THE PUBLIC UTILITIES BOARD

OF THE

NORTHWEST TERRITORIES

DECISION 17-2007 **November 8, 2007**

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

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

THE PUBLIC UTILITIES BOARD

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1. BACKGROUND and APPLICATION

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

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

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

By letter dated October 1, 2007, NTPC filed a response to Board Decision 13-2007.

By letter dated October 2, 2007, the Board established a written process for examination on the matters raised by NTPC in its October 1, 2007 Refiling.

The Board, the Hydro Communities ("**HC**") and the Thermal Generation Communities ("**TGC**"), by letters dated October 9, 2007, provided NTPC with information requests.

By letters dated October 16, 2007 and October 18, 2007, NTPC provided responses to all information requests.

As per Board's schedule, NTPC, HC and TGC, by letters dated October 23, 2007, submitted their argument.

NTPC and HC, by letters dated October 30, 2007, submitted their reply argument.

TGC, by letter dated October 31, 2007, submitted their reply argument.

2. EXAMINATION OF THE APPLICATION

The Board's considerations of the issues that arose during examination of the Phase 1 Refiling are discussed below.

Directive 1 Fort McPherson

The Board directed NTPC, in its Phase 1 refiling, to reduce the opening plant balance for 2006/07 by $193,000 being that portion of the rate base addition for the Fort McPherson plant that has not been explained nor demonstrated to be a prudent expenditure by NTPC.

NTPC indicated the $193,000 relates to insurance deductible on the Fort McPherson plant rebuild and should properly be included as a charge against the reserve for self insurance rather than capitalized as reflected in the application. NTPC reflected this correction together with any resulting adjustment to depreciation expense in the Phase I refiling.

The Board accepts NTPC's refiling as filed.

Directive 2 Aklavik Modular Power Plant

The Board directed NTPC, in its Phase 1 refiling, to reduce the cost of the Aklavik plant addition by 50% of the cost increase resulting from the delays. The costs to be included for the 50% risk sharing adjustment are overheads and Allowance for Funds Used During Construction ("**AFUDC**") resulting solely from

the delays in completion of the plant caused by the unforeseen length of time spent on community consultations and the fire at Fort McPherson.

NTPC calculated the 50% risk sharing adjustment for overheads and AFUDC related to the construction delays by comparing the overheads and AFUDC between the estimated original project budget - $3.5 million estimated project cost ($4.3 million with overheads and AFUDC) and the estimated revised budget submitted in the Phase 1 GRA - $4.4 million estimated project cost ($5.3 million with overheads and AFUDC). The following table sets out the AFUDC included in project costs at the time the original budget was prepared, at the time of the project permit application and at the time of the Phase 1 application:

	Original Budget	Budget at Time of Project Permit Application	Budget at Time of Project Permit Application - Corrected	Phase I Forecast
	$ Million	$ Million	$ Million	$ Million
Project costs excluding AFUDC & Overhe	3.463	4.385	4.385	4.420
AFUDC & Overhead	0.823	0.515	0.713	0.878
Total	4.286	4.900	5.098	5.298

Source TGC NTPC 1, Schedule C-4

TGC submitted the 50% risk sharing adjustment should be calculated as being the difference between the AFUDC and Overhead amounts approved as part of the project permit application in Decision 11-2006 (of $0.515 million) and the amount for overhead and AFUDC proposed for inclusion in rate base.

The Board notes the intent of the AFUDC and overhead sharing adjustment was to share the additional costs caused by delay resulting from the unforeseen length of time spent on community consultations and the fire at Fort McPherson.

The Board considers the adjustment to capital costs proposed by NTPC to be reasonable and appropriate. Accordingly, the Board accepts NTPC's calculation of the capital cost adjustments associated with the Aklavik modular plant.

Directives 5 and 6 Sinking Fund Earnings and Effective Cost of Long Term Debt

The Board directed NTPC, in its Phase 1 refiling, to use a 6% sinking fund return for each of the test years for purposes of calculating the effective cost of long-term debt. The Board also provided specific directions with respect to the calculation of the effective cost of long-term debt.

NTPC provided the calculation of the effective cost of debt rates for the two test years including the 6% return on sinking fund investments in response to HC NTPC-1.

NTPC stated it remains unclear as to the exact intent of the Board's Directive and requested the Board's clarification as to whether the 6% rate is meant only to apply to funds in non-immunized portfolios (with immunized portions of the portfolio reflecting the fixed returns known to be achieved by investments of these characteristics during the test years). NTPC submitted the difference is material to the final revenue requirement (approximately $400,000) and merits clarification from the Board.

