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Newmarket-Tay Power Distribution Ltd.

March 4, 2021

Registrar
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Suite 2700
Toronto, ON M4P 1E4
registrar@oeb.ca

Attention: Registrar

Re: Newmarket-Tay Power Distribution Ltd.
Incentive Regulation Mechanism ("IRM") Application (EB-2020-0041)
Reply Submission

Newmarket – Tay Power Distribution Ltd. ("NT Power") is the Applicant in the above-referenced proceeding. In accordance with the Ontario Energy Board's (the "OEB") Procedural Order No.1 dated January 7, 2021, parties were required to submit written submissions by February 18, 2021 with the reply submission due March 4, 2021.

Should you have any questions, please do not hesitate to contact the undersigned.

Respectfully submitted,

Original Signed By

Michelle Reesor
Regulatory Manager
Newmarket-Tay Power Distribution
mreesor@nmhydro.ca

IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Newmarket -Tay Power Distribution Ltd. for an Order or Orders approving or fixing a proposed schedule of adjusted distribution rates, retail transmission rates and other charges, effective May 1, 2021.

REPLY SUBMISSION

NEWMARKET – TAY POWER DISTRIBUTION LTD.

MARCH 4, 2021

INTRODUCTION

Newmarket-Tay Power Distribution Ltd. ("NT Power") filed an Incentive Rate-setting Mechanism ("IRM") application with the Ontario Energy Board ("OEB") on November 23, 2020 under section 78 of the Ontario Energy Board Act, 1998, seeking approval for changes to the rates that NT Power charges for electricity distribution, to be effective May 1, 2021 (the "Application"). As part of the Application, NT Power made a request for Incremental Capital Module ("ICM") funding.

The OEB accepted School Energy Coalition ("SEC"), Vulnterable Energy Consumer Coalition ("VECC") and Consumers Council of Canada ("CCC") as Intervenors.

In accordance with the OEB's Procedural Order No.1 dated January 7, 2021, parties were required to submit written submissions by February 18, 2021 with the Applicant's reply submission due March 4, 2021. NT Power received written submissions from OEB Staff on February 18, 2020. Submissions from SEC, VECC and CCC were received on February 19, 2020.

NT Power makes these reply submissions on the following four topics:

- Review and Disposition of Group 1 Deferral and Variance Accounts
- Lost Revenue Adjustment Mechanism Variance Accounts Disposition
- Incremental Capital Module
- Disposition of Account 1576 and Adjustment to Base Rates

Review and Disposition of Group 1 Deferral and Variance Accounts (DVA's)

OEB Staff supports the disposition of the Group 1 DVA balances for both rate zones. No other party made submissions on this issue.

Newmarket Tay Rate Zone ("NTRZ")

NT Power supports OEB Staff's submission to dispose Accounts 1588 and 1589 on a final basis as of December 31, 2019.

In response to a request for clarification identified by OEB Staff in submissions,[1] NT Power confirms the correction for the use of billed data, rather than monthly consumption data is limited to 2019. The correction was not required for the years 2013 to 2018.

NT Power is in agreement with OEB Staff's note that the Account 1595 (2017) balance for the NTRZ will be eligible for disposition in the 2022 rate year[2].

NT Power appreciates OEB Staff's assistance to make the updates to the Rate Generator model to reflect customers volume information for years 2013 and 2014 for Tab 6 and related Tab 6.1a and Tab 6.1.[3] The revised Rate Generator model provided with Staff Submission for NTRZ on tab '19. Final Tariff Schedule' is incorrectly populating an equal rate of $/KW 4.9977 for both Distribution Volumetric Rate - Thermal Demand Meter and Distribution Volumetric Rate - Interval Meter in cell E93 and cell E98 respectively.

Midland Rate Zone ("MRZ")

NT Power supports OEB Staff's proposal for final disposition of Account 1588 and 1589 balances as of December 31, 2019. NT Power supports and appreciates OEB Staff's correction to the Rate Generator model removing the balance for Account 1595 (2017).[4]

NT Power is in agreement with OEB Staff's note that the Account 1595 (2017) balance for the MRZ will be eligible for disposition in the 2022 rate year and not within the current proceeding[5].

[1] EB-2020-0041, OEB Staff Submission dated February 18, 2021 ("OEB Staff Submission"), page 5.
[2] OEB Staff Submission, page 6.
[3] OEB Staff Submission, page 6.
[4] OEB Staff Submission, page 8.
[5] OEB Staff Submission, page 8.

