Report on Newfoundland Power's Deferral Accounts

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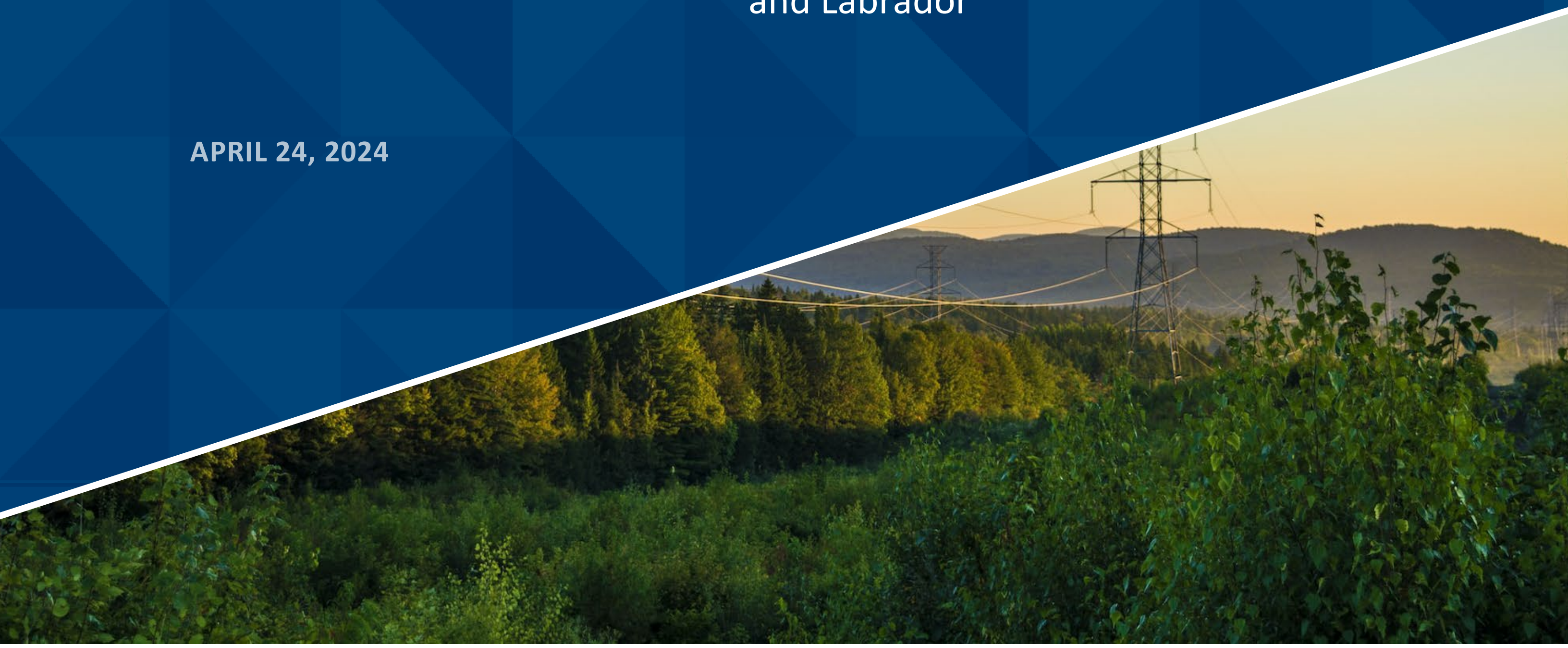

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I. Introduction

This report reviews the various deferral accounts and incentive mechanisms currently in use by Newfoundland Power ("NP"), which The Board of Commissioners of Public Utilities of Newfoundland and Labrador ("Board") has approved. This report places particular focus on determining whether these deferral accounts provide proper incentives for NP, allow for the elimination of regulatory lag and customer rate stabilization, and are consistent with other investor-owned Canadian electric utilities' deferral account procedures.

The structure of the report is as follows. Section II provides an overview of deferral accounts currently in place for NP. Section III examines the mechanics of the Rate Stabilization Account and other power supply cost accounts. Section IV will review NP's Excess Earnings Mechanism by comparing the mechanics of the account to earnings-sharing mechanisms implemented by other utilities. Section V compares the total account coverage of investor-owned Canadian electric utilities to that of NP. Section VI summarizes our conclusion and findings regarding NP's deferral accounts.

II. Overview of NP Deferral Accounts

Currently, NP has various deferral accounts, four of which are related to power supply costs and are outlined in Table 1. Other deferral accounts that have been approved for usage by NP relate to items such as excess earnings, electrification, demand management, pensions and employee benefits, and revenue shortfalls and are outlined in Table 2.

The balances in the deferral accounts are primarily recovered through the Rate Stabilization Account ("RSA"), which adjusts rates annually based on the balance of the RSA that has been amortized over 12 months. This report will discuss this in greater detail in Section III. Other accounts are recovered through rates either on a specific amortization schedule or at the discretion of the Board.

TABLE 1: POWER SUPPLY COST DEFERRAL ACCOUNTS

Account	Description	Board Order	Recovery Mechanism
Rate Stabilization Account	Accounts for variations in Newfoundland and Labrador Hydro's production costs, which are captured in their Rate Stabilization Plan to be recovered in NP's rates. Also accounts for recovery of other adjustments as described in this report.		Rate Stabilization Account
Energy Supply Cost Variance	Accounts for the difference between the average test year cost of supplying energy versus the marginal energy supply costs.	P.U. 32 (2007)	Rate Stabilization Account
Demand Management Incentive ("DMI") Account	Recovers cost variances associated with demand and energy cost variability and incentivizes NP to undertake initiatives to minimize peak demand.	P.U. 32 (2007) P.U. 43 (2009)	Application to the Board for disposition of account balances, which has historically been done through the Rate Stabilization Account.
Weather Normalization Reserve	Normalizes the effects of weather and hydrology on sales and power supply costs to avoid NP experiencing earnings windfall or shortfall as a result of weather conditions.	P.U. 32 (1968) P.U. 1 (1974) P.U. 13 (2013)	Application to the Board for disposition of account balances through the Rate Stabilization Account.

