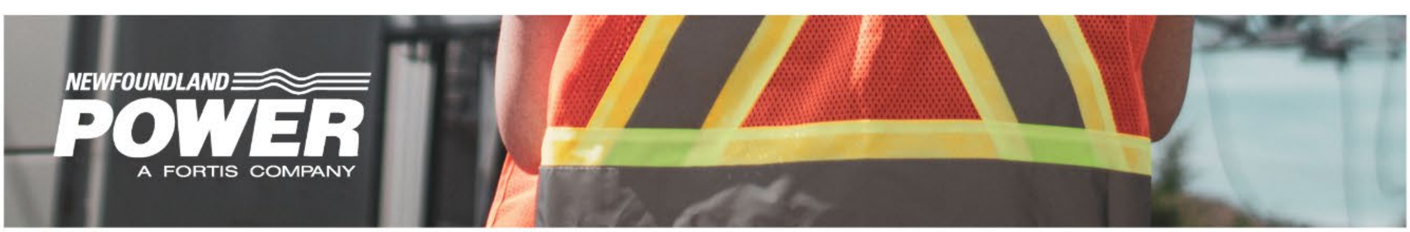
March 2026

Newfoundland Power Inc.
Supply Cost Mechanisms Review



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1.0 EXECUTIVE SUMMARY

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 reviewing its supply cost recovery mechanisms on or before December 31, 2025 (the "Supply Cost Mechanisms Report"). The filing date for the report was later revised to March 31, 2026 to coincide with the filing of Newfoundland Power's annual returns on that date.[1]

Newfoundland Power's review of its supply cost mechanisms includes a jurisdictional review completed by Utilis Consulting Inc. ("Utilis"). The review also addresses the recommendations of The Brattle Group Inc. ("Brattle") outlined in its report on Newfoundland Power's Deferral Accounts (the "Brattle Report"),[2] as well as the Board's request regarding the Company's hydro production.[3]

The review confirms that Newfoundland Power's supply cost mechanisms remain appropriate and necessary to ensure the Company fully recovers its power supply costs. Newfoundland Power continues to have effectively no control over its power supply costs, including the wholesale rate charged by Newfoundland and Labrador Hydro ("Hydro") to Newfoundland Power. Annual differences in supply costs from the level reflected in customer rates can be material, which could necessitate annual general rate applications ("GRA") in the absence of the Company's supply cost mechanisms.

The jurisdictional review shows that regulatory mechanisms that permit full recovery of energy supply costs are commonplace in Canada.[4] With respect to incentives, it was found that of the investor-owned electric utilities surveyed, only Newfoundland Power has an incentive mechanism associated with its supply costs. It is widely recognized that supply cost mechanisms promote regulatory efficiency and more stable customer rates, as well as provide financial stability for the utility.

Finally, the review found that while the Company's supply cost mechanisms are appropriate, there may be opportunities to simplify their operation and the regulatory process associated with balance disposition. Most utilities use a broader mechanism to recover their total supply cost variances as opposed to Newfoundland Power's more discrete and detailed mechanisms for separate impacts. While it remains necessary to maintain separate supply cost mechanisms at this time, the Company plans to bring forward proposals to change to these mechanisms in its next GRA to, where possible, better align their operation with industry practice and to simplify the regulatory process associated with their balance disposition.[5]

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1 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.

2 The Brattle Group Inc, *Report on Newfoundland Power's Deferral Accounts*, prepared by Philip Q. Hanser and Adam Wyonzek, April 24, 2024 filed as part of the Company's *2025/2026 GRA*.

3 See the Board's correspondence, *Re: Newfoundland Power Inc.- Normal Hydroelectric Production*, dated April 10, 2025.

4 Such regulatory mechanisms also appear to be commonplace in the U.S. See the Company's *2025/2026 General Rate Application, Volume 2, Supporting Materials, Expert Evidence, Cost of Capital: Mr. James Coyne, Concentric Energy Advisors, Inc., 4. Comparison to U.S. Electric Utility Proxy Group*, page 80, lines 21 to 25 which states: *"All of the electric utility companies in the U.S. proxy group have fuel adjustment clauses that allow them to pass through prudently-incurred fuel and purchased power costs to customers. As such, the U.S. Electric utility companies are not at risk for differences between the projected and actual cost of fuel and purchased power."*

5 In Newfoundland Power's view, this approach is consistent with the Board's focus on regulatory efficiency and further strengthening its efficiency initiatives. See, for example, the Board's *Annual Report for the Year Ending March 31, 2025*, pages 4 and 22.

2.0 NEWFOUNDLAND POWER'S SUPPLY COST MECHANISMS

2.1 General

Newfoundland Power is dependent upon Hydro for the power supply required by the Company to meet its obligation to serve its customers.[6] Purchased power expense is Newfoundland Power's largest cost, accounting for over two-thirds of revenue from customer rates.[7] The Company has effectively no control over its power supply costs, including the wholesale rate charged by Hydro to Newfoundland Power.[8]

Newfoundland Power's single supply dependence is relatively rare for investor-owned electric utilities in Canada.[9] Currently, the Company recovers its power supply costs through a combination of base customer rates and regulatory mechanisms.

Newfoundland Power has three supply cost mechanisms which allow the Company to recover its supply cost variances from the amount reflected in base customer rates related to energy purchases, native peak and weather effects.[10] They are: (i) the Energy Supply Cost Variance ("ESCV") Account, (ii) the Demand Management Incentive ("DMI") Account, and (iii) the Weather Normalization Reserve ("WNR"). The year-end balances in these accounts are transferred to Newfoundland Power's Rate Stabilization Account ("RSA") for recovery from, or credit to, customers in a timely manner.[11]

The Company's purchased power costs also vary from the amount reflected in base customer rates due to the annual operation of Hydro's wholesale rate adjustments, with recovery provided through the RSA.[12] Given the RSA provides flow-through recovery of these cost variances based on wholesale rate adjustments approved by the Board, it was not analyzed as part of this review.[13]

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6 Currently, Newfoundland Power purchases approximately 93% of its power supply requirements from Hydro. Newfoundland Power has no practical alternative to Hydro for the additional power supply required to meet an increase in customer load.