Lost Revenue Adjustment Mechanism Variance Accounts (LRAMVA) Disposition

NT Power is in agreement with OEB Staff to dispose of the LRAMVA debit balance of $463,882, as revised throughout the course of this proceeding. OEB staff submits that Newmarket-Tay Power has provided the appropriate supporting documentation to justify the additional savings amounts. OEB staff supports the disposition of the rate zones LRAMVA balances, as revised throughout this proceeding, and submits they are calculated in accordance with the OEB's LRAMVA guidelines[6].

Incremental Capital Module (ICM)

Ten-Year True-up Payment

Each of OEB Staff, SEC, VECC and CCC submit that the Holland TS CCRA ten-year true-up payment to be paid in 2021 (the "Ten-Year True-Up") meets the ICM criteria of materiality, need and prudence and should be approved for the maximum eligible incremental capital amount.[7]

Updated Evidence

On March 3, 2021, NT Power received updated results for the Ten-Year True-Up from Hydro One and has filed this updated evidence with the Board by way of letter dated March 4, 2021 ("Updated Evidence"). The following are the impacts as a result of this updated evidence:

1. Ten-Year True-Up updated from $6,100,000 to $6,585,200 (variance of $485,200)
2. CAPEX updated to $12,982,055 from $12,496,855 (variance $485,200);
3. Maximum Eligible Incremental Capital updated to $6,072,956 from $5,587,756 (variance $485,200); and
4. Incremental revenue requirement updated to $602,867 from $548,518 (variance $54,349).

Materiality

OEB Staff and SEC submit that the ICM calculations as adjusted are correct.[8]

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[6] OEB Staff Submission, page 11.
[7] OEB Staff Submission, page 15, EB-2020-0041 – School Energy Coalition Submission dated February 18, 2021 ("SEC Submission"), page 3, paragraph 4, EB-2020-0041 – Vulnerable Energy Consumers Coalition Submission dated February 18, 2021 ("VECC Submission"), page 6, EB-2020-0041 - Consumers Council of Canada Submission dated February 19, 2021 ("CCC Submission"), page 4.
[8] OEB Staff Submission, page 15, SEC Submission, page 3.

OEB Staff agreed that the $6.1 million Ten-Year True-up Payment does meet the project materiality threshold.[9] OEB Staff submits that the maximum eligible incremental capital amount calculated in response to OEB Staff Interrogatory NTRZ IR-19 is correct and should be approved at $5,587,756.[10] NT Power notes that at the time of OEB Staff submissions, the Updated Evidence was not yet available to provide the latest calculation for the Ten-Year True-Up amount. Based on the Updated Evidence, the Ten-Year True-Up amount is now $6,585,200 and the maximum eligible incremental capital amount is calculated to be $6,072,956.

NT Power agrees with OEB Staff that the Ten-Year True-up Payment is material and the calculation of maximum eligible incremental capital is correct. Accounting for the Updated Evidence, the calculation of the maximum eligible incremental capital amount applicable to the Ten-Year True-Up is updated as $6,072,956.

In this context, VECC argues that given the significant Ten-Year True-Up payment to HONI in 2021, NT Power should defer some capital spending in 2021 by 10% "to allow for better pacing of capital investments" – thereby reducing the maximum eligible incremental capital available in 2021 to $5,105,550.[11]

NT Power does not agree with VECC. NT Power filed its consolidated Distribution System Plan as part of this application, which fully supports the required capital expenditures in the 2020-2024 forecast period. NT Power explained that it already paced all categories of replacement at levels that were under the recommendation of the Asset Condition Assessment (ACA).[12] If NT Power were to further reduce its planned capital expenditures in 2021, it would result in an unsustainable system renewal program that is insufficient to maintain asset condition based on the information gained from the ACA. NT Power cannot agree to such an arbitrary reduction in its planned capital expenditures in 2021 without putting ongoing reliability of supply at a significant and imprudent level of risk.

In this context, NT Power notes that OEB Staff undertook a detailed review of the DSP and concluded that it "does support a reasonable capital expenditure level for 2021 which is the starting point of the ICM materiality threshold calculation for 2021 rates."[13]

[9] OEB Staff Submission, page 18.
[10] Ibid.
[11] VECC Submission, page 5.
[12] Response to Board Staff NTRZ IR-21(a).
[13] OEB Staff Submission, page 23.

