THE PUBLIC UTILITIES BOARD
OF THE
NORTHWEST TERRITORIES

DECISION 1-2023 **JANUARY 18, 2023**

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 (Phase I) by Northwest Territories Power Corporation for changes in the existing rates, tolls and charges for electrical energy and related services provided to its customers within the Northwest Territories for the 2022/23 Test Year.

THE PUBLIC UTILITIES BOARD

BOARD MEMBERS	Gordon Van Tighem	Chair
	Tina Gargan	Vice-Chair
	Danny Yakeleya	Member
	Myra Berrub	Member
	Joe Auge	Member

BOARD STAFF	Doris Minoza	Board Secretary
	Raj Retnanandan	Board Consultant
	Ayanna Ferdinand Catlyn	Board Counsel

APPEARANCES

Karen Salmon	Counsel for the Northwest Territories Power Corporation
Thomas D. Marriott	Counsel for the City of Yellowknife & Town of Hay River
G. Rangi Jeerakathil.	Counsel for the Thermal Generation Communities
Dennis Bevington	Stand Alone Energy Systems Ltd

WITNESSES

Northwest Territories Power Corporation

Paul Grant	Chief Financial Officer
Chuck Myles	Director, Finance
Belinda Whitford	Chief Operations Officer
Andrew McLaren	Consultant

Town of Fort Smith & Town of Hay River

Russ Bell	Consultant

Thermal Generation Communities

Dustin Madsen	Consultant

Stand Alone Energy Systems Ltd.

Jack Van Camp	Consultant

TABLE OF CONTENTS

1. BACKGROUND & APPLICATION

1. By letter dated March 30, 2022, the Northwest Territories Power Corporation ("**NTPC**" or the "**Corporation**") submitted to the Northwest Territories Public Utilities Board ("**Board**") its General Rate Application ("**GRA**"). The GRA outlines forecast costs for providing electricity service for the 2022/23 fiscal year (the **"Test Years"**).

2. By letter dated March 30, 2022, NTPC also submitted its 2022-23 Interim Rate Application. NTPC requested the following increases in rates effective May 1, 2022:
   - Thermal Zone – 2.5% increase to all customer classes
   - Snare Zone – 2.5% increase to all customer classes
   - Taltson Zone – 10% increase to all customer classes
   - Norman Wells - 10% increase to all customer classes

3. In Decision 2-2022 the Board approved a 2.5% across the board revenue increase for NTPC, effective May 1, 2022. By letter dated April 28, 2022 NTPC filed Revised Interim Rates as per the directions in Decision 2-2022. The Board issued Decision 5-2022 dated May 2, 2022 approving the Interim Rates effective May 1, 2022.

4. Pursuant to the provisions of section 13.(1) of the Rules of Practice and Procedure, the Board, by letter dated April 8, 2022, directed NTPC to publish notice of the proceedings in newspapers that circulate in the Northwest Territories.

5. The Towns of Hay River and Fort Smith ("**HRFS**"), the Thermal Generation Communities, comprised of the Town of Inuvik, Town of Norman Wells and Village of Fort Simpson ("**TGC**"), Stand Alone Energy System Ltd ("**SAES**")

and Northland Utilities Limited ("**NUL**") were registered as interveners in the GRA proceedings.

6. The 2022/23 GRA proceedings to examine NTPC's application included a discovery process through exchange of written interrogatories and responses, intervener evidence and rebuttal evidence by NTPC. On September 8 and 9, 2022 the Board held a technical hearing which was followed by public consultations.

2. PUBLIC HEARING

7. The technical hearing and public consultations with respect to the NTPC GRA were conducted as hybrid (virtual and in person) meetings, commencing with the hearing on technical matters followed by the public consultation meetings.

8. The technical hearing was held in the City of Yellowknife on September 8, 2022 at the Tree of Peace Friendship Center. The Board staff shared the relevant documents being referred to on the video conferencing link for the benefit of all hearing participants. The video link for participants in the hearing was distributed to all parties on the GRA distribution list.

9. Since this was a hybrid hearing (virtual and in person) all witnesses who filed written evidence did not be appear before the Board to be sworn in. Therefore all witnesses who filed written evidence were requested to file an affidavit identifying the person responsible for preparing each piece of filed evidence including responses to information requests.

10. The Public Consultation meetings was held at the Tree of Peace Friendship Center as well as at certain satellite locations in Fort Smith (Town office), Norman Wells (Heritage Hotel) and Inuvik (Midnight Sun Complex) on September 8, 2022: 7.00PM to 9.30PM and September 9, 2022: 9.00AM to 12.30PM.

11. Interested parties participated from their individual homes or business from anywhere in the NWT following registration with NTPC.

12. In this Decision the Board has set out its findings with respect to the issues raised during the proceedings. The Board findings include directions for NTPC to make adjustments to its 2022/23 GRA in a forthcoming Compliance filing. Following receipt of the Compliance filing the Board will determine NTPC's revenue requirement and final rates for the 2022/23 Test year.

3. RATE BASE

13. The following sections deal with rate base related issues that were raised during the proceedings.

3.1 Capital Planning and Asset Management

14. HRFS states, other than for the Sachs Harbour Power Station Asset Health Assessment and Plant Replacement Study provided in response to HR/FS.NTPC-19, NTPC provides no empirical evidence that assets have actually reached the end of life, and must be replaced. When a utility asserts that assets have reached the end of life, there must be empirical evidence that, based on analysis of the asset conditions, the asset is at end of life. Accordingly, HRFS submitted the Board should require NTPC to provide more than a cursory discussion of any asset management processes, but instead provide a discussion of asset heath, and risks of failure, similar to that provided by utilities in Alberta.[1]

[1] HRFS Argument Section III

15. HRFS states further, that an additional $0.300 million budgeted in 2022-23 is intended to cover the operational costs of managing new assets into NTPC's system as a result of the replacement of aging infrastructure. HRFS states, when older assets are replaced with newer assets, the cost of maintenance should decrease, and definitely not increase. At a minimum, the proposed increase of $0.3 million should be disallowed. Additionally, maintenance costs should decrease as older assets are replaced with newer assets.[2]

16. In response, NTPC stated it is not justifying the replacement of assets based solely on asset vintage or age and has provided details in relation to asset condition on the record. Details of assets that were being replaced for reasons other than the age of assets are discussed in NTPC's Rebuttal.[3]

Board Findings:

17. While the Board accepts the assumption that replacement of a specific asset by newer asset could result in reductions in Operating and Maintenance (O&M) expenses associated with the replaced asset, this assumption cannot be generalized for all assets and related O&M expenses, since overall O&M expenses increase or decreases due to a number of reasons including vintage changes, inflation, productivity, cyclicality of expenses. HRFS' has not provided any evidence that would support the view that operational costs of managing new assets would be offset by reduced maintenance arising from replacement of old assets

[2] HRFS Argument Section IV
[3] NTPC Rebuttal A12

during the 2022/23 test year. Therefore, the HRFS proposed reduction is not accepted.

18. The Board notes NTPC has developed a detailed capital planning process in response to prior directions of the Board[4]:

> The NTPC capital planning process supports the orderly replacement of aging infrastructure and provides effective management of NTPC assets on a Company wide basis. This process prioritizes the Corporation's assets for replacement, thereby ensuring the Corporation's asset base can deliver reliable power generation, transmission and distribution to meet the needs of its customers. An effective capital planning process is essential to ensure the continued long-term viability of the Corporation. Therefore, the Corporation has developed a comprehensive capital planning process that will allow it to achieve its strategic objectives and deliver reliable power to its customers.

19. The Board also notes NTPC conducts detailed asset health assessments where relevant and material. The Board does not see the relevance of HRFS' recommendation to require NTPC to provide a discussion of asset heath, and risks of failure, similar to that provided by utilities in Alberta.

20. Notwithstanding the above, the Board notes NTPC has yet to comply with Directive 4 of Decision 16-2017 that each project be assigned a unique number and or code for tracking projects from inception to completion. In the Board's view tracking of projects by unique identifiers is essential to track and compare forecasts against actuals and to understand cost variances.

[4] Decision 16-2017; Directives 2, 3 and 4

21. For example, for the Snare Forks G1 (Unit#1) Overhaul, a project permit application was filed by NTPC at the time of its 2016-19 Phase I GRA. The estimated cost of the project at the time was $7.8 million. The Board approved the project permit application in Decision 16-2017. In the 2022/23 GRA NTPC proposed to add $18.392 million with respect to the Snare Forks G1 (Unit#1) Overhaul. Unique identifiers for this project could have avoided confusion over whether the same project that was approved for project permit purposes was being proposed for addition to rate base, due to the significant change in costs and scope.[5]

22. Accordingly, NTPC is directed to institute a system, as part of its capital planning process, for assigning unique numbers/codes for projects and to track the same numbers/codes through the project execution phases for monitoring and reporting purposes.

23. In order to allow tracking of projects, the above noted project codes should be reflected in the five year capital plans requested by the Board in Directive 1 of Decision 16-2017[6].

24. As part of the above directive, the Board requested a narrative description of how the capital plan fits into the Corporation’s strategic direction including affordability of rates. The Board re-emphasizes the requirement for the narrative description explaining how the capital plan fits into the Corporation’s strategic direction including affordability of rates. Accordingly, the Board and directs NTPC to continue to file five-year capital plans in full compliance with Directive 1 from Decision 16-2017.

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[5] Post Hearing Information Requests BR NTPC 13a)
[6] Application page 13-1

25. The Board considers the filing of 5-year capital plans to be a useful accountability mechanism for NTPC in terms of meeting its strategic goals and targets. This matter is discussed further under Section 9.2. In view of the importance of this document, NTPC is requested to file this document with all parties to this proceeding. Following the filing of this document, the Board will determine if further process is required.

