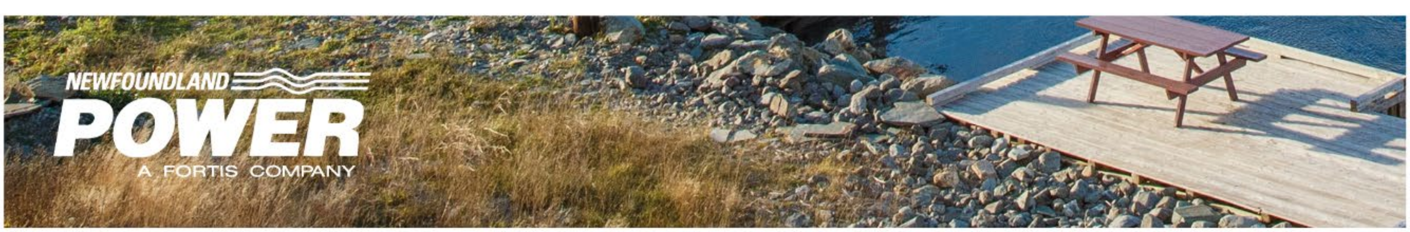
March 2026

Newfoundland Power Inc. Return on Rate Base Report



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1.0 INTRODUCTION

In Order No. P.U. 3 (2025), the Board of Commissioners of Public Utilities (the "Board") directed Newfoundland Power Inc. ("Newfoundland Power" or the "Company") to file a report by February 15, 2026 with respect to the calculation of rate base and rate of return on rate base.[1] The report is to address differences in average rate base and invested capital, including the cash working capital allowance as well as other allowances, and potential changes including deferral account changes.[2] The filing date for the report was later revised to March 31, 2026 to coincide with the filing of Newfoundland Power's annual returns.[3]

The report reviews the calculation of the Company's rate base and rate of return on rate base, including comparing the calculations to those of other investor-owned electric utilities across Canada based on a jurisdictional review completed by Utilis Consulting Inc. (the "Jurisdictional Review" and "Utilis", respectively). The utilities reviewed were Nova Scotia Power Incorporated ("NS Power"), Maritime Electric Company Limited ("MECL"), Algoma Power Inc. ("Algoma Power"), FortisAlberta Inc. ("FortisAB"), and FortisBC Inc. ("FortisBC").[4] Attachment A provides the Jurisdictional Review.

The report confirms that Newfoundland Power's calculations of rate base and rate of return on rate base are reasonable and provide results that are consistent with utility practice. While reasonable, the report identifies opportunities to simplify certain aspects of the calculations and minor changes to better align the calculations with industry practice. Finally, the report outlines changes in these areas the Company plans to bring forward in its next general rate application ("GRA").

2.0 RATE BASE

2.1 General

Because the cost-of-service standard provides for the full recovery of a utility's financing costs, a utility's calculation of rate base should reflect its invested capital. Invested capital is the total debt and equity financing of a utility to finance its net assets that are used to provide service to customers.[5]

Figure 1 on the following page demonstrates how a utility's net assets equal its invested capital by re-arranging the basic components of a balance sheet financial statement.[6]

1 Order No. P.U. 3 (2025), page 55.
2 *Ibid*.
3 See the Board's correspondence, *Re: Newfoundland Power Inc. - Supply Cost Mechanisms and Rate of Return on Rate Base Reports - To Parties - Request for Revised Filing Dates Granted*, dated December 10, 2025.
4 Jurisdictional Review, section 1.4.
5 Net assets = total assets - total liabilities (other than debt financing).
6 A balance sheet is a financial statement that presents an entity's financial position at a specific point in time by summarizing what it owns (assets), what it owes (liabilities), and the residual interest of owners (equity).

Figure 1:
Relationship of Net Assets and Invested Capital

Assets = Liabilities + Equity

$$\underbrace{\text{Assets - Liabilities (net of debt)}}_{\textbf{NET ASSETS}} = \underbrace{\text{Liabilities (debt) + Equity}}_{\textbf{INVESTED CAPITAL}}$$

In the 1990s, utility calculations of rate base could be limited to a utility's plant investment, along with regulatory accounts and allowances specifically approved by the regulator.[7] As such, historic rate base calculations did not necessarily include all the net assets of a utility and therefore would not align with the utility's invested capital in those cases.[8] Beginning in the early 2000s, it became more common that effectively all net assets were included in rate base calculations.[9] At that time, it was referred to as the Asset Rate Base Method ("ARBM").[10] Over time, the formality of a methodology to determine rate base for utilities has faded. In its place, the concept that rate base calculations should align with the net assets of a utility, subject to jurisdiction specific adjustments, has become standard utility practice.[11]

Figure 2 illustrates the basic components of a utility's rate base calculation.

Figure 2:
Rate Base Calculation: An Illustration

Net Utility Plant Investment[12]

+ Additions (Utility Assets)

- Deductions (Utility Liabilities net of debt)

± Rate Base Allowances (Inventories and Working Capital)

= Rate Base

The primary component of a utility's rate base is its investment in utility plant that is used and useful in providing service to customers. For investment in utility plant, it is the undepreciated value of the plant that must be financed. Additions to rate base are costs that have been incurred to provide service but have not yet been recovered through customer rates.[13]

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7 See, for example, Annual Return 3 of Newfoundland Power Annual Report to the Board for the year ended December 31, 1999. Hereafter, annual returns will be referenced in the following manner, using the above reference as an example: "Annual Return 3 for 1999". See also Requests for Information PUB-NP-242 and 250 filed in the Company's *2003 GRA*.

8 For example, assets and liabilities associated with employee future benefits.

9 See, for example, Order No. P.U. 19 (2003), pages 70-71.

10 In Order No. P.U. 19 (2003), the Board found that the ARBM should be used to calculate Newfoundland Power's average rate base. In Order No. P.U. 32 (2007), the Board approved the Company's calculation of rate base in accordance with the ARBM.

11 Jurisdictional Review, section 8.1.1.

12 For Newfoundland Power, its net plant investment is its plant investment less accumulated depreciation and customer contributions.

13 For example, deferred cost recovery assets approved by regulators to be recovered in future customer rates.

Deductions from rate base represent amounts that have been recovered through customer rates in advance of the required utility payment for those costs.[14] Finally, rate base is adjusted for allowances typically associated with maintaining the required inventories and working capital necessary to provide service to customers.[15]

Attachment B provides Newfoundland Power's calculation of average rate base as of December 31, 2025, which includes each component discussed above. As shown in the Jurisdictional Review, the Company's calculation of rate base is consistent with those of other investor-owned electric utilities across Canada.[16]

2.2 Differences in Rate Base and Invested Capital

As explained in section 2.1, a utility's net assets equal its invested capital. As such, as long as rate base components equal their balance sheet asset/liability counterpart, there would be no difference between rate base and invested capital balances.

While rate base calculations are designed to align with a utility's invested capital, certain components of rate base calculations are purposely computed on a different basis than its net assets comparator. For most utilities, these relate to construction work in progress ("CWIP"), inventories (i.e., materials and supplies), and cash working capital balances. There may also be other adjustments to a utility's rate base specific to that jurisdiction.

This section summarizes the prevailing utility practice, as well as Newfoundland Power's approach, in these areas.[17]

CWIP

It is common practice that a utility's rate base include only those assets that are used and useful in providing service to customers. As such, CWIP assets are typically excluded from rate base calculations and therefore results in a difference between rate base and invested capital.[18]

Consistent with industry practice, the plant investment component of Newfoundland Power's rate base excludes CWIP amounts.[19]

Inventories (materials and supplies)

It is common that an allowance is included in rate base related to utility inventories as opposed to the year-end inventory asset balance on a balance sheet financial statement.[20] This is because the year-end balance amount may not be representative of the average inventories the

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14 For example, other post-employment benefits ("OPEB") liabilities. OPEBs are earned by employees during their employment and therefore form part of employee future benefit expense reflected in current customer rates. However, payment for employees to receive those benefits in their retirement are paid by the Company at that time.

15 Working capital includes a variety of short-term assets and liabilities such as accounts receivables and payables. Working capital and inventory net assets are not included in the additions and deductions sections of a standard rate base calculation.

16 Jurisdictional Review, section 8.1.1.

17 Section 2.3 re-visits each area in more detail.

18 Jurisdictional Review, section 8.1.4. Of the five utilities reviewed (which excludes Newfoundland Power), four excluded CWIP assets from their rate base.

19 See Annual Return 4 for 2025.

20 Jurisdictional Review, section 8.1.2. Of the five utilities reviewed, one utility includes a discrete allowance in their rate base for inventories, three utilities include an allowance for inventories within their cash working capital allowance, while one utility charges its inventories directly to its capital assets in rate base.

utility was required to finance throughout the year. The differing approach to determining inventory balances results in a difference between rate base and invested capital.

Consistent with industry practice, Newfoundland Power includes a materials and supplies allowance in its rate base. The allowance is determined based on a 13-month average as opposed to its year-end balance.[21] The allowance also excludes inventories associated with the expansion of the electrical system, which are treated in the same manner as CWIP amounts.[22]

Cash working capital
It is also common that a regulatory approved allowance calculation is used to determine the amount in rate base related to utility cash working capital requirements as opposed to the year-end short-term asset and liability balances on a balance sheet financial statement.[23] Like inventories discussed above, this is because the year-end balances may not be representative of the average cash working capital requirements the utility was required to finance throughout the year. The differing approach to determining cash working capital balances results in a difference between rate base and invested capital.

Consistent with industry practice, Newfoundland Power includes a cash working capital allowance in its rate base. The Company's cash working capital rate base allowance is based on a lead/lag study, which analyzes the timing of customer receipts and vendor payments, as opposed to its year-end balances.[24]

Other
There may also be other adjustments to a utility's rate base which are jurisdiction specific that create differences between rate base and invested capital, such as the treatment of supply cost mechanisms.[25]

For Newfoundland Power, Rate Stabilization Account ("RSA") balances are excluded from its rate base calculation. In addition, the Electrification Cost Deferral Account balance is also excluded from rate base. Finally, minor differences may also arise due to the timing of the Company's credit facility issue costs.

Table 1 on the following page provides a reconciliation between average rate base and invested capital for 2025, noting each item described above.

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[21] See Annual Return 11 for 2025.

[22] In Order No. P.U. 1 (1974), Newfoundland Power was directed by the Board to identify and exclude all inventories and supplies related to expansion of the electrical system from rate base. The Board noted that materials and supplies related to future expansion were similar in nature to work in progress in that they are held to provide future service. Similar to the treatment of work in progress, materials and supplies related to expansion are excluded in the calculation of rate base. The Jurisdictional Review indicates that FortisAB follows a similar approach for its construction inventory. See the Jurisdictional Review, section 6.2.1.

[23] Jurisdictional Review, section 8.1.3. All five of the utilities reviewed include an allowance for cash working capital in their rate base.

[24] See Annual Return 12 for 2025 and the *2025 and 2026 Rate Base Allowances* report filed with the Company's *2025/2026 GRA*.

[25] Jurisdictional Review, section 8.1.5. Of the five utilities reviewed, four have supply cost mechanisms. Of these four utilities, two exclude supply costs from their rate base and two include supply costs in their rate base.

Table 1:
2025 Average Rate Base vs. Average Invested Capital
Reconciling Items
($000s)

Average rate base	1,419.7
Average invested capital	1,483.1
Difference	**(63.4)**
Reconciling items:	
CWIP	(18.1)
Materials and supplies[26]	(2.9)
Cash working capital[27]	34.9
Other – RSA	(75.5)
Other – minor items[28]	(1.8)
Total reconciling items	**(63.4)**

In 2025, average rate base was $63.4 million lower than Newfoundland Power's 2025 average invested capital. The difference was primarily related to the average RSA balance of $75.5 million which is purposely excluded from rate base as noted above.

While the other utilities reviewed do not complete a reconciliation of their rate base and invested capital,[29] they would experience differences in their rate base and invested capital for similar reasons as those outlined in Table 1.[30]

2.3 Assessment of Rate Base Calculation and Potential Changes

Overall, Newfoundland Power's calculation of rate base is reasonable and consistent with other Canadian investor-owned utilities.[31] This section re-visits each area of difference between rate base and invested capital discussed in section 2.2 to determine if the current approach remains appropriate and allows the Company to recover its financing costs in a reasonable manner. This section also considers potential changes in these areas, consistent with the Board's direction in Order No. P.U. 3 (2025).[32]

CWIP

Newfoundland Power's approach to exclude CWIP amounts from its rate base is consistent with utility practice.[33] The Company fully recovers its financing costs on the invested capital required to fund CWIP amounts through its Allowance for Funds Used During Construction Account

26 Average year-end materials and supplies balances versus the rate base allowance.
27 Average year-end cash working capital balances versus the rate base allowance.
28 Electrification deferral account and deferred credit facility issue costs.
29 Jurisdictional Review, section 1.2.
30 As provided in this section of the report, the areas of differences in rate base and invested capital are generally common between the utilities reviewed.
31 As outlined in sections 2.1 and 2.2 of this report.
32 See section 1.0 of this report.
33 See section 2.2 of this report.