7 Based on 2026 forecast total customer billings.

8 While the Company participates in regulatory processes associated with its wholesale rate, Newfoundland Power does not control Hydro's costs or its applications that are filed with the Board.

9 See the Company's *2025/2026 General Rate Application, Volume 2, Supporting Materials, Expert Evidence, Cost of Capital: Mr. James Coyne, Concentric Energy Advisors, Inc., 3. Comparison to other Canadian Investor-Owned Electric Utilities,* page 71, line 30 to page 72, line 2, which provides that: *"…Newfoundland Power is uniquely dependent on a single source of electric supply, creating greater supply risk than utilities such as FortisBC Electric, Nova Scotia Power, or the Alberta utilities that rely on a more diverse mix of generation and market sources."*

10 The Company also has a mechanism to capture fuel cost variances associated with Newfoundland Power's thermal plants. See paragraph II.1(ii) of the Rate Stabilization Clause in the Company's *Schedule of Rates, Rules and Regulations*, *effective July 1, 2025*.

11 Newfoundland Power's electricity rates are adjusted each year, effective July 1st, for among other things, the RSA balance as of March 31st of that year. For further information, see *Schedule 2: Proposed Customer Rates, Rules and Regulations to be effective July 1, 2025* of the Company's application filed in compliance with Order No. P.U. 3 (2025) on April 17, 2025.

12 The historic purpose for the RSA was to flow-through changes in Hydro's wholesale rate to customers in a timely manner. See paragraphs I and II.1 of the Rate Stabilization Clause in the Company's *Schedule of Rates, Rules and Regulations*, effective July 1, 2025. For further information on Hydro's wholesale rate adjustments, see *Schedule 2: Proposed Customer Rates, Rules and Regulations to be effective July 1, 2025* of the Company's application filed in compliance with Order No. P.U. 3 (2025) on April 17, 2025.

13 The wholesale rate adjustments reflected in current customer rates were approved by the Board in Order No. P.U. 2 (2025).

Overall, the operation of the RSA, in conjunction with the operation of the ESCV Account, DMI Account and WNR, ensures that purchased power costs not reflected in base customer rates are appropriately recovered from, or credited to, customers in a timely and efficient manner.

2.2 ESCV Account

The ESCV Account addresses variances in purchased power costs resulting from variances in normalized energy purchase requirements, and differences between the incremental rate that the Company pays and the average supply cost in customer rates.[14] The calculation of the ESCV Account is outlined in paragraph II.5 of the Rate Stabilization Clause in the Company's *Schedule of Rates, Rules and Regulations, effective July 1, 2025*.

Table 1 shows the calculation of the ESCV Account balance as of December 31, 2025.[15]

Table 1:
ESCV Calculation for the Year Ended, December 31, 2025
($000s)

Time Period	**Normalized Energy Variance (Actual vs Test Year)** ***(GWh)*** ***(A)***[16]	**Wholesale Second Block Energy Rate** ***(¢/kWh)*** ***(B)***[17]	**Average Test Year Energy Rate** ***(¢/kWh)*** ***(C)***[18]	**ESCV** ***($000s)*** ***(D)***[19]
January to March & December	(2.9)	9.698	7.420	(67)
April to November	(86.6)	3.354	7.420	3,522
Total ESCV Account Balance as of December 31, 2025				**3,455**

A new wholesale rate came into effect on January 1, 2025.[20] The wholesale rate has different second block energy rates for December to March and April to November. As such, the ESCV calculation for 2025 considers the normalized energy variances for each timeframe.

In the months of January to March and December, 2025 normalized energy purchases were 2.9 GWh lower than the 2025 test year. Given the wholesale second block rate is higher than the average test year energy rate for this time period, the Company had $67,000 in lower purchased power expense than what is reflected in customer rates. As such, the ESCV Account operates to credit that lower purchased power expense to customers.

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[14] The ESCV Account was approved for continued use in Order No. P.U. 43 (2009). Normalized energy purchases are actual/forecast energy purchases that have been adjusted so that they reflect normal weather conditions (temperature, wind, and water inflows) via the WNR.

[15] Before the annual ESCV Account balance transfer to the RSA, which occurs on December 31st of each year.

[16] 2025 actual normalized energy purchases minus 2025 test year normalized energy purchases.

[17] Based on the wholesale rates in effect as of January 1, 2025 approved by the Board in Order No. P.U. 1 (2025).

[18] 2025 test year purchased power normalized energy expense / 2025 test year normalized energy purchases, expressed in ¢/kWh.

[19] (A) x [(B) – (C)], shown in $000s.

[20] Order Nos. P.U. 1 and 2 (2025).

In the months of April to November, 2025 normalized energy purchases were 86.6 GWh lower than the 2025 test year. Given the wholesale second block rate is lower than the average test year energy rate for this time period, the Company had $3,522,000 in higher purchased power expense than what is reflected in customer rates.[21] As such, the ESCV Account operates to recover that higher purchased power expense from customers.

Overall, the ESCV Account operated in 2025 to ensure that Newfoundland Power recovered the variance in purchased power expense from that in base customer rates due to variances in normalized energy purchases – no more, no less.

Table 2 provides the ESCV Account balances for the last 5 years, 2021 to 2025.

Table 2:
ESCV Account Balances[22]
($000s)

2021	2022	2023	2024	2025
(25,413)	3,814	29,228	28,600	3,455

ESCV Account balances occur each year and are material, including under the new wholesale rate.[23] In addition, the wholesale rate is not anticipated to be static going forward.[24] Changes to the second block wholesale rates could further impact future ESCV amounts, which are outside of the Company's control.