26. The Board notes in the case of the Sachs Harbour Power Plant Replacement project, NTPC did not file a project permit application since the net cost of the project did not exceed the $5million threshold prescribed by legislation for project permit approval by the Board. In this regard NTPC states:

> NTPC did not file a project permit application as the estimated cost of the Sachs Harbour Power Plant Replacement project, net of ICIP funding, did not exceed the $5M threshold for project permits as per the Public Utilities Act.[7]

27. The Board considers the gross cost of the project is the relevant number for assessing need and evaluation of alternatives as part of project permit applications. Accordingly, NTPC is directed to file project permit applications where the forecast gross cost of a project exceeds $5 million in future.

3.2 Capital Additions- Electric Vehicles (EV) Charging Station

28. NTPC proposed to add $535,000 to plant in service and rate base with respect to an electric vehicle charging station in Behchokǫ̀. NTPC states,

[7] BR NTPC 13a)

this project is designed to encourage further electric vehicle (EV) adoption and advance NTPC's goal of reducing transportation related emissions. Increasing availability of charging stations removes one of the major barriers to EV adoption as it helps EV drivers travel greater distances and reduces EV driver range anxiety. Putting an EV fast charger at Behchokǫ̀, by adding another stop along a corridor of charging stations, would help to make Yellowknife accessible to EV drivers travelling from the south. NTPC states, this project will assist NTPC in achieving its goal of reducing transportation related emissions by 10 percent by 2030 and reducing overall emissions by 30 percent by 2030.[8]

29. In its Argument TGC submitted, the EV charging station costs should be denied or alternatively be supported through government grants and other funding.[9]

30. In its Rebuttal, NTPC states it now has a contribution agreement in place and this will significantly reduce the effect on rate payers; this will be reflected in updated tables to be filed.10

Board Findings:

31. In the Board's view EV Charging is not a monopoly service, unlike other utility services. If NTPC wishes to give effect to Government policy and increase sales, the charging station ought to be owned and operated by a non utility arm of NTPC, while NTPC would supply electricity to the station. The applicable rate for charging stations may be filed when the first EV station is constructed and commissioned. Accordingly, NTPC is directed to

[8] Application page 11-50
[9] TGC Argument para 95
[10] NTPC Rebuttal A10

remove the cost of the EV station from 2022/23 plant in service and rate base for the purposes of the compliance filing.

3.3 CAPITAL ADDITIONS- POLE REPLACEMENTS

32. NTPC proposes to add $2 million with respect to pole replacements in 2022/23.

33. TGC submitted the proposed pole replacement cost is particularly significant given NTPC does not appear to have tracked its prior year pole replacement costs separately from new pole replacements.[11]

34. TGC submitted that Poles should only be replaced if the asset management program can demonstrate based on testing a realistic risk of failure. Funding the pole replacement program at a rate of $1,000,000 in 2022/23 should achieve this objective until such time as NTPC provides additional evidence achieved from its advancing asset management program to support an accelerated level of spending.[12]

35. In its Rebuttal evidence NTPC stated, at an average replacement cost of approximately $10,000 per pole, replacing 1,000 poles would cost in the order of $10 million. The Corporation is proposing a staged approach to replacing these assets over time considering the magnitude of the investment required and the logistics of replacing the poles which considers

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[11] TGC evidence of Dustin Madsen, page 61
[12] Ibid, page 63

factors such as the number of communities involved and the fact that some poles must be replaced in winter months or outside of nesting seasons.[13]

Board Findings:

36. The Board accepts NTPC's staged approach to pole replacements as described above as it reflects a normalized level of expenditure. The Board notes the above staged approach to pole replacements would amount to $1 million in capital additions in each year. Accordingly, the Board directs NTPC to reduce the cost of pole replacement capital additions during the 2022/23 test year from $2 million to $1 million for the purposes of the compliance filing.

3.4 Capital Additions-Snare Forks Generating Unit #1 Overhaul

37. NTPC's application reflects a capital addition of $16.0 million in 2020/21 and a further capital addition of $2.4 million in 2021/22 with respect to the Snare Forks #1 overhaul project. The total capital addition with respect to this project amounts to $18.4 million. The $18.4 million addition is significantly higher than the $7.9 million project cost approved by the Board in Decision 16-2017 at the project permit approval stage and, the NTPC internal budget cost for the project of $9.6 million.

38. The following Table shows the reconciliation of the project permit costs to actual costs:

[13] NTPC Rebuttal A11

Reconciliation of Snare Forks G1 Cost Increases		
Line	**Description**	**$million**
1	Cost Estimate at the time of Project Permit Approval	7.9
	Contractor Costs:	
2	Planning - addition of initial 2013-14 study to assess scope of work required	0.2
3	The overhaul work was expected to start with engineering in March 2019 and on-site work on June 14, 2019. The failure necessitated immediate repair to put Unit 1 back into service and the start date of the Contract was accelerated to November 2018.	0.7
4	Increase in tender pricing over initial budget less contingency of $1.176 million built into the original budget	1.4
5	In October 2018, Unit 1 experienced a catastrophic bearing failure which immediately took SK G1 out of service. Cost increase for change orders based on GERE investigation of damage to unit - caused by the failure, including damage to the rotor, stator, generator shaft, upper and lower guide bearings, and various other components of the turbine. NTPC's insurers were notified of the failure.	4.7
6	The work on the unit was delayed due to Covid-19 and the need to establish new Safe Work Practices, including a 2-week selfisolation for contractor crew. All staff had to leave site to ensure appropriate safety for the contractors and NTPC employees. When the contractors returned to site in July 2020, NWT protocols required all out of territory workers to isolate in the territory prior to working. This meant NTPC had to pay for a crew to self-isolate for 14 days with limited ability to work. For all the shift changes until the unit was restarted in October 2020, isolation time was required.	0.4
	NTPC Resources and Contractors:	
7	Increases for outside of the specific planned work due to need for additional project oversight arising from challenges with the contractor and additional time required for the reinstatement and overhaul - scheduled originally for 9 months, the work compounding corrective work, COVID delays and contractor coordination took 21 months to complete	1.5
8	Fuel Costs	1.5
9	Overhead and IDC Increases	0.3
10	Total Actual Cost	18.6
	Notes:	
	1 . Source: BR NTPC 13, Table 1	
	2. Difference between the cost shown above and actual cost is due to rounding	

39. NTPC attributes a major portion of the cost increases to a bearing failure which resulted in the unit being off-line until October 31, 2020, and unable to produce at full capacity until July 25,2021. NTPC states, generally speaking, for rate setting purposes, a 5-year period for loss reporting with insurance companies is used. NTPC states it currently has one open claim from 2017 that is anticipated to be in excess of $8M. The claim remains open as the matter is ongoing.[14]

40. In BR NTPC 12d) NTPC was asked if the $5 million reflected in the application and the above noted $8 million relate to the same insurance claim and, whether there is any reason for not reflecting the approximate full amount of the claim (i.e. $8 million) in the rate base calculations. In response NTPC stated:

> The ultimate value of the insurance proceeds associated with the repair of the Snare Forks G1 hydro generator is still under negotiation. NTPC received $5 million in a preliminary installment on the insurance claim. Further insurance proceeds may be receivable in the future and the amount, if any, will be recognized at that time. At this time the amount of any additional insurance proceeds cannot be reasonably estimated. As outlined in TGC.NTPC-1(a) on Undertaking #6, the current open claim is anticipated to be in excess of $8M. In a best case scenario, future insurance proceeds will cover a significant portion of the additional costs incurred as a result of the failure. In any event, the additional project costs described in BR.NTPC-13(b) which includes costs incurred as a result of the failure, are costs that could not have reasonably been foreseen and were all reasonably incurred.[15]

[14] Undertaking #6 – TGC.NTPC-1

[15] BR NTPC 12d)

Board Findings:

41. NTPC was in the process of doing a major overhaul on Snare Forks Unit 1 and during the overhaul there was a catastrophic bearing failure and the costs arising from that catastrophic event together with the major overhaul costs were capitalized as part of the Snare Forks Unit 1 overhaul costs. The costs arising from the bearing failure account for a major portion of the cost increases for the project compared with the costs forecast at the time of the project permit application. The costs arising from the catastrophic event are insurable costs and NTPC has received partial settlement on the corresponding insurance claim in the amount of $5 million. The $5 million preliminary instalment has been treated as a contribution to partially offset the capitalized cost of overhauling Snare Forks Unit 1 in the GRA filing. As a result of NTPC's treatment as described above, the net cost of property added to rate base includes the Snare Forks Unit1 overhaul costs as well as a portion of the insurable expenses associated with the catastrophic event.

42. In the Board's view the costs that are the subject of the insurance claim should not be capitalized as part of the cost of plant additions (and plant in service) since such costs do not constitute prudent cost of acquisition related to the Snare Forks Unit 1 overhaul. Rather, those costs are related to insurance claims receivable and should therefore be treated as accounts receivable and the mid-year balance of the account included as part of necessary working capital.

43. The Board notes NTPC's view that the subject insurance claim is anticipated to be in excess of $8M. The Board also notes the statement

that "At this time the amount of any additional insurance proceeds cannot be reasonably estimated."

44. The Board interprets the above statements to mean there is a likelihood of NTPC receiving insurance proceeds in addition to the $5 million preliminary instalment. However, there appears to be some uncertainty regarding the amount and the timing of recovery of the insurance claim.

45. In view of the foregoing, NTPC is directed as follows for purposes of the Compliance filing:

- to remove the costs that are the subject of the insurance claim from the capital cost of the Snare Forks Unit 1 overhaul added to plant in service in 2020/21 and 2021/22; based on NTPC's evidence, the amount of costs related to the insurance claim would be in excess of $8 million;
- all costs related to the insurance claim should be included as accounts receivable in the books of NTPC;
- remove the preliminary instalment received from the insurance company of $5 million shown as an offset against capital additions in the 2020/21filing and credit the same amount against the corresponding insurance claims receivables account;
- any depreciation expense or amortization of insurance proceeds applicable to the above adjustments should be reversed for each of the relevant years including the 2022/23 test year;
- any anticipated insurance claim receipts in the 2022/23 test year should be credited against the insurance claims receivable account on a forecast basis and
- the mid-year balance of the accounts receivable respecting the insurance claim should be included in the calculation of working capital.