TABLE 2: OTHER DEFERRAL ACCOUNTS

Account	Description	Board Order	Recovery Mechanism
Excess Earnings Account	Credits all earnings in excess of 18 basis points above the approved return on rate base to this account.	P.U. 19 (2003)	Disposed of by determination of the Board.
Pension Expense Variance Deferral	Accounts for differences in test year pension expense compared to actual pension expense.	P.U. 43 (2009)	Rate Stabilization Account
Other Post Employee Benefits ("OPEB") Cost Variance Deferral	Accounts for differences in test year OPEB expense compared to actual OPEB expense.	P.U. 31 (2010)	Rate Stabilization Account
Pension Capitalization Cost Deferral Account	Accounts for the change in capitalization of pension costs mainly due to income tax effects.	P.U. 3 (2022)	Amortized over five years.
Deferred Conservation and Demand Management Deferral	Accounts for costs related to the conservation and demand side management programs implemented by NP.	P.U. 3 (2022)	Rate Stabilization Account to be amortized over ten years.
Electrification Deferral Account	Accounts for costs incurred in the implementation of the Customer	P.U. 3 (2022)	A future order will determine this account's disposition. As part of the current General Rate

Account	Description	Board Order	Recovery Mechanism
	Electrification Portfolio approved by the Board.		Application, NP is requesting amortizing this account over ten years.
Load Research and Rate Design Cost Deferral	Captures costs associated with the Load Research Study and a Retail Rate Design Study to be conducted.	P.U. 3 (2022)	A future order will determine this account's disposition.
2022 Revenue Shortfall	Recovery of a 2022 revenue shortfall.	P.U. 3 (2022)	Through the Rate Stabilization Account amortized over 34 months.
Hearing Cost Recovery Deferral	Recovery of hearing costs from the Board and the Consumer Advocate from the NP 2022-2023 General Rate Application.	P.U. 3 (2022)	Through the Rate Stabilization Account amortized over 34 months.

As part of NP's 2025-2026 General Rate Application ("GRA"), NP is requesting approval for amendments to its current deferral accounts and the establishment of new deferral accounts. NP is proposing amendments to the DMI Account, which includes setting the incentive threshold at ± $500,000, as opposed to the current threshold of ± 1 percent of test year billing demand costs.[1] For more details on the DMI Account, refer to Section III. NP is also proposing to amend the Pension Capitalization Cost Deferral Account to cease charges to the account effective December 31, 2024.[2] NP has proposed creating 1) a Hearing Cost Recovery Deferral for Board and Consumer Advocate costs related to the 2025-2026 GRA and 2) a deferral account for revenue shortfalls associated with 2024 and 2025.[3]

1 Newfoundland Power - 2025-2026 General Rate Application at Page 3-2.

2 *Id.*

3 *Id.*

III. Rate Stabilization Account and Power Supply Cost Accounts

Rate Stabilization Account

The RSA is the primary cost adjustment mechanism for NP and a means to adjust customer rates for various deferral account balances. The RSA was first created as a means to ensure that Newfoundland and Labrador Hydro's ("Hydro") Rate Stabilization Plan ("RSP") adjustment, relating to its power production costs, was captured in NP's customer rates. The current version of the RSA now also includes various adjustments from NP's deferral accounts. The RSA balance will be included in customer rates through the rate stabilization adjustment, which occurs July 1st of each year, which is amortized over 12 months and is comprised of pass-through items from Hydro and the balance of NP's RSA.

Currently, the RSA captures the following items from Hydro: 1) the annual recovery amount of Hydro's RSP, 2) the annual recovery of Hydro's Conservation and Demand Management Cost Recovery Adjustment, and 3) the Muskrat Falls Project Cost Recovery Rider.

The balance of NP's RSA captures the following items:

- The variance in actual versus test year charges or credits to NP resulting from Hydro's rate adjustments.
- The variance in the excess cost of fuel used by NP. The variance is calculated as the difference in the per kWh price difference between NP's generation of electricity at its thermal plans and Hydro's second block rate, which is multiplied by the total monthly kWh hours generated by NP.[4]
- The price differential of firmed-up secondary energy supplied from Deer Lake Power instead of Hydro.
- The variance of any RSA adjustments not included as part of the test year.
- Variances in municipal taxes.
- Variance in any changes in revenues or costs related to any changes in Hydro's wholesale rate.

[4] Hydro's second block rate is discussed in further detail below regarding the discussion of Energy Supply Cost Variance.

- Other deferral account items that are listed in Table 1 and Table 2 of the report.
- Any other amounts the Board determines to include in the RSA.

Energy Supply Cost Variance

As part of Order P.U. 32 (2007), the Board allowed NP to implement the Energy Supply Cost Variance ("ESCV") deferral account, which was intended to account for the difference in marginal energy supply costs from test year average energy supply costs included in customer rates. NP's customer rates are designed to recover the test year's estimated average energy supply costs. However, as load requirements on NP's system increase, the marginal supply cost exceeds the average supply cost recovered in rates.

This condition arises because of the structure of Hydro's wholesale rate, which is comprised of a demand charge and a two-block energy charge. As of Hydro's 2017 GRA Compliance filing, the first block monthly energy charge of 2.444 ¢ per kWh is applicable to the first 410 GWh from November to April and the first 250 GWh from May to October. In any of those months, if NP requires excess energy supply, they are required to pay the second block monthly energy charge of 18.165 ¢ per kWh. The second block energy charge is based on the cost of fuel burned at Hydro's Holyrood Thermal Generation Station.

The ESCV is calculated by taking the difference in the wholesale rate of the second block charge per kWh minus the test year's energy supply cost per kWh.[5] This result is then multiplied by the weather-normalized annual purchases in kWh minus the test year annual purchases in kWh.