NTPC submitted that while the Board's determination of a 6% return is based on actual returns realized in recent years, those returns were earned in years when the average time to maturity of the underlying investments was still in a range such that a broader range of investments for the entire portfolio was prudent (the

2003 to 2006 actual returns cited by the Board were during a period averaging 7 years or more to maturity for the underlying funds – far above the present situation) and during a period when NTPC had no funds immunized.

The HC indicated it is not clear how NTPC calculated sinking fund earnings in the test years. The HC submitted sinking fund earnings should be calculated by applying the 6% average return to the mid-year balance of sinking funds; if this method were used HC estimated the effective cost of long term debt will be 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.

In its Reply Argument, NTPC noted that Directive Nos. 5 and 6 did not require that the Corporation calculate the 6% sinking fund return on the simple mid-year average balance. Consequently, the Corporation applied the daily weighted average balance methodology consistent with the Application. Notwithstanding this, the Corporation agreed that sinking fund earnings could be calculated based on a mid-year balance.

In Decision 13-2007, the Board considered it appropriate to set the sinking fund returns so as to avoid windfall gains or, losses in any given year:

> "Further the Board considers basing the sinking fund return on a long term average sinking fund return would avoid potential windfall gains or losses to the Corporation which could be the case if the sinking fund returns were based on specific test year forecasts. Accordingly, for the purposes of these proceedings, the Board directs NTPC to use a 6% sinking fund return for each of the test years for purposes of calculating the effective cost of long-term debt."

The Board notes its estimate of normalized sinking fund return takes into account those years in which a component of sinking fund investments would be subject

to immunization; these are years 2007 and 2008 as set out at page 24 of Decision 13-2007. Accordingly, in the Board's view the normalized sinking fund return of 6% estimated by the Board reflects an average, which factors the returns during immunization as well as the non-immunization periods. Accordingly, the Board confirms the 6% normalized return for sinking fund earnings determined by the Board is properly applicable to the entire sinking fund portfolio balances in the two test years.

The Board agrees that the sinking fund balance should be calculated on a mid year basis consistent with the mid year debt and debt interest calculations. The Board notes from the response to HC.NTPC-1 that NTPC failed to use the mid year convention for calculating the debt interest on the 6.42% coupon, $20 Million debt. The Board considers the debt interest for all long-term debt instruments should be calculated on a mid year basis. The Board's calculation of the effective cost of long term debt reflecting the mid year method for calculating sinking fund balance and sinking fund earnings as well as the mid year method for calculating interest on the 6.42% debt is shown below:

	Effective Cost of Long Term Debt				
	Long Term Debt Balance Mar 31 2006	Long Term Debt Balance Mar 31 2007	Long Term Debt Balance Mar 31 2008	Mid Year Balance 06/07	Mid Year Balance 07/08
11.000%	20000	20000	20000	20000	20000
11.125%	15000	15000	15000	15000	15000
10.750%	20000	20000	20000	20000	20000
8.410%	8700	8700	8700	8700	8700
6.330%	10000	10000	10000	10000	10000
6.420%	18000	17333	16667	17667	17000
5.955%	25000	25000	25000	25000	25000
5.000%	15000	15000	15000	15000	15000
Total Mid Year Debt				131367	130700
Sinking Fund Opening Balance Per NTPC Reply P4				37804	43068
Add 1/2 Contributions in the year Per NTPC Reply P4				1522	1522
Add 1/2 Sinking Fund Earnings in the year				1110	1266
Mid Year Sinking Fund Balance				40436	45856
Mid Year Debt net of Sinking Fund				90931	84844
Interest on Mid Year Debt				10756	10714
Sinking Fund Earnings as per NTPC Reply P4				-2220	-2532
Amortization of Finance Costs				120	126
				8656	8307
Effective Cost of Long Term Debt				9.520%	9.791%

NTPC is directed to reflect the effective cost of debt rates of 9.520% in 2006/07 and 9.791% in 2007/08, for purposes of its second refiling application.

Directives 10 and 11 Station Service

In Directive 10 the Board directed NTPC, in its Phase 1 refiling, to calculate forecast station service using the same procedure used for fuel efficiencies. Forecast station service is to be calculated using 3 years of actual data with a weighting of “3” given to the lowest station service year, a weighting of “2” given to the middle station service year and a weighting of “1” given to the highest station service year.