46. NTPC may address the regulatory treatment of any difference between the expenses constituting the insurance claim amount and the final insurance settlement at the time of the next GRA.

3.3 AMORTIZATION

Account 341 Diesel Plant – Structures and Improvements:

47. TGC's expert witness Dustin Madsen, recommended that a 40-S3 curve be used for account 341 as opposed to Concentric's (NTPC's Expert Witness) recommended 35-S3 curve. TGC's expert noted that the 40-S3 curve reflects a better visual fit to the observed retirement data and also reflects a moderate increase to the life that is more gradual than a move to a 45-S3 curve.[16]

48. NTPC submitted, while a life extension is warranted, Concentric and NTPC do not agree that a 25% increase in service life (to 40 years) is warranted. This account has only seen retirements through to approximately 70 percent of the total exposures. As there have not yet been a large number of retirements seen, the actuarial analysis may change drastically in future depreciation studies. In the interest of gradualism and moderation, Concentric believes that the 35-S3 Iowa curve should be used for the depreciation calculations at this time with further life extensions examined in future depreciation studies.[17]

[16] TGC Argument, para 117
[17] NTPC Argument, para 119

Board Findings:

49. The difference between experts reflects their respective judgments on how much weight to give gradualism and moderation. The Board accepts NTPC's proposal for purposes for this Decision. However, the Board expects NTPC to consider the analysis carried out by TGC respecting account 341 at the time of its next depreciation study.

Account 342 Diesel Plant – Fuel Holders, Producers, and Accessories:

50. TGC recommended the continuation of the currently approved 30-L4 or a 35-R3 curve for account 342 as opposed to Concentric's recommended 27-R2 curve.[18]

51. In support of its recommendation for account 342 TGC stated:

> As stated by Mr. Madsen in his evidence, a 35-R3 curve also has a superior visual fit through approximately age 10. This evidence is not refuted by Concentric. This is also an important period that should not be ignored.
>
> Further, while the TGC accepts there is a higher period of retirement between ages 7.5 to 24.5 and it is important to fit the curve to this period, Concentric appears to disregard an important piece of Mr. Madsen's evidence. Specifically, Mr. Madsen noted that "a significant percentage (more than 40%) of the investment in Account 342.00, is surviving beyond 40 years."
>
> The TGC submits Mr. Madsen's evidence in this regard is important. While the period of 7.5 to 24.5 years reflects a period of high retirement based on the retirements studied more than 40% of the investment in the account is surviving beyond 40 years.

[18] TGC Argument para 108

> Approving a 27-R2 curve results in the clear discounting of this evidence.[19]

52. In response to TGC's proposals NTPC stated as follows:

> While previous depreciation studies had hoped for a life lengthening impact from the double walled tanks now in service, at this time the data has not supported this. Further, an average expected age of 30 years is in line with an average service life of 27 years, as it is expected that some of the old single walled tanks will still need to be replaced in the coming years. The expected engineering life of 30 years also does not take into account reasons for retirement other than the physical life of the assets – it is expected that the assets may be retired due to any number of other forces of retirement which will reduce the average service life of the entire account. A 27 year service life at this time allows for the retirement of any single walled tanks still in service, recognizes the historical retirement experience, and allows for interim retirements over the life of the double walled tanks.[20]

53. With respect to the life lengthening effect of double walled tanks TGC stated:

> The second portion of Concentric's rebuttal suggests that there is no evidence of a life-lengthening impact from the installation of double-walled tanks. The TGC has two points in this regard. First, if there has been no life-lengthening impact from the installation of double-walled tanks, the TGC questions why this was ever an assumption in the first place. Second, there is no evidence from NTPC's engineers stating clearly that there was no life-lengthening effect from the double-walled tanks in practice. It can take years before the depreciation study sees any impact on retirements (i.e., through changes in retirement rates or patterns) of a change to double-walled tanks but this should not prevent the lengthening of the life for this account. Finally, the TGC again notes Mr. Madsen's evidence above that investment within the existing account appears to be surviving much longer than the depreciation study expects it to. This fact cannot be discounted as Concentric has done and is

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[19] TGC Argument paras 122, 123, 124
[20] NTPC Argument, para 121

> supportive of a life extension when considered in tandem with the installation of the double-walled tanks.[21]

Board Findings:

54. The Board agrees with TGC that it is premature to conclude from the retirement data that double walled tanks would not have longer average service lives (as did Concentric) given that they are of more recent vintages. Considering this factor and TGC's evidence that the average service life for account 342 should in fact be lengthened rather than be reduced as proposed by NTPC, the Board considers it would be best to leave the life parameters for account 342 at the existing 30L4 parameter for the purposes of this proceeding. The Board expects NTPC to consider the analysis carried out by TGC respecting account 342 at the time of its next depreciation study.

55. NTPC is directed to adjust its depreciation calculations to reflect continuation of the 30L4 curve for account 342 for the purposes of the Compliance filing.

Account 343.00 – Diesel Plant – Prime Movers:

56. TGC recommended a 25-R3.5 curve for account 343 as opposed to Concentric's recommended 23-R3 curve.

57. TGC submitted that a 25-R3.5 curve provides a better mathematical fit to the entirety of the observed retirement data without discounting later years. Further, in TGC's view, it achieves a superior average service life that provides a better approximation of the actual observed life, while also

[21] TGC Argument, para 125

factoring in the fact that the life extending efforts for Account 344.00 should, absent evidence to the contrary, also impact Account 343.00.[22]

58. With respect to the linkage between account 343 and 344 Mr. Madsen states in his evidence as follows:

> The assets in Account 343.00 are also in large part linked to the assets in Account 344.00 (Diesel Plant – Generators), which Concentric has proposed a life extension for with a 32-R3 Iowa curve as opposed to a 28-R4 curve. I understand the prime movers included in Account 343.00 are in effect the engine that powers the generators in the diesel plant. While the two components have different purposes, they would both be subject to general overriding conditions that broadly influence the forces of retirement, such as the regular schedule of maintenance and overhauls described by Concentric in support of the life extension for Account 344.00.[23]

59. With respect to TGC's proposals, NTPC submitted as follows:

> In regards to Account 343, Mr. Madsen recommends moving from the proposed 23-R3 curve to a 25-R3.5 curve. Concentric and NTPC emphasize that the retirements post age 22.5 (the section of the curve that Mr. Madsen is weighting most heavily) represent 11 million dollars, or 33% of the total retirements observed. Concentric placed a substantially higher degree of weighting on the 66% of retirements that occurred before this point as these make up the period of greatest retirement experience in arriving at its proposed adjustment.
>
> Mr. Madsen comments that the mathematical fit of the 25-R3.5 is superior to the 23-R3 recommended by Concentric. This is an expected outcome of the longer life. In accounts with "stub curves", or curves which do not show the entire life cycle of assets such as Account 343, it is very common for the lagging retirement transactions at the tail end of the curve to skew the residual measure calculation. This is due to the mathematical calculation performed in calculating the residual measure placing equal weighting on every year, which often results in curves with an

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[22] Evidence of Dustin Madsen, page 77
[23] ibid

> inappropriately long life having a better residual measure than curves with an appropriate life through the area of greatest retirement activity.[24]

Board Findings:

60. The Board notes NTPC's statement that NTPC's witness, Concentric, placed a substantially higher degree of weighting on the 66% of retirements that occurred before age 22.5 for this account as these make up the period of greatest retirement experience in arriving at its proposed adjustment. The Board also notes NTPC's view that the better mathematical fit claimed by TGC with respect to its proposed 25-R3.5 curve may not represent reality for accounts with stub curves.

61. As opposed to NTPC's arguments opposing TGC's views as stated above, the Board also notes TGC's view that there is some inconsistency between the average service lives for account 344.00 (Diesel Plant – Generators) and account 343-Diesel Plant Prime Movers since both are subject to general overriding conditions that broadly influence the forces of retirement, such as the regular schedule of maintenance and overhauls. The inconsistency arises from the fact NTPC has proposed a 32-R3 curve for account 344 while it has proposed a 23-R3 curve for account 343 with a much shorter average service life.

62. In the Board's view there is insufficient evidence to support the view the life extending efforts for Account 344.00 would also impact Account 343.00. Further the Board notes NTPC's view that in accounts with "stub curves", or curves which do not show the entire life cycle of assets such as Account 343, it is very common for the lagging retirement transactions at the tail end

[24] NTPC Argument para 122, 123

of the curve to skew the residual measure calculation. In this regard the Board notes Mr. Madsen's view that a period of high retirement based on the retirements studied shows more than 40% of the investment in the account is surviving beyond 40 years.[25] In balancing the views of both Experts, the Board has decided to not direct any changes to the proposed parameters for the purposes of this Decision. However, the Board expects NTPC to consider the analysis carried out by TGC respecting account 343 at the time of its next depreciation study.