Need

VECC agrees that the Ten-Year True-Up to HONI is adequately justified based on the OEB's direction with respect to the construction of Holland TS, CCRA agreement with set true-up dates and forecasted load that did not materialize.[14]

Each of OEB Staff, VECC, SEC and CCC agree that NT Power has passed the Means Test for the Ten-Year True-Up.[15]

Both OEB Staff and VECC agree with NT Power that the Holland TS is a discrete project and that the Holland TS true-up payments were not included in the base on which the rates were derived.[16]

OEB Staff submits that it would have been reasonable in 2009 for NT Power to forecast that there would be a future CCRA true-up payment to HONI due to the decreased load; however, the materiality of the true-up would have been uncertain and beyond the test year.[17]

Prudence

Each of OEB Staff, VECC, SEC and CCC agree that the Ten-Year True-Up payment to HONI for Holland TS is prudent.[18]

OEB Staff argues that the draft 2021 load forecasted for Holland TS included load growth and if not realized, could result in a fifteen-year true-up payment. While this may be true, only the passage of time will tell. NT Power does not propose to make any adjustments to its 2021 load forecasted for the Holland TS as part of this proceeding.

OEB Staff, VECC and CCC note in their submissions that the true-up payment amounts are still subject to change because NT Power has yet to finalize the payment amounts with HONI. As such, they suggest that NT Power could use the associated ICM variance accounts to track any differences between the actual ICM amount and the actual payment to HONI.[19] OEB Staff suggests that any differences can be trued-up at NT Power's next rebasing application in accordance with the OEB's ICM policy.[20]

NT Power agrees that this is the correct way to address differences between the forecasted Ten-Year True-Up payment and actual amounts paid to HONI under the OEB's ICM policy.

[14] VECC Submission, page 6.
[15] OEB Staff Submission, page 19, VECC Submission, page 6, SEC Submission, page 3, CCC Submission page 4.
[16] OEB Staff Submission, page 19, VECC Submission, page 6.
[17] OEB Staff Submission, page 19.
[18] VECC Submission, page 6, VECC Submission 6, SEC Submission, page 3, CCC Submission page 4.
[19] OEB Staff Submission, page 21, VECC Submission, page 6, CCC Submission, page 4.
[20] OEB Staff Submission, page 21.

Application of the Half-Year Rule

OEB staff agrees with NT Power that the half-year rule does not apply to the ICM, as per Chapter 3 of the 2021 Filing Requirements.[21]

Timing of the True-ups

Finally, CCC noted that the CCRA agreement sets out true-ups for years 5, 10 and 15 but finds it unclear that, given the project went into service in 2009, why those years are not 2014, 2019 and 2024?

Under the CCRA, the true-ups are calculated in respect of actual loading data in each of 2014, 2019 and 2024. However, as a practical implication of using actual data the true up payments cannot be calculated or charged until after that actual loading data has been collected and analysed (i.e. usually a year later). NT Power expects that COVID-19 may be part of the reason for HONI's delay in finalizing the Ten-Year True-Up calculations.

Five-Year True-up Payment

Both the Five-Year True-Up and Ten-Year True-Up relate to the same underlying asset (the "Holland TS") and obligations owing under the same CCRA. As a result, much of the underlying evidence supporting need, prudence and materiality for both the Five-Year True-Up and the Ten-Year True-Up is substantially similar.

Given this, NT Power believed it would be more efficient for the OEB to hear the ICM request in respect of both true-up payments at the same time – rather than staggering the applications over multiple years.

Despite the similarities in the underlying facts associated with the two true-up payments, each of OEB Staff, SEC, VECC and CCC argue that the Holland TS CCRA five-year true-up payment made to HONI in 2015 (the "Five-Year True-Up") does not satisfy the criteria for ICM applications and should be denied.[22]

Availability of the ICM Mechanism

The principle concern raised by OEB Staff relates to the availability of the ICM mechanism in 2021 to fund the Five-Year True-Up made in 2015.

[21] OEB Staff Submission, page 22.
[22] OEB Staff Submission, page 17, VECC Submission, page 1, SEC Submission, page 1, and CCC Submission, page 4.

OEB Staff argues that the approval of the Five-Year True-Up through a 2021 ICM application is not supported by the OEB's ICM policy as the payment was made in 2015.[23]

NT Power does not agree.

The OEB has previously demonstrated a willingness to grant incremental capital funding when unique circumstances merited such treatment.

For example, in its Decision and Order dated September 12, 2019 in EB-2018-0305, the OEB approved funding for Enbridge Gas Inc.'s ("EGI") Sudbury replacement project (costing $95.3 million) that went into service in 2018 under a capital-pass through mechanism in 2019, even though (1) that project did not qualify for incremental rate treatment under that same capital pass-through mechanism in 2018; and (2) the rate setting plan proposed by EGI did not include the same capital pass-through mechanism in 2019.

EGI did not demonstrate the level of financial need that NT Power has with this application, and despite this, the result was a practical and sensible outcome that allowed the newly merged EGI to achieve some level of rate recovery for a material capital project over the remainder of its deferred rebasing period.

NT Power is seeking a similarly fair and reasonable treatment with respect to its request for ICM funding for the Five-Year True-Up.