("AFUDC").[34] AFUDC, which is also referred to as Interest Capitalized during Construction, is the standard practice used by utilities to ensure the financing costs associated with CWIP amounts are appropriately capitalized and recovered from customers over the useful life of the related asset.[35]

Accordingly, the Company's approach regarding CWIP in its rate base calculation is reasonable and no changes are necessary.

Inventories (materials and supplies)

Newfoundland Power uses a 13-month average to determine its materials and supplies allowance. While specific details for each utility's approach to determining their inventories allowance are not available, the Company observes that both NS Power and FortisBC reference use of averages in their approaches.[36] For Newfoundland Power, the 13-month average approach fairly reflects the invested capital needed on a monthly basis to maintain sufficient inventory levels to provide service to customers.[37]

Based on the above, Newfoundland Power will continue its current approach to determine its materials and supplies rate base allowance in its next GRA. While reasonable, the Company plans to further assess if there is potential to simplify the process to determine its allowance. The Jurisdictional Review provides that only NS Power has a discrete allowance similar to Newfoundland Power. MECL, FortisAB and FortisBC include inventories as part of their working capital allowance and Algoma Power charges materials and supplies directly to its capital assets.[38] Any changes in the determination of the allowance would be outlined by Newfoundland Power at that time.

Cash working capital

The Company uses a lead/lag study to determine the cash working capital allowance included in its rate base.[39] In general, the use of a lead/lag study to determine cash working capital requirements remains common utility practice.[40] However, most utilities do not update their lead/lag studies as frequently as Newfoundland Power.[41] In Ontario, a distributor can use a default factor in lieu of a lead/lag study.[42]

Given these findings, Newfoundland Power plans to maintain its current approach in determining its cash working capital rate base allowance by using a lead/lag study. However, in the Company's view, completing the lead/lag study on a five-year basis rather than for each

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34 For the definition of the AFUDC account, see page 11 of the Company's System of Accounts filed with the Board on March 31, 2026 as part of its Annual Report to the Board for the year ended December 31, 2025.

35 Jurisdictional Review, section 8.1.4.

36 In its 2026-2027 GRA filing, NS Power provided that it has based its fuel and supplies inventory on the projected monthly average for 2026-2027. See page 53 of that filing, dated September 18, 2025. In a 2013 filing, FortisBC provided that the average value of its inventory is included in its cash working capital balance in its rate base. See page 75 of its *Response to Commercial Energy Consumers Information Request No. 1* filed on September 20, 2013 as part of its *Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018*.

37 See Annual Return 11 for 2025. The monthly balances are relatively consistent throughout the year providing for a relatively predictable level of invested capital requirements and financing costs.

38 Jurisdictional Review, section 8.1.2.

39 The Company's method for calculating the cash working capital allowance was approved by the Board in Order No. P.U. 37 (1984).

40 Jurisdictional Review, section 8.1.3.

41 *Ibid*.

42 *Ibid*.

GRA test year, would be reasonable. This approach would be consistent with utility practice,[43] as well as with the longer intervals used for other Newfoundland Power studies.[44] The Company will complete a lead/lag study for its next GRA, with the intention to propose moving to a 5-year cycle thereafter (i.e., for inclusion in every second GRA filing).

Other – RSA

Invested capital is required for Newfoundland Power to finance variances in its power supply costs from the level included in base customer rates. The Company's supply cost mechanisms are the Rate Stabilization Account ("RSA"), the Energy Supply Cost Variance ("ESCV") Account, the Demand Management Incentive ("DMI") Account, and the Weather Normalization Reserve ("WNR").[45]

RSA

Rate base calculations exclude the RSA. In addition, the Company removes RSA balances and RSA interest revenue from its test year forecasts. Financing costs on RSA balances are ultimately recovered from, or credited to, customers as part of the annual July 1st rate adjustment.[46]

Of the five utilities reviewed, four have supply cost mechanisms. Of these four utilities, two exclude supply costs from their rate base and two include supply costs in their rate base. As such the Company's approach with its RSA reasonably aligns with utility practice. Further, given the current circumstances surrounding the RSA balance at this time,[47] the continued exclusion from rate base with separate recovery of financing costs remains reasonable.

ESCV, DMI and WNR

Newfoundland Power's ESCV, DMI and WNR supply cost mechanisms operate separately, and in a different manner, from the RSA in the year the variances occur.[48] That is, the monthly supply cost variances accumulate in these accounts throughout the year before year-end balances are transferred to the RSA. The ESCV balance transfer occurs on December 31st while the DMI and WNR year-end balances are transferred to the RSA on March 31st in the subsequent year. Unlike the RSA, these supply cost mechanisms do not include a component to address the financing of the monthly balances.[49]

From a rate base perspective, the ESCV Account is not included in the rate base calculation given its transfer to the RSA on December 31st. The ESCV Account can contain material

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43 *Ibid*. FortisAB and MECL appear to review and update their working capital factors on a more periodic basis, with active use of working capital parameters that date back to the early 2010s. In addition, it appears that FortisBC filed its latest lead/lag study in 2023 compared to the previous version filed in 2018 and NS Power filed its latest lead/lag study in 2025 compared to the previous version filed in 2011. Algoma Power uses the default factor in Ontario in lieu of completing a lead/lag study.

44 For example, Newfoundland Power's depreciation study is completed every 5-years and included with every second Company GRA filing.

45 For further information on these mechanisms, see the Company's *Supply Cost Mechanisms Review* filed with the Board on March 31, 2026.

46 Financing costs are recovered via the interest charge component of the RSA. See subparagraph II.1(v) of the Rate Stabilization Clause in Newfoundland Power's *Schedule of Rates, Rules and Regulations,* effective July 1, 2025.

47 The current RSA balance is historically large with its recovery currently being deferred in an effort to smooth customer rate impacts. See Order No. P.U. 23 (2025) for further details.

48 For further information on these mechanisms, see the Company's *Supply Cost Mechanisms Review* filed with the Board on March 31, 2026.

49 Monthly balances could be either recoverable from customers or credited to customers depending on monthly supply cost dynamics.

balances on a monthly basis, albeit the variances are considerably lower under the current wholesale rate that came into effect January 1, 2025, when compared to previous years.[50] While the DMI and WNR balances are included in the rate base calculation, they typically have zero year-end balances in test year rate base calculations given the rebasing of supply costs occurring as part of the GRA process, resulting in no forecast variance activity.[51] As a result, recovery of financing costs associated with these supply cost variances, in general, does not occur until the balances are transferred to the RSA. Finally, as detailed in its *Supply Cost Mechanisms Review*, the Company plans to propose a revision to its Rate Stabilization Clause to provide for the disposition of the year-end balances in the DMI Account and WNR to the RSA on December 31st on an annual basis in its next GRA.[52] This proposal will align the treatment of the DMI Account and the WNR with the ESCV Account and will therefore result in their exclusion from rate base given their transfer to the RSA on December 31st.

As provided by the Jurisdictional Review, and in line with cost of service principles, utilities are afforded the ability to fully recover their financing costs, whether they are associated with a balance included in rate base or not.[53] Newfoundland Power also observes that the situation regarding its ESCV Account, DMI Account and WNR is somewhat unique as most utilities use a broader mechanism to recover their total supply cost variances as opposed to the Company's more discrete and detailed mechanisms for separate impacts.[54]

Based on the foregoing, Newfoundland Power plans to propose a financing cost recovery component, similar to that for the RSA, for the ESCV Account, DMI Account and the WNR in its next GRA.[55] The revisions to the Rate Stabilization Clause for this change will be proposed in conjunction with the revisions to allow for the disposition of the year-end balances in the DMI Account and WNR to the RSA on December 31st as described above. The financing charge component will be designed with consideration of the timing of the mechanism's transfer to the RSA as well as for it to be simple and transparent.[56]

Ultimately, the proposed changes will result in the Company's multiple supply cost mechanisms operating together as if they were one broader supply cost mechanism to the extent possible. The proposed approach would ensure all financing costs associated with supply cost variances are recovered from, or credited to, customers.[57]

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[50] While supply cost variances are much lower than previous years due to the new wholesale rate, the impact can still be material and future wholesale rate changes remain largely outside of the Company's control. For further information, see section 2.2 of the Company's *Supply Cost Mechanisms Review* filed with the Board on March 31, 2026.

[51] See Newfoundland Power's compliance filing associated with its *2025/2026 GRA, Schedule 1, Appendix A*. The calculations for 2025 and 2026 average rate base do not include balances associated with the ESCV, DMI and WNR mechanisms. With respect to the cash working capital allowance, the allowance only considers the typical lag in the monthly purchased power invoice of approximately 30 days. It does not take into consideration the lag associated with the recovery of purchased power cost variances from the latest test year.

[52] See sections 3.2, 3.3, and 6.0 of the Company's *Supply Cost Mechanisms Review* filed with the Board on March 31, 2026.

[53] For recovery of financing costs associated with supply costs, see section 8.1.5 of the Jurisdictional Review.

[54] See section 1.0 of the Company's *Supply Cost Mechanisms Review* filed with the Board on March 31, 2026.

[55] RSA interest is determined on a monthly basis by multiplying the balance in the RSA at the beginning of the month by a monthly rate equivalent to the mid-point of the Company's allowed rate of return on rate base.

[56] For example, financing charges would only be computed on opening balances (same basis as the RSA) to ensure interest would not be computed twice on a supply cost mechanism balance. The Company also envisions completing the interest calculation on an annual basis (each December 31st) to coincide with the disposition of the balances to the RSA and to not complicate the monthly calculations.

[57] With the new wholesale rate, which has materially reduced monthly variances in supply costs, financing cost recovery amounts are not anticipated to be material. For example, if Newfoundland Power planned approach was in place in 2025, the financing cost recovery amount would have been less than $0.2 million.

Other – Minor Items
There is a difference between rate base and invested capital due to the exclusion of the Electrification Cost Deferral Account from the rate base calculation. The exclusion of the account was settled between the parties to Newfoundland Power's *2022/2023 GRA* on November 22, 2021 and approved by the Board in Order No. P.U. 3 (2022) issued on February 16, 2022.[58] At that time, the order on Newfoundland Power's *2021 Electrification, Conservation and Demand Management Application* was not yet issued and therefore there was uncertainty regarding the Company's future spending on electrification initiatives. On November 10, 2022, the Board issued Order No. P.U. 33 (2022) regarding that application. In accordance with that order, Newfoundland Power's expenditures related to electrification are limited and are subject to Board approval.[59]

Given the certainty associated with electrification cost levels provided by Order No. P.U. 33 (2022), as well as the limited activity in the Electrification Cost Deferral Account, Newfoundland Power plans to include the account balance in rate base, beginning with its next GRA. This will align the treatment of the account balance with the Company's other non-supply cost related deferral accounts and eliminate the difference in rate base and invested capital.[60]

Finally, there is a minor difference between rate base and invested capital related to the Company's deferred credit facility issue costs.[61] Consistent with the balance sheet financial statement presentation, these deferred costs are shown as an addition to rate base when determining rate base for actual years.[62] The deferred costs are relatively minor – for example, the 2025 deferred credit facility balance is $0.2 million.[63] However, for test year purposes the deferred costs are treated as invested capital (i.e., netted from the debt instrument) and are therefore excluded from rate base.[64]

Newfoundland Power plans to exclude deferred credit facility issue costs from rate base for both actual and test year rate base calculations. This will eliminate minor differences in rate base and invested capital for non-test year rate base computations. Similar with its other changes, the Company will begin this practice beginning with its next GRA.

2.4 Summary of Rate Base

The following summarizes the key findings of the review of Newfoundland Power's rate base:

- The Company's calculation of rate base is reasonable and aligns with common utility practice.