Accordingly, the continued operation of the ESCV Account is appropriate and necessary to allow both the Company and customers to be protected from annual variances in normalized energy purchases from Hydro.

2.3 DMI Account

The DMI Account provides for the recovery, or credit, of variances in actual demand costs from the amount reflected in base customer rates outside of a ±$500,000 threshold amount.[25] The threshold amount is intended to provide an incentive to Newfoundland Power to undertake reasonable initiatives to minimize peak demand, while also recognizing that the Company's ability to reduce its purchased power demand costs has become more limited since the creation of the DMI Account in 2008.[26]

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21 With a decrease in energy purchases of 86.6 GWh, revenues from base customer rates were lower by $6.4 million (86.6 GWh x 7.420 ¢/kWh). However, the Company only actually experienced lower purchased power expense of $2.9 million (86.6 GWh x 3.354 ¢/kWh). The net amount to be recovered is therefore $3.5 million.

22 A debit balance represents an amount owing from customers. A credit balance represents an amount owing to customers.

23 The 2025 test year rate of return on rate base is 6.65%, in a range of 6.47% to 6.83%. The total range of 36 basis points translates to a total range in dollars of $5.1 million. The after-tax 2025 ESCV Account balance of $2.4 million ($3.5 million x 0.7%), represents approximately half of the total range of return on rate base.

24 Order No. P.U. 1 (2025), page 2, lines 21-22.

25 Order No. P.U. 3 (2025), page 10, lines 1-22. The Board approved the creation of the DMI Account in Order No. P.U. 32 (2007) and the continued operation of the DMI Account in Order No P.U. 43 (2009).

26 Order No. P.U. 3 (2025), page 10, lines 1-22.

Detailed calculations for the DMI Account for 2025 are provided in Newfoundland Power's letter regarding the DMI Account filed with the Board on February 19, 2026.

Table 3 summarizes the DMI Account calculation for 2025.

Table 3:
DMI Account Calculation for the Year Ended, December 31, 2025

2025 Actual Unit Cost of Demand (¢ per kWh)[27]	A	1.370
2025 Test Year Unit Cost of Demand (¢ per kWh)[28]	B	1.368
2025 Normalized Energy Purchases (MWh)	C	5,814,164
Demand Supply Cost Variance ($000s)	**D[29]**	**116**
Demand Management Incentive ($000s)	E	±500
Amount Exceeding Demand Management Incentive ($000s)	**F[30]**	**-**

In 2025, actual unit demand costs were slightly higher than the 2025 test year unit demand costs reflected in base customer rates. This resulted in a demand cost variance of $116,000. As the amount was within the ±$500,000 DMI threshold, the additional purchase power expense was absorbed by Newfoundland Power and there was no transfer to the RSA for recovery from customers.

Table 4 provides the annual demand cost variations from 2021 through 2025 as well as a breakdown of the cost (savings) allocation between the Company and its customers.

Table 4:
DMI Account: Demand Cost Variations[31]
($000s)

		2021	2022	2023	2024	2025
Demand Cost Variance	A	2,672	(904)	2,148	2,958	116
Company Cost (Savings)	B	755	(751)	751	751	116
Customer Cost (Savings)	C[32]	1,917	(153)	1,397	2,207	-

27 2025 demand charges billed by Hydro / 2025 normalized energy purchases.
28 2025 test year demand charges / 2025 test year normalized energy purchases.
29 (A - B) x C, shown in $000s.
30 D – E. If the amount is less than $500,000, then zero. Any amount exceeding the DMI would be transferred to the RSA on March 31st of the subsequent year.
31 Prior to 2025, the DMI threshold was ± 1% of test year wholesale demand charges.
32 A – B.

Demand cost variances occur each year and can be material.[33] As recognized by the Board in Order No. P.U. 3 (2025), and confirmed by the jurisdictional analysis included in this report, the use of thresholds associated with supply cost mechanisms is not the norm in Canada.[34] The reduction in the threshold amount to ±$500,000 effective January 1, 2025 helps to better align the demand cost variance recovery with industry practice while maintaining the incentive component of the DMI Account.

Overall, as provided by the Board in Order No. P.U. 3 (2025), the DMI Account, in conjunction with the ESCV Account, provides Newfoundland Power with the ability to recover its costs associated with variability in purchased power costs inherent in the demand and energy wholesale rate.[35]

2.4 WNR

Newfoundland Power continues to serve a substantial heating load.[36] Variations in weather, therefore, can have a substantial effect on the Company's purchased power expense. The WNR normalizes the effects of weather and hydrology on Newfoundland Power's sales and purchased power expense.

The WNR has two components: the Degree Day Normalization Reserve (the "Degree Day Component") and the Hydro Production Equalization Reserve (the "Hydro Component"). The Degree Day Component adjusts for the effects of abnormal weather (i.e., temperature and wind speed) on revenue from rates and purchased power expense. The Hydro Component adjusts for the effects on purchased power expense that result from abnormal stream flows to the Company's hydro-electric plants. Both components of the WNR have operated for over 50 years.[37]

Calculations for the WNR for 2025 are provided in Newfoundland Power's *Application for Approval of Balance in Weather Normalization Reserve*, which was filed with the Board on February 19, 2026. In addition, further details on the calculations of both the Degree Day and Hydro Components of the WNR are provided in Attachment A.

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33 For example, the after-tax 2024 DMI balance of $2.1 million ($3.0 million x 0.7%), represents approximately 40% of the total range of return on rate base as described in footnote 23.
34 Order No. P.U. 3 (2025), page 10, lines 1-22.
35 Order No. P.U. 3 (2025), page 10, lines 10-12.
36 In 2025, approximately 78% of weather normalized energy sales were from electric heat customers.
37 The Degree Day Component was approved in Order No. P.U. 1 (1974). The Hydro Component was approved in Order No. P.U. 32 (1968).