3.4 SALVAGE COSTS

63. The NTPC recommended net salvage percentages as compared with net salvage percentages that were requested by NTPC in the context of the 2016/2019 GRA and the net salvage percentages that were subsequently approved by the Board in Decision 16-2017 in the context of the 2016/19 GRA are show in Table 6-4 of NTPC's application as per below:

[25] TGC Argument, para 124

Table 6.4

Net Salvage Percentages

FERC Account	Description	Net Salvage: Concentric 2016 Full Recommended Percentage	NTPC 2016-19 GRA Recommended Percentage	2016-19 GRA Approved	2020 Study Recommended
121	Wind Turbines	-15.0%	-10.0%	-5.0%	-5.0%
331	Hydro Structures & Improvements	-30.0%	-5.0%	-2.5%	-8.0%
332	Resv., Dams & Waterways	-30.0%	-5.0%	-2.5%	-8.0%
333	Turbines and Generators	-15.0%	-5.0%	-2.5%	-8.0%
334	Hydro Accessory Electric Equip.	-20.0%	-5.0%	-2.5%	-8.0%
335	Misc. Power Plant Equipment	-10.0%	-8.0%	-4.0%	-5.0%
336	Roads and Bridges	-5.0%	-5.0%	-2.5%	-8.0%
341	Thermal Structures & Improvements	-35.0%	-8.0%	-4.0%	-13.0%
342	Fuel Holders, Prod., & Access.	-75.0%	-10.0%	-5.0%	-25.0%
343	Prime Movers	-25.0%	-8.0%	-4.0%	-8.0%
344	Generators	-5.0%	-5.0%	-2.5%	-5.0%
345	Thermal Accessory Electric Equip.	-10.0%	-5.0%	-2.5%	-8.0%
353	Transmission Station Equipment	-20.0%	-5.0%	-2.5%	-10.0%
354	Towers and Fixtures	-25.0%	-5.0%	-2.5%	-13.0%
355	Poles and Fixtures	-25.0%	-5.0%	-2.5%	-13.0%
356	Overhead Conductors and Devices	-25.0%	-5.0%	-2.5%	-13.0%
364	Distribution Poles & Fixtures	-25.0%	-5.0%	-2.5%	-5.0%
365	Overhead Conductors and Devices	-25.0%	-5.0%	-2.5%	-5.0%
368	Line Transformers	0.0%	-5.0%	-2.5%	-5.0%
369	Distribution Services	-10.0%	-5.0%	-2.5%	-8.0%
373	Street Lighting	-20.0%	-5.0%	-2.5%	-8.0%
390.01	Hay River Office Building	15.0%	15.0%	7.5%	0.0%
390.02	General Structures & Improvements	5.0%	5.0%	2.5%	0.0%
391	Office Furniture	10.0%	10.0%	5.0%	0.0%
392	Transportation Equipment	10.0%	5.0%	2.5%	5.0%
396	Power Operated Equipment	15.0%	15.0%	7.5%	8.0%
397	Communication Equipment	10.0%	10.0%	5.0%	10.0%

64. To trace the history of net salvage recovery, the 2011 depreciation study for NTPC showed net salvage accumulated amortization surplus of approximately $20 million. Accordingly, for the 2012-14 GRA, the Board approved a “pause” on the collection of net salvage to gradually permit the surplus to decrease over time.

65. For the Corporation’s 2016 study, the variance for net salvage accumulated amortization was still a surplus of approximately $6.3 million. Because of this remaining surplus, NTPC proposed to re-implement net salvage accruals in rates at approximately one-quarter of the amount otherwise recommended.

66. In Decision 16-2017 the Board approved the phase in of net salvage rates at one eighth of the full net salvage rates proposed at that time.

67. With respect to the 2020 net salvage NTPC states the current application based on a 2020 study incorporates a phased-in approach to net salvage and proposes limited adjustments to net salvage rates where required, notably below the levels indicated by the net salvage activity analysis.[26]

68. TGC States the core issue with NTPC's salvage costs is that it is failing to fully recover its forecast net salvage costs while at the same time providing limited transparency into the evolution of the reserve balance for these costs. The TGC states it is concerned that continued failure to fully recover the forecast costs will place undue burden on future ratepayers who will need to true up any shortfall.[27]

69. TGC expressed concern over lack of transparency respecting the size of any unfunded net salvage reserve balance:

> TGC agrees with Mr. Madsen that more transparency is required regarding the size of any unfunded net salvage reserve balance. Having increased transparency into this amount will significantly increase the Board's ability to make decisions on how to address the collection of these costs in a reasonable manner.[28]

70. With respect to the transparency issue TGC's witness, recommends:

> ..that the Board direct NTPC to establish the net salvage accumulated depreciation account as a separate account that is tracked in its schedules. Transparent reporting of the balance is

[26] Application page 6-4, 6-5
[27] TGC Argument para 65
With respect to the salvage rates proposed by NTPC TGC[28] TGC Argument para 68

> important to ensure that all parties are aware of the amounts that have been funded and how those amounts have varied from year-to-year.[29]

71. With respect to the full salvage rates proposed by NTPC, TGC expressed the following concern:

> There appears to be no consistent rate between the accounts, and the TGC is unaware of any justification for the differences between accounts. The TGC submits this inconsistency lends further support to the TGC's recommendation to revisit the approach to recovering salvage costs. The TGC submits that whichever approach is approved, the approach should be rational and supported. The approach should also be systematic and supported by the underlying salvage study.[30]

72. TGC requested that the Board direct a comprehensive review in NTPC's next GRA of the salvage collection method including a detailed list and discussion of all alternatives known to NTPC and its experts for the funding of net salvage costs, including the estimated costs and impacts on NTPC's applied for revenue requirement of such changes.[31]

Board Findings:

73. The Board notes NTPC's statement that net salvage estimates under the current depreciation study are more negative than the proposed net salvage percentages:

> The current depreciation study notes that net salvage estimates are more negative than the recommended net salvage percentages being applied. Please see response TGC-NTPC-20(a-c), which notes that NTPC's last full depreciation study indicated net salvage

[29] Evidence of Dustin Madsen, page 44
[30] TGC Argument, para 73
[31] TGC Argument, para 69

accruals should be approximately $3.8 million/year. The previous GRA implemented net salvage accruals under $0.5 million/year, and the current GRA proposes to increase this to $1.438 million/year.[32]

74. The significant gap between the required net salvage accrual and the actual annual accrual, raises the issue of the unfunded salvage reserve. The Board agrees with TGC's recommendation for greater transparency over any unfunded salvage costs. This means the regulatory and accounting records of NTPC must make it possible to track the booked accumulated salvage reserve and the theoretical (or calculated) salvage reserve at an account level. For this comparison to be made NTPC needs to establish the net salvage accumulated depreciation account as a separate account in NTPC's regulatory and accounting records.

75. Accordingly, NTPC is directed as follows for the purposes of filing the next depreciation study, at the time of the next GRA:

- Establish regulatory and accounting records to reflect the booked accumulated salvage reserve and the theoretical (or calculated) salvage reserve at an account level.
- Propose methods for fully funding any salvage reserve deficiency having regard to rate stability.

4. RETURN ON RATE BASE

76. The following sections deal with return on rate base related issues that were raised during the proceedings.

[32] BR NTPC 6c)

4.1 Return on Equity

77. NTPC proposed a Return on Equity (ROE) of 8.0% for the 2022-23 Test Year based on the last approved ROE in Decision 16-2017.

78. In Decision 16-2017 the Board approved a Return on Equity of 8.0% noting that it considered both the reduced risk arising from GNWT risk mitigation and the last generic rate of return determined by the Alberta Utilities Commission (AUC) (8.3%). NTPC notes the AUC's most recently approved ROE is 8.5% for 2022/23, which is somewhat higher than the 8.3% referenced by the Board in Decision 16-2017. Despite the increase in the AUC generic rate of return since NTPC's 2016-19 GRA, the Corporation stated it is proposing to maintain its ROE at 8.0%. NTPC states this proposal is being made in order to simplify the review process for the current GRA but without prejudice to the ability to seek a higher return more consistent with peer utilities in future applications.

Board Findings:

79. The Board recognizes that NTPC's approach to determination of the ROE facilitates regulatory efficiency. The Board notes none of the parties objected to NTPC's proposed ROE of 8%. Accordingly, the Board approves an ROE of 8% for the purposes of these proceedings.

4.2 Snare Cascades Capital Lease

80. In Decision 16-2017 NTPC was directed by the Board to examine whether refinancing of the NWTEC loan to Dogrib Corporation and any related

debenture debt instruments (issued by NTPC or its subsidiaries) would benefit NTPC's hydro Zone customers without violating the contractual rights and obligations of the Dogrib Corporation; if this examination were to indicate the above objectives could be met reasonably, NTPC was directed to proceed with the restructuring of the financing of the capital lease and to report on this matter at the time of the next GRA.

81. In response NTPC stated:

> Since the previous GRA, DPC has exercised their rights under the Snare Cascades financing agreements to repay 100% of the debt outstanding to NWTEC. This debt was on a schedule to be repaid by 2026, so this represents an advancement of the repayment by approximately 5 years. As a result, there is no further analysis required of options to refinance this debt. The Snare Cascades lease cost in this GRA no longer includes the noted debt instruments as part of the cost of capital. NWTEC has also discharged the debt obligations and all associated repayment costs will be deferred and fully discharged over the next 5 years.[33]

82. The early repayment of the loan by the Dogrib Power Corporation (DPC) to NWT Energy Corporation (NWTEC), an affiliate of NTPC, resulted in NWTEC in turn repaying its debt to third parties (i.e. debt which was initially obtained by NWTEC to provide debt financing to DPC). As a result of NWTEC incurred certain penalties related to the early repayment of debt to third party lenders. In the current application NTPC is requesting to recover the early repayment penalty incurred by NWTEC from NTPC's hydro zone customers.

[33] NTPC Application page 13-5

83. NTPC explained how the penalty amount incurred was determined and how it was treated for regulatory purposes as follows:

> The prepayment calculation is based on the difference between the market rate of interest payments over the remaining term of the loans at the payoff dates compared to the stated rates of interest on the three debentures. The prepayment penalty is being amortized over the original debenture terms which is the same period that NTPC/NTEC would have incurred interest expense on the three debentures.[34]

84. The Snare Cascade lease was initially financed by a combination of debt and equity by DPC. With the early repayment of debt referred to above the proposed lease cost reflects 100% equity financing plus amortization of the early repayment penalty.

Board Findings:

85. The Board notes that among the various financing agreements, only the Loan Agreement between DPC and NWTEC speaks to early repayment of debt by DPC to NWTEC.[35] It would appear that neither the DPC Lease agreement with NTPC nor any agreement between NWTEC and NTPC contemplated the flow through of penalty costs triggered by an early repayment of debt by DPC to customers of NTPC, as part of the lease agreement. This means NWTEC took on the risk of early repayment penalties that may be incurred by NWTEC in the event DPC early repaid its debt to NWTEC and NWTEC in turn had to early repay the corresponding borrowing from third parties.