[58] See Order No. P.U. 3 (2022), pages 9-11.
[59] See Schedule A to the settlement agreement on Newfoundland Power's *2022/2023 GRA* dated November 10, 2022 for the definition of the Electrification Cost Deferral Account. As of December 31, 2025, the balance in the Electrification Cost Deferral Account is $2.7 million.
[60] The change in approach will require a revision to the definition of the Electrification Cost Deferral Account to remove the requirement to calculate financing costs on a monthly basis. The Company will propose the revision to the account as part of its next GRA to coincide with the timing of the change in the rate base calculation.
[61] Costs are incurred to maintain credit facilities, such as those related to financial banking services. For financial reporting purposes, these costs are deferred and amortized over the term of the agreement.
[62] See Annual Return 3 for 2025.
[63] *Ibid*.
[64] See, for example, Newfoundland Power's compliance filing associated with its *2025/2026 GRA*, Schedule 1, Appendix A, line 5. The $37,000 showing for 2025 average rate base relates to the 2024 year-end balance.

- Differences in rate base and invested capital exist in certain areas and are common across all utilities.
- Newfoundland Power will bring forward the following minor changes related to its rate base calculation in its next GRA to better align with the practices of other Canadian investor-owned utilities:[65]
    - While continuing the lead/lag study to determine the cash working capital allowance, moving to a five-year cycle for its completion.
    - Revisions to the Rate Stabilization Clause to include a financing cost recovery component for the ESCV Account, DMI Account and the WNR.
    - Inclusion of the Electrification Cost Deferral Account in rate base.
    - Exclusion of the Credit Facility Costs deferral from rate base.
- While the Company will continue its current approach of determining its materials and supplies rate base allowance, it plans to further assess if there is potential to simplify the process to determine the allowance.

Table 2 summarizes the areas in which rate base and invested capital will differ, with consideration of the changes outlined above, beginning with Newfoundland Power's next GRA. The table also provides how financing costs will be recovered for each area:

Table 2:
Areas of Differences in Rate Base and Invested Capital
(After Changes)

Area of Difference	**Reason for Difference**	**Financing Cost Recovery**
CWIP	Excluded from rate base as not considered to be used and useful in the provision of electrical service.	AFUDC
Materials and Supplies and Cash Working Capital	Allowance included in rate base reflects financing requirements more accurately than invested capital year-end balances.	Return on Rate Base
Supply Cost Mechanisms (RSA, ESCV, DMI, WNR)	Excluded from rate base due to variable nature of power supply costs.	Separate Finance Charge

Following implementation, the differences in the Company's rate base and invested capital will be clear, as will the recovery of financing costs associated with the differences. Further, beginning with its next GRA, Newfoundland Power will include a reconciliation of rate base and invested capital to ensure clarity and transparency in the areas where there are differences.

[65] These minor changes would have little to no impact on the overall recovery of the Company's finance costs, except for the inclusion of the financing cost recovery component related to the ESCV Account, DMI Account, and the WNR. This impact is not anticipated to be material, as described in footnote 57.

3.0 RATE OF RETURN ON RATE BASE

3.1 Newfoundland Power's Approach

The cost-of-service standard provides for the full recovery of a utility's financing costs. More formally, these financing costs are referred to as a utility's return on rate base.[66] Return on rate base includes the combined effect of a return on equity and a return on debt. However, as discussed in section 2.0 of this report, financing costs may be recovered through the return on rate base component of revenue requirement or via other means such as AFUDC or through a separate financing charge typically associated with supply cost mechanisms.

Table 3 provides Newfoundland Power's calculation of its return on rate base and rate of return on rate base for the 2025 test year and 2025 actual.[67]

Table 3:
Return on Rate Base and Rate of Return on Rate Base
2025 Test Year and 2025 Actual
($000s, unless otherwise noted)

	2025 Test Year	**2025 Actual**
Regulated return on common equity	54,483	58,478
Return on debt		
Interest on long-term debt	38,600	40,757
Interest on credit facility and short-term bank indebtedness	1,936	2,230
Amortization of debt issue expenses	221	250
AFUDC	(1,350)	(1,973)
	39,408	**41,264**
Regulated earnings	**93,891**	**99,742**
Adjustment[68]	-	(4,474)
Return on rate base	**93,891**	**95,268**
Average Rate Base	1,412,495	1,419,718
Rate of Return on Rate Base[69]	**6.65%**	**6.71%**
Weighted Average Cost of Capital ("WACC")[70]	6.65%	6.73%

66 Section 80(1) of the *Public Utilities Act* states that a public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board.

67 The Company's calculation of its 2025 return on rate base and rate of return on rate base is provided in Annual Return 13 for 2025.

68 The adjustment for 2025 is equal to total RSA interest in 2025 of $4,473,600 as provided in Annual Return 16 for 2025. The explanation for the adjustment is provided below the table. A similar adjustment was necessary for 2024 as provided in Annual Return 13 for 2025 and more fully detailed in Annual Return 13 for 2024.

69 Return on rate base / average rate base = rate of return on rate base.

70 WACC represents a company's overall cost of financing, weighted by the proportion of each capital source (i.e., equity and debt) in the company's capital structure.

Newfoundland Power calculated its 2025 test year and 2025 actual return on rate base by adding its return on debt and its return on common equity together. The return on debt component in each situation is reduced by the financing costs recovered through AFUDC. RSA balances and RSA interest were removed from the 2025 test year calculations.[71] For this reason, the Company must also make an adjustment to remove RSA interest from its 2025 actual return on rate base to ensure there is a valid comparison between actual and test year return on rate base calculations.[72] In both test year and actual situations, the approaches provide for a rate of return on rate base that aligns with WACC.

The comparability of Newfoundland Power's actual and test year return on rate base is important as the determination of excess earnings is based on the difference in the Company's actual and test year rate of return on rate base.[73]

Overall, Newfoundland Power's approach to determining its return on rate base provides for recovery of its financing costs in a reasonable manner and delineates between returns to be recovered in base rates and returns to be recovered through separate accounts. Further, the approach allows for a comparison between actual and test year rate of return on rate base, which is necessary in the determination of excess earnings for a given year.

3.2 Comparison to Utility Practice and Assessment of Alternative Approach

The Jurisdictional Review outlines two general approaches used by utilities in determining their test year return on rate base.[74] Ultimately, the two approaches provide for a similar end result – the utility fully recovering its forecast costs associated with financing its rate base.[75]

NS Power and MECL determine their test year return on rate base by adding their forecast return on equity and return on debt together as part of their revenue requirement calculations.[76] As part of their return on debt computations, they deduct debt costs recovered via other means, such as AFUDC and interest associated with their supply cost mechanisms.[77] As such, their approaches are similar in nature to Newfoundland Power's approach outlined in section 3.1 of this report.

FortisAB, FortisBC and Algoma Power determine their test year return on rate base by multiplying their average rate base by their WACC (the "Rate Base x WACC Approach").[78]

With respect to actual return on rate base and rate of return on rate base calculations, it appears that it is not common practice for utilities to complete these calculations on an actual basis.[79] This is likely a function of utility earnings sharing mechanisms being dependent on their

71 See Newfoundland Power's compliance filing associated with its *2025/2026 GRA*, Schedule 1, page 4.
72 For further information, see Annual Return 13 for 2025.
73 See the definition of the Excess Earnings Account on page 20 of the Company's System of Accounts filed with the Board on March 31, 2026 as part of its Annual Report to the Board for the year ended December 31, 2025.
74 Jurisdictional Review, section 8.1.6.
75 *Ibid.*
76 Jurisdictional Review, sections 3.3, 4.3 and 8.1.6. Regarding MECL, the Company further observes that in its *2023 to 2025 GRA*, MECL determined its rate of return on rate base by dividing its forecast return on rate base by its forecast average rate base. See Table 6-7 on page 97 of MECL's *2023 to 2025 GRA*.
77 Jurisdictional Review, sections 3.3, 4.3 and 8.1.6.
78 Jurisdictional Review, section 8.1.6.
79 An internal jurisdictional scan provided that actual return on rate base and rate of return on rate base calculations for 2024 for the five utilities reviewed were not readily available.

rate of return on equity which differs from Newfoundland Power's earnings sharing mechanism which is dependent on its return on rate base and rate of return on rate base calculations.[80]

While these findings show that the Company's approach in determining its return on rate base is reasonable when compared to the other utilities reviewed, Newfoundland Power completed a preliminary analysis to assess what impact using the Rate Base x WACC Approach could have on its return on rate base calculations compared to its current approach.

Table 4 provides the results of that analysis. The analysis is most relevant to the test year, however actual results for 2025 were also assessed to understand what differences could actually occur.

Table 4:
Return on Rate Base Analysis:
Rate Base x WACC Approach vs. Current Approach
2025 Test Year and 2025 Actual
($000s)

	2025 Test Year	2025 Actual
Rate Base x WACC Approach		
Average Rate Base (from Table 3)	1,412,495	1,419,718
WACC (from Table 3)	6.65%	6.73%
***Pro forma* Return on Rate Base**[81]	**93,931**	**95,547**
Return on Rate Base (Current Approach)[82]	93,891	95,268
Difference	40	279

The analysis shows that Newfoundland Power's current approach to determining its test year return on rate base provides for substantially similar results as the Rate Base x WACC Approach.

As part of the analysis, the Company also assessed if it could provide a valid comparison between test year and actual returns to meet the requirements of its Excess Earnings Account under the Rate Base x WACC Approach. In Newfoundland Power's view, the approach used to determine its 2024 return on rate base could be used under the Rate Base x WACC Approach.[83]

80 Each of the utilities reviewed determine their excess earnings with consideration of their rate of return on equity. See footnote 138 in the Company's *Supply Cost Mechanisms Review* filed with the Board on March 31, 2026.
81 Average Rate Base x WACC = *Pro forma* Return on Rate Base.
82 From Table 3.
83 See Annual Return 13 for 2024. For details on the approach used for 2024, see also Newfoundland Power's *2024 Rate of Return on Rate Base Application* filed with the Board on September 26, 2024 in compliance with Order No. P.U. 20 (2024). In particular, see pages 2-3 of the letter, as well as Appendix A, filed with the application.

Order No. P.U. 24 (2024) set Newfoundland Power's 2024 return on rate base for rate-setting purposes using the Rate Base x WACC Approach.[84] To ensure the Company's 2024 actual return on rate base was calculated consistent with the approach set in Order No. P.U. 24 (2024), an adjustment was necessary to the calculation of 2024 actual return on rate base to also exclude return amounts related to invested capital balances greater than average rate base.[85]

Table 5 uses the approach used in 2024 for both the 2025 test year and 2025 actual on a *pro forma* basis.

Table 5:
***Pro Forma* Return on Rate Base and Rate of Return on Rate Base**
2025 Test Year and 2025 Actual
($000s, unless otherwise noted)

	2025 Test Year	**2025 Actual**
Regulated return on common equity	54,483	58,478
Return on debt (condensed from Table 3)	39,408	41,264
Regulated earnings	**93,891**	**99,742**
Adjustment	40[86]	(4,195) [87]
Return on rate base	**93,931**	**95,547**
Average Rate Base	1,412,495	1,419,718
Rate of Return on Rate Base	**6.65%**	**6.73%**
Weighted Average Cost of Capital ("WACC")	6.65%	6.73%

The analysis shows that the Rate Base x WACC Approach is possible to use for test year purposes as well as for actual calculations.[88]

Based on the preliminary analyses provided in this section, Newfoundland Power plans to further explore determining its return on rate base and rate of return on rate base using the Rate

84 See Schedule 2 to the *2024 Rate of Return on Rate Base Application* filed in compliance with Order No. P.U. 20 (2024).
85 See line 15 on Annual Return 13 for 2024.
86 2025 test year average rate base of $1,412,495 x WACC of 6.65% = $93,931 - regulated earnings of $93,891 = $40.
87 2025 actual average rate base of $1,419,718 x WACC of 6.73% = $95,547 - regulated earnings of $99,742 = ($4,195).
88 For any material adjustment amounts, explanations could be provided. For 2025, it can be provided that of the ($4,195) adjustment, ($4,474) relates to interest charges on RSA balances which are excluded in 2025 test year rate base and return on rate base calculations and therefore must also be excluded from 2025 actual results.

Base x WACC Approach in the preparation of its next GRA.[89] If the Company's current approach is maintained, comparisons to the Rate Base x WACC Approach with reconciliations of any material differences would be provided to assist the Board in its consideration of the Company's proposed return on rate base and rate of return on rate base.

3.3 Summary of Rate of Return on Rate Base

The following summarizes the key findings of the review of Newfoundland Power's rate of return on rate base:

- The Company's current approach to determining its return on rate base and rate of return on rate base is reasonable.

- The Rate Base x WACC Approach is an alternative approach used by other utilities to determine their return on rate base.

- The Company's approach and the Rate Base x WACC Approach provides for substantially similar determinations of its return on rate base.