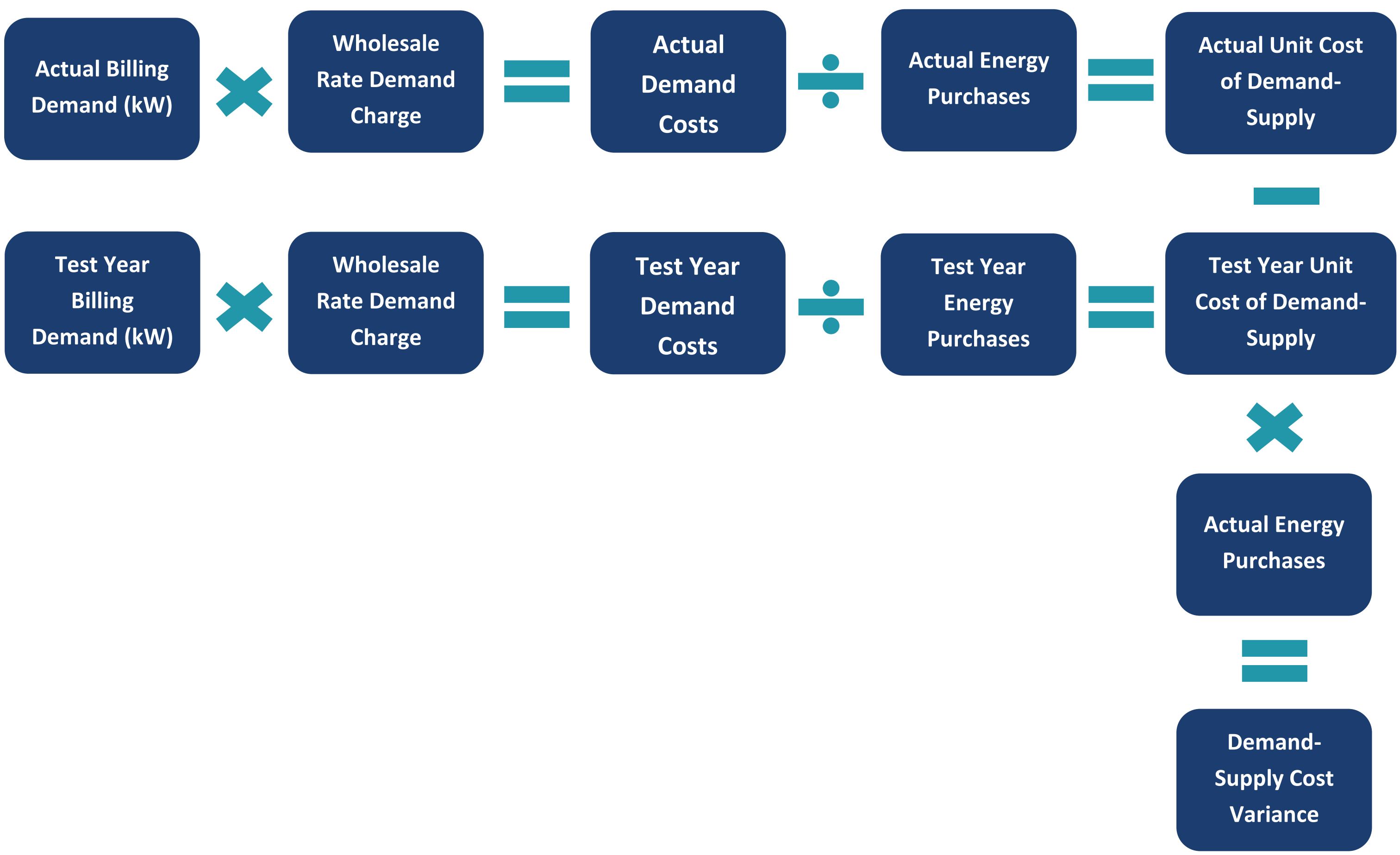
DMI Account

As part of Board Order P.U. 32 (2007), the DMI Account was approved by the Board. The DMI was intended to provide an incentive for NP to undertake initiatives to minimize peak billing demand and also provide the company with the ability to recover costs associated with variability in purchased power costs inherent in the demand and energy wholesale rate. The billing demand for NP is simply the maximum native load (i.e., total customer load) less any generation or service curtailment from NP, which is essentially the power purchases NP must make from Hydro. The disposition of the balance of the DMI Account is up to the discretion of the Board.

5 In NP's 2025-2026 General Rate Application the average supply cost rate included in NP's rates was 6.940 ¢ per kWh while the second block marginal rate was 18.165 ¢ per kWh.

The DMI Account achieves this by two mechanisms. Firstly, it provides an incentive to NP to lower its peak billing demand costs whereby any variance within a range of ± 1 percent of its test year demand costs compared to its actual demand costs will require no transfer. As a result, any savings or excess costs associated with variance in billing demand costs within ± 1 percent will be kept by NP. Secondly, any variance below or above the Demand Management Incentive bandwidth in the demand-supply cost variance will be charged or credited to the DMI Account. The demand-supply cost variance is calculated as the difference in the actual unit cost of demand-supply minus the test year unit cost of demand-supply multiplied by the actual energy purchases. Figure 1 below outlines the calculation of the demand-supply cost variance, which essentially considers the variance in billing demand and energy purchases from the test year to the actual.[6]

FIGURE 1: DEMAND-SUPPLY COST VARIANCE CALCULATION



[6] Note actual billing demand and actual energy purchases are based on a weather-normalized billing demand and energy purchases.

NP has proposed a change to the DMI Account in its 2025-2026 GRA. Instead of a threshold of ± 1 percent of test year billing demand costs as an allowable variance to be kept by NP, NP instead proposes that the threshold be replaced with a ± $500,000 allowable variance.[7] NP states this change is required to account for the lack of ability of NP to reduce its peak billing demand costs coupled with the fact that the ± 1 percent threshold has been increasing primarily due to increased wholesale supply costs.

Weather Normalization Reserve

NP utilizes a Weather Normalization Reserve to normalize the effects of weather and hydrology on variations to both revenues and power supply costs. This reserve is composed of two different components: a Hydro Production Equalization, which was initially approved in Board Order P.U. 32 (1968), and the Degree Days Normalization, which was initially approved in Board Order P.U. 1 (1974). Finally, the Board, in Order P.U. 13 (2013), determined that the Weather Normalization Reserve will be disposed of in the RSA on March 31st of each year.

The Degree Days Normalization determines the number of abnormal weather days in each of the eight NP operating areas and for each of NP's weather-sensitive rate classes. NP determines if an area experiences an abnormal weather day based on three weather variables: the heating degree days ("HDD"), cooling degree days ("CDD"), and wind speeds. Once abnormal weather days are calculated, they are multiplied by their corresponding coefficients for each applicable weather variable to determine the adjustment to kilowatt-hour sales and kilowatt-hour purchases for each month. The weather coefficients used to calculate this normalization were derived using a methodology approved by the Board on March 29th, 1995. The final balance of the Degree Days Normalization is determined net of income taxes.

The Hydrology Production Equalization seeks to account for changes in power purchase expense when inflows or steam flows vary from the normal stream flows reflected in the test year. NP provides the Board with a formal study, approximately every five years, that determines the average monthly normal hydroelectric production of its generation facilities. This formal hydroelectric study is conducted by reviewing a time series of stream flows from 1984-2018 that is then input into a power generation model to determine the estimated average potential annual power production. NP then adjusts this annual production level for any scheduled outages of its facilities that may impact potential generation. NP then measures the monthly actual stream flow for its generation facilities, and the difference between average and actual, in terms of

7 Newfoundland Power - 2025-2026 General Rate Application at Page 3-54.

megawatt-hours, is multiplied by the purchase power rate to determine the purchase power expense adjustment.