In Directive 11 the Board directed NTPC, in its Phase 1 refiling, to apply a 5% cap on station service as a percentage of generation.

The Corporation indicated it has reflected this change in its refiling Schedules – Schedules 2.1 through 2.3 and Appendix A. NTPC indicated 2006/07 forecasts reflect the weighted average station service results from 2003/04; 2004/05 and 2005/06. The 2007/08 station service forecasts reflect the weighted average station service results from 2004/05; 2005/06 and the forecast station service for 2006/07.

NTPC noted, for Fort Resolution, Norman Wells and Fort McPherson, where the existing plants have less than three years of actual operating experience, the Corporation has relied only on the operating experience with the existing plants, consistent with the Board's approval for the calculation of the fuel efficiencies in those communities in Decision 13-2007.

TGC noted that while NTPC filed revised station service losses in its refiling, it did not provide detailed computations to support the 3:2:1 weighting method described above.

NTPC indicated it will file a table showing the calculation of the weighting factors by community with its final Phase 1 schedules. NTPC is directed to provide a schedule showing the calculation of station service using the weighting method for station service directed by the Board in Directive 10 of Decision 13-2007, as part of the second refiling.

Directive 12 Costs and Benefits of Automatic Meter Reading ("AMR")

The Board directed NTPC, in its Phase 1 refiling, to provide complete and accurate analyses of the costs and benefits of the AMR projects that incorporate the reasons for and the effects of the redeployment of the linemen. These analyses are to be provided both from the perspective of the individual communities and NTPC.

In response to this directive, NTPC provided further details of cost savings from AMR by community. NTPC stated from the perspective of the individual communities, the communities that received AMR units are receiving the enhanced service benefits, as well as the cost savings. Other communities (those that did not receive AMR units to date) including smaller communities also benefit from the enhanced service quality made possible by freeing up and redeployment of line workers for other tasks such as expediting new service extensions.

NTPC stated the benefits of AMR relate to being able to better balance the workloads and allocation of line workers to priority tasks.

NTPC noted that the GRA does not directly budget any staff time to Norman Wells for meter reading and budgets meter reading time (and other distribution function time) to Fort Smith and Fort Simpson largely as "area" or major NTPC offices - this time will be allocated to all of the various communities and regions as part of the Phase 2 Cost-of-Service analysis that has not yet been completed.

The HC submitted to ensure that the meter reading savings in Fort Smith are in fact realized by the customers in Fort Smith, the Board should direct NTPC to

specifically demonstrate the redeployment of linemen budgeted in Fort Smith to all communities in their Phase 2 filing.

The Board directs NTPC to demonstrate how the benefits of AMR are reflected in the cost of service by community, as part of the Phase 2 application.

Directive 15 Refund of Amounts Collected for Brushing

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

NTPC stated the Corporation will be filing a review and variance application respecting Directives 15 and 45 and as such, no adjustments respecting these Directives are currently reflected in the refiling.

The HC submitted it reserves the right to respond to NTPC's application for review and variance, if and when it is filed. However, the HC considered 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.

The Board considers irrespective of any pending Review and Variance applications, the refund ordered by the Board ought to take effect in accordance with the Board's directions. Accordingly, NTPC is directed to reflect the brushing refund in the calculation of any riders for recovery/refund of revenue

deficiency/excess as a result of delay in implementation of final rates in its second refiling application.

Directive 17 Reserve for Site Restoration

The Board directed NTPC, in its Phase 1 refiling, to provide an assessment of the significant and growing gap between the accumulated balance in the reserve for site restoration and the estimated site restoration costs in light of the Board's discussion of the issue and propose a cap to the accumulated reserve balance until such time as studies on the adequacy of the current balance can be completed.

NTPC submitted that the Board may have incorrectly concluded there is "significant and growing gap between the accumulated balance in the reserve for site restoration and the estimated site restoration costs" based on a comparison of the FRSR reserve 2004/05 fiscal year end balance of $37.154 million versus $12.9 million for diesel plant site restoration costs plus $12.959 million (2005 dollars) for diesel site soil decontamination costs.

NTPC stated the Future Removal liability applies not only for diesel plants but also for hydro facilities, transmission lines, distribution lines and the general asset category. The costs summarized in Board Decision 13-2007 of $12.9 million for "diesel plant site restoration, excluding soil remediation costs" plus $12.959 million in 2005 dollars as "the estimated cost of soil decontamination" from the Biogenie study only address assets in FERC categories 341, 342 and 343. These categories comprise only three of the six diesel related FERC categories, out of a total 45 FERC categories for depreciable plant.