- The Company plans to further explore determining its return on rate base and rate of return on rate base using the Rate Base x WACC Approach in the preparation of its next GRA. If the Company's current approach is maintained, comparisons to the Rate Base x WACC Approach with reconciliations of any material differences would be provided.

4.0 CONCLUSION

The report confirms that Newfoundland Power's calculations of rate base and rate of return on rate base are reasonable and provide results that are consistent with utility practice. While reasonable, the report identifies opportunities to simplify certain aspects of the calculations and minor changes to better align the calculations with industry practice and support Board approvals of the Company's rate base and rate of return on rate base.

Newfoundland Power plans to implement the changes related to its rate base outlined in section 2.4 of this report beginning with its next GRA. The changes will simplify certain aspects of the Company's rate base calculation and better align its practices with other investor-owned electric utilities in Canada. Further, supporting reconciliations in areas of difference between rate base and invested capital will improve transparency associated with Newfoundland Power's rate base and rate of return on rate base calculations.

Similarly, further exploration of using the Rate Base x WACC Approach for determination of Newfoundland Power's return on rate base in its next GRA will, at a minimum, support the Company's current approach and will improve transparency associated with its return on rate base and rate of return on rate base calculations.

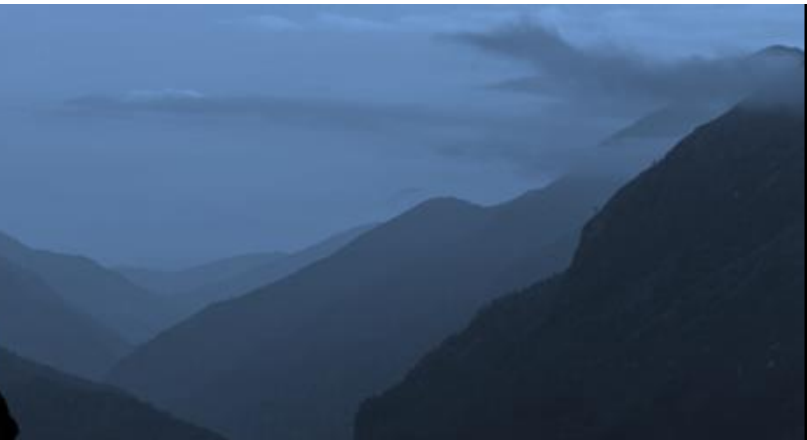
[89] For example, understanding if a change in approach would complicate the Company's internal GRA processes in determining its test year revenue requirements and customer rates while providing substantially similar results. Of note, these potential complications would not impact the use of the Rate Base x WACC Approach in determining Newfoundland Power's return on rate base and rate of return on rate base for non-GRA years. For example, Order No. P.U. 24 (2024) set Newfoundland Power's 2024 return on rate base and rate of return on rate base using the Rate Base x WACC Approach.

Jurisdictional Review

Jurisdictional Review of Rate Base

Prepared for:

Newfoundland Power Inc.
March, 2026



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1 Introduction

1.1 Background and Purpose

This Rate Base Review ("Review") has been prepared by Utilis Consulting Inc. ("Utilis") on behalf of Newfoundland Power Inc. ("Newfoundland Power"). In its Order No. P.U. 3 (2025) regarding Newfoundland Power's 2025/2026 General Rate Application, the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB" or "Board") directed Newfoundland Power to file a report by February 15, 2026 (amended in Q4 of 2025 to an updated deadline of March 31, 2026) with respect to the calculation of rate of return on rate base and the Asset Rate Base Method, addressing differences in average rate base and invested capital, including the cash working capital allowance and other allowances, and potential changes which may be considered. This Review provides a jurisdictional scan to assist Newfoundland Power in performing its report on this subject.

1.2 Report Structure and Methodology

Utilis was asked to review Newfoundland Power's rate base and return on rate base practices relative to other relevant utilities in Canada. Utilis first established the list of relevant utilities for inclusion in this Review, as outlined in section 1.4 describing the Peer Group below. Sections 2-7 of the report then proceed with a jurisdiction-by-jurisdiction review of Newfoundland Power and the Peer Group utilities' practices. Finally, Utilis was further instructed that its jurisdictional review should include a summary of findings and a comparison of Newfoundland Power's practices to those of peer utilities. This summary is available in section 8, inclusive of recommendations and conclusions.

To perform this comparative analysis, Utilis first reviewed the components that form Newfoundland Power's calculation of its rate base under the Asset Rate Base Method. These include its calculation of net plant investment, additions to rate base, deductions from rate base, and rate base allowances. This analysis then compared the components included in Newfoundland Power's calculation of its rate base with the components included by the Peer Group utilities in their respective calculations of their own rate base. This comparison includes a review of the components included in each Peer Group utility's rate base calculation, with reference to the authority or methodology that governs how each Peer Group utility calculates its rate base, where that information was available, as well as close analysis of how certain components themselves are calculated. These components include analysis of Peer Group utilities' allowances for materials and supplies, their calculation of working capital amounts, their treatment of Construction Work in Progress (CWIP) amounts, and their treatment of supply costs in rate base.

In conducting this review, Newfoundland Power's process of reconciling its rate base with its invested capital amounts was compared with the Peer Group utilities' treatment of their own invested capital. All utilities employ capital in service of obligations beyond the capital that is invested in their rate base. While this capital is not considered a component of rate base, it is "tied up" in the sense that it is invested in the business and could not otherwise be deployed or invested by the utility's shareholders. As two examples, this capital may be used to fund the construction of assets that are in progress and not yet capitalized, or it may be booked to regulatory accounts held by the utility.

All Peer Group utilities analysed in this Review naturally have an invested capital sum, but notably, none of them distinctly refer to or calculate their invested capital for comparison and/or reconciliation with their amounts in rate base. For this reason, this Review has chosen to proceed with its description of Peer Group utilities' practices based on the common elements that form their rate base calculations, and make reference to invested capital only where the concept is relied upon by respective utilities.

Finally, this review compares Newfoundland Power's method for calculating its return on rate base with that of the Peer Group utilities. To complete this comparison, Utilis first summarized Newfoundland Power's approach to calculating its return on rate base, both in dollars and expressed as a percentage rate. Subsequently, Utilis completed this same analysis for the Peer Group utilities to compare approaches and identify common or divergent approaches.

1.3 Utilis Consulting Inc.

Utilis is Canadian regulatory intelligence and consulting firm, based out of Ontario. Utilis was formed in October 2020 and as of Q1 2026 has 59 clients in Canada who have purchased its consulting and regulatory intelligence services, including electricity distributors, electricity transmitters, electricity generators, natural gas utilities, industry associations, non-governmental organizations, law firms, and government agencies and ministries. Utilis is an active participant in Canadian regulatory processes; supporting or having supported 28 cost-based regulatory applications[1] spanning the 2024 to 2027 rates years. Further, Utilis's regulatory intelligence services provides a strong foundation for the completion of jurisdictional reviews and analyses, having produced over 100 customized, client-led research papers since 2020.

Utilis's distinction from other regulatory consulting firms is the layering of technology onto the regulatory expertise of its staff. Utilis's suite of products includes the *Utilis Pursuit* regulatory search engine; proprietary technology that allows for advanced, AI-complemented keyword searches of all 13 Canadian energy regulators' databases. *Utilis Pursuit* is planned for commercial availability in 2026, and was leveraged by the Utilis team in the completion of this Review.

This Review was prepared under the leadership of Utilis Founder and Partner **Brandon Ott.**

Brandon Ott is an experienced regulatory strategist, rate-modeller, and case manager known for his ability to work with other experts and professionals to unpack complex and obscure issues. Brandon has led numerous regulatory application processes from general rate applications, to

[1] E.g. Cost of Service / General Rate Application, incremental capital / capital tracker applications, Z-Factor storm applications, non-wires applications, complex deferral and variance account applications.

leave to construct applications, to complex settlement negotiations and policy consultations; ranging from a few million to billions in expenditure value. Brandon is regarded as one of the premier regulatory writers in Canadian Energy Regulation and is experienced in the preparation of cost-based utility rates and incentive rate-setting frameworks.

Substantial contributions to this Review were provided by **Kiran Waterhouse**.

Kiran Waterhouse is a trained lawyer with experience on Bay Street and on the Regulatory Applications team at Toronto Hydro, positioning her to provide clients with industry leading regulatory analysis. Kiran is an entrepreneur who brings a can-do and results-focused mindset to help clients efficiently and strategically meet their regulatory objectives.

1.4 Peer Group

Utilis relied upon the following peer group ("Peer Group") to serve as the basis for its Review. This Peer Group was selected as appropriate comparators based upon the below characteristics, in addition to maintaining general alignment with the Supply Cost Mechanisms Review also directed by Order No. P.U. 3 (2025) and performed by Utilis. For the purposes of this Review, a single utility per provincial jurisdiction was selected. Utilis considered the following attributes in selecting the Peer Group:

- **Investor-Owned Utilities:** Priority was given to utilities which are investor-owned, as opposed to operating as publicly owned entities;
- **Size:** Utilities selected were of a sufficient size to allow for an appropriate comparison against the scale of Newfoundland Power; excluding small utilities from the analysis. One exception was made with respect to Algoma Power Inc. ("Algoma Power") of Ontario, as the approach to calculating rate base in Ontario is directed by the Ontario Energy Board and is largely consistent across both large and small utilities;
- **Geography:** A cross-section of Provincial jurisdictions was sought out to canvass the different approaches approved by different economic regulators in Canada. The Peer Group also sought to capture all investor-owned utilities in Atlantic Canada in light of their proximity to Newfoundland Power; and
- **Market Structure:** Priority was given to jurisdictions with non-vertically integrated structures, to better reflect the asset mix of Newfoundland Power.

Based on the criteria outlined above, the following utilities were selected for inclusion in the Report Peer Group:

Table 1: Peer Group for Review of Rate Base Methodology

Utility	Regulator	Ownership
Newfoundland Power	Newfoundland & Labrador Board of Commissioners of Public Utilities	Investor-owned
Nova Scotia Power	Nova Scotia Energy Board	Investor-owned
Maritime Electric	Prince Edward Island Regulatory & Appeals Commission	Investor-owned
Algoma Power	Ontario Energy Board	Investor-owned
FortisAlberta	Alberta Utilities Commission	Investor-owned
FortisBC Inc.	British Columbia Utilities Commission	Investor-owned

2 Newfoundland Power

2.1 Overview of Newfoundland Power's Rate Base Calculation

Newfoundland Power's approach to calculating rate base uses the Asset Rate Base Method first approved in Part Four of Procedural Order 19 (2003) issued by the PUB to Newfoundland Power in its 2003 General Rate Application. This Procedural Order directed Newfoundland Power to adopt the Asset Rate Base Method for determining rate base, replacing its previous invested capital approach.[2] The completion of this transition was facilitated by the Board's decision in Newfoundland Power's 2008 General Rate Application.[3]

As indicated in Table 2 below, Newfoundland Power's calculation of rate base as set out in its most recent General Rate Application for 2025-2026 has four phases. The utility first determines its net plant investment. The utility next calculates its additions and deductions to rate base and sums these to determine its year end rate base. Following this the utility averages its opening

[2] Board of Commissioners of Public Utilities, "Backgrounder, the General Rate Application of Newfoundland Power", 2002; P.0. 19(2003) "Part Three Summary of Board Decisions", page 115.
[3] Board of Commissioners of Public Utilities, "2008 General Rate Application filed by Newfoundland Power Inc.", P.U. 32(2007), page 15.

and year end rate base for each year, to determine average rate base for each year. Finally, the utility sums its rate base allowances and adds this amount to establish its average rate base.[4]

Table 2: Newfoundland Power's Calculation of Average Rate Base[5]

1		Plant Investment
	-	Accumulated Depreciation
	-	Contributions in Aid of Construction
	=	**Net Plant Investment**
2		Deferred Pension Costs
	+	Credit Facility Costs
	+	Cost Recovery Deferral – Conservation
	+	Cost Recovery Deferral – 2022 Revenue Shortfall
	+	Cost Recovery Deferral – Load Research and Retail Rate Design Review
	+	Cost Recovery Deferral – Hearing Costs
	+	Cost Recovery Deferral – Pension Capitalization
	+	Customer Finance Programs
	=	**Additions to Rate Base**
3		Weather Normalization Reserve
	+	Demand Management Incentive Account
	+	Other Post-Employment Benefits
	+	Customer Security Deposits
	+	Accrued Pension Obligation
	+	Accumulated Deferred Income Taxes
	+	Refundable Investment Tax Credits
	+	Excess Earnings Account
	=	**Deductions from Rate Base**
4		**Net Plant Investment + Additions to Rate Base – Deductions from Rate Base = Year End Rate Base**
5		**Average Year End Rate Base Across Year to Determine Average Rate Base**
6		Materials and Supplies Allowance
	+	Cash Working Capital Allowance
	=	**Rate Base Allowances**
7		**Average Rate Base Before Allowances + Rate Base Allowances = Average Rate Base**

[4] Newfoundland Power, 2026 Capital Budget Application, "Rate Base: Additions, Deductions and Allowances Report", page 1.
[5] Newfoundland Power, 2026 Capital Budget Application, Schedule D.