Table 3 provides the transfers to the Weather Normalization Reserve broken down into the Degree Days Normalization and the Hydrology Production Equalization.

TABLE 3: NP WEATHER NORMALIZATION RESERVE 2014-2023[8]

Year	Degree Days Normalization	Hydrology Production Equalization	Transfer to the Weather Normalization Reserve
	Net Debt (Credit) Transfer	Net Debit (Credit) Transfer	Net Debit (Credit) Transfer
2023	(83,145.68)	6,404,415.75	6,321,270.07
2022	(8,341,792.61)	1,766,055.79	(6,575,736.82)
2021	(10,365,788.42)	8,346,072.73	(2,019,715.69)
2020	(3,855,448.47)	121,941.65	(3,733,506.82)
2019	1,347,147.05	4,307,326.74	5,654,473.79
2018	90,635.56	1,426,688.42	1,517,323.98
2017	(111,943.00)	4,882,772.51	4,770,829.51
2016	(101,790.00)	1,822,494.94	1,720,704.94
2015	108,010.00	4,302,527.35	4,410,537.35
2014	103,981.00	(71,080.00)	32,901.00

Comparison to Other Utilities' Power Supply Cost Recovery Practices

Power supply cost recovery methods are common amongst investor-owned Canadian electric utilities. Typically, utilities will have deferral account coverage for both revenues and expenses related to power supply to account for variances in weather, customer loads, and power purchase expenses. These power supply cost deferral accounts are generally recovered from customers either through an automatic annual adjustment to the cost of service or through

[8] Sources: NP Applications for Approval of Balance in the Weather Normalization Reserve, 2015-2024.

adjustments to rate riders. While many electric utilities have some form of demand-side management incentive for programs related to reducing customer load requirements, it is less common for utilities to have an incentive to reduce peak demand requirements. The following subsections outline the recovery treatment of power supply costs for investor-owned Canadian electric utilities.

British Columbia

In FortisBC Inc.'s ("FBC") most recent Multi-Year Rate Plan ("MRP"), flow-through treatment was approved for revenue and power supply variances and would be captured in the Flow-through deferral account, which captures all items that have flow-through treatment for FBC. The balance of the Flow-through deferral account is recovered through revenue requirements for subsequent years during the MRP period.[9]

FBC was also approved to create a Power Supply Incentive ("PSI") mechanism, which results in the sharing of power supply cost savings resulting from active portfolio optimization in order to provide an incentive to FBC to reduce its power purchase supply expense. The PSI mechanism recognizes the reduction in power supply costs related to lower-priced power purchasing agreements, displacing current capacity with lower-priced capacity, the release of surplus capacity on a day-ahead basis, and future approved optimization activities. These savings will be shared with customers on the following basis: the first $7.5 million in savings will be to the total benefit of the customers, and any remaining reduction will be apportioned 90 percent to the customers and 10 percent to FBC.

Alberta

Alberta Utilities Commission ("AUC") regulated electricity distribution utilities provide distribution-only tariffs and are not required to recover commodity costs through their revenue requirements. Therefore, power supply cost recovery methods are not applicable to these utilities.

Ontario

The Ontario Energy Board ("OEB") allows electricity distributors to receive deferral account coverage for various pass-through costs related to commodity, Independent Electricity System Operator ("IESO"), and other third-party charges. These pass-through deferral accounts related

9 British Columbia Utilities Commission, Decision and Orders G-165-20 and G-166-20, at 65.

to power supply costs are included in the Retail Settlement Variance Account ("RSVA") and include the following items:

- Wholesale Market Service Charge: record the net difference between the amount charged by the IESO for using its grid and markets and the amount billed to customers using the OEB-approved wholesale market service rate.
- Retail Transmission Network Charge: record the net difference between the amount charged by the IESO for transmission network service and the amount billed to customers using the OEB-approved transmission network charge.
- Retail Transmission Connection Charge: record the net difference between the amount charged by the IESO for transmission connection service and the amount billed to customers using the OEB-approved transmission connection charge.
- Power Account: record the net difference in energy costs from the IESO and the amount billed to the customer for energy costs.
- Global Adjustment: record the net difference in spot prices charged from the IESO and the amount billed to the customers who are under a non-regulated price plan.

The pass-through cost items above are recovered or refunded automatically through adjustments to rates if a threshold of $0.001 per kWh (debit or credit) is exceeded.[10] The onus is on the distributor to justify why any account balance over the threshold should not be disposed of, and distributors may elect to dispose of the account balance even if they do not meet the automatic threshold adjustment.

<u>Nova Scotia</u>

Nova Scotia Power Inc. ("NSPI") utilizes a Fuel Adjustment Mechanism ("FAM") to account for variances in its test year power supply costs. The FAM consists of the following components:

- The base cost of fuel ("BCF") is the test year forecasted fuel, energy, and power supply costs that are included in customer rates. Any variance between the test year and actual fuel costs is recorded in the BCF monthly as a regulatory asset/liability and is held in the BCF until the end of the GRA term.
- The actual adjustment ("AA") represents the difference in the current year between the amount spent on fuel and the fuel-related revenue recovered from customers. This

[10] Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Application – 2023 Edition for 2024 Rate Applications, at 9.

account tracks the variance in current-year customer revenues related to the fuel component of rates.

- The balance adjustment (“BA”) represents the difference in the prior year between actual fuel costs and the fuel-related recovery from customers. The BA is comprised of previously deferred FAM amounts and any residual amounts of the AA related to previous years not fully refunded or recovered by the AA. The BA may also be used to return any non-fuel revenues exceeding the approved return on equity (“ROE”).

The FAM rate is calculated annually to account for the AA and BA and is recovered through rates. The FAM accounts are also subject to an audit every two years to ensure completeness and accuracy and to ensure fuel and purchased power costs were incurred reasonably and prudently.

Prince Edward Island

The Maritime Electric Company (“Maritime Electric”) has an Energy Cost Adjustment Mechanism (“ECAM”) that ensures the timely collection of prudently incurred energy supply costs from customers and includes deferral of fluctuations in energy supply costs during a rate-setting period. The ECAM captures the variance between the basic energy charge included in customer rates, which is based on a forecast of annual energy supply costs, and actual energy supply costs incurred by Maritime Electric. The balance of the ECAM is recovered through future rates via the ECAM Adjustment, which the Island Regulatory and Appeals Commission (“IRAC”) approves at the beginning of a rate-setting period.