Similarly, in its March 22, 2018 Decision and Rate Oder in EB-2017-0265 in respect of Rideau St. Lawrence Distribution Inc., the OEB approved for ICM funding of the remaining net book value of a project in a year subsequent to an assets in-service date (the "RSL Decision").

The rationale agreed to by OEB Staff to support the approval of ICM funding, which was ultimately approved by the OEB in the RSL Decision was:

> "*This IRM application is the first opportunity that RSL has had to request funding for this significant and planned purchase. The digger truck is providing a benefit to RSL's customers, as it replaced an aging and unreliable truck. The digger truck represents a significant capital expenditure over the level of normal capital expenditures recovered through RSL's base distribution rates. The level of capital expenditures approved in EB-2015-0100 for the 2016 test year (and also for 2017) is $464,088, ignoring the digger truck capital cost of $379,015. Not recovering prudently incurred costs for the truck – which is in service to allow RSL to provide safe, reliable and quality distribution services to its customers – could pose a significant financial risk to RSL's financial picture over the current Price Cap IR term.*

[23] OEB Staff Submission, page 16 and 17.

> *RSL views the capital funding as a means to appropriately recover this capital expenditure necessarily incurred to service its customers.*"[24]

This rationale identifies four key considerations that informed the OEB's determination on the RSL ICM request. First, RSL was precluded from filing for an ICM in the year in which the capital expenditure was made and the asset went into service. Second, the asset in question is providing benefit to customers. Third, the capital expenditure represented a significant capital expenditure over the level of normal capital expenditures recovered through RSL's base distribution rates. Fourth, not recovering the costs could pose significant financial risk to RSL's financial picture over the remaining term of the current rate plan.

The rationale for ICM funding for the Five-Year True-Up is largely the same rationale as was approved by the OEB to support ICM funding in the RSL Decision.

A. *ICM was not available in the year in which the capital expenditure was made and the asset went into service*

As noted by OEB Staff in their submissions, Rideau St. Lawrence Distribution Inc. ("RSL") was precluded from filing for an ICM in the year in which the capital expenditure was made and the asset went into service.[25]

How did this unusual circumstance arise?

RSL did not file its application for rates effective May 1, 2016 until October 10, 2016.[26] As a consequence, given the normal time it takes to process such an application, the OEB did not issue its Decision and Order in EB-2015-0100 until June 15, 2017. This was a foreseeable consequence of the late filing.

In its Decision and Order in EB-2015-0100, the OEB approved a July 1, 2017 effective date and the OEB removed RSL's ability to file for an IRM application for rates effective May 1, 2017 by stating "*[t]he OEB finds that Rideau St. Lawrence Distribution should file its next IRM application for May 1, 2018 rates as this Decision and Order is issued in the 2017 rate year.*" Again, this is arguably a foreseeable consequence of the late filing.

Because of this, RSL was unable to file for ICM funding for the truck in 2017. Notably, the OEB did not seek to punish RSL for the late cost of service filing by denying it ICM recovery for the truck.

Despite this, several parties are now suggesting that the OEB should punish NT Power for selecting the Annual IR option in 2015 – an option which is readily available to all distributors and entirely consistent with the OEB's policies and procedures.

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[24] RSL Decision, Schedule B, at page 11.
[25] OEB Submissions at page 17.
[26] RSL Application dated October 21, 2016 in EB-2015-0100.

NT Power was unable to file for ICM funding for the Five-Year True-Up in 2015 because NT Power was operating under Annual IR and the OEB's policies expressly prohibited it.

However, in late 2018 NT Power and Midland Power Utility Corporation ("Midland Power") merged and commenced a 10-year deferred rebasing period. In this context, the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* provides:

> "*To encourage consolidation, the 2015 Report extended the availability of the ICM for consolidating distributors that are on Annual IR Index, thereby providing consolidating distributors with the ability to finance capital investments during the deferral period without being required to rebase earlier than planned.*"

In this context, each of OEB Staff, CCC and SEC argues that NT Power consciously chose the Annual IR rate-setting method, which included the trade-off of no ICM available in the applicable test year.[27] VECC, CCC and SEC argue that NT Power had every opportunity to rebase and recover the Five-Year True-Up payment given its significance to the utility at the time.[28]

It is correct to say that ICM was not available in the 2015 test year due to NT Power's decision to file under the Annual IR mechanism. As a direct result of this decision, NT Power has foregone incremental revenue totalling $3,959,839 to the end of 2020 arising as a direct result of the Five-Year True-Up.[29]

This is shown in Table 1 of the Application, which is reproduced again below for ease of reference.