NTPC noted the total future requirement for diesel is at least approaching $26 million compared to only the $12.156 million set aside, resulting in a shortfall of over $13 million in the FRSR reserve attributable to diesel plants alone.

The Board notes NTPC's evidence that the requirement for future removal and site restoration for diesel plants may exceed the reserve by a substantial amount. Accordingly, the Board will not require NTPC to cap the accumulated reserve balance as per Directive 17, for purposes of this Decision.

Directive 18 Policy on Deferred Expenditures

The Board directed NTPC, in its Phase 1 refiling, to file a written policy with regards to the criteria that are to be used to determine the eligibility of expenditures for deferral account treatment.

NTPC noted the following differences between deferral accounts and deferred costs.

NTPC stated the purpose of deferral accounts is to protect the Customer and the Corporation from the impact of hard to predict or costs that occur sporadically and to smooth out rates related to costs for a particular expenditure incurred on an annual basis but where the amount of the expenditures may fluctuate significantly from one year to the next. The establishment of deferral accounts and deferral account mechanism must be approved by the Board before implementation. NTPC stated examples of deferral accounts currently in place include the overhaul deferral account, the Board regulatory costs deferral account, and the reserve for injuries and damages account.

NTPC submitted deferred costs are costs incurred for intangible assets, generally incurred over a short period of time, that create a long-term or enduring benefit to Customers. They are similar to fixed costs with the exception of their intangible nature. NTPC stated that examples of deferred costs put in place in the past include debt financing costs, depreciation studies, and the job evaluation study. NTPC stated appropriate deferred costs should meet the following tests:

1. there is a benefit to the Customer of more than one year
2. the expenditure is not covered in the Corporation's current revenue requirement

NTPC stated deferred costs will be amortized over a 5-year period or a more applicable term if one can be demonstrated by applying a matching test of benefit duration to amortization period.

NTPC stated qualifying deferred costs will be presented as regulatory assets on the Corporation's balance sheet.

HC indicated it sought further details as to the level of deferred costs that are considered significant from a rate impact point of view and examples of such deferred costs, in HC.NTPC-4. HC expressed concern that NTPC may include deferred items having an impact as little as $10,000 for treatment as deferred costs. HC was also concerned by the extent of the list of examples for deferred cost treatment. In this regard NTPC indicated the following items may be subject to deferred cost treatment in addition to those identified in the refiling:

> "In addition to the examples provided in the re-filing, other expenditures that could be treated as deferred costs include franchise renewal costs, load forecast remodeling, alternative energy funding studies, weather normalization models, investigation of station service and investigations of line losses." [HC.NTPC-4b)]

The HC submitted 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.

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

Directive 19 Sales Forecast

The Board directed NTPC, in its Phase 1 refiling, to adjust the test year sales forecasts by community having regard to historical normalized average use per Customer and any other relevant factors considered in the top down and bottom up approaches. NTPC was also directed to reflect in the refiling any consequential impacts of any changes in sales forecasts on fuel costs and any other second order impacts.

NTPC indicated it does not have a method for normalizing sales due to weather (i.e. temperature, precipitation, etc) from actual years to correct for variations due to weather and could not develop one in the short time period available for the re-

filing. However the Corporation agreed with the Board that average use per Customer can be a helpful test of reasonableness for Residential sales forecasts. NTPC undertook a comparison of the most recent 4-year simple average use per Customer by community for Residential Customers. NTPC noted that on a Community-by-Community basis, only three communities in each test year had variance between the two methods of more than plus or minus 8 percent.

With respect to General Service Customers, the Corporation noted that based on a preliminary review of this issue, it would expect that the average use per Customer method would be much less appropriate for General Service Customers than for residential customers for the following reasons:

- Residential customers tend to be more homogeneous than general service customers. There is a smaller range of consumption levels for residential customers than general service customers.
- There tend to be more residential customers in a community than general service customers; therefore changes in the load patterns of one general Service customer will have a much greater impact on the class average.