2.2 Calculation of Newfoundland Power's Rate Base Components

2.2.1 Calculation of Newfoundland Power's Allowance for Materials and Supplies

Newfoundland Power's computation of rate base includes the addition of two allowances after additions and deductions are performed. Newfoundland Power defines allowances for rate base as costs associated with maintaining the required working capital and inventories necessary to provide service.[6] The first is an allowance for materials and supplies and the second is an allowance for the utility's cash working capital requirements.

Newfoundland Power's allowance for materials and supplies is included in its rate base as a means to recover the cost of financing its inventories that are not related to the expansion of the electrical system. The allowance is based on an average of materials and supplies, minus an expansion adjustment which is determined by multiplying the average of materials and supplies by an expansion factor. The expansion factor most recently applied in Newfoundland Power's 2026 Capital Budget Application as part of its computation of its 2024 average rate base was 19.08% and was approved by the Board in Order No. P.U. 3 (2022), which itself references a report by Grant Thornton in its Board of Commissioners of Public Utilities Financial Consultants Report filed as part of the same 2022-2023 General Rate Application.[7]

2.2.2 Calculation of Newfoundland Power's Allowance for Cash Working Capital

Newfoundland Power determined its cash working capital allowance in its most recent 2025-2026 General Rate Application through an internal analysis performed using the same methodology as was approved in its 2022 and 2023 General Rate Application. This methodology uses a lead/lag study analysing transactions over a period of time to determine net lags and net leads. The weighted average expense lag is then subtracted from the weighted average revenue lag. The result is divided by 365 days to establish a cash working capital factor.[8] Newfoundland Power's cash working capital factor for 2023 and 2024, which the utility produced in its most recent 2026 Capital Budget Application as part of its computation of its 2024 average rate base, was 1.199%.[9] To determine its cash working capital allowance, the utility then multiplied this factor by its total regulated expenses to calculate first the average amount of working capital and then its cash working capital allowance.

[6] Newfoundland Power, 2026 Capital Budget Application, "Rate Base: Additions, Deductions and Allowances Report", page 1.
[7] Newfoundland Power, 2026 Capital Budget Application, "Rate Base: Additions, Deductions and Allowances Report", page 1; Board of Commissioners of Public Utilities, "Decision and Order of the Board Order No. P.U. 3(2022)", page 16; Grant Thornton "Board of Commissioners of Public Utilities Financial Consultants Report", Newfoundland Power 2022-2023 General Rate Application, page 10.
[8] Newfoundland Power, 2022-2023 General Rate Application, Volume 2, 2022 and 2023 Rate Base Allowances.
[9] Newfoundland Power, 2026 Capital Budget Application, "Rate Base, Additions, Deductions and Allowances Report", page 14.

2.2.3 Treatment of Newfoundland Power's CWIP in Rate Base

Newfoundland Power receives financing cost recovery on CWIP through an Allowance for Funds Used During Construction ("AFUDC").[10] These amounts are capitalized once assets are placed into service, incorporating AFUDC within rate base moving forward. Similarly, financing costs for inventories that are related to expansion are excluded from Newfoundland Power's Materials and Supplies Allowance and instead are subject to AFUDC which is capitalized once expansion assets are placed into service.[11]

2.2.4 Treatment of Newfoundland Power's Supply Costs in Rate Base

Newfoundland Power receives recovery of financing charges on balances in its Rate Stabilization Account ("RSA") through an RSA financing charge, which is equal to the utility's approved return on rate base.[12] As such, Newfoundland Power's RSA is not included within rate base. Of note, Newfoundland Power does not transfer amounts from its Energy Supply Cost Variance ("ESCV") Account into its RSA for a given year's power supply costs until December 31st of each year. The ESCV account does not include a finance charge. As a result, while Newfoundland Power receives its return on rate base as a financing charge on power supply cost variances in the year after they are incurred, no return or interest recovery is provided on energy supply cost variances during the year in which they take place.

2.3 Newfoundland Power's Derivation of Return on Rate Base

Newfoundland Power's method for determining its rate of return on rate base, both in terms of a percentage return and return in dollars, begins by summing Newfoundland Power's return on debt and return on common equity. The return on the debt component is known based on Newfoundland Power's forecast interest expense based on actual and planned borrowing, net of an AFUDC adjustment. The return on the equity component is also based on Newfoundland Power's forecasts and is calibrated to align with equity returns informed by cost of capital evidence.[13] In its 2025-2026 General Rate Application Newfoundland Power removed RSA balances and interest revenue from its Test Year forecasts.[14]

To derive a percentage-based Return on Rate Base, Newfoundland Power divides its Return on Rate Base (in dollars) by its Average Rate Base. Table 3 below, taken from Newfoundland Power's 2025 / 2026 General Rate Application Compliance Filing, depicts this calculation:[15]

[10] Newfoundland Power, 2025-2026 General Rate Application, Volume 1, Exhibit 5, Line 7.
[11] Section 5.1 Rate Base: Additions, Deductions and Allowances, page 14.
[12] Newfoundland Power; Rates, Rules & Regulations effective July 1, 2025, Section II.1(v).
[13] Newfoundland Power 2025-2026 General Rates Application, PUB-NP-076.
[14] Newfoundland Power 2025-2026 General Rates Application, Compliance Filing, Schedule 1, Appendix B.
[15] Ibid.

Table 3: Newfoundland Power 2025 Return on Rate Base Calculation

Newfoundland Power Inc.

2025 Rate of Return on Rate Base
($000s)

		2025P[1]	Changes	2025R
1				
2	**Average Capitalization**			
3	Debt	786,781	(8,012)	778,769
4	Common Equity	640,195	(6,597)	633,598
5		1,426,976	(14,609)	1,412,367
6				
7	**Average Capital Structure (%)**			
8	Debt	55.14	0.00	55.14
9	Common Equity	44.86	(0.00)	44.86
10		100.00	0.00	100.00
11				
12	**Cost of Capital (%)**			
13	Debt	5.21	(0.15)	5.06
14	Common Equity	9.85	(1.25)	8.60
15				
16	**Weighted Average Cost of Capital (%)**			
17	Debt	2.87	(0.08)	2.79
18	Common Equity	4.42	(0.56)	3.86
19		7.29	(0.64)[2]	6.65
20				
21	**Return on Rate Base**			
22	Return on Debt	41,002	(1,594)	39,408
23	Return on Common Equity	63,047	(8,564)	54,483
24		104,049	(10,158)[2]	93,891
25				
26	2025 Average Rate Base ($000s)	1,406,816	5,679	1,412,495
27				
28	**2025 Rate of Return on Rate Base (%)**	7.40	(0.75)[2]	6.65

As shown above, both Newfoundland Power's WACC and Rate of Return on Rate Base are reported as 6.65%. Of note, the dollar amount in Line 24 entitled "Return on Rate Base" is derived from invested capital requirements as opposed to Rate Base. Dividing this return amount by Average Rate Base will yield a different resulting rate than dividing the same return amount by Average Capitalization (i.e. invested capital) because Average Rate Base is a subset of invested capital, as was highlighted in information requests in Newfoundland Power's 2025/2026 General Rate Application.[16]

When taking into account the adjustments for AFUDC and the removal of RSA balances and interest, the derived Return on Rate Base (%) under Newfoundland Power's method is highly comparable to, albeit not precisely equal to, the utility's WACC. Mathematically, Newfoundland Power is receiving its WACC as a Return on Rate Base as well as its WACC on the portions of invested capital which are outside of rate base, consistent with historical practice and policy applicable to the utility. The components of Newfoundland Power's invested capital that lie outside of its rate base are described in Table 4 below.

[16] Newfoundland Power 2025-2026 General Rates Application, PUB-NP-076.

Table 4: **Components of Newfoundland Power's Invested Capital Not Included in Rate Base**[17]

1		**Construction Work in Progress**
2		**Materials and Supplies vs. Rate Base Allowance**
3		Accounts receivable, prepaids and accounts payable vs. rate base allowance
	+	Energy Supply Cost Variance Account Amounts
	+	Rate Stabilization Account
	+	Deferral Accounts and Other
	=	**Cash Working Capital Detail**
4		**Construction work in progress + Materials and supplies reconciliation + Cash working capital amounts = invested capital not reflected in rate base**

3 Nova Scotia Power

3.1 Overview of Nova Scotia Power's Rate Base Calculation

In evaluating Nova Scotia Power's computation of rate base, the Nova Scotia Energy Board ("NSEB") is directed by the *Public Utilities Act* in Nova Scotia to determine a separate rate base for each type of service provided by the utility. This *Act* states that in its review and approval of a utility's rate base, the NSEB has the discretion to make allowances for necessary working capital, organizational expenses prudently expended out of capital accounts, construction overheads, expenses of valuations charged to capital accounts, and the cost of land acquired in reasonable anticipation of future requirements.[18]

Nova Scotia Power's 2026-2027 General Rate Application, filed in September 2025 for review by the NSEB, includes an overview of the utility's rate base and a detailed review of each component included in its calculation. This application notes that Nova Scotia Power's computation of rate base is calculated in line with a methodology first established in NSEB's 2006 Rate Decision that has since been used as the foundation for calculating utility rate base in subsequent applications.

Nova Scotia Power's calculation of rate base is provided in Table 5 below. Nova Scotia Power's calculation of average rate base adds up the components of average capital assets net of accumulated depreciation, average deferred charges and credits, long-term income tax receivable, average materials and supplies inventory, and the average cash working capital allowance to determine average rate base.

[17] Newfoundland Power "2025/2026 General Rate Application", Requests for Information PUB-NP-076.
[18] *Public Utilities Act*, RSNS 1989, c. 380, sections 42(1)-42(2).

Nova Scotia Power's general approach has been to include all physical and financial assets for which it receives a return in its calculation of rate base, though it may receive an additional return at its WACC rate on regulatory assets and liabilities that lie outside of rate base. For example, while Nova Scotia Power included its Fuel Adjustment Mechanism deferral charges, Demand Side Management deferral charges, renewable to retail, retired hydro assets and deferred income tax charges in its calculation of rate base in its 2026-2027 General Rate Application, the NSEB considered the financing charges for this group of regulatory assets and liabilities as a discrete question from its calculation of rate base in its previous General Rate Application Settlement Agreement, determining that this group of charges should also attract financing costs at Nova Scotia Power's WACC rate.[19]

Table 5: Nova Scotia Power's Calculation of Average Rate Base

1		Forecast average net book value of property, plant and equipment
	+	Construction work in progress costs
	=	**Average Capital Assets**
2		Financing Charges
	+	Pension Charges
	+	FAM Deferral
	+	SCRR Deferral
	+	DSM Rider Deferral
	+	Other General Charges
	+	Retired Assets (Roseway, Annapolis, Smart Grid NS)
	+	DDA Asset
	+	Cost of Removal Liability
	+	Asset Retirement Obligation
	+	Deferred Income Taxes
	+	Other Deferred Credits
	=	**Average Deferred Charges & Credits**
3		**Long-term Income Tax Receivable**
4		**Average Materials and Supplies Inventory**
5		**Average Cash Working Capital Allowance**
6		**(1) Average Capital Assets + (2) Average Deferred Charges & Credits + (3) Long-term Income Tax Receivable + (4) Average Materials and Supplies Inventory + (5) Average Cash Working Capital Allowance = Average Rate Base**

[19] 2023 NSUARB 12 M10431, "GRA Settlement Agreement Approval", Page 46-49.

3.2 Calculation of Nova Scotia Power's Rate Base Components

3.2.1 Calculation of Nova Scotia Power's Allowance for Materials and Supplies

Nova Scotia Power includes its material and supplies inventory as an item that gets added into rate base, based on the projected monthly average required for the rate term.[20]

3.2.2 Calculation of Nova Scotia Power's Allowance for Cash Working Capital

Nova Scotia Power defines its cash working capital allowance as the "average amount of capital required above and beyond investments in plant and other separately identified rate base items… to bridge the gap between the time expenditures are made and payment in the form of revenue is received."[21] Nova Scotia Power commissioned a lead/lag study carried out by consultant ScottMadden on its behalf in 2025 that analysed cash flows arising from its billing, payment and collection procedures to determine its cash working capital allowance for its 2026-2027 General Rate Application.