Maritime Electric also has a Weather Normalization Reserve that provides deferral account coverage for variations in sales and energy supply costs caused by changes in temperature relative to historical averages. Contributions to this account equal the following:

- **Contributions to Weather Normalized Reserve = MWh Variation from Average x Marginal Net Revenue**
  - **MWh Variation from Average** = (Actual HDD Value – Average HDD) x (MWh per HDD Coefficient)
  - **Marginal Net Revenue** = Forecast Unit Revenue per MWh – Forecast Unit Energy Cost per MWh

Maritime Electric utilizes a 10-year rolling average of HDD in Charlottetown to determine average HDD. It determines an annual MWh per HDD Coefficient by using a linear regression, which estimates the change in MWh sales resulting from a unit variation in HDD. Disposition of the Weather Normalized Reserve is at the discretion of the IRAC during rate-setting periods.

Findings

Based on a review of NP's deferral accounts related to power supply cost recovery mechanisms and a comparison to other investor-owned Canadian electric utilities, we provide the following findings:

1. NP has a similar amount of coverage for power supply cost recovery mechanisms compared to other investor-owned electric utilities, and the RSA is an appropriate mechanism for the disposition of account balances related to power supply costs.

2. The ESCV deferral only accounts for variances in costs related to marginal energy supply and does not account for any variance in revenues that NP may receive. Since the revenues related to energy supply costs are not captured in the ESCV deferral, then in the situation where the marginal cost of energy supply is below the average energy supply costs, included in NP's rates, NP will be overcompensated in that current year, by capturing all associated energy supply revenues in their net income and deferring the energy costs supply costs via the ESCV. Customers do not receive a credit for the excess revenues unless NP's return exceeds the approved range of return for that year when the excess above the range is transferred to the Excess Earnings Account. However, in the situation where the marginal cost of energy supply is above the average energy supply costs, NP's rates would not capture sufficient revenues to cover the additional costs, which would be reflected in lower net income. Once again, the ESCV would defer the supply costs to future recovery, while NP's net income in the current year would be undercompensated. To limit the impact of any variance between marginal energy supply costs and average energy supply costs on NP's ROE, it would be advantageous for NP and the Board to capture both costs and revenues associated with energy supply in the ESCV deferral.

   FBC has such a treatment of its flow-through deferral accounts related to both power supply costs and revenues. FBC's flow-through deferral accounts related to power supply credit the flow-through account for any revenues collected and debit the flow-through account for any costs related to power supply.[11] Any variance from test year revenues associated with changes in sales is captured, and any variance related to power supply costs associated with changes in sales or marginal supply costs is captured. The variances

11 FBC Application for Annual Review for 2024 Rates, Table 12-2, at Page 118.

from both revenue and costs are then netted off, and the resulting balance is either recovered or refunded through next year's rates.

Recommendation: The Board should redefine the ESCV deferral to account for both the costs and *revenues* associated with energy supply. Amending the deferral account to track variance in both revenues and costs will limit the variability in NP's ROE associated with energy supply and ensure the matching of costs and revenues by both being deferred.

3. As outlined by NP in their 2025-2026 GRA, their ability to manage their demand costs has been limited in recent years, and they have requested a change to the incentive threshold of ± $500,000 in the DMI Account. Given NP's limited ability to manage their demand costs, which in the past has been managed by practices such as curtailing service during peak load conditions, even when there is not a *bona fide* system constraint, although now prohibited by the Board in Order P.U. 49 (2016), the need to provide an incentive to NP to lower these peak demands may no longer be required. Furthermore, incentives related specifically to demand cost management are not common amongst investor-owned Canadian electric utilities. As mentioned previously, FBC does have a PSI, but this incentive relates specifically to cost savings associated with energy procurement and supply optimization. NP has a limited ability to optimize its energy procurement due to its primary energy supplier being Hydro and the lack of alternatives. Efforts and incentives related to more targeted programs, such as conservation and demand management, may be a better means to reduce peak demand than generic incentives related to demand costs. These types of targeted demand reduction programs are typically amongst other utilities and could be achieved through the existing Conservation and Demand Management Program.

   Recommendation: We recommend that the DMI Account should be modified to remove the incentive threshold related to peak demand. The account should still be maintained to capture variance from actual to test year demand costs via the calculation of the Demand-Supply Cost Variance. However, netting off the demand management incentive should no longer be included. If the Board wishes to incentivize reductions in peak demand, incentives to specific demand reduction programs through the existing Conservation and Demand Management Program should be considered instead.

4. While NP does file an annual application for the disposition of the balance of their Weather Normalization Reserve, the methodology to determine the coefficients used to calculate the account balances has not been reviewed since Board Order P.U. 8 (1994-95).

Given the unique structure of NP’s Weather Normalization Reserve, as compared to other investor-owned Canadian electric utilities, a review of this methodology is warranted.

Furthermore, NP’s use of the Hydrology Production Equation is unique amongst other investor-owned Canadian electric utilities, and it is not evident that it should be included in the Weather Normalization Reserve. Variances in customer sales due to abnormal weather conditions are out of NP's control and are accounted for in the Degree Days Normalization. However, hydrology only partially impacts variances in NP’s hydroelectric generation. NP has control over the maintenance and upgrading of its hydroelectric facilities. As shown in Table 3, nine out of the last ten years of the Hydrology Production Equalization have resulted in lower hydroelectric generation compared to the estimated average, resulting in NP requiring greater than expected purchases of power supply and increased costs, which need to be collected in future rates. To the extent the Board may want to implement incentives to NP to provide efficient, low-cost hydroelectric generation, it would be limited to do so under the current Weather Normalization Reserve that combines the Degree Days Normalization, which accounts for uncontrollable weather events, and the Hydrology Production Equalization, which accounts for partially controllable hydroelectric generation. Therefore, it would be beneficial for the Board to separate the two calculations included in the Weather Normalization Reserve for the potential to create incentives for NP to maintain efficient and low-cost hydroelectric facilities.

Recommendation: We recommend that the Board require NP to file a report as part of its next GRA providing a detailed explanation of its Weather Normalization Reserve methodology for both its Degree Days Normalization and Hydrology Production Equalization. Included in this report should be a review of the model utilized to calculate the weather coefficients in both the Degree Days Normalization and Hydrology Production Equalization, the appropriateness of the weather variables included in the Degree Days Normalization as compared to other utilities weather normalization practices, the appropriateness of the Hydrology Production Equalization being included in the Weather Normalization Reserve, and the appropriateness of utilizing a Hydrology Production Equalization compared to other utilities’ practices of hydroelectric production variation.