NTPC submitted that for the current proceeding, given that the average use per customer method was first proposed by the HC in its argument, and the short time period available to the Corporation to prepare its Phase 1 re-filing, it cannot recommend that the average use per customer method be adopted as the prime forecasting method for Residential and General Service customers in the 2006/08 Phase 1 General Rate Application. As a cross check on the methods applied by the Corporation, this approach may be suitable. Using this approach as a cross check, the analysis indicates that the Corporation's 2006/07 and 2007/08 sales forecasts are reasonable and should be approved. [BR.NTPC-4b)]

NTPC noted the Corporation remains open to testing and evaluating different load forecasting methods following this GRA, such as the average use per

customer method that may be simpler to apply and understand. NTPC stated it will undertake to review the average use per customer method for both Residential and General Service customers as a load forecasting method for its next Phase 1 General Rate Application if directed by the Board. [BR.NTPC-4b)]

HC submitted that 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 Heating Degree Day Deficiencies ("**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. [HC Argument, p.8]

HC also submitted the use of the 20-year HDD would be an acceptable proxy for normal weather. HC stated the 4-year average of HDD is close to this average in each of the three communities noted in HC.NTPC-5. [HC Argument, p.7]

TGC submitted the simple average of 4 years, or the weighted 4-year average assessment undertaken by NTPC, is suitable to use as a cross check on the results provided in the Refiling. However, TGC considered, given the limited number of years of data and the fact NTPC has not been able to develop a method for normalizing sales to correct for variations in weather, the average use per customer method may not be appropriate for purposes of this GRA. [TGC Argument, p.11-12]

TGC submitted NTPC should be directed to provide at its next GRA, a proper method which uses a longer period (at least 10 years of data), for developing a weather normalization method and determination of average use per customer.

TGC submitted NTPC should also ensure its current method of customer count is applied to the years prior to 2002/03 so that there is consistency in the method of developing customer counts. [TGC Argument, p.12]

The Board notes NTPC's view that average use per customer can be a helpful test of reasonableness for residential sales forecasts. However, the Board is not persuaded that average use should be used only as a test and that no weight should be given to this method in arriving at the residential sales forecast for the test years. The Board considers the four-year average use per customer reflects the effect of averaging weather related changes in usage over four years and therefore the average use can be considered a form of normalized usage per customer for purposes of these proceedings. The Board notes NTPC's top down and bottom up methods used for sales forecasting give recognition to recent historical sales and the corporations' expectations of growth for the test years but do not explicitly consider the effect of weather on historical sales. On balance, the Board considers the residential sales forecast for the test years should be established giving 50% weight to the Corporation's original sales forecast and 50% weight to the residential sales forecast by community using the four-year simple average consumption per customer method. NTPC is directed to give 50:50 weighting to the Corporation's original sales forecast by community and the residential sales forecast by community using the four-year simple average consumption per customer method, in its second refiling application.

With regard to the general service sales forecast the Board notes the Corporation's concern that a forecast using four year average use per customer may not provide reliable results because of less homogeneity in customer sizes and load patterns within the general service class compared with the residential class and the relatively small number of general service customers in certain

communities. Accordingly, the Board will accept the Corporation's general service sales forecast for purposes of these proceedings.

In Decision 13-2007 the Board directed NTPC as follows in Directive 40:

> "The Board directs NTPC in its next Phase 1 GRA, to consider, among other forecasting techniques, the use normalized average use per customer."

In view of the evidence considered in the Phase 1 refiling application, the following, more complete, directive will replace Directive 40 from Decision 13-2007.

At the time of the next GRA, NTPC is directed to:

- prepare its residential sales forecast having regard to, among other relevant factors, the economic drivers for residential customer growth and historical temperature normalized average use per customer, by community;
- prepare its general service sales forecast having regard to, among other relevant factors, the economic drivers for general service customer growth and historical temperature normalized sales, by community;
- provide evidence on the appropriate number of historical years to be used in calculating the normalized heating and cooling degree days as applicable;
- provide evidence on the appropriate number of years of historical data to be considered in determining the normalized sales used for forecasting purposes

Directive 21 Risks to be Included in the Water Stabilization Fund

The Board directed NTPC, in its Phase 1 refiling, to propose a cost effective approach to excluding the costs and risks associated with generation and transmission outages from the Snare-Yellowknife water stabilization fund, having

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

In response to this direction, NTPC calculated the forecast additional diesel generation resulting from hydro plant and transmission forced outages, based on the composite forced outage rates ("**FOR**") for all hydro plants and the transmission lines and included the corresponding costs in revenue requirement. NTPC stated this is the simplest method the Corporation could develop in the time available that would be suitable to apply and test in future General Rate Applications.