[34] BR-NTPC 14h)
[35] BR NTPC 14 e-g)

86. The Board considers that since the risk of incurring penalties was assumed by NWTEC and since none of the agreements speak to the flow through of such penalties to customers of NTPC, the customers of NTPC were not made aware of any responsibility on their part for any early repayment penalties resulting from NWTEC's early repayment of debt to third partis. Therefore, it is the Board's view that having assumed the risk of penalties associated with early repayment, NWTEC should assume responsibility for the payment of penalties associated with the early repayment and not the customers of NTPC.

87. The Board notes the proposed blended capital lease rate in 2022/23 of 10.69% is higher than the lease rate of 8.20% in 2021/22.[36] Due to the paydown of the high cost debt instruments, the blended capital lease rate would have been lower than in 2021/22 had there been no prepayment of debt.

88. The Board considers the customers of NTPC should neither benefit nor suffer harm as a result of the early repayment of debt by NWTEC to third parties since the risk of costs and benefits associated with early repayment was assumed by NWTEC.

89. The Board notes NTPC's statement that the three debentures associated with the prepayment penalty were originally scheduled to be paid off between May 1, 2025 and September 1, 2026.[37] In order to ensure customers of NTPC are not harmed as a result of the early repayment penalties, NTPC is directed to recalculate the lease financing rate for 2022/23 as follows and reflect the recalculated capital lease rate in the Compliance Filing:

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[36] NTPC GRA Main Schedules, Tab 7.0 RORB
[37] BR NTPC 14h)

i) Calculate the total interest expense that would have been incurred on each of the debt instruments had there been no early repayment, over the remaining life of each debt instrument

ii) Amortize the total interest calculated in i) over the original debenture terms which is the same period that NTPC/NWTEC would have incurred interest expense on the three debentures

iii) Calculate the capital lease rate using 100% equity financing at an ROE rate of 7.75%[38] plus amortization of interest expense calculated as in ii) above.

5. OPERATING AND MAINTENANCE EXPENSES

90. The following sections deal with issues related to Operating and Maintenance (O&M) expenses, raised during the proceedings.

5.1 FUEL AND PURCHASED POWER- LINE LOSSES AND STATION SERVICE

91. In its application NTPC states, line losses and station service forecasts are higher on both an absolute basis (30.7 GWh in 2018-19 compared to 34.1 GWh in 2022-23) and as a percentage of total generation (9.2% in 2018-19 compared to 10.0% in 2022-23). NTPC states, forecast line losses have increased by 2.4 GWh from the 2018-19 Test Year to the 2022-23 Test Year- 1.7 GWh of this increase is from the Snare zone (1.3 GWh) and Taltson zone (0.4 GWh) where line losses have little impact on Revenue Requirement due to surplus hydro generation. Line losses are forecast to

[38] BR NTPC 7

increase in both absolute terms and as a percentage of generation in the Thermal zone in the 2022-23 Test Year compared to the 2018-19 Test Year. [39]

92. The following Table shows a summary of line losses and station service from 2018/19 to 2022/23:

Losses and Station Service						
	Generation	**Losses**	**Station Service**	**Total**	**% Losses**	**% Station Service**
	MWh	MWh	MWh	MWh	%	%
2018/19 Actual	339541	17623	13975	31598	5.2%	4.1%
2019/20 Actual	341665	19245	14720	33965	5.6%	4.3%
2020/21 Actual (Per Application)	339104	22824	15171	37995	6.7%	4.5%
2020/21 Actual (Corrected BR NT	335767	19488	15171	34659	5.8%	4.5%
2021/22 Forecast	337462	19206	14426	33632	5.7%	4.3%
2022/23 Forecast	340210	19566	14566	34132	5.8%	4.3%

93. In BR NTPC 4, NTPC stated that following NTPC's filing of the 2022-23 GRA, NTPC became aware of an error in its hydro generation data for the Taltson zone for 2020-21. Annual generation and line losses should have been lower than were reported in the original filing. NTPC states the generation for the Taltson zone has since been adjusted resulting in updated data for line losses, losses as a percent of generation, and station service as a percent of generation. NTPC stated that the adjustment impacts hydro generation only, therefore it has no impact on production fuel costs or revenue requirement.[40]

[39] NTPC Application, page 4-3
[40] BR NTPC 4a)

Board Findings:

94. The Board is concerned by the trend of increasing line losses in all of the zones relative to the 2016/19 GRA.

95. The Board notes NTPC's statement that line losses have little impact on Revenue Requirement due to surplus hydro generation. In the Board's view NTPC's view of losses fails to recognize that increasing losses, whether it be in the Hydro Zone or in the Thermal Zone is wasted energy. In this regard the Board notes the following statement by SAES:

> It forecasts the continued installation of fossil fuel infrastructure that will 'lock-in' GHG emissions for decades (i.e., LNG in Inuvik and Fort Simpson etc.). At the same time, it allows large amounts of zero emission hydroelectricity to be wasted while customer rates inflate to unsustainably high levels in the Hydro Zones.[41]

96. In the Board's view minimizing go forward line losses should be a strategic priority for the Corporation as that would be consistent with NTPC's objective of reducing carbon emissions. Reduction in line losses could potentially displace fossil fuel use directly or indirectly in a variety of ways as well as increase sales in certain cases. For example, making more hydro generation available in the Taltson Zone by minimizing line losses, could help increase heat sales and displace fuel oil used for home heating.

97. Accordingly, the Board directs NTPC to investigate why line losses are increasing (both in absolute terms and as a percent of generation) and develop/ implement strategies to optimize line losses having regard to any capital expenditures required for loss mitigation and their potential rate

[41] SAES Argument page 7 of 13

impacts. NTPC should report progress made in the direction of line loss mitigation at the time of NTPC's next GRA.

5.2 Insurance Costs

98. TGC submits, NTPC's insurance costs as a percentage of applied for O&M costs has increased from 3.2% in 2018/2019 to 6.2% in 2022/23. This increase in costs, when viewed in the light of the benchmarking analysis performed by TGC's witness, confirms that NTPC's insurance costs warrant a detailed review to confirm that NTPC is acting in the most reasonable manner possible in relation to insurance.[42]

99. TGC noted, NTPC has not conducted any detailed quantitative or qualitative analysis to support its current blend of commercial and self-insurance. In light of the dramatically increasing costs of commercial insurance owing to the hard insurance market, the TGC submitted it is imperative that such a review be conducted sooner rather than later.[43]

100. NTPC attributed the increases in insurance costs to previous loss experience and a hard insurance market. NTPC stated, decisions with respect to reduction in limits or increased levels of self-insurance would pose a significant risk to the organization.[44]

[42] TGC Argument, para 79, 81
[43] TGC Argument, para 85
[44] NTPC Argument, para 105, 106

Board Findings:

101. The Board notes the benchmarking analysis performed by TGC's witness indicates that NTPC's insurance costs as a percent of gross plant exceed the comparable costs being paid by other Canadian integrated utilities. While the reasons for NTPC's relatively high insurance costs in relation to gross plant may be reflective of the significant loss event which occurred in 2020/21 to an extent, it is not entirely clear whether NTPC is taking all steps necessary to manage and mitigate its insurable risks using industry best practices for asset management and maintenance, on a go forward basis.

102. NTPC is therefore directed to review its management of insurable risks in light of industry best practices with a view to jointly optimizing the costs associated with managing insurable risks, insurance premiums and self- insurance costs and report on the steps taken to address this matter at the time of the next GRA.

5.3 Capitalization Policy

103. TGC submitted that NTPC's capitalization rate is lower than that of other utilities. In TGC's view the current customers are bearing costs related to serving future customers. TGC's witness recommended increase in the labour capitalization rate from 20.3% to 25%.[45] TGC states the 25% was conservatively recommended by Mr. Madsen, TGC's Expert witness.

[45] TGC Argument, para 13, 60

TGC recommended a comprehensive review of capitalization percentages be conducted for each position.[46]

104. TGC submitted further if the Board does not approve a generalized increase in the capitalization rate as TGC recommends, then the Board should at minimum direct that a portion of asset management costs ($0.3m) and human resources (HR) costs ($0.54m) be capitalized.[47]

105. With regard to asset management costs TGC submitted it is entirely reasonable for the costs of $0.3 million to be capitalized where those costs are necessary to allow new assets to function in the manner intended by management.[48]

106. With regard to HR costs TGC stated, that no HR related costs are being capitalized at present and that customers are harmed by waiting until a future budgeting process to make this change.[49]

107. NTPC stated it relies on cost causation basis for capitalizing salaries. NTPC's capitalization rate may not conform to the capitalization policies used by other utilities, which have different asset configurations, different use of employees and contractors to lead or support the capital program and different work environments and requirements.[50]

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[46] TGC Argument, para 63
[47] TGC Argument para 64
[48] TGC Argument para 46
[49] TGC Argument para 50, 51
[50] NTPC Argument, para 96

Board Findings:

108. The Board agrees with NTPC that it would be inappropriate to compare NTPC's capitalization rate with that of other utilities with different asset configurations, different use of employees and contractors to lead or support the capital program and different work environments and requirements. Accordingly, TGC's recommendation to increase NTPC's overhead capitalization rate is not accepted.

109. With respect to the $0.3 million asset management costs, in the Board's view to the extent these costs are incurred after the in service date of assets to allow the new assets to function in the manner intended by management, they are properly treated as operating costs. Therefore, TGC's recommendation to capitalize these costs is not accepted.

110. With respect to capitalization of a portion of HR costs the Board notes that no HR related costs are being capitalized at present. However the Board considers there are likely some HR costs that are required to support the workers whose costs are considered capital related. Accordingly NTPC is directed to review and determine the HR costs that are reasonably allocated to workers whose costs are considered capital related and reflect that portion of HR costs as capitalized overhead as opposed to O&M, for the purposes of the Compliance filing.

5.4 Common Costs

111. SAES expressed concerns with NTPC's common costs as follows:

> The GRA shows common costs of $33M out of a total budget of $110M. Thirty percent of the revenue requirement is for

> headquarters administrative costs. It should be noted that NWT customers in the Hydro Zones also pay 100% of the administrative costs of Northland Utilities. We note as well the addition of 17 new administrative positions in the system with minimal justification. Is it fair for NWT customers to have to pay for such high administration costs?[51]

112. SAES submitted, the Board should direct NTPC to seek an independent external operational audit of the Common Costs identified in this application, to be completed in 18 months.

