-year balance of sinking funds (line 11) with the result that the SFE on line 12, Schedule 3.7 Revised should be (2,430) in 2006/07 and (2,764) in 2007/08. This results in an effective cost of long term debt of 9.50% and 9.74% in 2006/07 and 2007/08 respectively with corresponding reductions to the return on mid-year rate base of \$205,000 and \$234,000.

Directive 12

At page 86 of Decision 13-2007, the Board directed NTPC, in its Phase1 refiling, to provide complete and accurate analyses of the costs and benefits of the AMR projects that incorporate the reasons for and the effects of the redeployment of the linemen. These analyses are to be provided both from the perspective of the individual communities and NTPC.

Based on the evidence adduced during the hearing process, it appeared that there would be a \$206,000 capital addition at Fort Smith in 2006/07 but no operating cost reductions due to the redeployment of linemen from meter reading to “more meaningful and productive work.” However, in the Response to Directive 12, NTPC clarified that the GRA budgets meter reading time and other distribution function time to Fort Smith and Fort Simpson largely as “area” or office time and that this time will be allocated to all of the various communities and regions as part of the Phase II Cost-of-Service analysis that has not yet been completed. With this clarification, the economic analysis, and specifically the reduction in meter reading time due to redeployment of linemen, appears more reasonable.

However, to ensure that the meter reading savings in Fort Smith are in fact realized by the customers in Fort Smith, the HC submit that the Board should direct NTPC to specifically demonstrate the redeployment of linemen budgeted in Fort Smith to all communities in their Phase II filing.

Directives 15 and 45

The Board directed NTPC to propose a procedure to return \$345,000 to ratepayers over a 3 year period. NTPC has indicated that it intends to file for review and variance of Directives 15 and 45. The HC consider that ratepayers paid \$345,000 for brushing services that they did not receive from 2001/02 through 2005/06 and that forecast test year expenditures should be reduced accordingly. The HC reserve their right to respond

to NTPC's application for review and variance, if and when it is filed. However, the HC consider that the revenue requirements should be reduced at this time to reflect the \$345,000 which was over-collected pending the review and variance application.

Directive 18

At page 123 of Decision 13-2007, the Board directed NTPC, in its Phase I refiling, to file a written policy with regards to the criteria that are used to determine the eligibility of expenditures for deferral account treatment. HC.NTPC-4 sought further details as to the level of deferred costs that was considered significant from a rate impact point of view and examples of such deferred costs. The HC are concerned that NTPC may include deferred items having an impact as little as \$10,000 for treatment as deferred costs. The extent of the list of examples is also concerning.

The ultimate inclusion of the examples provided by NTPC in future GRA's will clearly result in a reduction to NTPC's risk. The HC consider that each of the deferred costs should be brought forward for review and approval at the next GRA along with a detailed explanation as to why some or all of such costs should not have been included in operating and maintenance expenses in the years incurred.

Directive 19

At page 134 of Decision 13-2007, the Board considered that NTPC should consider historical normalized average use for residential and general service customers by community averaged over the most recent four years if there are out of cycle metering issues. The Board directed NTPC, as part of its Phase 1 refiling, to adjust the test year sales forecasts by community having regard to historical normalized average use per customer and to provide the consequential impacts on sales forecasts and fuel costs.

Although NTPC "considered" historical average use per customer among other methods, it did not make any adjustments to its sales forecast. NTPC asserted that any adjustments

to bring the three communities within the 8 percent tolerance for residential would be small. With respect to general service customers, NTPC stated that “there is enough uncertainty with respect to the relevance of an average use per customer that such an approach cannot be considered to be meaningful.” Having said that, NTPC then goes on to state in BR.NTPC-5d), that Manitoba Hydro uses a forecasting method for residential customers based on average use per customer and an individual review of the top general service customers and regression for all other general services customers. It should be noted that ATCO Electric (page 13-2 and 13-3 of its 2003-2005 GRA) states that number of customers and average use per customer are the key inputs for residential, commercial, REA and company farm forecasts. ATCO Electric then does a regression analysis that includes per capita real GDP, Heating Degree Days, past energy consumption and time to determine the forecast use per customer which is multiplied by the number of customers.