Table 1: Foregone Revenue and Incremental Revenue Requirement

Foregone Revenue for 2015 Contribution by year		
Application Table 1		
	2015	
2015	659,973	
2016	659,973	
2017	659,973	
2018	659,973	
2019	659,973	
2020	659,973	
Total	**3,959,839**	

27 OEB Staff Submission, page 16 and 17, CCC Submission, page 3, and SEC Submission, page 1 and 2, paragraph 3(a).
28 VECC Submission, page 3, CCC Submission, page 3, and SEC Submission, page 2.
29 2021 IRM Rate Application NT Power – NTRZ – ICM Application at Table 1: Foregone Revenue and Incremental Revenue Requirement.

NT Power has been living with the consequences of this decision since 2015 – and ratepayers have financially benefitted with savings of approximately $660,000 per year since that time. NT Power is not asking for ratepayer funding to make up any of these prior year amounts as part of this Application.

However, it is not correct to suggest (as various parties have) that NT Power is not entitled to rate recovery for the Five-Year True-Up at any time because of a single decision made in 2015.

So what has changed that has led NT Power to seek ICM funding in this Application?

As discussed in greater detail under part D below, the utility's financial circumstances have changed to the point where management determined it would be prudent to alert the OEB of the situation and seek ICM funding for the Five-Year True-Up.

B. <u>The asset in question is providing benefits to customers</u>

In the RSL Decision, it was recognized that the digger truck was providing a benefit to RSL's customers, as it replaced an aging and unreliable truck.

Similarly, the Holland TS is providing a benefit to NT Power customers, as it helped address the most urgent areas of need for electricity supply in York Region at the material time, as identified by the OEB in its Decision and Order in EB-2005-0315.

SEC argues that NT Power ratepayers have not in fact had any material benefit from the Holland TS, and may never have any benefit.[30] This is not factually accurate and the benefit of Holland TS can be understood through looking at the rationale behind the construction of Holland TS.

Due to the significant growth in demand for electricity in York Region that exceeded the capacity of the existing electricity infrastructure in the region, in early 2005, the OEB directed the utilities serving York Region: Newmarket Hydro (the predecessor to NT Power), Aurora Hydro Connections Limited, Power Stream Inc. and Hydro One Networks Inc. (Distribution) (collectively, the "York Region Utilities") and Hydro One Networks Inc. (Transmission) ("Hydro One") to identify the optimal transmission and/or distribution infrastructure investment to serve York Region.[31]

The Ontario Power Authority ("OPA") was directed by the OEB to conduct a study, and its key conclusion was that the existing infrastructure to serve York Region has not kept up with the growth of the Region.

[30] SEC Submission, page 2.
[31] EB-2005-0315 Decision and Order dated November 22, 2005, pg. 3.

Specifically, the Armitage TS in Newmarket had a planning limit of 317 MW. It had passed that capacity in 2002 and had been serving beyond its planning limit since then. The actual peak load in the Armitage TS service area was 370 MW, so there was an existing shortfall of 53 MW.

The OPA agreed with the York Region Utilities that the Holland Junction Proposal was the preferred solution to relieve the existing capacity shortfall.[32] A new transformer station will provide 150 MW of new capacity and eight feeder positions.[33]

As an immediate solution to this problem, the OPA recommended that the installation of a new transformer station at the Holland Junction in King Township and associated capacitators and distribution feeders – in other words, the OPA agreed with the York Region Utilities that the Holland Junction Proposal was the preferred solution to relieve the existing capacity shortfall.[34]

The Holland TS was the immediate solution to the problem that York Region, and in turn, NT Power customers were facing at the material times. Failure to take steps to increase supply would have increased equipment loading and have adversely impacted supply reliability in case of a contingency.[35] By having the Holland TS address the imminent supply issue at that time, NT Power customers were able to benefit and continue to benefit from a reliable supply of electricity.

C. *<u>The capital expenditure represents a significant capital expenditure over the level of normal capital expenditures recovered through base distribution rates</u>*

As shown in Table 3 of the ICM Application, the Five-Year True-Up is approximately 174.8% of NT Power's normal capital expenditures for 2015 and the Ten-Year True-Up approximately 95.4% of NT Power's normal capital expenditures for 2021. Approximately 45.8% of NT Power's total normal capital expenditures from 2015 to 2021 is on true-ups, which are not in rate base.

On this basis, undoubtedly the Five-Year True-Up represents a significant capital expenditure over the level of normal capital expenditures recovered through base distribution rates for 2015.

[32] Ibid pg. 4.
[33] Ibid pg. 8.
[34] Ibid pg 3.
[35] Ibid pg. 2.