IV. Excess Earnings Mechanism

As part of Order P.U. 19 (2003), the Board approved the continued use of an established range of 36 basis points for the rate of return on rate base, which the Board established to provide an incentive for NP to improve productivity.[12] This Order effectively creates a ± 18 basis point band around the approved return on average rate base. NP can earn above or below its approved return resulting from deviations from NP's approved revenue requirement that do not have deferral account coverage. The return on rate base for NP is typically equal to its weighted average cost of capital ("WACC"). The WACC for a regulated utility is calculated as the summation of the approved return components of the capital structure (i.e., return on debt, ROE, and return on preferred equity) and then multiplied by their respective approved capital structures.

NP files annual reports with the Board regarding the determination of excess earnings (i.e., does the actual return on average rate base exceed 18 basis points above the approved return on average rate base). Any earnings in excess of this upper limit are then credited to the Excess Earnings Account and are subject to disposition as the Board sees fit. In the past, the Board disposed of this account via a refund to customers as per Order P.U. 37 (2000-2001). More recently, they have been deferred to future revenue requirement proceedings to offset these excess earnings.

Table 4 outlines NP's approved, actual, and upper limit of return on average rate base since 2017. As indicated in NP's 2025-2026 GRA, it had not earned a return on rate base above the upper limit of the band from 2013 until 2023. NP indicated that the 2023 return on rate base would be above the approved range due to a higher forecasted return on debt compared to 2023's test year.[13]

[12] Board Order No. P.U. 19 (2003) at 76.

[13] Newfoundland Power – 2025-2026 General Rate Application at Page 3-12 and 3-13.

TABLE 4: NP'S RETURN ON RATE BASE 2017-2023[14]

Return on Average Rate Base	2017	2018	2019	2020	2021	2022	2023F
Approved	7.19%	7.04%	7.01%	7.04%	6.65%	6.61%	6.39%
Upper Limit	7.37%	7.22%	7.19%	7.22%	6.83%	6.79%	6.57%
Actual	7.22%	7.13%	6.97%	7.04%	6.74%	6.72%	6.85%F
Excess Earnings (Actual – Upper Limit)	0%	0%	0%	0%	0%	0%	0.28%F

Comparison to Other Utilities Excess Earnings Mechanisms

Excess Earnings or Earnings Sharing Mechanisms ("ESM") are common amongst many utilities within Canada. However, all of these ESMs look at excess earnings from an ROE basis and not from the return on rate base as is done with NP. The ESM excess earnings assessment is performed this way to reflect that the ROE, which is a component of the return on rate base, represents the net income that a utility would earn by providing service to its customers, for which it can decide to hold within retained earnings to reinvest into its system or payout as dividends to shareholders.

The following subsections outline the excess earnings mechanisms that some investor-owned Canadian electric utilities have. All these utilities determine excess earnings on an ROE basis as opposed to a return on rate base basis as NP does.

British Columbia

As part of FBC's recent Multi-Year Rate Plan MRP, the British Columbia Utilities Commission ("BCUC") has approved an ESM that allows a 50/50 share for earnings above and below the allowed ROE.[15] This ESM accounts for all items that are not subject to deferral account treatment

[14] Sources: Newfoundland Power 2018-2022 Annual Reports to the Board and Newfoundland Power - 2025-2026 General Rate Application at Page 3-12 and 3-13.

[15] British Columbia Utilities Commission, Decision and Orders G-165-20 and G-166-20, at 82.

and, therefore, has an impact on achieved ROE, providing an incentive for FBC to reduce its controllable expenses. Items subject to the ESM include gross operations and maintenance ("O&M") costs, interest expense, income tax, and variances in capital spending. The MRP rates are adjusted annually to account for any excess or deficit in achieved ROE, with 50 percent going to the account of the customers and 50 percent to FBC.

Alberta

As part of the AUC's third-generation performance-based regulation ("PBR"), all Alberta natural gas and electric distribution utilities are subject to a two-tiered asymmetric ESM.[16] Utilities will not collect any share of earnings below the approved ROE from customers. Instead, utilities will receive 100 percent of the earnings above the approved ROE for the first 200 basis points. For earning between 200 and 400 basis points above the ROE, the ESM will be allocated 60/40 between the utility and customers, respectively. All earnings above 400 basis points above the approved ROE will be shared 20/80 between the utility and customer, respectively. This ESM is applicable to all costs that do not have a specific deferral account or capital tracker funding treatment. Rates are then adjusted annually with the typical PBR formula to account for any ESM from the previous year.

Ontario

The OEB provides a filing guide for incentive rate-setting applications for electricity distribution utilities within its jurisdiction. While the OEB does not have a specific ESM in place for electricity distribution utilities, it does have specific off-ramp provisions by which, if a utility earns an actual ROE that exceeds ± 300 basis points from the OEB-approved ROE, a regulatory review may be triggered to determine the treatment of these earnings in excess of the range.[17]

On March 7, 2019, the OEB approved an application filed by Hydro One Networks Inc. ("Hydro One") for amendments to its electricity distribution rates from 2018 to 2022. As part of the application, the OEB approved an asymmetrical ESM that allows for 50/50 sharing of any earnings in excess of 100 basis points of the OEB-approved ROE. The ESM is calculated on an actual basis (earnings not normalized for weather) and held within an interest-bearing deferral account to be disposed of during Hydro One's next rebasing application.[18]

[16] Alberta Utilities Commission, Decision 27388-D01-2023, at 81-83.

[17] Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Application – 2023 Edition for 2024 Rate Applications, at 23-24.

[18] Ontario Energy Board, Decision and Order EB-2017-0049, at 40-41.

Nova Scotia

NSPI has a ± 25 basis point range from its allowable ROE. Any earnings in excess of this band are at the discretion of the Nova Scotia Utility and Review Board ("NSUARB") to determine the disposition of these excess earnings. In recent years, excess earnings have been applied directly to balances owing by ratepayers through the Fuel Adjustment Mechanism.[19]

Prince Edward Island

Maritime Electric has a rate of return adjustment ("RORA") account that collects any earnings in excess of Maritime Electric's approved ROE.[20] The balance of the RORA account is refunded annually to ratepayers as directed by the IRAC.