Degree Day Component

Table 5 details the Degree Day Component of the WNR for 2021 to 2025.

Table 5:
WNR: Degree Day Component

		2021	2022	2023	2024	2025
Sales Normalization (GWh)[38]	A	188.1	149.6	1.3	122.9	81.7
Revenue Normalization ($000s)	B	21,125	16,668	129	13,690	9,335
Purchased Power Normalization (GWh)	C	197.8	157.4	1.4	128.9	85.7
Purchased Power Normalization ($000s)	D	35,933	28,585	248	23,422	5,883
Net Normalization (GWh)	**E[39]**	**(9.7)**	**(7.8)**	**(0.1)**	**(6.0)**	**(4.0)**
Net Normalization ($000s)	**F[40]**	**(14,808)**	**(11,917)**	**(119)**	**(9,732)**	**3,452**

The Table shows that both the revenue and purchased power weather normalization amounts can be material.[41] Further, it shows that the purchased power normalization is impacted by the wholesale rate in place at that time.[42] Finally, it is important to recognize that common utility practice allows for full recovery of variances in power supply costs, which would include weather effects.[43] The normalization of the Company's revenues provides for a natural offset of purchased power effects, resulting in a net amount being recovered from, or credited to, customers. From a practical standpoint, the net amount represents the net impact that weather had on the Company's customer energy requirements in that year.

38 A positive figure represents warmer than normal weather.

39 A – C.

40 B – D. The net amount is what is transferred to the RSA for recovery from, or credit to, customers in the subsequent year.

41 For example, the after-tax 2025 revenue normalization of $6.5 million ($9.3 million x 0.7%) is approximately 1.3 times the total range of return on rate base as described in footnote 23. The after-tax 2025 purchased power normalization of $4.1 million ($5.9 million x 0.7%) is approximately 80% of the total range of return on rate base. The after-tax 2025 net normalization of $2.4 million ($3.4 million x 0.7%) is approximately 50% of the total range of return on rate base.

42 Purchased power normalization, in dollars compared to GWh, are larger from 2021 to 2024 compared to 2025 as the second block wholesale rate of 18.165 ¢/kWh in place at that time is higher than the current second block rate structure of 9.698 ¢/kWh in December to March and 3.354 ¢/kWh in April to November. Also, it should be noted that the WNR operates with customer and wholesale rates that are in effect that month.

43 See section 3.3 of this report.

Hydro Component

Table 6 details the Hydro Component of the WNR for 2021 to 2025.

Table 6:
WNR: Hydro Component

		2021	2022	2023	2024	2025
Actual Hydro Inflows (GWh)	A	369.2	423.0	375.2	392.4	309.6
Normal Hydro Inflows (GWh)[44]	B	434.8	436.9	425.6	423.2	416.8
Hydro Inflows Variance (GWh)	**C[45]**	**(65.6)**	**(13.9)**	**(50.4)**	**(30.8)**	**(107.2)**
Purchased Power Expense ($000s)	D	8,346	1,766	6,404	3,917	2,312

The Table shows that Newfoundland Power experiences variances in hydro inflows each year and the associated purchased power expense can be material.[46] Notably, actual hydro inflows were significantly lower than the Company's normal hydro inflows in 2025 due to historically low precipitation levels in 2025.[47] While the purchased power expense impact in 2025 was much lower than previous years (on a per GWh basis) due to the new second block wholesale rate, the impact can still be material and future wholesale rate changes remain largely outside of the Company's control.[48]

Overall, both the Degree Day Component and the Hydro Component of the WNR continue to operate in a necessary capacity to ensure variances in customer revenues and purchased power expenses due to weather conditions are recovered in an appropriate and timely manner.

3.0 COMPARISON TO CANADIAN UTILITY PRACTICE

3.1 Primary Findings

Attachment B to this report provides Utilis' report, *Jurisdictional Review of Supply Cost Mechanisms*, dated March, 2026 (the "Jurisdictional Report"). The Jurisdictional Report reviewed the supply cost mechanisms of a peer group of investor-owned electric utilities across Canada. The utilities reviewed were Nova Scotia Power Incorporated ("NS Power"), Maritime Electric Company Limited ("MECL"), Algoma Power Inc. ("Algoma Power"), FortisAlberta Inc. ("FortisAB"), ATCO Electric and FortisBC Inc. ("FortisBC").[49] The peer group was expanded to gas and crown utilities when reviewing weather normalization practices to ensure the practices

44 Based on a long-term average of 30+ years. Each completed year is added to the running long-term average.
45 A – B.
46 For example, the after-tax 2025 hydro variance of $1.6 million ($2.3 million x 0.7%), represents approximately 30% of the total range of return on rate base as described in footnote 23.
47 Using St. John's as a proxy, 2025 was the driest year on record in, at least, the past 25 years. Precipitation was 15% lower in St. John's in 2025 when compared to the 25-year historical average.
48 Purchased power expense, in dollars compared to GWh, are larger from 2021 to 2024 compared to 2025 as the second block wholesale rate of 18.165 ¢/kWh in place at that time is higher than the current second block rate structure of 9.698 ¢/kWh in December to March and 3.354 ¢/kWh in April to November.
49 Jurisdictional Report, Table 1.

of utilities more exposed to weather and hydro production than the main peer group were also reviewed in those areas.[50]

The Jurisdictional Report provides two primary findings:

1. ***Full recovery of annual variances in power supply costs is common utility practice in Canada.***

   All utilities in the main peer group fully recover their prudently incurred power supply costs.[51] Each utility has supply cost mechanisms, or rate riders, to provide for timely recovery of annual variances in power supply costs from the level reflected in base rates.[52]

   While the result of full cost recovery is the same across Canada for the main peer group, most utilities' supply cost mechanisms are broader and simpler than the Company's more discrete and detailed separate mechanisms. For example, MECL's Energy Cost Adjustment Mechanism ("ECAM") simply compares its actual energy costs to its test year energy costs to determine the recovery amount.[53] For Newfoundland Power, five separate supply cost mechanisms, including four separate regulatory filings, work together to provide for the same result.[54]

   As discussed later in this report, opportunities exist to better align the operation of the Company's supply cost mechanisms with industry practice and to simplify the regulatory process associated with their balance disposition while maintaining appropriate transparency of the variances for regulatory oversight and review.