ScottMadden's methodology was to compute the leads and lags associated with fuels expenses, operations, maintenance and general expense (labour and non-labour both included), income taxes, grants in lieu of taxes, sales taxes including HST GST and PST, and demand-side management program payments. The study then proceeded to compare the difference between the company's revenue lag and expense leads to measure lead/lag days, which were then applied to the company's test period expenses to derive its cash working capital requirement. This requirement then formed a component of rate base in the form of an allowance.[22] The company did not develop a working capital factor on a percentage basis as part of its computation of cash working capital requirements, instead deriving the cash working capital requirement based on the number of lead/lag days in the analysis.

3.2.3 Treatment of Nova Scotia Power's CWIP in Rate Base

Construction Work in Progress ("CWIP") costs and deferred charges held in regulatory accounts are included in Nova Scotia Power's calculation of its rate base.[23]

3.2.4 Treatment of Nova Scotia Power's Supply Costs in Rate Base

Nova Scotia Power includes power supply costs deferred via its Fuel Adjustment Mechanism ("FAM") as a rate base addition, and as such receives its WACC as a return on these outstanding balances. As noted, the NSEB previously approved the use of Nova Scotia Power's WACC for determining interest on outstanding balances.[24]

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[20] Nova Scotia Energy Board, 2026-2027 General Rate Application M12451, page 53.
[21] *Ibid* at page 53.
[22] Nova Scotia Energy Board, 2026-2027 General Rate Application M12451, SR-04 Attachment 1 page 4.
[23] Nova Scotia Energy Board, 2026-2027 General Rate Application M12451, pages 50-61.
[24] 2023 NSUARB 12 M10431, "GRA Settlement Agreement Approval", Page 46-49.

3.3 Nova Scotia Power's Derivation of Return on Rate Base

Nova Scotia Power's 2026-2027 General Rate Application demonstrates a greater focus by the utility and the regulator on Return on Equity, as opposed to Return on Rate Base inclusive of financing costs. In reporting Revenue Requirement, the utility distinctly reports Interest and Other Expenses (including AFUDC and FAM interest) from Return on Equity.[25] Nova Scotia Power does not appear to report on or seek approval of a Rate of Return on Rate Base, instead separately calculating forecast interest expense and Return on Equity. Return on Equity in dollars is equal to the utility's requested Rate Base, multiplied by requested equity thickness, multiplied by requested Return on Equity Rate.[26] No comparable calculation of interest expense is presented, indicating interest is provided in dollars on a forecast basis.

4 Maritime Electric

4.1 Overview of Maritime Electric's Rate Base Calculation

Section 21 of the provincial *Electric Power Act* details how the Regulatory and Appeals Commission of Prince Edward Island ("IRAC") should establish rate base, including details prescribing how the value of the utility's used and useful assets should be determined, accrued depreciation should be deducted, how additions and deductions from rate base should be calculated, and that an allowance for working capital may be established.[27]

Maritime Electric provided an overview of its calculation of average rate base in section 6 of its most recent 2023-2025 General Rate Application. In this filing, the utility defines rate base as "the total of the investor-funded plant, facilities and other investments used by the Company to provide service to customers."[28] A step-by-step calculation of Maritime Electric's rate base is laid out in Table 6. Maritime Electric, after first computing its fixed assets, determines additions and deductions to rate base, adds/subtracts these amounts to rate base, and finally adds its cash working capital allowance to arrive at annual rate base.

As discussed below, Maritime Electric is entitled to earn a rate of return on its Energy Cost Adjustment Mechanism (ECAM) balance but does not earn this rate of return on all of its deferral accounts as a matter of default. One illustration of this principle is IRAC's determination that the utility's Rate of Return Adjustment account, originally established in 2011 to return collections to customers in excess of the utility's approved rate of return, should attract interest at the company's short-term debt borrowing rate.[29]

[25] Nova Scotia Energy Board, 2026-2027 General Rate Application M12451, page 74.
[26] Nova Scotia Energy Board, 2026-2027 General Rate Application M12451, CS-01-CS-03 Attachment 1.
[27] *Electric Power Act,* Prince Edward Island, updated December 20, 2017, section 21.
[28] Maritime Electric, 2023 to 2025 General Rate Application, Application and Evidence, page 91.
[29] Prince Edward Island Regulatory & Appeals Commission, Docket UE20000, Order UE11-04.

Table 6: Maritime Electric's Calculation of Annual and Average Rate Base

1		**Fixed Assets**
2		CTGS Reserve Variance
	+	ECAM
	+	Intangible Assets
	+	Other Post Employment Benefits
	+	Weather Normalization Reserve
	+	Deferred Charges
	+	Deferred Financing
	=	**Subtotal of Additions to Rate Base**
3		Future Income Tax
	+	Contributions
	+	Employee Future Benefits
	+	Return on Rate Base Refund
	=	**Subtotal of Deductions from Rate Base**
4		Inventory
	+	Operating Expenses x 3.6%
	+	Income Taxes Paid x 3.6%
	=	**Subtotal of Working Capital**
5		**Fixed Assets + Additions to Rate Base – Subtractions from Rate Base + Working Capital = Annual Rate Base**

4.2 Calculation of Maritime Electric's Rate Base Components

4.2.1 Calculation of Maritime Electric's Allowance for Materials and Supplies

In its 2023-2025 General Rate Application, Maritime Electric included its inventory purchases as a sub-component of its working capital requirements in its calculation of rate base. Maritime Electric assumes a consistent year-end inventory level comparable to historical actuals for the purposes of this calculation.[30]

4.2.2 Calculation of Maritime Electric's Allowance for Cash Working Capital

Maritime Electric applies a working capital factor of 3.6% to its base of income taxes and operating expenses in order to determine its cash working capital allowance, stating that this factor is consistent with previous rate applications. No lead/lag study or rationale for this 3.6% factor is provided. Previous applications indicate that the 3.6% figure appears to be used at least

[30] Maritime Electric, 2023 to 2025 General Rate Application, Application and Evidence, page 60, page 95.

since 2011.[31] Section 21(3) of the provincial *Electric Power Act* provide IRAC with the power to establish an allowance for necessary working capital as part of its rate base.[32]

4.2.3 Treatment of Maritime Electric's CWIP in Rate Base

A report prepared by third-party consultant Concentric for Maritime Electric's 2023-2025 General Rate Application states that utilities in Canada are not allowed to earn a cash return on construction work in progress, but that utilities are permitted an allowance for funds used during construction ("AFUDC").[33] Maritime Electric uses AFUDC to fund the cost of financing capital additions during construction. The AFUDC rate reflects the cost of debt and equity financing, which is approved by the Commission through Maritime Electric's annual capital budget application process and is amortized over the service life of the related assets.[34]

4.2.4 Treatment of Maritime Electric's Supply Costs in Rate Base

Maritime Electric includes power supply costs deferred via its Energy Cost Adjustment Mechanism ("ECAM") as a rate base addition, and as such receives its WACC as a return on these outstanding balances.

4.3 Maritime Electric's Derivation of Return on Rate Base

In its most recent 2023-2025 General Rate Application, Maritime Electric explained that its return on rate base is equivalent to the total annual cost of financing its rate base, including the cost of short-term debt, long-term debt and shareholders' equity.[35] On investigation, the utility's requested Return on Equity in its 2023-2025 General Rate Application is equal to the average of 2024 and 2025 Shareholder's Equity reported in its Pro Forma Balance Sheet, multiplied by the requested ROE rate of 9.95%.[36] Similarly, Maritime Electric's Financing Costs are based on a ground up forecast of charges, adjusted for AFUDC.[37] When forecast Financing Costs and calculated ROE are summed together, they are reported by Maritime as Total Earnings on Rate Base, and this amount is divided by Average Rate Base to calculate Return on Average Rate Base.[38] From this, the utility is by definition receiving WACC on the invested capital requirements relied upon to forecast Financing Charges and ROE.

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[31] Letter to Island Regulatory and Appeals Commission, "RE: Maritime Electric Rate Base", January 2011.
[32] *Electric Power Act,* Prince Edward Island, updated December 20, 2017, section 21(3).
[33] Maritime Electric, 2023 to 2025 General Rate Application, Application and Evidence, Cost of Capital report, page 72.
[34] Maritime Electric, 2023 to 2025 General Rate Application, Application and Evidence, page 61.
[35] Maritime Electric, 2023 to 2025 General Rate Application, Application and Evidence, page 97.
[36] Maritime Electric, 2023 to 2025 General Rate Application, Application and Evidence, Appendix I, Balance Sheets and Statements of Earnings.
[37] Maritime Electric, 2023 to 2025 General Rate Application, Application and Evidence, page 59.
[38] Maritime Electric, 2023 to 2025 General Rate Application, Application and Evidence, page 97.

5 Algoma Power

5.1 Overview of Algoma Power's Rate Base Calculation

Algoma Power's calculation of its rate base is directed by section 2.2 of the Ontario Energy Board Filing Requirements ("OEB Filing Requirements"), which instructs distributors to include the components of rate base, the opening and closing balances for each year of rate base, and the average of the opening and closing balances for gross fixed assets and accumulated depreciation in their calculation. Distributors must indicate if they use an alternative method such as calculating average in-service fixed assets based on the average of monthly or quarterly values and provide documentation to justify their methodology.[39] Algoma Power's calculation of its rate base is laid out in Table 7 below.

Algoma Power's funds held in regulatory accounts and funds expended during the construction of an asset are not included in its rate base and do not attract a return at the utility's WACC.

Algoma Power, like other electricity distributors regulated by the OEB, receives a prescribed rate of interest on amounts held in its regulatory accounts at an interest rate reviewed quarterly by the OEB. In its most recent cost of service application, Algoma Power listed its ongoing accounts, which include a Group 1 set of variance accounts that account for variances in wholesale power costs, transmission network charges and smart metering entity charges, and a series of other accounts common to all Ontario electricity distributors, which are routinely disposed of on an annual basis. In addition, a Group 2 set of accounts includes less routine accounts for revenue variances from attachments to utility-owned pole infrastructure, pension deferrals, expenses and other post-employment benefits, tax variances, accounting changes from CGAAP to IFRS, and other matters which may vary by utility.[40] Group 2 accounts are typically only disposed of during a Cost of Service application, which in Ontario takes place once every five years (subject to requested and approved deferrals of such applications).

[39] Ontario Energy Board, Filing Requirements – Chapter 2, section 2.2, page 18.

[40] EB-2024-0007 Algoma Power "Exhibit 9 Deferral and Variance Accounts", pages 6-14.

Table 7: Algoma Power's Calculation of Test Year Rate Base[41]

1		Book value of existing assets
	+	Capital in-service additions[42]
	-	Accumulated Depreciation[43]
	=	**Average Net Fixed Assets**
2		Operations, Maintenance and Administrative Expenses (inclusive of Low Income Energy Assistance Program funds and Property Tax)
	+	Cost of Power Expense
	=	**Total Expenses for Working Capital / "Working Capital Base"**
3		Working Capital Base
	x	Working Capital Allowance Rate (7.5%)
	=	**Working Capital Allowance**
4		**Average Net Fixed Assets + Working Capital Allowance = Rate Base**

5.2 Calculation of Algoma Power's Rate Base Components

5.2.1 Calculation of Algoma Power's Allowance for Materials and Supplies

Under Algoma Power's capitalization policy, the utility charges its materials and supplies to its capital on the basis of actual costs for non-stock materials and the weighted average price for materials in inventory.[44] Materials and supplies are charged to capital on the basis of actual costs for non-stock materials and the weighted average price for materials in inventory.

5.2.2 Calculation of Algoma Power's Allowance for Cash Working Capital

Section 2.2.5 of the OEB Filing Requirements assigns electricity distributors a default Working Capital Allowance of 7.5%. The Filing Requirements permit utilities to submit a lead/lag study in support of a different working capital allowance. If filed, the lead/lag study is required to include the following details:

a) The time between the date customers receive service and the date that the customers' payments are available to the distributor (the revenue lag).
b) The time between the date when the distributor receives goods and services from its suppliers and vendors and the date that it pays for them (the expense lead).