Board Findings:

113. In the Board's view there is insufficient evidence to suggest NTPC's common costs are unreasonable. In the Board's view it is more appropriate to test the components of common costs such as insurance and additions to administrative positions, rather than arriving at any conclusions as to the overall level of common costs based on the 30% metric alluded to by SAES. Therefore, the Board does not consider an external operational audit to be necessary. The Board accepts NTPC's proposed common costs for the purposes of this Decision.

6 SALES AND REVENUES

114. With respect to forecasting sales and revenues NTPC stated:

- It used a 5-year rolling average method to calculate Usage Per customer (UPC) for each customer class.
- The average annual customer count is forecast based on December 2021 actual customer counts.

[51] SAES Argument page 8 of 13

- A top-down review of sales forecasts is undertaken to incorporate considerations such as economic growth rates and other local knowledge.
- The Snare zone and the Taltson zone wholesale forecasts assume a 5-year rolling average based on temperature normalized monthly sales for the last five years, respectively.[52]

115. In Undertaking #9 NTPC was requested by the Board to assess whether the actual sales for Snare wholesales are tracking NTPC's forecast, or whether they are more consistent with pre-pandemic levels of sales for the Snare wholesale rate.

116. In Undertaking #10 NTPC was requested by the Board to compare the 2023 forecast sales with the 2022-23 year-to-date and prior months (unaudited preliminary) actuals for all relevant rate classes to see to what extent the forecast reflects pre-pandemic levels.

117. In its Argument NTPC submitted that the responses to Undertakings #9 and #10 clearly demonstrate the accuracy of NTPC's forecasts.[53]

Board Findings:

118. Having examined the sales and revenue forecasts submitted by NTPC as described above the Board is prepared to accept the sales and revenue forecasts as filed for the purposes of this Decision.

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[52] Application pages 2-6, 2-7
[53] NTPC Argument, para 69

7 RATES REBALANCING

119. In its application NTPC, requested rate adjustments over two years. Higher than average rate increases (or disproportionate increases) were proposed by NTPC for the Taltson Zone and the community of Norman Wells in order to rebalance customer rates in the Taltson Zone and in Norman Wells to bring them closer to cost recovery percentages targeted by the 2017 GNWT Rate Policy Direction. The NTPC proposed rates are as follows:

- Thermal Zone – 2.5% increase in 2022-23 and a further 2.5% increase in 2023-24 to all customer classes
- Snare Zone – 2.5% increase in 2022-23 and a further 2.5% increase in 2023-24 to all customer classes
- Taltson Zone – 10% increase in 2022-23 and a further 10% increase in 2023-24 to all customer classes
- Norman Wells (as rates transition into the Thermal zone) - 10% increase in 2022-23 and a further 10% increase in 2023-24 to all customer classes

120. By way of an Interim Rate Application dated March 30, 2022, NTPC requested that the increases applicable to the 2022-23 year be approved effective May 1, 2022. However, the Board did not approve the disproportionate increases requested for the Taltson zone and the community of Norman Wells as requested by NTPC. Instead, the Board in Decision 2-2022, approved an increase in rates that would result in a 2.5% across the board increase in revenues, effective May 1, 2022.

121. With regard to the 10% increases proposed for the Taltson Zone and the community of Norman Wells NTPC states its proposed rate increase addresses the longstanding issues of ensuring each zone reasonably covers the costs of providing service in that zone. Under NTPC's rate proposal each rate zone will be within 90%-110% Revenue to Cost

Coverage (RCC) range targeted by the 2017 GNWT Rate Policy Direction. NTPC states, the Taltson zone costs will be increasing further in the future as the major Taltson Overhaul project is put into service. Without proper rate adjustments in the current application the Taltson zone cost recovery shortfall will continue to increase. NTPC states it proposed rates will bring Norman Wells rates closer to (but still below) the remainder of the Thermal zone and continue the transition to the Thermal zone Rates, as per the 2011 GNWT Rate Policy Guidelines.[54]

122. HRFS stated it is not convinced that these disproportionate rate increase proposals are compliant with the Government direction.[55] The Government direction HRFS is referring to is the February 23, 2017 Directive issued to the Board by the Government of Northwest Territories (GNWT) titled 2017 Electricity Rate Policy Direction, which states in part as follows:

[54] NTPC Argument paras 52, 53, 54
[55] HRFS Argument para 11

Rate Rebalancing:

4. **1% Rate Rebalancing for non-Government customers**
   To allow a gradual transition to rates that are not within the range of reasonableness for revenue to cost ratios by customer class and by zone, any rate impacts to non-Government customers arising from the realignment of rates between zones and customer classes should not exceed one percent per year.

5. **3% Rate Rebalancing for Government customers**
   To allow a gradual transition to rates that are not within the range of reasonableness for revenue to cost ratios by customer class and by zone, any rate impacts to Government customers arising from the realignment of rates between zones and customer classes should not exceed three percent per year.

123. HRFS stated further that NTPC's proposal to increase rates for the Taltson Zone by 10% in each of two years results in rate shock and therefore not in the public interest. HRFS submitted that a 15% increase considered reasonable by the Board under different circumstances is not reasonable under current difficult economic circumstances.[56]

124. HRFS also pointed to the absence of a recent Cost of Service Study (COSS) to support the proposed disproportionate increases. HRFS stated the fair allocation of costs is not fixed for all time by a prior study but must in fairness be revisited from time to time to ensure allocations of costs are still being done in an appropriate and fair manner.[57]

125. HRFS submitted there is evidence before the Board that the proposed rate increases are considered unaffordable in light of present

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[56] HRFS Argument paras 19, 20, 21
[57] HRFS para 25

circumstances, and that the affected customers are shocked by the prospect of their approval.[58]

126. SAES submitted the utility has requested a major rate increase in the Taltson Zone that is not related to increased cost of service in the Zone. The new fairness principle they wish to apply is based on relative rates. The customers with the lowest rates (i.e., those with the lowest cost of service) are being assigned an increased revenue share because they have the lowest rates. SAES stated, the NWTPUB must decide on the fairness of this new principle.[59]

Board Findings:

127. The Board notes one of reasons put forward by NTPC for the proposed disproportionate increase for the Taltson zone is that costs will be increasing further in the future as the major Taltson Overhaul project is put into service. However, the Board gives little or no weight to this argument since other potential changes that could also impact the Taltson zone costs and revenues such as potential increased industrial or heat sales, have not been considered.

128. The Board agrees with the concerns expressed by HRFS, SAES and other community members who participated in the public consultations that the proposed consecutive increases of 10% in each of two years for the Taltson Zone and Norman Wells would result in an unacceptable level of rate shock under current economic conditions.

[58] HRFS Argument para 26
[59] SAES Argument page 2 of 13

129. The Board is concerned by NTPC's attempt to make significant rate rebalancing adjustments without the benefit of a full Phase II proceeding in which many of the issues could have been addressed. The absence of relevant evidence and due process in the context of a Phase II proceeding limits the Board's ability to make any significant changes in rates for the Taltson Zone and for the community of Norman Wells as requested by NTPC. Accordingly, NTPC is directed to file a Phase II application concurrent with its next GRA Phase I application to address any under recovery of costs by rate Zone and by rate class.

130. For the purposes of this Decision the Board is willing to consider limited rate realignment increases for the customer classes in the Taltson Zone and in Norman Wells that are below the RCC range targeted by the 2017 GNWT Rate Policy Direction based on the last approved cost of service study, in order to directionally move them closer to cost recovery. In the Board's view such rate rebalancing increases should not exceed the maximum rate rebalancing increases contemplated in the 2017 GNWT Rate Policy Direction.

131. Accordingly, the Board directs NTPC to give effect to the limited rate rebalancing adjustments considered reasonable by the Board for the purposes of this Decision and the compliance filing as follows:

i) NTPC to allocate the 2022/23 rate level revenue requirement (determined as set out in Section 8 of this Decision) to rate zones and classes using the cost of service allocation methodology last accepted by the Board in the 2018/2019 GRA Phase II proceeding.[60] For the community of Norman Wells its share of the Thermal Zone cost of

[60] 2018-19 Phase II approved RCC ratios as per Directive 3 response provided in the 2018-19 GRA Phase II compliance filing, dated March 16, 2018 as described in BR NTPC 11.

service may be estimated using the community's 2022-23 billing determinants and thermal zone cost of service average unit costs as described in BR NTPC 11a). The post test year fuel savings of $2.6million (which is a component used in determining rate level revenue requirement) should be reflected as an offset to cost of service for the Thermal Zone since the savings relate to that Zone.

ii) For the Taltson Zone and Norman Wells, rate rebalancing increases should not exceed 1% for non Government and 3% for Government customers consistent with the GNWT Policy Direction. The rate rebalancing increases would be in addition to the average increases arising from the increase in 2022/23 rate level revenue requirement relative to revenues generated from existing interim rates.

iii) For the Taltson Wholesale rate, to the extent the RCC ratio is at or above to 100%, no more than the average increase should be applied.

iv) For the Street lighting class in the Taltson Zone and in Norman Wells, rate rebalancing increases should not exceed the 1% for non Government street lights (if any) and 3% for Government street lights, consistent with the GNWT Policy Direction, in addition to average increases.

v) Any increased revenues arising from rate rebalancing increases in Norman Wells should be reallocated and credited proportionately within the Thermal Zone to ensure the Thermal Zone benefits from the reduction in cross subsidies to Norman Wells.

vi) Any increased revenues arising from rate increases to Government and non Government customers in the Taltson Zone should be reallocated proportionately to customer classes within the Snare Zone and the Thermal Zone.

vii) As part of the compliance filing NTPC to include schedules that show the percent increase in revenues and rates proposed under the

Compliance filing relative to the existing interim revenues and rates, as well as, the RCC ratios by rate class and zone under the rates proposed in the compliance filing.