NTPC proposed the diesel fuel costs related to peaking and exercising diesel units would continue to flow through the Snare water stabilization fund. The calculation of the diesel fuel costs associated forced outages and the diesel fuel costs associated with peaking and exercising are shown in Table 2 HC.NTPC-2. NTPC proposed that diesel generation expenses during outages related to hydro and transmission capital projects would be capitalized as part of project costs on an individual project-by-project basis, as opposed to being applied to the Water Stabilization Fund.

The HC submitted the calculation of forced outage rates by individual unit is a prerequisite to approving any method based on the utilization of FOR's. HC submitted NTPC on the other hand had used a composite forced outage rate applicable to all hydro plants. HC also noted NTPC 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 these observations, HC submitted that NTPC has not demonstrated that the use of the FOR's times the forecast hydro generation is an appropriate method for estimating the generation related to forced outage.

The HC submitted although it continued 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, HC was extremely concerned with the validity of the "simplest method" of estimating the fuel costs required to mitigate the risk of hydro and transmission outages. HC submitted 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 HC submitted 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 HC submitted 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.

The Corporation acknowledged it does not have an hourly dispatch model that could be used to assess outage events throughout the year and isolate corresponding diesel generation requirements or provide a probabilistic estimate of the percentage of time when diesel generation is required to replace hydro generation when a hydro unit experiences a forces outage. NTPC stated development of such a model would be extremely costly and have limited benefits given the complexity of the Snare-Yellowknife system and range of variables, which system operators must account for when dispatching generation.

The Board considers the forecast diesel generation associated with hydro plant and transmission forced outages is best determined using an hourly dispatch model which can simulate on a probabilistic basis the diesel generation related to such forced outages. The Board notes NTPC presently does not have the capability to carry out this analysis. The NTPC proposed additional diesel costs, calculated on the basis of one composite forced outage rate for all hydro units, assumes that a diesel unit is dispatched every time a hydro unit is forced out. However this does not reflect the reality that a hydro unit could be dispatched when another hydro unit is forced out of service. NTPC has made no adjustments to recognize the probability of diesel units being dispatched as a result of hydro unit outages. In view of these deficiencies the Board finds that NTPC's proposed simplified method of estimating the forecast diesel generation associated with hydro forced outages does not produce reasonable results. NTPC's refiling proposal for including the diesel fuel costs associated with forced outages in revenue requirement is therefore not accepted. Instead, the Board approves the Snare water stabilization fund as originally filed. NTPC is directed to zero out any diesel fuel costs related to the Snare system from revenue requirement in its second refiling.

The Board directs NTPC, at the next GRA, to investigate further the feasibility and costs of using probabilistic methods for determination of the diesel fuel costs associated with hydro plant and transmission forced outages. Further, having regard to the intent of the water stabilization fund as a means to mitigate the risk of the availability of the hydro resource for power generation, NTPC is directed to address whether the diesel fuel peaking and exercising should be part of the Snare water stabilization fund or not.

Directive 22 Fuel Stabilization Rider

Directive 22 states:

> "The Board notes NTPC's concern respecting material costs for maintaining separate fuel stabilization accounts by community. However, the Board considers the premise of community-based rates can be maintained if the change in fuel cost following a change in the reference price of oil can result in different riders for each community based on the forecast efficiencies and station service/losses for that community. Since the change in the fuel cost on a per kWh basis could be expected to be approximately the same for all communities, there will be no requirement to maintain separate fuel stabilization accounts by community. The reconciliation of revenues and costs recorded in the fuel stabilization account could be carried out as at present using a single fund. The Board directs NTPC to consider these comments and propose a procedure for determining future fuel stabilization riders triggered by fuel price changes as part of the refiling."

In response to this direction, NTPC developed a community specific index that recognizes differences in fuel efficiency, line losses and station service in determining the fuel rider for each community designed to pass through a given fuel price change.

The TGC submitted the major flaw in NTPC's indexing proposal is it does not take into account the differential costs related to fuel delivery. TGC submitted while an increase, for example, in the "reference price for crude oil" may affect the incremental costs of all communities in a similar manner, the same does not hold true for changes in transportation/delivery costs. That is, changes in transportation/delivery costs do not all affect all communities in the same manner.