2. ***The use of incentive thresholds associated with power supply costs is not common practice in Canada.***

   None of the utilities in the main peer group had an incentive threshold associated with their power supply cost recovery.[55] Newfoundland Power is unique in that it has a ±$500,000 threshold associated with its power supply costs, although in this jurisdiction, Hydro also has a ±$500,000 threshold associated with certain of its supply costs.[56] Further, and as more fully discussed in sections 3.3 and 4.4 in this report, no utilities in the expanded weather normalization group has an incentive threshold directly associated with their hydro production, including Hydro.

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50 *Ibid*., Tables 2 and 3.
51 *Ibid*., section 3.1
52 *Ibid*., Table 4.
53 See, for example, MECL's *Application for an Order to Approve an ECAM Rate Adjustment, Application and Evidence of MECL,* December 11, 2025, Table 2.
54 The five supply cost mechanisms are the ESCV Account, the DMI Account, the Degree Day Component of the WNR, the Hydro Production Component of the WNR and the RSA. The four regulatory filings are the annual normal hydro production letter, the DMI balance disposition application, the WNR application and the RSA application.
55 Jurisdictional Report, section 3.1.
56 Hydro's Isolated Systems Supply Cost Variance Deferral Account and the Other Island Interconnected System Supply Cost Variance component of its Supply Cost Variance Deferral Account include a ± $500,000 cost variance threshold.

3.2 Energy and Demand Variance Mechanisms

Consistent with the first finding in section 3.1 of this report, of the utilities reviewed that incur energy and demand cost variances from the level reflected in their base customer rates (NS Power, MECL, Algoma Power, and FortisBC), none have separate mechanisms like Newfoundland Power's ESCV and DMI Accounts.[57] Rather, their broader supply cost mechanism implicitly provide for recovery of these cost variances.[58]

For Newfoundland Power, the ESCV Account and DMI Account operating separately accounts for the ±$500,000 threshold associated with the DMI Account. However, an opportunity exists to treat the recovery of the DMI Account the same as the ESCV Account. Per the definition of the ESCV Account in the Company's Rate Stabilization Clause, the year-end balance in the ESCV Account is transferred to the RSA annually on December 31st without the necessity of an application to the Board.[59] Conversely, the DMI Account requires an annual application to dispose of the December 31st balance in the account to the RSA.[60] The application is routine in nature and has been approved as filed since first required in 2008.[61]

As part of its next GRA, Newfoundland Power plans to propose an amendment to its Rate Stabilization Clause to transfer the year-end balance in the DMI Account to the RSA each December 31st, which would no longer require an annual application. This approach is consistent with regulatory efficiency, consistent with the treatment of the ESCV Account and better aligns with industry practice while recognizing the necessity to maintain both supply cost mechanisms. From a regulatory oversight perspective, the separate accounts will maintain transparency and key information for the DMI Account is provided in the Company's Annual Returns filing.[62] The Company also anticipates providing analyses associated with its supply cost mechanisms as part of its GRA filings.[63]

3.3 Weather Normalization Mechanisms

The main peer group was expanded when reviewing weather normalization practices to ensure the practices of utilities more exposed to weather and hydro production than the main peer group were also reviewed. For the review of mechanisms associated with temperature (i.e., degree day), six gas utilities were added to the main peer group.[64] Gas distribution utilities typically have weather normalization accounts to manage the risk of weather on heating load.[65] For the review of mechanisms associated with variance in hydro production, four crown utilities were added to the main peer group.[66] Crown utilities own the majority of hydro generation assets across Canada.

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57 Jurisdictional Report, sections 3.2 and 3.3.
58 *Ibid.* See also footnote 53 for an example.
59 See paragraph II.5 of the Rate Stabilization Clause in the Company's *Schedule of Rates, Rules and Regulations*, effective July 1, 2025.
60 The application is filed in February each year to dispose of the previous year's year-end balance to the RSA on March 31st.
61 The application has not been contentious and has not required Requests for Information since its initial year.
62 Return 18 details the DMI Account each year.
63 To balance transparency and efficiency, it is anticipated that each GRA would include details on the operation of the Company's supply cost mechanisms for the Board's review. Jurisdictional reviews would be included as necessary, as requested by the Board or, at minimum, at specific intervals (e.g. every 10 years).
64 See the Jurisdictional Report, Table 2 for the gas utilities added.
65 See, for example, the ***2025/2026 General Rate Application, Volume 2, Supporting Materials, Expert Evidence, Cost of Capital: Mr. James Coyne, Concentric Energy Advisors***, page 75, lines 9-12.
66 See the Jurisdictional Report, Table 3 for the crown utilities added.

Degree Day Related Mechanisms

For degree day related mechanisms, it was only necessary to review the normalization of sales and revenues. As provided in sections 3.1 and 3.2 of this report, full recovery of variances in power supply costs, which would implicitly include variances due to weather, is commonplace in Canada.

Of the 12 utilities reviewed (excluding Newfoundland Power), six utilities have mechanisms that normalize revenues for weather, either directly or implicitly.[67] Of the six utilities that do not normalize their sales for weather, three are electric utilities that operate in a region where the majority of space and water heating is not served by electricity.[68]

Overall, the normalization of Newfoundland Power's revenues for weather remains aligned with industry practice. Further, as more fully described in section 2.4 of this report, the normalization of the Company's revenues for weather remains appropriate as it continues to serve a substantial heating load.[69] This results in weather having a material impact on both Newfoundland Power's revenues and purchased power costs.