Order P.U. 19 (2003) – Determination on NP's Excess Earnings Mechanism

The issue of whether the Excess Earnings Account could include consideration of earnings related to ROE has been considered previously by the Board.[21] In Order P.U. 19 (2003), the Board referred to the opinion rendered by the Court of Appeal of Newfoundland and Labrador pursuant to Section 101 of the *Public Utilities Act* ("*Act"*). This Court of Appeals opinion provided, among other matters, clarifications regarding the Board's jurisdiction to set and fix the level of return on common equity, regulate the return on rate base, require a public utility to maintain ratios within its capital structure and deal with excess earnings of the regulated utilities.

The Board found that given the Board's jurisdiction as outlined in the Court of Appeals opinion, it can make determinations on excess earnings that exceed the allowed range of return on rate base as set by the Board and can not with respect to excess earnings related to ROE.[22]

Findings

Excess earnings mechanisms are typically applied to a utility's ROE to recognize that it represents the net income that a utility would earn by providing service to its customers, for which it can

[19] Nova Scotia Utility and Review Board, Decision M10431, at 87.

[20] Island Regulatory & Appeals Commission, Order UE23-04 for Docket UE20946, at 13.

[21] Board Order No. P.U. 19 (2003) at 21.

[22] *Id.*, at 24-26.

decide to hold within retained earnings to reinvest into its system or payout as dividends to shareholders. As can be seen above, this has been the typical treatment for excess earnings or ESM across investor-owned Canadian electric utilities.

Constructing an excess earnings mechanism based on the return on rate base of a utility creates perverse incentives. It could lead to unintended consequences that may cause harm to the utility or its customers. An example of such a consequence presented itself in NP's 2025-2026 GRA in Table 3-10.[23] In Table 3-10, NP presents that it was not subject to the excess earnings mechanism in 2022, although its actual ROE was above its approved ROE. However, in 2023F, NP is expecting excess earnings due to the higher-than-forecast cost of debt, even though its actual ROE is below its approved level. The return on debt component of a utility's return aims to compensate the utility for paying expenses associated with bondholders and other long-term debt holders. These expenses are fixed and must be paid by a utility or risk credit downgrades, which increases the utility's overall cost of capital.

Recommendation: While it is understood that this issue has been previously considered and the Court of Appeal determined there are limits on the Board's jurisdiction in this matter, it would be beneficial for NP and its customers if an ESM based on its approved ROE could be put in place to provide NP with proper incentives and to avoid any unintended consequences resulting from the current excess earnings methodology that determines excess earnings through return on rate base.

V. Comparison of Total Deferral Account Coverage to Other Utilities

Investor-Owned Canadian Electric Utilities Deferral Account Coverage

This section will compare the total deferral account coverage of investor-owned Canadian electric utilities to that of NP. We include consideration of the total number of deferral accounts, regulatory framework, and treatment of deferral account recovery.

British Columbia

[23] Newfoundland Power - 2025-2026 General Rate Application, Table 3-10, at Page 3-12.

FBC is currently under an MRP, which provides a performance-based framework to determine FBC rates. This framework includes an index-based approach to the determination of FBC's controllable O&M expenses. However, FBC does have flow-through or specific deferral account treatment for a variety of uncontrollable cost items or innovative growth projects. The items included in FBC's Flow-through deferral account or that have specific deferral accounts include 1) revenue and power supply variances,[24] 2) variances from the forecast of pensions and OPEB expenses, 3) revenue related to clean growth projects, 4) depreciation related to clean growth projects, 5) income tax related to clean growth projects, 6) property tax, and 7) income tax rate variances.

Alberta

Alberta electric distribution utilities are currently in a performance-based regulation ("PBR") framework that sets electricity rates via a price cap formula in which rates are indexed by inflation less the X-Factor.[25] The AUC does allow flow-through or deferral account treatment for a select group of items that are not indexed by the inflation minus X-Factor.[26] They include:

- Z-Factors: these account for funding for both capital and O&M expenses associated with exogenous events that have a material impact on the utility.[27] Funding for Z-Factors must be applied to and approved by the AUC on a case-by-case basis.
- Y-Factors: these include expenses that are flowed through to customers. These include Alberta Electric System Operator flow-through items, farm transmission costs, accounts that are the results of Commission directions (AUC fees, intervenor hearing costs, etc.), income tax impacts other than tax rate changes, municipal fees, and load balancing deferral accounts.
- Type 1 Capital Tracker Funding Mechanism: is a capital tracker funding mechanism that currently does not meet Z-Factor or Y-Factor treatment and meets the following criteria: 1) extraordinary and not previously included in distribution utilities rate base, 2) required by a third party or otherwise directly cause by law related to net-zero objectives, and 3) project cost must have a material effect on distribution utility.

[24] Power supply variances are net of the PSI as outlined in Section II.

[25] An X-Factor in the PBR framework accounts for the productivity improvements a utility is expected to achieve during their PBR plan.

[26] Alberta Utilities Commission, Decision 27388-D01-2023, at 118-120.

[27] The threshold for a material impact is determined as being above a 40 basis point change in ROE on an after-tax basis.

Ontario

The OEB provides a framework for incentive rate-setting ("IR") applications and describes three incentive rate-setting methods: 1) Price-Cap IR, 2) Annual IR Index, and 3) Custom IR.[28] Furthermore, the OEB also provided a report on Electricity Distributors' Deferral and Variance Accounts that classify deferral accounts into Group 1 and Group 2 deferral accounts based on the depth of review the OEB would require for the disposition of the account balances.[29] Group 1 accounts do not require an OEB prudence review and include balances that are cost pass-throughs and accounts whose original balances were approved by the OEB in a previous proceeding. Group 2 account will require a prudence review from the OEB to determine the cost recovery of the balance.

While the OEB may approve any deferral or variance account it deems appropriate, it uses a uniform system of accounts applicable to electricity distribution companies under its jurisdiction.[30] The uniform accounts that relate to Group 1 deferral account coverage include the following:

- Low Voltage Account
- Smart Metering Entity Charge Variance
- RSVA Wholesale Market Service Charge Account
- RSVA Retail Transmission Network Charges Account
- RSVA Retail Transmission Connection Charge Account
- RSVA Power
- RSVA Global Adjustment
- Disposition and Recovery/Refund of Regulatory Balances

In addition to the uniform deferral accounts, electricity distribution companies may also request recovery of costs associated with unforeseen events that are outside of their ability to manage,

[28] Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Application – 2023 Edition for 2024 Rate Applications, at 1.

[29] Report of the Ontario Energy Board on Electricity Distributors' Deferral and Variance Account Review Initiative, at 6.