Algoma Power did not file a lead/lag study and chose to apply the default 7.5% allowance for working capital to its test year, consistent with the approach taken by the vast majority of Ontario

[41] EB-2024-0007, Algoma Power "Exhibit 2 Rate Base & DSP", page 5.
[42] Subject to half-year rule.
[43] In-service year depreciation expense subject to half-year rule.
[44] EB-2024-0007, Algoma Power "Exhibit 2 Rate Base & DSP", page 54.

distributors. To compute its allowance, it summed up its Cost of Power as determined using registered price plan prices and uniform transmission rates, and its Controllable Expenses (including operations, maintenance, billing and collecting, community relations, administration and general) to determine its Working Capital Base. These two line items were then multiplied by the allowance of 7.5% to determine the utility's Cash Working Capital Allowance (which Algoma Power simply refers to as its Working Capital Allowance).[45]

5.2.3 Treatment of Algoma Power's CWIP in Rate Base

Algoma Power does not add CWIP amounts as a discrete line item into its rate base but does track these amounts where projects span multiple years and require capital expenditures to be held in OEB Account 2055-Work in Progress. Amounts tracked in Account 2055 are added to the utility's capital asset accounts once the asset is placed in service, at which point they become part of rate base.[46] Algoma Power does not currently capitalize interest during construction of multi-year projects, and in its most recent Cost of Service application it confirmed that none of the projects presented included capitalized interest.[47] This means that the cost of CWIP is included in rate base when the asset is capitalized, but the interest on the CWIP is not capitalized. Interest on CWIP accrues at an interest rate prescribed by the OEB that is reviewed and updated on a quarterly basis.[48] Stated differently, were Algoma Power to capitalize interest on CWIP as other Ontario electricity distributors do, it would receive a rate of interest on its CWIP that was different than its WACC rate.

5.2.4 Treatment of Algoma Power's Supply Costs in Rate Base

Algoma Power records variances in power supply costs, including transmission and other charges, in a series of generic deferral and variance accounts prescribed for all Ontario electricity distributors by the OEB. As described below, deferral and variance account balances (including those related to power supply costs) are not included within Algoma Power's rate base.

5.3 Algoma Power's Derivation of Return on Rate Base

The return on rate base of Ontario distributors is determined by multiplying a utility's rate base by its approved WACC, which as noted above is made up of some utility-specific rates (i.e. long-term debt) and some generically established rates (i.e. ROE and short-term debt). In most instances, this calculation is completed by first segmenting approved rate base into the capital structure components of equity, long-term debt, and short-term debt, multiplying each segment by its respective rate, and summing the results.[49] In practice, this calculation yields the same mathematical result as multiplying approved rate base by approved WACC.

[45] EB-2024-0007, Algoma Power "Exhibit 2 Rate Base & DSP", page 55.
[46] EB-2024-0007, Algoma Power "Exhibit 2 Rate Base & DSP", page 6.
[47] Ibid., pages 20, 54.
[48] Ontario Energy Board, "Regulatory Rules and Documents: Prescribed Interest Rates."
[49] EB-2024-0007, Partial Decision and Order, Attachment RRWF1, Page 6.

6 FortisAlberta

6.1 Overview of FortisAlberta's Rate Base Calculation

FortisAlberta's calculation of its rate base is dictated by Alberta Utilities Commission ("AUC") Rule 005, which requires electric utilities to file annual reports with a schedule detailing their mid-year rate base and their return on rate base. FortisAlberta provided its calculation of rate base in its most recent rate-setting application, its 2023 Cost of Service Application, for the purpose of calculating its revenue requirement. This application contains both a description of the utility's rate base, as well as Appendix A, which details the utility's revenue requirement and a numerical calculation of rate base. FortisAlberta's rate base calculation has the following components laid out in Table 8. FortisAlberta noted in its Appendix A rate base calculation that some utilities maintain a capital funding balance in excess of the amount needed to fund the mid-year rate base, but that FortisAlberta did not maintain such a balance.[50]

In addition to the amounts listed as part of FortisAlberta's calculation of rate base above, FortisAlberta maintains regulatory accounts. Under the AUC's current performance based regulation policies, these are called Y factor accounts, and they are defined as costs that qualify for deferral account treatment if they meet certain criteria.[51] The AUC entitles FortisAlberta to recover carrying costs associated with its Y factor accounts in accordance with AUC rule 023. This rule provides a utility with the opportunity to recover interest costs resulting from regulatory lag or where revenue forecasts differ from actual results. Carrying costs are calculated at the Bank of Canada policy interest rate plus 1 ¾% on a per annum basis, meaning that Y factor accounts do not attract a return at the utility's WACC.[52]

[50] FortisAlberta Inc., "2023 Cost of Service Applications", proceeding 26615, Appendix A.

[51] FortisAlberta Inc. "2023 Cost of Service Application", proceeding 26615, page 84. The funds must be: Attributable to events outside management's control, material, without a significant influence on the inflation factor in the PBR formulas, prudently incurred, of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

[52] Alberta Utilities Commission Rule 023, "Rules Respecting Payment of Interest."

Table 8: FortisAlberta Rate Base Calculation

1		Mid-Year Gross Utility Plant in Service
	-	Mid-Year Accumulated Depreciation
	-	Mid-Year Utility Contributions in Aid of Construction
	+	Mid-Year Utility Amortization of Contributions
	=	**Mid-Year Net Utility Plant in Service**
2		**Necessary Working Capital**
3		**Other No Cost Capital**
4		**Deferred Charges**
5		**Mid-Year Net Utility Plant in Service + Necessary Working Capital + Other No Cost Capital + Deferred Charges = Mid-Year Net Rate Base**
6		**Average Net Fixed Assets + Working Capital Allowance = Rate Base**

6.2 Calculation of FortisAlberta's Rate Base Components

6.2.1 Calculation of FortisAlberta's Allowance for Materials and Supplies

As noted below, FortisAlberta relies on lead lag indicators approved in its 2012 rate application for the purpose of establishing its cash working capital. Review of the 2012 calculations indicates that FortisAlberta considers mid-year operating materials and supplies inventory in the derivation of working capital, indicating that FortisAlberta's allowance for cash working capital is the means through which the utility receives cost recovery for operating materials and supplies investments.[53] Conversely, construction inventory is included within the derivation of AFUDC on CWIP, indicating that inventories directly relating to the construction of assets which will be placed into rate base are excluded from allowance treatment of materials and supplies.[54]

6.2.2 Calculation of FortisAlberta's Allowance for Cash Working Capital

FortisAlberta's determination of its cash working capital allowance in its most recent 2023 Cost of Service application was performed using lead lag indicators that were first approved by the AUC in the utility's 2012 rate application. In its 2023 application, FortisAlberta wrote that it had reviewed the lead lag indicators from its 2012 application and determined that they are still reasonably representative of the utility's operations.[55] The 2012 application uses a study

[53] FortisAlberta Inc., 2012-108, Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Appendix 4, pages 56-57.
[54] Ibid., page 48.
[55] FortisAlberta Inc. "2023 Cost of Service Application", proceeding 26615, page 154.

prepared by a third-party consultant, Chymko Consulting. This study notes that FortisAlberta's revenue lag as of the 2012 application was 44.6 days.[56]

6.2.3 Treatment of FortisAlberta's CWIP in Rate Base

FortisAlberta's capital in-service additions for a given year are calculated as capital expenditures, less CWIP, thus excluding CWIP from FortisAlberta's rate base.[57] Per AUC Rule 026, regulated utilities in Alberta include the debt and equity components of AFUDC when capitalizing financing costs associated with CWIP, resulting in FortisAlberta receiving its WACC on CWIP via AFUDC, which is included with asset costs in rate base once placed into service.

6.2.4 Treatment of FortisAlberta's Supply Costs in Rate Base

Alberta utilities such as FortisAlberta receive their revenues through customer bills distributed by independent energy suppliers, as opposed to energy suppliers placing their charges on regulated utility bills as is the case in most other Canadian jurisdictions. As such, FortisAlberta does not incur power supply expenses to be included or excluded from rate base.

6.3 FortisAlberta's Derivation of Return on Rate Base

FortisAlberta calculates its return on rate base, in dollars, by applying its capital structure and cost of capital as they are determined in the AUC's cost of capital proceeding to determine its weighted average cost of capital, which is then applied to its rate base to determine its return on rate base in dollars.[58] As such, return on rate base is equal to rate base multiplied by WACC.

7 FortisBC

7.1 Overview of FortisBC's Rate Base Calculation

The British Columbia Utilities Commission ("BCUC") is responsible for regulating rates for the regulated utilities in the province, including FortisBC Inc. ("FortisBC"). Rule setting by the BCUC for specific application elements, including rate base, occurs through a mix of methodology setting that is established in particular proceedings and carried forward into future applications, as well as Directions to the BCUC that are attached directly to the *Utilities Commission* Act and encode specific directions regarding elements of rate-setting. These formal regulatory Directions are generally reserved for directing elements of crown corporation BC Hydro's rate setting process through specification of its rate base and its cash working capital allowance for a given time period.[59]

The *Utilities Commission Act* itself does not contain specific directions for calculating rate base for other utilities and provides the BCUC with significant discretion to direct the elements of the

[56] FortisAlberta, "2012/2013 Distribution Tariff Application", Section 21 – Distribution Necessary Working Capital, page 21-1.

[57] FortisAlberta Inc. "2023 Cost of Service Application", proceeding 26615, demonstrated by way of example at page 101, and in Schedule 4.1.

[58] FortisAlberta Inc. "2023 Cost of Service Application", proceeding 26615, pages 85-86.

[59] Direction No. 8 to the British Columbia Utilities Commission, *Utilities Commission Act*, B.C. Reg 24/2019.

rate-setting process that are not specifically prescribed in a given Direction. Section 60 of the *Act* indicates that "the commission may use any mechanism, formula or other method of setting the rate that it considers advisable."[60] FortisBC's 2014-2018 Multi-Year Performance Based Ratemaking Plan contains an extensive analysis and approval of FortisBC's performance based ratemaking methodology. The primary elements of this methodology, including calculation of rate base and setting of an Annual Review process to review projections and actuals for rate base elements including plant balances, deferral account balances and other depreciation and amortization information to be included in rates, have been carried forward to FortisBC's most recent rate setting application, its 2025-2027 Rate Setting Framework Application.[61]

FortisBC's 2025-2027 Rate Setting Framework Application describes its rate base as comprising of "the mid-year net plant in service of each utility, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital, deferred income taxes, and other utility plant adjustments." This application proceeds to note that its calculation of rate base increases the mid-year net plant in service by capital additions and reduces them by accumulated depreciation. It also notes that its proposed regulatory accounts, including deferral accounts, may or may not be included in rate base if approved, based on whether FortisBC is able to forecast balances for them so that they can be included in revenue requirements.[62] Non-rate base deferral accounts that sit outside of rate base remain subject to regulatory approval and attract a WACC return that is equal to a rate base return.[63] FortisBC's rate base is calculated in the manner shown in Table 9 below.

During the Annual Review process, FortisBC presents the current year's projections and upcoming year forecasts, flow-through items are trued-up to actuals for the prior year, and inputs in the performance-based regulation formulation, such as inflation and customer growth, are re-forecast, in line with its current ratemaking methodology as set out in its 2014-2018 Multi-Year Performance Based Ratemaking Plan .[64]

[60] *Utilities Commission Act*, RSBC 1996, Chapter 473, section 60(1).
[61] British Columbia Utilities Commission, "Multi-Year Performance Base Ratemaking Plan for 2014 through 2018", Decision, page 179, commission order G-139-14.
[62] British Columbia Utilities Commission, "Multi-Year Performance Base Ratemaking Plan for 2014 through 2018", Decision, page 272, commission order G-139-14; British Columbia Utilities Commission "Application for Approval of a Rate Setting Framework for 2025 through 2027, FortisBC Energy Inc. and FortisBC Inc., pages C-150 to C-151.
[63] British Columbia Utilities Commission "Application for Approval of a Rate Setting Framework for 2025 through 2027, FortisBC Energy Inc. and FortisBC Inc., page C-153.
[64] British Columbia Utilities Commission, "Multi-Year Performance Base Ratemaking Plan for 2014 through 2018", Decision, page 177, commission order G-139-14.