NTPC has clearly not complied with the Board’s Directive 19 nor has it justified its forecast methodology. .

In BR.NTPC-4a), NTPC acknowledged that it does not have a method for normalizing sales due to weather and it provided a simple 4-year average use per customer. In response to BR.NTPC-4a), NTPC provided the four year average for residential and general service customers for the years 2002/03 to 2005/06 inclusive, albeit it revised its 2002/03 customer counts by undefined amounts. This is a different 4-year period than utilized by the HC in Argument because, as noted by the HC, 2005/06 was some 15% milder than the 30 year average Heating Degree Days (HDD). The four years utilized by the HC were within 0.4% of the 30 year average HDD’s.

In HC.NTPC-5b) & c), NTPC is critical of the HC’s use of the 30 year average reported by Environment Canada because it does not include data up to 2005/06. The HC would simply respond that that was the readily available information published by Environment Canada as indicative of the 30-year long term average HDD. NTPC provided the 10 and 20 year averages for three communities and concludes that there has been a warming trend. Various methods that purport to give greater effect to trends and more recent years

(i.e. the 0.3 Exponential Method by Northwestern Utilities) have been rejected by the Alberta Energy and Utilities Board and the 20 year average of HDD was been settled upon (page 7.0.1, ATCO Gas 2005-2007 GRA and Page 24, AltaGas Utilities 2005-2006 GRA). The HC consider that the use of the 20-year HDD would be an acceptable proxy for normal weather. The 4 year average of HDD is close to this average in each of the three communities noted in HC.NTPC-5.

In BR.NTPC-4b), NTPC provided a comparison of the test year sales forecast based on a 4-year simple average compared to a 4-year weighted average. The weighted average placed a weighting of 4 on 2005/06, 3 on 2004/05, 2 on 2003/04 and 1 on 2002/03. The HC see logical reason to weight the average use per year but would observe that 2005/06 was 15% milder than the 30 year average HDD. The HC submit that the 4 year weighted average should thus be rejected outright.

NTPC concludes at page 4 of BR.NTPC-4 that there would be little impact on the overall revenue requirement and resulting rates if either 4-year average were adopted. The HC must stress that it would be highly inappropriate to judge the methodologies based on the overall impact on revenue requirements. In Fort Smith alone, the variance in residential sales between the application and the simple 4-year average sales per residential customer are 8.5% and 8.4% in the test years. The impacts on general service are smaller. Given the fixed nature of costs on the Taltson hydro system, this would make a significant difference on residential customer rates, and even greater if 2005/06 was excluded from the 4-year average for the reasons noted above and in the HC Argument.

At page 3 of BR.NTPC-4, NTPC says it remains open to testing and evaluating different load forecasting methods following this GRA. What it does not say is that that would amount to Board acceptance of their method in this proceeding which incorporates 2005/06 which was 15% below normal HDD in Fort Smith as the base for the test years. That method cannot be viewed as reasonable by any standard and should be rejected by the Board, at least insofar as Fort Smith and the Yellowknife system residential sales forecasts are concerned.

In summary, the HC submit that the use of the most recent 4-years average use should be utilized to forecast residential sales in Fort Smith, Fort Resolution, Behchoko and Dettah. The average use over this 4-year period is similar to the method used by ATCO Electric in Alberta and the use of the 20-year average HDD used by Alberta Gas utilities for normalizing gas sales. Although it has a much lesser impact on general service sales, the same method should be used for general service sales forecasts based on experience in Alberta and to some extent in Manitoba.

Directive 21

At page 141 of Decision 13-2007, the Board stated:

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

The Board notes that costs associated with the hydro plant or transmission outages are generally considered part of the utility's risk. Including such costs and associated risks in the water stabilization fund could potentially weaken the utility's incentive to efficiently manage its generation and transmission outages. The Board therefore agrees with the HC that it would be appropriate to not include the diesel costs associated with generation and transmission outages in the water stabilization account.”