In its Reply submission, NTPC submitted given that the Corporation purchases its fuel for the communities from one supplier, namely PPD, the chance that transportation costs would increase dramatically for only one community is unlikely. What is certain, however, is that the requirement to unbundle transportation costs from other elements of the fuel cost and track those costs separately on a community-by-community basis would amount to a considerable extra administrative cost to the Corporation and customers, with limited, if any, added cost tracking benefits. Therefore, the TGC's suggestion should be denied.

The Board notes NTPC's statement the chance that transportation costs would increase dramatically for only one community is unlikely. In view of this, the Board considers the indexing proposal submitted by NTPC for determining the fuel rider provides a reasonable mechanism for the recovery of the corresponding cost changes by community. Accordingly, the Board accepts NTPC's community specific indexing method for determining fuel riders by community in future fuel rider proceedings.

Directive 51 Reports on Projects

The Board directed NTPC to provide the Board with biannual reports that discuss the following:

1. The efforts and progress of NTPC and its affiliates in pursuing alternative energy, demand side management and energy efficiency projects;
2. Justification for any projects being pursued by NTPC's affiliates rather than NTPC;
3. Funding programs that are, or will be, available and any efforts and progress by NTPC and its affiliates in obtaining funding.

TGC submitted the Corporation should be directed to provide additional details as part of its filings as follows:

(i) Availability of all federal and other funding available to kick start the "green" energy projects in thermal communities;
(ii) Efforts made by NTPC to secure private/public funding;
(iii) Updates on the status of all "green projects" identified in the 2006-08 GRA and projects identified subsequently;
(iv) Changes made in the Corporation's resource planning to specifically include costs of carbon emissions;
(v) Details of market developments related to valuation and trading of greenhouse gas emissions (GHG)
(vi) Efforts to secure GHG credits arising from both new "green" projects or from prior such projects already in place;
(vii) Discussions with thermal communities with a view to assisting the communities to get the required funding;
(viii) Rationale for any new green projects being undertaken by non-regulated affiliates as opposed to by NTPC (see discussion of Board concerns in Decision 13-2007, page 165)
(ix) How NTPC has managed risk considerations "through appropriate business arrangements with third parties" [Decision 13-2007, page 165]
(x) Details of all "green" projects undertaken by NTPC's affiliates and why these were not, or could not be undertaken by NTPC.

In its Reply Argument, NTPC submitted it is simply premature at this time to judge the completeness of the Corporation's response to Directive No. 51, which has not yet been considered and assessed by the Corporation, much less drafted. The Board made its expectations sufficiently clear in Decision 13-2007. The TGC has also made its expectations clear. NTPC submitted the Corporation will consider both sets of expectations in preparation of its response to Directive No. 51 having regard to the corresponding costs of monitoring and reporting on the items identified by the TGC and the potential benefit to its customers of the underlying work.

The Board expects NTPC to comply with the Board's Directive 51 having regard to the TGC's comments as set out above.

3. OTHER APPROVALS AND DIRECTIONS

The Board has examined the Corporation's refiling Schedules including its responses to Directives 3, 4, 7, 8, 9, 13, 14, 16 and 20. The Board finds NTPC has responded satisfactorily to these directives and therefore accepts them as filed in the refiling application.

NTPC is directed to provide a second Phase I refiling application by November 30, 2007. As part of the second Phase I refiling, NTPC is directed to file the rate base, return on rate base, revenue requirement, revenue and revenue deficiency/excess for the two test years resulting from the Board's directions and approvals in this Decision and Decision 13-2007 together with all supporting calculations in Excel format.

NTPC is also directed to file interim rate schedules reflecting the revenue requirement and revenue deficiency/excess resulting from the Phase 1 second refiling including any proposed riders for recovery/refund of revenue deficiency/excess due to delay in implementation of rates resulting from the Phase 1 second refiling revenue requirement. The proposed rates for each community should be supported by Schedules in Excel format showing for each community the annualized core and non-core revenue deficiency/excess for each test year, the recoveries through interim rates and fuel riders up to the effective date of new rates, the annualized change in base rates and fuel riders as applicable and riders for recovery/refund of any revenue deficiency/excess due to delay in implementation of new rates. The revenue deficiency/excess by community may be based on preliminary Phase 2 community cost of service estimates if available or based on the 2002/03 cost of service study with due adjustments for known changes in community revenue requirement and revenues. In order to assess the rate impacts the schedules should reflect the

percentage changes in overall revenues by community, as a result of the proposed rates.