132. In summary, the Board expects NTPC to give effect to the following in the rates put forward in the Compliance filing:

i) Final general increase in rates of X% effective Jan 1, 2023 for all customers, based primarily on the increase in rate level revenue requirement (the X% to be determined after reflecting all adjustments to 2022/23 revenue requirement directed in this Decision) relative to the interim rate revenues.
ii) Additional rate realignment increases of 1% and 3% for non Government and Government customers respectively, in the Taltson Zone and Norman Wells Zone, effective Jan 1, 2023. The additional revenues arising from realignment increases are to be reallocated to other classes and zones as set out in the preceding paragraph.

8 RATE LEVEL REVENUE REQUIREMENT AND RATES

133. NTPC states it sought to minimize rate impacts on customers through a two step phase in approach to rates (the first phase in occurred effective May 1, 2022 through the interim rate increase) and by including certain post test year fuel savings benefits (quantified to be $2.6m) that are scheduled to arise in the Thermal zone from the installation of the Inuvik High Point Wind project after the test year.[61] Accordingly, NTPC states, the application was prepared based on assessing whether the Corporation could absorb a $2.6M shortfall and still

[61] NTPC Application pages 1-4, 1-5

be in a position to provide safe and reliable service. NTPC provided that assurance in its response to BR.NTPC-001.

134. NTPC acknowledged that it understands that its request to set just and reasonable rates for the 2022/23 test year including a shortfall of $2.6m would result in NTPC failing to realize the fair return on equity fixed by the Board with respect to the 2022/23 test year on a forecast basis had those rates gone into effect at the beginning of the 2022/23 fiscal year.[62]

Board Findings:

135. The Board notes NTPC's statement that it is in a position to provide safe and reliable service in 2022/23, notwithstanding the reduction in the revenue requirement arising from recognition of a $2.6 million shortfall. Having regard to the above assurance provided by NTPC and in the interest of maintaining rate stability from year to year, the Board accepts the proposal to reduce the 2022/23 revenue requirement by $2.6million to arrive at the rate level revenue requirement which is the level of the net revenue requirement that would be used to design rates.

136. Accordingly, NTPC is directed, for the purposes of the Compliance filing, to reflect the directives in this Decision for determination of the 2022/23 revenue requirement. Further, NTPC is directed to recognize the above mentioned $2.6 million shortfall as a reduction to the 2022/23 revenue requirement determined in the compliance filing, in establishing the 2022/23 rate level revenue requirement and rates for the purposes of the Compliance filing.

[62] NTPC Argument para 35, 37

9 OTHER MATTERS

9.1 FILING REQUIREMENTS

9.1.1 Threshold for Filing Business Cases in support of Capital Additions

137. NTPC states, the Corporation has provided additional detail for projects over $400,000 including projects previously approved by the Board through Project Permit Applications. The $400,000 threshold for providing senior management with supporting information for their approval was described in NTPC's description of its capital planning process in the 2016-2019 GRA.[63]

138. In its 2022/23 application NTPC proposed to increase the above threshold for providing detailed business cases and or support, to projects costing $1 million or above. NTPC noted the $400,000 threshold results in a substantial amount of effort to summarize while a $400,000 typically reflects less than a $40,000 (less than 0.4%) increase to revenue requirement.

139. TGC submitted if there is to be a reduction in transparency of costs as a result of NTPC's proposal, then that reduction should have material benefits to ratepayers. TGC expressed the view that NTPC has not forecast to receive any material benefit in place of the reduction in transparency. Considering the risks of the proposal, TGC submitted that NTPC's recommendation be denied. Further, TGC submitted that the Board should direct NTPC to quantify the level of effort it requires to prepare its business cases and based on this

[63] NTPC 2016-2019 GRA, Section 11.2

quantification, estimate the level of costs that could be removed from future applications if the threshold were increased.[64]

Board Findings:

140. Detailed review and approval internally by senior management for projects exceeding $400,000 was confirmed by NTPC in the Corporation's 2016-19 GRA.[65] In the Board's view filing the same detailed supporting information provided to senior management in support of proposed capital additions in a GRA would further the interest of regulatory scrutiny of material capital additions as well as facilitate greater transparency of NTPC's internal processes. Further, since the information is already being prepared for senior management approval, there would be no additional costs associated with filing the same information in support of capital additions exceeding $400,000. Since preparation of detailed business cases, often involving external consultants, could be costly, the Board will only require detailed business cases to be filed in support of capital additions exceeding $1 million.

141. Accordingly, NTPC is directed to file copies of project proposals submitted for senior management approval in support of all projects with costs exceeding $400,000 but less than $1 million. For projects with costs exceeding $1 million, NTPC is directed to file detailed business cases in support of proposed capital additions.

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[64] TGC Argument, para 105-107
[65] NTPC 2016-2019 GRA, p11-8

9.1.2 Forecast Accuracy

142. HRFS states, NTPC's forecast methodology does not accurately reflect actual operating performance. There are wide swings in forecast accuracy. While a part of one year of forecast and actual information provided by way of an undertaking is not useful in assessing the variances and forecast methodology for NTPC, the kind of information provided in the undertaking response would be useful if it was provided for all years that are not a test year in the next NTPC GRA.[66]

143. In response, NTPC stated if the Board is of the view that further information (including interim and/or unaudited information) will assist it in fully testing future GRA applications, NTPC urges the Board to initiate a Standardized System of Accounts/Minimum Filing Requirements (SSA/MFR) review and seek input from all interested parties as to the extent of that additional information.[67]

Board Findings:

144. The systematic monitoring and reporting of actual financial results against forecasts with variance explanations facilitates accountability on the part of management for prudent and efficient management of costs. NTPC's partial response to the undertaking to HRFS as well as the significant shifts in functional costs between forecasts and actuals (as observed by HRFS) suggest that the Corporation may not be placing a high priority on management of costs

[66] HRFS Argument Section V
[67] NTPC Argument, para 116

through systematic variance monitoring and reporting, with feedback loops into the forecasting process.

145. In view of this the Board shares HRFS' concerns respecting NTPC's forecasting methods and the apparent lack of rigor in administering accountability mechanisms, such as budgetary controls. The Board expects NTPC to take steps to ensure its policies, practices and mechanisms respecting forecasting, monitoring of actuals and variance reporting are reviewed and updated and implemented in a manner consistent with best industry practice. NTPC should be prepared to provide internal variance reports (with redaction if necessary) if requested by the Board or by interested parties, in the context of future GRAs.

9.2 STRATEGIC DIRECTION

146. SAES submitted the NWTPUB should not approve the NTPC 2022-23 GRA without a credible plan to achieve de-carbonization goals that are at least consistent with the legislated targets of Canada.

147. In this regard SAES submitted that some promising projects have been announced (wind and solar projects in Inuvik), but the following concerns exist:

- NTPC has no plan to increase renewable energy penetration or to couple with other sectors in any of the Rate Zones.
- NTPC retains a disingenuous "net metering" policy that caps renewable energy penetration at a ridiculously low level in order to protect the incumbent diesel generation systems.

- NTPC has no plan to maximize the use of surplus renewable energy available in the hydro zones to offset the carbon emissions from heating, transportation or industry.
- NTPC forecasts the continued installation of fossil fuel infrastructure that will 'lock-in' GHG emissions for decades (i.e., LNG in Inuvik and Fort Simpson etc.).
- NTPC allows large amounts of zero emission hydroelectricity to be wasted while customer rates inflate to unsustainably high levels in the Hydro Zones.[68]

148. With regard to expansion of heat sales in Fort Smith, SAES submitted:

> The use of green electricity for heating would help the NWT meet its GHG commitments. The Town of Fort Smith, in its new Energy Plan has identified electric heating as an essential requirement to accomplish its GHG reductions. A constraint to electric heat from the Taltson is the lack of demand for 6 months of the year. Another constraint is the condition of the distribution system in Fort Smith. NTPC stated they were moving ahead with a study this year on upgrading that distribution system. Investment in the upgrading of the distribution systems in the communities could be significant, but could be amortized over a very long term.[69]

149. SAES submitted that:

- A hydrogen plant located on the Taltson grid would have the capacity to load follow and use any surplus in the system.
- The extension of the transmission line to Fort Providence would replace diesel fired electricity in two small communities where the total demand is less than 4GWh.

[68] SAES Argument p7 of 13
[69] SAES Argument p 9 of 13

- Potential for use of the Taltson surplus to supply a mining company (earliest commencement 2028), with whom NTPC has an MOU.[70]

Board Findings:

150. During the Public Consultations, NTPC summarized its views with respect to the strategic direction of the Corporation as follows:

> However, looking to the future, we recognize that rate increases can't be the only solution. There are challenges facing the electricity sector in the NWT. We acknowledge that. But customers have to see balanced efforts and a plan for the future in order to have greater confidence in NTPC.
>
> We've developed a strategic plan that has two primary goals: We want to reduce the gap between electricity rates in the NWT and the Canadian national average while at the same time achieve the 25 percent greenhouse gas reduction target for electricity generation that is included in the GNWT's 2030 Energy Strategy. We've been moving forward with this strategy over the past several years and will continually share information about our progress with the public and other stakeholders. Building stronger partnerships with community and Indigenous governments and Indigenous organizations is one of the keys to the success of our strategic plan.
>
> So just to wrap things up, it is important to remember that the GNWT is NTPC's sole shareholder, and our relationship with them is critically important to achieving the priorities of moderating electricity price increases, maintaining and improving reliability of electricity systems, and reducing greenhouse gas emissions.[71]

151. While the above goals are commendable, the Board considers that accountability mechanisms, put in place through the regulatory process, could help NTPC to be accountable for achievement of strategic goals and targets.