The Board directed NTPC to propose in its refiling, a cost effective approach to excluding the costs and risks associated with generation and transmission outages from the water stabilization account.

NTPC used the approved Forced Outage Rates (FOR's) for hydro and transmission lines to estimate the forecast diesel generation required for forced outages in the test years in Table 1. When asked by the Board in BR.NTPC-6a) to provide the supporting hydro outage calculations by unit, NTPC indicated that it did not prepare its hydro forecast by unit and thus could not provide that information. The HC consider that examining the outage calculations by individual unit is a prerequisite to approving any method based on the utilization of FOR's. Therefore, the HC submit that the Board should not approve the "simplest method" proposed by NTPC without that information.

In BR.NTPC-6b), NTPC confirmed that a hydro unit outage does not necessarily result in the need for additional diesel generation but did assert that the loss of a unit could result in diesel generation of \$40,000 per day depending on load, water availability, availability of other hydro units, and how quickly these units could be returned to service. NTPC did not provide any empirical support for the \$40,000, whether or not it was included in the diesel generation calculation for forced outages nor any statistical data as to the probability of such an event occurring. In BR.NTPC-6b), NTPC acknowledged that it has not undertaken any analysis to support a probabilistic estimate of the percentage of time when diesel generation is required to replace hydro due to forced outages. Based on this evidence, the HC again submit that NTPC has not demonstrated that the use of the FOR's times the forecast hydro generation is an appropriate method particularly when other hydro units may be available to offset hydro unit outages. Even NTPC characterizes this method as the "simplest method" in the response to Directive 21.

In BR.NTPC-6c), NTPC provided estimates of diesel generation over the last three years as a result of various outages. Although a three year comparison is too short to draw any meaningful conclusions, the proposed forecast diesel fuel requirements as estimated in Directive 21 resulting from forced outages of hydro and transmission exceed the charges

that would have been made over the last three years by a factor of four. The HC submit this is another reason that the FOR method should not be approved absent further details and full and complete testing.

In HC.NTPC-6g), NTPC indicates that Directive 21 did not specifically direct the Corporation to include normal generation dispatch, including exercising and peaking requirements in the revenue requirements. This appears to contradict the Board's statement at page 141 of Decision 13-2007 that "there does not appear to be a valid reason to insulate NTPC from risks associated with incidents that are not directly related to the availability of the hydro resource."

Although the Hydro Communities continue to believe that NTPC should not be insulated from the risks associated with incidents not directly related to the availability of the hydro resource which it believes was the original intent of the Snare Water Stabilization Fund, they are extremely concerned with the validity of the "simplest method" of estimating the fuel costs required to mitigate the risk of hydro and transmission outages. New and unsupported evidence has been entered during the refiling process without adequate opportunity for full and complete testing.

Under these circumstances and in the absence of a fully tested method of estimating the fuel required to mitigate hydro and transmission outages, the Hydro Communities submit that, in an abundance of caution, that it would be prudent to defer final resolution of the treatment of the Snare Water Stabilization Fund until the next GRA. The Hydro Communities submit that NTPC be directed to address the issues that arose during the application and refiling process in their next GRA filing and that the Snare Water Stabilization Fund be approved as originally filed in the GRA for purposes of this application.

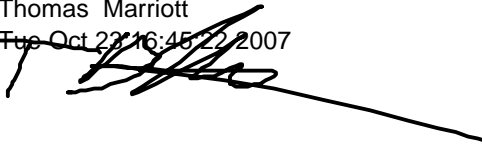
All of which is respectfully submitted this 23rd day of October, 2007

Brownlee Fryett LLP, Counsel to the Hydro Communities

Per:

Thomas Marriott

~~Tue Oct 23 16:45:22 2007~~

A handwritten signature in black ink, appearing to read 'T. Marriott', is written over the date stamp. A long horizontal line extends from the end of the signature across the page.