The Jurisdictional Report also provides details of the weather normalization practices used by the reviewed utilities so that Newfoundland Power could compare its core assumptions to industry practice.[70] The core assumptions analyzed were: (i) the weather variables used in weather normalization,[71] (ii) the time-based data relied upon to establish weather normal averages,[72] and (iii) the temperature balance point for weather variables, where applicable.[73]

The review found that there are varied approaches to weather normalization. The key findings for comparison to the Company's practices are summarized below.[74] The comparison is focused on the three utilities other than Newfoundland Power that have a specific mechanism to normalize their revenues for weather (MECL, Energir Inc. ("Energir") and ATCO Gas).[75] To support the analysis, the practices of the five remaining utilities in Table 10 in the Jurisdictional Report that analyze weather effects on their sales, without having a specific mechanism to normalize their sales, were also considered.[76]

- *Weather variables*
  MECL and Energir use HDD as their primary weather variable(s), while ATCO Gas employs a somewhat unique approach. Of the remaining five utilities, three utilities use HDD as their primary weather variable(s).

67 Jurisdictional Report, section 3.6.
68 *Ibid*. The three electric utilities are ATCO Electric, FortisAB and Algoma Power.
69 Newfoundland Power has the highest penetration of electric heat of the electric utilities reviewed. See the Jurisdictional Report, Table 9.
70 Jurisdictional Report, Table 10. See also Attachment A which details the Company's WNR calculations.
71 A heating degree day ("HDD") is a standardized way to measure how cold a day is. It is computed by comparing a daily average temperature to a base temperature. A base temperature of 18 degrees Celsius ("ºC") is used by Environment Canada. See https://climate.weather.gc.ca/glossary_e.html#hdd.
72 "Normal" weather is based on a historical average.
73 See footnote 71.
74 For full details, see the Jurisdictional Report, Table 10.
75 Jurisdictional Report, pages 23-26.
76 In general, their practices were reasonably in line with the practices of MECL, Energir and ATCO Gas.

For Newfoundland Power, HDD is the underlying data point used in its weather normalization calculation.[77] It is readily available by weather station and is a standardized method in determining temperature impacts.[78] Based on the jurisdictional review, its weather variables align with industry practice and are appropriate.

- *Historical average to establish normal weather*
  MECL and ATCO Gas use 10-year historical averages when determining their normal weather, while Energir uses a 30-year historical average. Of the remaining five utilities, three utilities use a historical average within a range of 10 to 30 years.

  Newfoundland Power uses a 30-year average to establish its normal weather, which is reasonable when compared to industry practice.

  While its current approach is reasonable, the Company plans to analyze what impact changing to a 10-year average may have on its weather normalization adjustments and test year forecasts to further explore that alternative approach. Newfoundland Power will provide the results of that analysis in its next GRA.

- *Temperature balance point*
  Temperature balance points vary by utility. MECL uses a 12ºC balance point, Energir uses a 13ºC balance point and ATCO Gas uses 14-16ºC. Of the remaining five utilities, four utilities use a balance point in the range of 15ºC to 18ºC.

  Newfoundland Power uses a temperature balance point of 18ºC to establish its normal weather. A number of factors support maintaining the 18°C temperature balance point:

  - Industry practice provides for a broad range of temperature balance points, primarily ranging from 12°C to 18°C.[79]

  - 18ºC is a standard figure used to determine HDD with published data readily available through Environment Canada.[80] 18°C is also used in the National Building Code of Canada.[81]

  - Further analysis would be required, including assessing the impacts on the coefficients used in the normalization calculations, to assess if a change from a temperature balance point of 18°C would be appropriate and/or meaningful.[82]

  Given the results of this review, on an initial basis, Newfoundland Power plans to maintain its temperature balance point of 18°C. However, in conjunction with its analysis

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77 The Company also uses wind speeds and Cooling Degree Days (“CDD”), though they are less significant for Newfoundland Power’s normalization adjustments.

78 HDDs are published by Environment Canada over various timeframes and weather stations.

79 Newfoundland Power has the highest among the electric investor-owned utilities reviewed. Pacific Northern Gas Ltd. also has a high heating load of an estimated 92% and also uses 18 °C as its temperature balance point. See the *Home Energy Upgrade Program, Feasibility Study and Final Report,* dated September 2023, page 27.

80 If 12 ºC was used, it would require internal computations and adjustments from the published data, increasing the complexity of the Company’s weather normalization processes.

81 *National Building Code of Canada 2025, Volume 2, Division B*, page 9-328.

82 For example, MECL’s analysis associated with differences in normalization adjustments between using a temperature balance point of 18°C versus 12°C showed little difference between the two alternatives. MECL’s analysis included changes to its coefficients. See Tables 3 and 4 in MECL’s report, *Comprehensive Review of the Weather Normalization Mechanism and Reserve,* September 27, 2024.

of the historical average to establish normal weather following this review, the Company will analyze what impact a change to a lower temperature balance point may have on its weather normalization adjustments and test year forecasts and will provide the results of that analysis in its next GRA.

Hydro Production Related Mechanisms

The practices for recovery of hydro production related variances were reviewed for six Canadian utilities (NS Power, FortisBC, Hydro, New Brunswick Power Corporation ("NB Power"), Ontario Power Generation Inc. ("OPG"), and Manitoba Hydro-Electric Board ("Manitoba Hydro")), all of whom are subject to variances in supply costs associated with their hydro facilities.[83] Of those six utilities, four utilities recover the variances in their supply costs associated with their hydro production implicitly through a broader supply cost mechanism, consistent with the discussion in sections 3.1 and 3.2 of this report.[84] OPG employs a discrete mechanism to recover its supply cost variances associated with its hydro facilities.[85] Only Manitoba Hydro, a crown corporation, did not have a supply cost mechanism associated with variance in its hydro production. As provided by the Jurisdictional Report, while Manitoba Hydro does not have a supply cost mechanism for its hydraulic flows, recent history demonstrates that the Provincial Government and the Manitoba Public Utilities Board will act, within reason, to assist the utility in managing large variations in hydraulic flows and revenues.[86]

Similar to the discussion associated with Newfoundland Power's ESCV and DMI Accounts, it is common practice for utilities to recover variances related to their hydro facilities implicitly though their broader supply cost mechanisms as compared to a more detailed mechanism like the Hydro Component of Newfoundland Power's WNR.