D. <u>Not recovering the costs could pose significant financial risk to the utility's financial picture over the remaining term of the current rate plan</u>

If NT Power continues to forego the revenue requirement associated with the Five-Year True-Up, this lack of incremental cash flow now represents a risk to the utility's financial picture over the remaining term of the current rate plan.

This is the reason NT Power management brought an ICM application for the Five-Year True-Up.

This is illustrated in Table 2 of the ICM Application, which has been updated below to reflect the addition information provided for 2020 and 2021 in the response to interrogatories NTRZ IR-18 and CCC-5.

Table 2: NT Power Actual and Forecasted ROE Performance (2015-2021)

Year	**Deemed ROE**	**Achieved ROE**	**Variance**	**Rate Zone**
2015	9.66%	8.51%	(1.15%)	NTRZ
2016	9.66%	8.01%	(1.65%)	NTRZ
2017	9.66%	2.41%	(7.25%)	NTRZ
2018	9.66%	11.19%[36]	1.53%	NT Power (NTRZ + MRZ)
2019	9.66%	6.94%	(2.72%)	NT Power (NTRZ + MRZ)
2020 (estimate)[37]	9.66%	6.41%	(3.25%)	NT Power (NTRZ + MRZ)
2021 (forecast)[38]	9.66%	4.81%	(4.85%)	NT Power (NTRZ + MRZ)
7 Year Average	9.66%	6.89%	**(2.76%)**	

In this context both OEB Staff and VECC argue that NT Power has in all the years, except 2017, achieved a rate of return that was within the 300 basis point dead band.[39]

This is not factually correct as shown in Table 2 above.

[36] CCC-5 shows that the 2018 ROE of 11.59% was due to recognition of an extraordinary LRAMVA claim relating to the 2011-2017 fiscal periods. Removing this one-time exceptional adjustment, the achieved ROE in 2018 was 7.23%.
[37] NT Power Response to Interrogatories - Board Staff NTRZ IR – 18(a).
[38] As described in NTRZ IR-18, this forecasted ROE assumes the Five-Year True-Up is denied. In addition, it excludes the impact of any incremental revenues arising from an Account 1576 disposition.
[39] OEB Staff Submission, page 15, VECC Submission, page 3.

VECC and SEC submit that NT Power and the OEB did not indicate any doubt to NT Power's financial viability at the time of the merger.[40] While this is true - NT Power's ROE in 2018 at the time of the merger was 11.19% and NT Power did not have reason to forecast the subsequent reduction in its ROE at that time. Things have changed. Certainly a single point in time forecast cannot be determinative of a subsequent ICM request that is driven by an actual reduction in NT Power's ROE.

In this context, the OEB has a statutory objective to ensure the financial viability of the electricity industry (including NT Power).

In addition, NT Power management has an ethical obligation to inform the OEB of its situation and to propose practical solutions to address the situation.

While OEB Staff is correct that many factors may contribute to a lower ROE in any given year,[41] that is not a good enough reason to entirely ignore the evidence on ROE performance. It is also true that:

- the OEB adopted the deemed ROE standard as the means by which it will meet its legal obligation to ensure a utility achieves the fair return standard;[42] and
- the OEB adopted a 300 basis point earnings dead band as an off-ramp in its rate-setting framework to ensure that both utilities and ratepayers are protected.[43]

In this context, NT Power recognizes that the OEB has several options available of how it might choose to address the current situation.

NT Power submits that the most efficient and practical solution would be for the OEB to grant ICM funding for the Five-Year True-Up due to special circumstances noted above, which would be enough to bring NT Power's ROE back to within the 300 basis point ROE dead band in 2021.

This would avoid the considerable incremental regulatory burden, cost and expense that would arise should the OEB instead choose to cut short the OEB-approved ten year deferred rebasing period approved in EB-2017-0269.[44]

Since the 2020 ROE figure is an estimate and 2021 is a forecast, it is too early to determine whether or not a specific deadband threshold has been crossed. However, these figures do reflect a useful indication of why ICM recovery for the Five-Year True-Up is needed.

[40] SEC Submission, page 2 paragraph 3(d).
[41] OEB Staff Submission, page 16.
[42] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084).
[43] Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach dated October 18, 2012 at page 11.
[44] EB-2017-0269 Decision and Order dated August 23, 2018 at page 21.