Table 9: FortisBC Rate Base Calculation

1		Mid-year net plant in service
	+	Capital Additions
	-	Accumulated Depreciation
	=	**Mid Year Net Plant in Service**
2		**Construction Advances**
3		**Work in Progress not attracting AFUDC**
4		**Unamortized Deferred Charges**
5		**Working Capital**
6		**Deferred Income Taxes**
7		**Other Utility Plant Adjustments**
8		**New Deferral Accounts to be Included in Rate Base**
9		**Mid Year Net Plant in Service + Construction Advances + Work in Progress not attracting AFUDC + Unamortized Deferred Charges + Working Capital + Deferred Income Taxes + Other Utility Plant Adjustments + New Deferral Accounts to be Included in Rate Base = Rate Base**

7.2 Calculation of FortisBC's Rate Base Components

7.2.1 Calculation of FortisBC's Allowance for Materials and Supplies

FortisBC includes its inventory of materials and supplies in its working capital component of rate base.[65] In its Annual Review for 2025 and 2026 rates application, the utility set its forecast requirements for 2025 and 2026 based on its 2024 actual levels.[66]

7.2.2 Calculation of FortisBC's Allowance for Cash Working Capital

In its most recent 2025-2027 Rate Setting Framework Application, FortisBC sought and received approval to update its lead/lag days as determined in a 2023 lead/lag study that the utility had previously internally conducted. The methodology of the study is similar to previous studies

[65] British Columbia Utilities Commission, "Annual Review for 2025 and 2026 Rates", FortisBC Inc., section 7, page 65.

[66] British Columbia Utilities Commission, "Annual Review for 2025 and 2026 Rates", FortisBC Inc., section 7, page 65.

performed by FortisBC in 2018.[67] FortisBC calculated its cash working capital requirements as described below. FortisBC does not derive a working capital factor on a percentage basis as one of the steps in its computation of its cash working capital allowance.

For the individual revenue and expense components, the study multiplied the applicable lead/lag days by the respective forecast revenue and expenditure amount to derive the dollar days. It then divided the total revenue and expenditure dollar days by the total forecast revenues and expenditures to derive total weighted average revenue lag days and expenditure lead days. Following that, it deducted the total weighted average expenditure lead days from the total weighted average revenue lag days to determine the net weighted average lag days. Finally, it multiplied the total budgeted expenditures by the net weighted average lag days and divided this product by 365 days to determine the cash working capital requirement of the Company. The study included the following categories of expenses in its calculation of leads and lags. It included sales revenue, service, billing, collection, and other revenue (apparatus and facilities, contract, transmission access revenue, late payment charges, connection charges and other utility income) lags. For expense leads it considered power purchases, water fees, wheeling, operations and maintenance, property taxes, GST and income tax. [68]

7.2.3 Treatment of FortisBC's CWIP in Rate Base

FortisBC includes its work-in-progress costs not attracting AFUDC in its rate base.[69] Costs not eligible for inclusion in rate base during construction are added to rate base once in-service, inclusive of AFUDC accumulated over the construction period. FortisBC applies AFUDC to projects that are greater than three months in duration and cost more than $100k.[70]

7.2.4 Treatment of FortisBC's Supply Costs in Rate Base

As noted above, FortisBC includes a series of deferral account balances in its rate base, however not all FortisBC deferral accounts receive this treatment. The account through which FortisBC manages its energy supply costs is known as the Flow-Through Deferral Account, and is not included in rate base.[71] As noted below, though this account sits outside of rate base, it still attracts a return at the utility's WACC.

[67] British Columbia Utilities Commission "Application for Approval of a Rate Setting Framework for 2025 through 2027, FortisBC Energy Inc. and FortisBC Inc., page D-27.
[68] British Columbia Utilities Commission "Application for Approval of a Rate Setting Framework for 2025 through 2027, FortisBC Energy Inc. and FortisBC Inc., Appendix D3-2.
[69] British Columbia Utilities Commission "Application for Approval of a Rate Setting Framework for 2025 through 2027, FortisBC Energy Inc. and FortisBC Inc., pages C-150 to C-151.
[70] British Columbia Utilities Commission, "Annual Review for 2025 and 2026 Rates", FortisBC Inc., section 7, page 70.
[71] Ibid., page 142.

7.3 FortisBC's Derivation of Return on Rate Base

FortisBC calculates its return on rate base in dollars by establishing its weighted average cost of capital and applying it to rate base, as laid out in its annual review for 2025 and 2026.[72] Some of FortisBC's deferral accounts sit outside of rate base, but these still attract a return at the utility's weighted average cost of capital.[73]

8 Comparison and Conclusions

8.1 Comparison

Newfoundland Power's practices with respect to calculating its rate base in line with the Asset Rate Base Method share several similarities, and a few discrete divergences, with the methods employed by the Peer Group utilities considered in this Review. These similarities and differences are considered in detail below.

8.1.1 Calculation of Rate Base

All utilities in the Peer Group calculate their rate base in a similar way, in all cases relying on approaches that are consistent with the Asset Rate Base Method concept employed by Newfoundland Power. Every utility surveyed begins by summing up the net value of its physical assets and financial assets, and every utility includes a representation of cash working capital in rate base. While all utilities account for materials and supplies, supply costs, and construction work in progress costs in some form, specific treatment of these items varies across the Peer Group, as further discussed below. Every utility employs regulatory accounts, though again practices diverge across the Peer Group with respect to the inclusion of these accounts within or outside of their rate base calculation, and with respect to the rate of return that these accounts attract. As discussed above, the Peer Group utilities do not explicitly include the concept of invested capital in their applications or their calculation of revenue requirements like Newfoundland Power does, though it remains a reality of their businesses.

Different utilities within the Peer Group cite different sources for their rate base calculation methodology. Two utilities, Nova Scotia Power and Maritime Electric, have specific statutory instructions that direct their regulators on how their rate base should be calculated. Two utilities, Algoma Power and FortisAlberta, receive instructions provided by the regulator through rules or filing requirements. Finally, two utilities (Newfoundland Power and FortisBC) have calculations that rely on existing utility practice established through previous applications.

[72] British Columbia Utilities Commission, "Annual Review for 2025 and 2026 Rates", FortisBC Inc., page 96.
[73] British Columbia Utilities Commission, "Annual Review for 2025 and 2026 Rates", FortisBC Inc., section 7, page 65.

8.1.2 Materials and Supplies Allowances

All six of the Peer Group utilities include an allowance for materials and supplies in one manner or another. This allowance goes by a number of names, depending on the utility, including being referenced as inventory. Three utilities, FortisBC, FortisAlberta and Maritime Electric, include this allowance within their calculation of working capital requirements, while two other Peer Group utilities, Newfoundland Power and Nova Scotia Power, include it within rate base as its own discrete line item. Algoma Power is the exception as it charges materials and supplies directly to its capital assets.

8.1.3 Working Capital Requirements

A variety of methods for calculating working capital requirements are used across the Peer Group, though these methods all appear to follow similar steps and achieve similar outcomes for customers. One Peer Group utility, Algoma Power in Ontario, which is one of many utilities operating within a single jurisdiction, has a default factor applied by the regulator to all utilities in lieu of requiring a lead/lag study by default, though other Ontario utilities may proceed with their own lead/lag analysis as conducted by a third-party consultant if seeking approval of a different working capital factor. Nova Scotia Power commissions third-party lead/lag studies by default as part of its rate-setting application. Two utilities, Newfoundland Power and FortisBC, conduct and periodically update internal lead/lag analyses to determine their working capital allowances. The final two utilities, FortisAlberta and Maritime Electric, appear to review and update their working capital factors on a more occasional basis, with active use of working capital parameters that date back to the early 2010s. The general practice employed by the Peer Group utilities is to include an allowance for working capital that is based on lead/lag studies.

8.1.4 Treatment of CWIP

Of the six members of the Peer Group, five of them do not include CWIP as an addition to ratebase. Nova Scotia Power is the sole member of the Peer Group that adds CWIP to its rate base for rate-making purposes, while Newfoundland Power, Maritime Electric, Algoma Power, FortisAlberta and FortisBC all exclude CWIP from rate base. Four of these five utilities, Newfoundland Power, Maritime Electric, FortisAlberta and FortisBC, calculate AFUDC on CWIP and capitalize this amount in rate base for amortization over the life of the asset in question, thus receiving their WACC in the derivation of AFUDC. The exception to this rule is Algoma Power, which states that it does not capitalize CWIP financing costs. Algoma Power is permitted to calculate AFUDC on CWIP and capitalize these amounts under OEB policy, however the AFUDC rate is an interest-based rate prescribed by the OEB and is not equal to the WACC of Ontario utilities.

8.1.5 Treatment of Supply Costs

Three of the six members of the Peer Group exclude supply cost balances from their rate base, instead collecting financing charges on these amounts via alternative methods, noting that FortisAlberta does not have a supply cost mechanism, as supply costs are billed by third-party energy retailers rather than regulated utilities. Specifically, Newfoundland Power, Algoma Power, and FortisBC all hold these balances outside of rate base, with Newfoundland Power and FortisBC receiving financing charges equal to their WACC on these non-rate base balances, and Algoma Power receiving interest based on OEB prescribed interest rates for deferral and variance account balances. Conversely, Nova Scotia Power and Maritime Electric include their supply cost balances in their rate base as additions, securing a WACC return on these amounts.

8.1.6 Determination of Return on Rate Base

Three of the six utilities within the Peer Group (Algoma Power, FortisAlberta and FortisBC) calculate their return on rate base, in dollars, by multiplying their rate base by their WACC. Conversely, Newfoundland Power, Maritime Electric, and Nova Scotia Power each sum forecast interest expense and return on equity to derive forecast return on rate base, or an equivalent thereof with respect to Nova Scotia Power, as is described in section 3.3.

The differences between these utilities is at most a difference in calculation to achieve the same or similar end, and at least a matter of presentation. With specific respect to Newfoundland Power, adjustments in its 2025-2026 General Rate Application significantly narrowed any difference between its WACC and derived Return on Rate Base (%) for its 2025 and 2026 Test Year forecasts.

8.2 Conclusions

Newfoundland Power's practices with respect to its calculation of rate base, calculation of its working capital and materials and supplies allowances, treatment of CWIP and supply costs, and derivation of return on rate base all lie well within the range of practices demonstrated by the Peer Group. For many of these parameters, each Peer Group utility employs practices that reflect the culture and particularities of the jurisdiction in which they operate. These parameters often also reflect the operating realities of the jurisdiction, including the number of active utilities: jurisdictions with more active utilities like BC, Alberta and Ontario tend to have a higher number of generic proceedings to set rules, whereas jurisdictions with a smaller number of active utilities may set parameters on an application-by-application basis. Stated differently, while the details and specifics of these approaches and calculations vary by utility, the broad principles employed by utilities and regulators are highly consistent, yielding largely comparable outcomes.

Of note, while the concept of invested capital is implicit amongst the entire Peer Group, it is not common for other utilities to make active reference to invested capital to the degree done by Newfoundland Power. This being said, Newfoundland Power effectively receives its WACC as a return on rate base, which is an outcome entirely consistent with all members of the Peer Group. Moving forward, Newfoundland Power may consider an alternative or expanded presentation of its calculation of return on rate base and rate of return on rate base. Specifically, the separation of returns which are explicitly tied to average rate base from returns which are derived from invested capital not included in rate base, would explicitly demonstrate that Newfoundland

Power is appropriately receiving its WACC on average rate base as well as on the portions of invested capital not included in rate base.

Newfoundland Power Inc.
Calculation of Average Rate Base as of December 31, 2025
($000s)

Newfoundland Power Inc.
Calculation of Average Rate Base
For the Years Ended December 31
($000s)

	2025	2024
Net Plant Investment		
Plant Investment	2,519,619	2,403,246
Accumulated Depreciation	(1,053,362)	(1,004,688)
Contributions in Aid of Construction	(47,587)	(47,797)
	$1,418,670	$1,350,761
Additions to Rate Base		
Deferred Pension Costs	109,843	108,293
Credit Facility Costs	161	167
Cost Recovery Deferral – Conservation	21,475	21,280
Cost Recovery Deferral – 2025 Revenue Shortfall	17,156	-
Cost Recovery Deferral – Load Research and Retail Rate Design Review	986	635
Cost Recovery Deferral – Hearing Costs	560	874
Cost Recovery Deferral – Pension Capitalization	849	1,198
Customer Finance Programs	1,101	1,049
Demand Management Incentive Account	-	1,545
	$152,131	$135,041
Deductions from Rate Base		
Weather Normalization Reserve	(4,035)	2,896
Other Post-Employment Benefits	88,543	86,308
Customer Security Deposits	688	618
Accrued Pension Obligation	5,671	5,512
Accumulated Deferred Income Taxes	34,678	33,287
Refundable Investment Tax Credits	33	294
	$125,578	$128,915
Year End Rate Base	1,445,223	1,356,887
Average Rate Base Before Allowances	1,401,055	1,334,897
Rate Base Allowances		
Materials and Supplies Allowance	17,319	14,743
Cash Working Capital Allowance	1,344	7,551
Average Rate Base at Year End	$1,419,718	$1,357,191