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[70] Ibid p10 of 13
[71] T20 (Sep 9, 2022-Public Consultations), L18

Accordingly, as part of its next 5 year capital plan filing NTPC is directed to describe the connection between the capital plan and the corporation's strategic goals described in the above quote, including the following:

- Expansion of heat sales for Fort Smith
- Capital costs, operating costs or revenue implications arising from expanding hydro power sales from the Taltson grid
- Capital plans that would enable NTPC to meet the Corporation's decarbonization target for 2030
- Review of the current net metering policy (including caps) in relation to the intended goals of the policy and its effectiveness in achieving those goals.

9.3 PUBLIC CONSULTATIONS

152. During the public consultations held on September 8 and 9, 2022, the NTPC Public Consultations Panel provided an overview of the GRA and rate setting process.

153. The following participants in the public consultations asked questions and/or made their views known to the Board in the context of the rate increases requested by NTPC for the Taltson Zone and for Fort Smith. Some participants also commented on expanding heat sales among others to create additional revenue streams for NTPC in the Taltson Zone.

Carl Cox-Resident
Don Jaque-Resident
Frieda Martselos-MLA for Thebacha, NWT
Chief David Poitras-Salt River First Nation

Allan Heron-President Fort Smith Metis Council

Fred Daniels-Mayor, Town of Fort Smith

Dianna Korol- Councilor, Town of Fort Smith

Diane Seals-Resident

154. Susan Wright of North-Wright Airways asked questions and/or made a submission in the context of the rate increases requested by NTPC for Norman Wells.

155. Chief Thaidene Paulette expressed concern that high rates from NTPC would translate to higher rates for the Smith's Landing First Nation which lies on the NWT/Alberta border, on the Alberta side.

Board Findings:

156. The Board finds the comments and questions posed by the participants in the public consultations to be helpful in that they reflect the concerns of impacted customers. The Board has considered these comments in the context of its determinations in Section 9.2, dealing with Strategic Direction.

10 SUMMARY OF BOARD DIRECTIONS

157. The following is a summary of the directions arising from this Decision.

Directions for the Compliance Filing:

1. Accordingly, NTPC is directed to remove the cost of the EV station from 2022/23 plant in service and rate base for the purposes of the compliance filing. [Para 31]

2. Accordingly, the Board directs NTPC to reduce the cost of pole replacement capital additions during the 2022/23 test year from $2 million to $1 million for the purposes of the compliance filing. [Para 36]

3. In view of the foregoing, NTPC is directed as follows for purposes of the Compliance filing:

   - to remove the costs that are the subject of the insurance claim from the capital cost of the Snare Forks Unit 1 overhaul added to plant in service in 2020/21 and 2021/22; based on NTPC's evidence, the amount of costs related to the insurance claim would be in excess of $8 million;
   - all costs related to the insurance claim with respect to the Snare Forks Unit 1 overhaul should be included as accounts receivable in the books of NTPC;
   - to remove the preliminary instalment received from the insurance company of $5 million shown as an offset against capital additions in the 2020/21 filing and credit the same amount against the corresponding insurance claims receivables account;
   - any depreciation expense or amortization of insurance proceeds applicable to the above adjustments should be reversed for each of the relevant years including the 2022/23 test year;
   - any anticipated insurance claim receipts in the 2022/23 test year should be credited against the insurance claims receivable account on a forecast basis and the mid-year balance of the accounts receivable

respecting the insurance claim should be included in the calculation of working capital. [Para 45]

4. NTPC is directed to adjust its depreciation calculations to reflect continuation of the 30L4 curve for account 342 for the purposes of the Compliance filing. [Para 55]

5. In order to ensure customers of NTPC are not harmed as a result of the early repayment penalties, NTPC is directed to recalculate the lease financing rate for 2022/23 as follows and reflect the recalculated capital lease rate in the compliance filing:
   i) Calculate the total interest expense that would have been incurred on each of the debt instruments had there been no early repayment, over the remaining life of each debt instrument
   ii) Amortize the total interest calculated in i) over the original debenture terms which is the same period that NTPC/NWTEC would have incurred interest expense on the three debentures
   iii) Calculate the capital lease rate using 100% equity financing at an ROE of 7.75%[72] plus amortization of interest expense calculated as in ii) above. [Para 89]

6. Accordingly NTPC is directed to review and determine the HR costs that are reasonably allocated to workers whose costs are considered capital related and reflect that portion of HR costs as capitalized overhead as opposed to O&M, for the purposes of the Compliance filing. [Para 111]

[72] BR NTPC 7

7. Accordingly, the Board directs NTPC to give effect to the limited rate rebalancing adjustments considered reasonable by the Board for the purposes of this Decision and the compliance filing as follows:

i) NTPC to allocate the 2022/23 rate level revenue requirement (determined as set out in Section 8 of this Decision) to rate zones and classes using the cost of service allocation methodology last accepted by the Board in the 2018/2019 GRA Phase II proceeding.[73] For the community of Norman Wells its share of the Thermal Zone cost of service may be estimated using the community's 2022-23 billing determinants and thermal zone cost of service average unit costs as described in BR NTPC 11a). The post test year fuel savings of $2.6million (which is a component used in determining rate level revenue requirement) should be reflected as an offset to cost of service for the Thermal Zone since the savings relate to that Zone.

ii) For the Taltson Zone and Norman Wells, rate rebalancing increases should not exceed 1% for non Government and 3% for Government customers consistent with the GNWT Policy Direction. The rate rebalancing increases would be in addition to the average increases arising from the increase in 2022/23 rate level revenue requirement relative to revenues generated from existing interim rates.

iii) For the Taltson Wholesale rate, to the extent the RCC ratio is at or above to 100%, no more than the average increase should be applied.

iv) For the Street lighting class in the Taltson Zone and in Norman Wells, rate rebalancing increases should not exceed the 1% for non Government street lights (if any) and 3% for Government street lights consistent with the GNWT Policy Direction, in addition to average increases.

[73] 2018-19 Phase II approved RCC ratios as per Directive 3 response provided in the 2018-19 GRA Phase II compliance filing, dated March 16, 2018 as described in BR NTPC 11.

v) Any increased revenues arising from rate rebalancing increases in Norman Wells should be reallocated and credited proportionately within the Thermal Zone to ensure the Thermal Zone benefits from the reduction in cross subsidies to Norman Wells.

vi) Any increased revenues arising from rate increases to Government and non Government customers in the Taltson Zone should be reallocated proportionately to customer classes within the Snare Zone and the Thermal Zone.

vii) As part of the compliance filing NTPC to include schedules that show the percent increase in revenues and rates proposed under the Compliance filing relative to the existing interim revenues and rates, as well as, the RCC ratios by rate class and zone under the rates proposed in the compliance filing. [Para 132]

8. Accordingly, NTPC is directed, for the purposes of the Compliance filing, to reflect the directives in this Decision for determination of the 2022/23 revenue requirement. Further, NTPC is directed to recognize the above mentioned $2.6 million shortfall as a reduction to the 2022/23 revenue requirement determined in the compliance filing, in establishing the 2022/23 rate level revenue requirement and rates for the purposes of the Compliance filing. [Para137]

Directions for the Next GRA

9. Accordingly, NTPC is directed as follows for the purposes of filing the next depreciation study at the time of the next GRA:
   - Establish regulatory and accounting records to reflect the booked accumulated salvage reserve and the theoretical (or calculated) salvage reserve at an account level

- Propose methods for fully funding any salvage reserve deficiency having regard to rate stability [Para 75]

10. Accordingly, the Board directs NTPC to investigate why line losses are increasing (both in absolute terms and as a percent of generation) and develop/ implement strategies to optimize line losses having regard to any capital expenditures required for loss mitigation and their potential rate impacts. NTPC should report progress made in the direction of line loss mitigation at the time of NTPC's next GRA. [Para 97]

11. NTPC is therefore directed to review its management of insurable risks in light of industry best practices with a view to jointly optimizing the costs associated with managing insurable risks, insurance premiums and self-insurance costs and report on the steps taken to address this matter at the time of the next GRA. [Para 103]

12. Accordingly, NTPC is directed to file a Phase II application concurrent with its next GRA Phase I application to address any under recovery of costs by rate Zone and by rate class. [Para 130]

Other Directions:

13. Accordingly, NTPC is directed to institute a system, as part of its capital planning process, for assigning unique numbers/codes for projects and to track the same numbers/codes through the project execution phases for monitoring and reporting purposes. [Para 22]

14. The Board re-emphasizes the requirement for the narrative description explaining how the capital plan fits into the Corporation's strategic direction including affordability of rates. Accordingly, the Board and directs NTPC to

continue to file five-year capital plans in full compliance with Directive 1 from Decision 16-2017. [Para 24]

15. Accordingly, NTPC is directed to file project permit applications where the forecast gross cost of a project exceeds $5 million in future. [Para 27]

16. Accordingly, NTPC is directed to file copies of project proposals submitted for senior management approval in support of all projects with costs exceeding $400,000 but less than $1 million. For projects with costs exceeding $1 million, NTPC is directed to file detailed business cases in support of proposed capital additions. [Para 142]

17. Accordingly, as part of its next 5 year capital plan filing NTPC is directed to describe the connection between the capital plan and the corporation's strategic goals described in the above quote, including the following:

- Expansion of heat sales for Fort Smith
- Capital costs, operating costs or revenue implications arising from expanding hydro power sales from the Taltson grid
- Capital plans that would enable NTPC to meet the Corporation's decarbonization target for 2030
- Review of the current net metering policy (including caps) in relation to the intended goals of the policy and its effectiveness in achieving those goals. [Para 152]

11 BOARD ORDER

158. The Board directs NTPC to file with the Board and interested parties a Compliance application reflecting amendments to the 2022/23 GRA arising from this Decision, including all supporting information and MFR schedules within 7 business days of this Decision.

159. The Board directs NTPC to file proposed rates effective for January 1, 2023 based on the 2022/23 rate level revenue requirement set out in the Compliance filing, within 7 business days of this Decision

160. 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 NORTHWEST TERRITORIES
PUBLIC UTILITIES BOARD

Gordon Van Tighem

Digitally signed by Gordon Van Tighem
Date: 2023.01.18 19:08:13 -07'00'

Gordon Van Tighem
Chairman

Dated January 18, 2023