E. Out-of-Period Costs

CCC also argues that the ICM mechanism is not intended to allow for recovery of an asset from a prior period and those assets/payments are included in rate base upon rebasing. It is not appropriate to claim a 2015 cost in 2021.[45] Both SEC and VECC argue that allowing the ICM claim for the Five-Year True-Up would effectively be retroactive ratemaking.[46]

These submissions neither consider nor address the OEB's determination at pages 4-5 of the RSL Decision, which provides:

> "The first is the statement that: "recovery of costs for 2017 may be considered out-of-period". The OEB does not consider the cost for the digger truck to be an out-of-period cost in 2018. No incremental funding is being sought for 2017, and the cost used for the calculation of the funding starting in 2018 is the net book value of the asset in 2018 (i.e. it has been reduced by the depreciation in both 2017 and 2018).
>
> The second statement is that: "the cost recovery for the digger truck beginning in 2018 is not an Incremental Capital Module as the digger truck entered service prior to 2018." The OEB agrees that the typical approach to the incremental capital module (ICM) is for the incremental funding to start in the year that an asset is planned to go into service. The OEB's models have therefore been designed for this typical situation. However, the OEB considers the approach used for incremental capital funding as part of this settlement proposal consistent with the OEB's policy for the ICM. The policy states that the advanced capital module (ACM) and ICM are for incremental funding for "capital projects scheduled to go into service during the IRM term". The OEB considers any period of time between cost of service applications to be part of the IRM term. The digger truck therefore went into service during the IRM term. In the unique circumstances of Rideau St. Lawrence Distribution there was no 2017 rate application and, therefore, no incremental funding was available for the digger truck in 2017, but this does not prohibit incremental funding for 2018.
>
> The OEB's ICM policy also states that: "Funding shall not commence for any projects that are not forecasted to be in service during the subject IR year". The digger truck is in service in 2018 and is therefore eligible for the ICM, subject to the other conditions."

NT Power followed the OEB's guidance in this decision very carefully in preparing its ICM request for the Five-Year True-Up:

[45] CCC Submission, page 3.
[46] SEC Submission, page 2, VECC Submission, page 4.

- The 2021 ICM funding requested reflects only for the net book value of the capital contribution in 2021 (i.e. it has been reduced by depreciation for the years between 2015 to 2020).
- No incremental funding is being sought for 2015-2020. Therefore, consistent with principles set out in the RSL Decision the depreciated Five-Year True-Up it is not an out-of-period cost in 2021.
- NT Power's NTRZ was in 2015 and continues to be in 2021 operating under the OEB's Annual IR rate setting plan. There has been no changes made to NT Power's NTRZ rate setting plan between 2015 and 2021. This is clearly reflected in the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* at page 15 which indicates that distributors must "[c]ontinue with current plans for chosen deferred rebasing period" in circumstances where one distributor is on Price Cap IR (MRZ) and one is on Annual IR (NTRZ). The MAADs handbook does not suggest a new rate plan commences following a merger transaction. Rather, the opposite is true – the current plans continue for the chosen deferred rebasing period. Applying the RSL Decision in these circumstances, the ICM policy continues to be available to NT Power as it is within the period of time between cost of service applications.
- The Five-Year True-Up was paid in 2015 which is within the term of current Annual IR plan.
- Finally, in the unique circumstances of this case, NT Power was prohibited from seeking ICM recovery in 2015 due the application of the OEB's policies as it relates to Annual IR at that time. This prohibition is no longer applicable in 2021 due to the application of the OEB's consolidation handbook.

F. <u>2021 Maximum Eligible Incremental Capital</u>

Each of OEB Staff, CCC and SEC argues that any ICM funding for 2021 must be established based on the available funding in 2021. Once the funding for the Ten-Year True-Up payment is taken into account, NT Power does not have any available amounts for the Five-Year True-Up.[47]

OEB Staff's view is that the OEB should not allow for more funding than the maximum eligible incremental capital funding based on the 2021 calculation given that funding is requested for 2021 rates and the ICM materiality test is effectively a cash flow test.[48]

NT Power does not agree.

Through the course of this proceeding NT Power identified two reasonable approaches to calculating the maximum eligible incremental capital applicable to the Five-Year True-Up.

[47] OEB Staff Submission, page 17, CCC Submission, page 3, and SEC Submission, page 2.
[48] OEB Staff Submission, page 17.

If the maximum eligible incremental capital is indeed a cash-flow test, then the process set out in the Application is appropriate.

In the Application NT Power calculated the maximum eligible incremental capital applicable in 2015 – the year the Five-Year True-Up was made – and used this limit value of the Five-Year True-Up in 2015. NT Power then depreciated this value to 2021 dollars and seeks recovery of this amount.