[30] Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Application – 2023 Edition for 2024 Rate Applications, at 10.

known as a Z-Factor event. The event must have a material impact on the distributor, which is based on a threshold determined by the size of the utility's revenue requirement.[31]

Nova Scotia

As part of NSPI's most recent GRA, the NSUARB approved the following deferral accounts: 1) the FAM deferral to account for variances in energy supply costs, 2) the Demand Side Management Cost Recovery Rider, 3) the Renewable to Retail deferral to account for variances in costs associated with providing renewable electricity, 4) the Deferred Income Tax account primarily related to the FAM deferral variances, 5) a Storm Rider that will account for variances in adverse storm activity in the province that result in power outages, and 6) the Decarbonization Deferral Account to recover accelerated depreciation required to allow for full recovery of NSPI's coal-fired assets and to account for direct and indirect costs associated with the transition to clean energy.

Prince Edward Island

During Maritime Electric's 2023-2026 GRA, the IRAC approved the following deferral accounts: 1) the Rate of Return Adjustment that accounts for ROE in excess of Maritime Electric's approved ROE, 2) the 2020 Revenue Shortfall Account, which includes loss of revenue in 2020, 3) the Energy Efficiency and Conservation Plan, 4) the Charlottetown Thermal Generation Station Reserve Variance resulting from unrecovered depreciation and reserve variance amortization of the Charlottetown Thermal Generation Station, 5) the Weather Normalized Reserve, 6) the Energy Cost Adjustment Mechanism, and 7) the Point Lepreau Write-Down deferral associated with the write-down of the generation facility.

Comparison to NP's Deferral Account Coverage

Based on a review of NP's deferral accounts compared to other investor-owned Canadian electric utilities, we provide the following findings:

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[31] As outlined in the Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors the OEB outlines the following thresholds:

1) $50 thousand for distributors with less than $10 million revenue requirement;
2) 0.5% of distributor revenue requirement for distributors with a revenue requirement between $10 million and $200 million; and
3) $1 million for distributors with more than $200 million revenue requirement.

1. NP has a similar amount and treatment of deferral coverage to other utilities. However, many of these other utilities have some form of incentive regulation that requires them to find efficiencies for large portions of their costs. NP lacks this additional incentive to reduce costs and find efficiencies while also benefiting from a similar amount of deferral account coverage.

2. Items such as pension/OPEB expenses are recovered in the same manner by some of the investor-owned Canadian electric utilities. DSM and electrification/innovation deferral accounts are also common amongst investor-owned Canadian electric utilities.

3. Recovery of hearing costs and fees associated with rate application have also been recovered in rates by flow-through accounts such as the Y-Factor in the AUC PBR. As part of the hearing cost recovery process, applications are filed to the AUC to determine the appropriateness of cost from intervenors. This is consistent with the practice followed within Newfoundland and Labrador regarding the recovery of hearing costs.

VI. Conclusions

This report provides a comprehensive review of NP's deferral accounts and their comparison to other investor-owned Canadian electric utilities. This report reviews specifically the deferral accounts related to NP's power supply cost recovery mechanisms and Excess Earnings Mechanism, providing findings and commentary on potential improvements the Board may consider to ensure NP is provided proper incentives through these deferral accounts. A comparison of NP's total deferral account coverage to that of other investor-owned Canadian electric utilities is also undertaken while considering the regulatory framework present in each jurisdiction. Summarized below are the potential improvements and commentary regarding NP's power supply cost recovery mechanisms, Excess Earnings Mechanism, and total deferral account coverage:

Power Supply Cost Mechanisms

1. **Power Supply Cost Mechanism Coverage:** NP has a similar amount of coverage for power supply cost recovery mechanisms compared to other investor-owned electric utilities, and the RSA is an appropriate mechanism for the disposition of account balances related to power supply costs.

2. **Energy Supply Cost Variance Deferral:** The Board should redefine the ESCV deferral to account for both the costs and *revenues* associated with energy supply. Amending the deferral account to track variance in both revenues and costs will limit the variability in NP's ROE associated with energy supply and ensure the matching of costs and revenues by both being deferred.

3. **DMI Account:** We recommend that the DMI Account should be modified to remove the incentive threshold related to peak demand. The account should still be maintained to capture variance from actual to test year demand costs via the calculation of the Demand-Supply Cost Variance. However, netting off the demand management incentive should no longer be included. If the Board wishes to incentivize reductions in peak demand, incentives to specific demand reduction programs through the existing Conservation and Demand Management Program should be considered instead.

4. **Weather Normalization Reserve:** We recommend that the Board require NP to file a report as part of its next GRA providing a detailed explanation of its Weather Normalization Reserve methodology for both its Degree Days Normalization and Hydrology Production Equalization. Included in this report should be a review of the model utilized to calculate the weather coefficients in both the Degree Days Normalization and Hydrology Production Equalization, the appropriateness of the weather variables included in the Degree Days Normalization as compared to other utilities weather normalization practices, the appropriateness of the Hydrology Production Equalization being included in the Weather Normalization Reserve, and the appropriateness of utilizing a Hydrology Production Equalization compared to other utilities' practices of hydroelectric production variation.

Excess Earnings Mechanism

1. While it is understood that the issue of determining NP's excess earnings on an ROE basis has been previously considered and the Court of Appeal determined there are limits on the Board's jurisdiction in this matter, it would be beneficial for NP and its customers if an ESM based on its approved ROE could be put in place to provide NP with proper incentives and to avoid any unintended consequences resulting from the current excess earnings methodology that determines excess earnings through return on rate base.

Total Deferral Account Coverage

1. **Regulatory Framework:** NP has a similar amount and treatment of deferral coverage to other utilities. However, many of these other utilities have some form of incentive regulation that requires them to find efficiencies for large portions of their costs. NP lacks this additional incentive to reduce costs and find efficiencies while also benefiting from a similar amount of deferral account coverage.

2. **Pension/OPEB Expenses:** Items such as pension/OPEB expenses are recovered in the same manner by some of the investor-owned Canadian electric utilities. DSM and electrification/innovation deferral accounts are also common amongst investor-owned Canadian electric utilities.

3. **Hearing Cost Recovery:** Hearing costs and fees associated with rate applications have also been recovered in rates by flow-through accounts such as the Y-Factor in the AUC PBR. As part of the hearing cost recovery process, applications are filed to the AUC to determine the appropriateness of cost from intervenors. This is consistent with the practice followed in Newfoundland and Labrador regarding the recovery of hearing costs.