4. SUMMARY OF BOARD DIRECTIVES

1. NTPC is directed to reflect the effective cost of debt rates of 9.520% in 2006/07 and 9.791% in 2007/08, for purposes of its second refiling application.

2. NTPC is directed to provide a schedule showing the calculation of station service using the weighting method for station service directed by the Board in Directive 10 of Decision 13-2007, as part of the second refiling.

3. The Board directs NTPC to demonstrate how the benefits of AMR are reflected in the cost of service by community, as part of the Phase 2 application.

4. NTPC is directed to reflect the brushing refund in the calculation of any riders for recovery/refund of revenue deficiency/excess as a result of delay in implementation of final rates in its second refiling application.

5. The Board considers deferred cost items may typically include financing costs and any material costs incurred in conducting special studies. In order for such expenditures to be considered eligible, NTPC should be able to demonstrate corresponding benefits that extend beyond a single year. Further, for deferred cost items that arise in non-test years the quantum of the expenditure proposed for deferred cost treatment should be material and

NTPC should demonstrate why they are not considered part of the forecast variance in operations and maintenance expenses in that year. In future proceedings, NTPC is directed to provide evidence showing how each item proposed for deferred cost treatment meets the conditions outlined above.

6. NTPC is directed to give 50:50 weighting to the Corporation's original sales forecast by community and the residential sales forecast by community using the four-year simple average consumption per customer method, in its second refiling application.

7. In view of the evidence considered in the Phase 1 refiling application, the following, more complete, directive will replace Directive 40 from Decision 13-2007.

   At the time of the next GRA, NTPC is directed to

   - prepare its residential sales forecast having regard to, among other relevant factors, the economic drivers for residential customer growth and historical temperature normalized average use per customer, by community;
   - prepare its general service sales forecast having regard to, among other relevant factors, the economic drivers for general service customer growth and historical temperature normalized sales, by community;
   - provide evidence on the appropriate number of historical years to be used in calculating the normalized heating and cooling degree days as applicable;
   - provide evidence on the appropriate number of years of historical data to be considered in determining the normalized sales used for forecasting purposes

8. The Board approves the Snare water stabilization fund as originally filed. NTPC is directed to zero out any diesel fuel costs related to the Snare system from revenue requirement in its second refiling.

9. The Board directs NTPC, at the next GRA, to investigate further; the feasibility and costs of using probabilistic methods for determination of the diesel fuel costs associated with hydro plant and transmission forced outages.

10. Having regard to the intent of the water stabilization fund as a means to mitigate the risk of the availability of the hydro resource for power generation, NTPC is directed, at the next GRA, to address whether the diesel fuel peaking and exercising should be part of the Snare water stabilization fund or not.

11. NTPC is directed to provide a second Phase 1 refiling application by November 30, 2007. As part of the second Phase 1 refiling, NTPC is directed to file the rate base, return on rate base, revenue requirement, revenue and revenue deficiency/excess for the two test years resulting from the Board's directions and approvals in this Decision and Decision 13-2007 together with all supporting calculations in Excel format.

12. NTPC is also directed to file interim rate schedules reflecting the revenue requirement and revenue deficiency/excess resulting from the Phase 1 second refiling including any proposed riders for recovery/refund of revenue deficiency/excess due to delay in implementation of rates resulting from the Phase 1 second refiling revenue requirement. The proposed rates for each community should be supported by Schedules in Excel format showing for each community the annualized core and non core revenue deficiency/excess

for each test year, the recoveries through interim rates and fuel riders up to the effective date of new rates, the annualized change in base rates and fuel riders as applicable and riders for recovery/refund of any revenue deficiency excess due to delay in implementation of new rates. The revenue deficiency/excess by community may be based on preliminary Phase 2 community cost of service estimates if available or based on the 2002/03 cost of service study with due adjustments for known changes in community revenue requirement and revenues. In order to assess the rate impacts the schedules should reflect the percentage changes in overall revenues by community, as a result of the proposed rates.

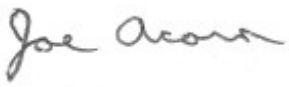
5. BOARD ORDER

NOW, THEREFORE IT IS ORDERED THAT:

1. NTPC is to file a Phase 1 second refiling in accordance with the directions and approvals in this Decision by November 30, 2007, together with rate schedules resulting from the Phase 1 second refiling.

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

ON BEHALF OF THE
PUBLIC UTILITIES BOARD
OF THE NORTHWEST TERRITORIES



Joe Acorn
Chairman

Dated November 8, 2007