Disposition of Account 1576 and Adjustment to Base Rates

Account 1576 Disposition

NT Power supports OEB Staff's submission for final disposition of the balance in Account 1576, subject to the recalculation of the balance using the 2020 unaudited capital additions and depreciation figures. OEB staff notes that by using these figures, the credit balance of Account 1576 would increase by $163,717.[49]

NT Power submits the Account 1576 balance with the 2020 unaudited actual figures, rather than the amounts originally forecast when the application was originally filed in November 2020. NT Power is in agreement with OEB Staff that the 2020 actual figures represent a greater degree of accuracy compared to the forecast.[50]

NT Power agrees with SEC and OEB Staff that the adjusted amount of the final 1576 clearance is correct.[51]

Adjustment to Base Distribution Rates

NT Power agrees with OEB Staff that the weighted average cost of capital (WACC) should be applied to the rate base differential arising from the changes of the capitalization and depreciation policies on a going forward basis.[52]

In addition, NT Power agrees with OEB Staff that this adjustment to base distribution rates is similar to a narrow scope rebasing application.[53]

[49] OEB Staff Submission, page 25.
[50] OEB Staff Submission, page 25.
[51] SEC Submission, page 3.
[52] OEB Staff Submission, page 25.
[53] Ibid.

In justifying its approach to using NT Power's last OEB approved WACC for this narrow scope rebasing in NTRZ Staff-17(f), NT Power incorrectly cited the Whitby Hydro 2019 IRM Settlement Proposal in EB-2018-0079.

As OEB Staff correctly note in their submissions, this settlement is not on point.[54] NT Power apologizes for this error.

NT Power had intended to cite the Whitby Hydro 2018 IRM Settlement Proposal found at Schedule B of the OEB's Decision and Order dated December 20, 2017 in EB-2017-0085/EB-2017-0292. OEB Staff was party to this settlement, and of course must be aware of its contents.

In this Decision, the OEB approved a settlement proposal that included an adjustment to base distribution rates to account for smart meter incremental revenue requirement,[55] which adjustment was calculated using Whitby Hydro's last OEB cost of capital parameters from 2011.[56]

Similar to this case, the smart meter incremental revenue requirement was a narrow scope rebasing application.

In this context, NT Power disagrees with OEB Staff's proposal to apply a WACC of 5.00% or a working capital allowance (WCA) of 7.5% to the rate base differential. There is no evidence on the record to support that use of a WACC of 5.00% is appropriate given the factual circumstances of NT Power, or the use of a 7.5% WCA is appropriate given the factual circumstances of NT Power.

If the OEB wishes to recalculate the WACC applicable to NT Power, then the appropriate approach would be to apply the policies and procedures set out in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation* dated December 20, 2006 and the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* dated December 11, 2019 (EB-2009-0084).

With regards to the 40% equity component of rate base, the OEB's new deemed ROE would apply. However, with regards to the 60% debt component of rate base, it is first necessary to examine NT Power's actual long-term debt instruments to calculate an actual weighted-average cost of long-term debt. Only in limited circumstances, for example when

[54] OEB Staff Submission, page 26.
[55] OEB's Decision and Order dated December 20, 2017 in EB-2017-0085/EB-2017-0292 at Schedule B: Settlement Proposal at pages 7-8.
[56] See Stand-Alone Rate Application in EB-2017-0085/EB-2017-0292 at Exhibit 1 page 7 lines 16-17.

a long-term debt instrument is held by an affiliate and is callable on demand, would the OEB's deemed long-term rate apply as a cap on that particular debt instrument.

NT Power has significant amount of non-affiliated long-term debt held by third parties at interest rates that greatly exceed the OEB's current deemed long-term debt rate. NT Power holds this debt because the utility needed financing at a particular point in time, and the rate the utility obtained was the best possible in the circumstances at that time.

In this context, OEB Staff is asking the OEB to entirely ignore the existence of third party long-term debt held by NT Power and instead assume that the deemed long-term debt rate should be used for all long-term debt to calculate WACC.

This is an adverse inference that is without precedence and severely underestimates NT Power's actual WACC.

In this context, NT Power submits that use of the last OEB approved WACC from 2011 is both consistent with the Whitby Hydro smart meter incremental revenue precedent and is a more appropriate and accurate reflection of NT Power's actual WACC.

Similarly, OEB Staff is asking that the OEB apply a WCA of 7.5% without any evidence that this is appropriate in the circumstances.

By contrast, if this were a real rebasing application, NT Power would be given the option to take one of two approaches for the calculation of its WCA: (1) use the default allowance of 7.5% of the sum of Cost of Power (CoP) and OM&A or (2) file a lead/lag study.

NT Power has not selected the use of 7.5%. And there is no evidence on the record that, in light of the winter disconnection ban as well as recent amendments to the Distribution System Code extending certain billing and collections timelines, that NT Power's actual working capital requirement approaches 7.5%.

In this context, and similar to the WACC, NT Power submits that the last OEB approved WCA of 15% should apply.

- All of which is respectfully submitted -