Opportunities exist to simplify the Hydro Component of the WNR and the regulatory filings associated with its operation and disposition. Currently, Newfoundland Power's normal hydro inflows, which are then compared to actual hydro inflows to determine the annual variance for the Hydro Component, is set on an annual basis via a regulatory filing early in that year.[87] This process is unique to the Company. As discussed above, only OPG has a discrete mechanism similar to Newfoundland Power's for recovery with the remaining utilities recovering these variances through their broader supply cost mechanisms.[88] For OPG, their normal inflow figure is equal to the amount in their latest test year. Using test year values for the operation of supply cost mechanisms is common Canadian utility practice.[89]

Based on these findings, Newfoundland Power plans to begin using its test year hydro inflows figure to determine the annual variance in the Hydro Component of the WNR, starting with its next test year. Using this industry standard approach, the annual regulatory filing to set the normal on an annual basis would no longer be required.

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[83] Jurisdictional Report, section 3.7.

[84] *Ibid*. Of note, NB Power's broader mechanisms include $5 million cost variances, though these are associated with their overall supply costs as opposed to directly associated with their hydro facilities.

[85] *Ibid*.

[86] *Ibid*.

[87] See, for example, Newfoundland Power's letter re. *Newfoundland Power's Normal Hydroelectric Production for 2025*, dated February 21, 2025. The normal hydro inflows for 2025 is equal to the normal hydro production provided in that letter.

[88] Excluding Manitoba Hydro.

[89] For example, the broader mechanisms of the other utilities would compare actual to test year amounts.

In addition, an opportunity exists to treat the disposition of the WNR in the same manner as the ESCV Account, as well as the planned approach for the DMI Account, as described in section 3.2 of this report. The Company's Rate Stabilization Clause already provides for the disposition of the WNR to the RSA each March 31st for the previous year-end balance,[90] however Newfoundland Power continues to file an application for approval of the annual balance. The application is routine in nature and has been approved as filed each year.

As part of its next GRA, Newfoundland Power plans to propose an amendment to its Rate Stabilization Clause to transfer the year-end balance in the WNR to the RSA each December 31st and no longer file an annual application for approval of the annual balance. This approach is consistent with regulatory efficiency and consistent with the treatment of the ESCV Account and the planned treatment of the DMI Account. It also better aligns with industry practice while recognizing the necessity to maintain the WNR. From a regulatory oversight perspective, key information for the WNR is provided in the Company's Annual Returns filing.[91] The Company also anticipates providing analyses associated with its supply cost mechanisms as part of its GRA filings.[92]

4.0 RESPONSE TO BRATTLE'S RECOMMENDATIONS

4.1 General

In the Brattle Report, Brattle provided four recommendations for the Board to consider in its order on the Company's 2025/2026 GRA. Three of the recommendations relate to Newfoundland Power's supply cost mechanisms and one relates to its Excess Earnings Account.

In Order No. P.U. 3 (2025), the Board directed Newfoundland Power to address the recommendations in the Brattle Report in the Company's review of it's supply cost mechanisms.[93]

The following provides Newfoundland Power's responses to the recommendations in the Brattle Report.

Overall, the Company's, Utilis' and Brattle's jurisdictional reviews all confirm that mechanisms which permit full recovery of supply costs by investor-owned distribution utilities are commonplace in Canadian regulatory practice.[94]

4.2 ESCV Account

Brattle recommends that the Board should redefine the ESCV Account to include revenue variances associated with energy supply. To support this recommendation, Brattle provides that a similar practice is followed by FortisBC.[95]

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90 See paragraph II.8 of the Rate Stabilization Clause in the Company's *Schedule of Rates, Rules and Regulations*, effective July 1, 2025.
91 Return 17 details the WNR each year.
92 See footnote 63.
93 Order No. P.U. 3 (2025), page 10, lines 24-34.
94 See the response to Request for Information PUB-NP-071, the Brattle Report, page 9, and the Jurisdictional Report, sections 3.1 and 4.1.
95 Brattle Report, pages 13-14.

Brattle's recommendation regarding Newfoundland Power's ESCV Account does not fully reflect how the ESCV Account operates in conjunction with the Company's base rates and its purchased power costs. Brattle's recommendation is also based on a comparison to a FortisBC deferral account which is substantially different, both in purpose and operation, to Newfoundland Power's ESCV Account.

Brattle's findings were that (i) Newfoundland Power will be overcompensated, through higher net income, when the marginal cost of energy supply is below the average cost of energy supply and (ii) the Company will be undercompensated, through lower net income, when the marginal cost of energy supply is above the average cost of energy supply.[96] Based on these findings, Brattle recommends capturing both costs and revenues associated with energy supply in the ESCV Account to limit the impact of any variance between marginal energy supply costs and average energy supply costs on Newfoundland Power's net income.[97]

The potential issue raised by Brattle is the very reason the ESCV Account exists.[98] The fundamental purpose of the ESCV Account is to ensure Newfoundland Power is not over- or under- compensated due to differences in its marginal energy costs when compared to the average cost included in its base rate revenues. The ESCV Account, and its predecessor (the Purchased Power Unit Cost Variance Reserve), have operated to this effect since the two-block energy wholesale rate was implemented in 2005.[99]

Table 7 on the following page demonstrates how the ESCV Account operates in conjunction with the Company's base rates and its purchased power costs in both (i) a situation where the marginal cost of energy supply is below the average cost of energy supply and (ii) a situation where the marginal cost of energy supply is above the average cost of energy supply.

96 Brattle Report, page 13.
97 *Ibid.*
98 Order Nos. P.U. 44 (2004), P.U. 32 (2007) (page 27) and P.U. 43 (2009) (pages 7-8).
99 *Ibid.*

Table 7:
Recovery of Energy Supply Costs
(Based on a variance in energy purchases of one kWh)

	Marginal Cost Below Average	Marginal Cost Above Average
Base rate revenue related to energy supply (A)[100]	7.430	7.430
Purchased power cost related to energy supply (B)[101]	3.354	9.698
Over (under) compensation before ESCV Account (C)[102]	4.076	(2.268)
ESCV Account (D)[103]	(4.076)	2.268
Over (under) compensation after ESCV Account (E)[104]	-	-

As shown in the table, the Company's base rates work in conjunction with the ESCV Account to ensure Newfoundland Power recovers its purchased power energy costs – no more, no less.

First, consider the situation where energy purchases are one kWh higher than the test year forecast in a month when the marginal cost of energy supply is below the average cost of energy supply included in base rate revenues. Before operation of the ESCV Account, Newfoundland Power is over-compensated. The ESCV Account then operates to reduce the Company's revenues equal to the over-compensation.[105] After operation of the ESCV Account, there is no impact on the Company's net income. The reduction in revenues creates an amount payable to customers in the ESCV Account, which is credited to customers through the annual rate stabilization adjustment.[106]

Next, consider the situation where energy purchases are one kWh higher than the test year forecast in a month when the marginal cost of energy supply is above the average cost of energy supply included in base rate revenues. Before operation of the ESCV Account, Newfoundland Power is under-compensated. The ESCV Account then operates to increase the Company's revenues equal to the under-compensation. After operation of the ESCV Account,

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100 The average cost of energy supply included in Newfoundland Power's customer rates. Based on the Company's 2026 test year revenue requirements and customer rates approved by the Board in Order No. P.U. 23 (2025).

101 The second block rate included in Hydro's wholesale rate charged to Newfoundland Power effective January 1, 2025 as approved by the Board in Order No. P.U. 2 (2025). The second block rate is 3.354 ¢/kWh for the months of April to November and 9.698 ¢/kWh for the months of December to March.

102 C = A – B.

103 The calculation of the ESCV Account is outlined in paragraph II.5 of Newfoundland Power's Rate Stabilization Clause included in its *Schedule of Rates, Rules and Regulations*, effective July 1, 2025.

104 E = C + D.

105 The ESCV Account is an adjustment to Newfoundland Power's revenues. See, for example, line 19 in Return 14 of the Company's *2024 Annual Report* to the Board, filed on March 31, 2025.

106 An accounting entry has two components - a debit and a credit. In this situation, the ESCV transfer would debit Newfoundland Power's revenues and credit the ESCV Account. A credit in the ESCV Account reflects a liability, which is an amount owing to customers. In accordance with the Company's Rate Stabilization Clause, the balance in the ESCV Account as at December 31st is transferred to the RSA. For details on the operation of the ESCV Account and the RSA, see the *Rate Stabilization Account Report* for the period ended December 31, 2025 filed with the Board on February 13, 2026.

there is no impact on the Company's net income. The increase in revenues creates an amount owing from customers in the ESCV Account, which is recovered from customers through the annual rate stabilization adjustment.[107]

In summary, no adjustments are necessary to the Company's ESCV Account. Since its approval by the Board two decades ago, the ESCV Account has operated in an appropriate manner to ensure Newfoundland Power is not over- or under- compensated due to differences in its marginal energy costs when compared to the average cost included in its base rate revenues. The ESCV Account, as currently constructed, is fundamental to both the interests of the Company and customers to provide for the recovery of Newfoundland Power's purchased power energy costs due to variability inherent in the demand and energy wholesale rate.

As part of its findings on Newfoundland Power's ESCV Account and in support of its recommendation on the ESCV Account, Brattle refers to a FortisBC Inc. ("FortisBC") deferral account.[108] The FortisBC deferral account referenced by Brattle is its Flow-Through Deferral Account.[109] FortisBC's Flow-Through Deferral Account is substantially different, both in purpose and operation, to Newfoundland Power's ESCV Account.

FortisBC's Flow-Through Deferral Account is used to capture the annual variances between approved and actual amounts for a broad set of costs and revenues that are included in rates on a forecast basis, not subject to earnings sharing, and do not already have a separate, approved deferral account.[110] Components recorded in FortisBC's Flow-Through Deferral Account include variances related to: revenues, power purchase expense, wheeling, water fees, operating and maintenance expense, depreciation and amortization, property taxes; other revenues, interest expense, and income taxes.[111] The deferral account is part of the MRP framework approved by the BCUC to set electricity rates for FortisBC.[112] Under this approach, FortisBC's revenue deficiency for the upcoming year is recovered through an annual customer rate change.[113] The recovery of the annual changes in utility costs are approved by the BCUC outside of a typical GRA process used in a traditional cost of service model ("COS").

In comparison, and as more fully discussed above, Newfoundland Power's ESCV Account relates to the recovery of power supply energy costs only.

Overall, it would not be appropriate for Newfoundland Power's ESCV Account to adopt only the revenues component of FortisBC's Flow-Through Deferral Account. The revenues component is one of many components included in FortisBC's Flow-Through Deferral Account, which operates within a rate-setting framework that is materially different than that used for Newfoundland Power. Further, the Jurisdictional Report provides that the practice followed by

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107 In this situation, the ESCV transfer would credit Newfoundland Power's revenues and debit the ESCV Account. A debit in the ESCV Account reflects an asset, which is an amount owing from customers.

108 Brattle Report, pages 13-14.

109 See FortisBC's filing, *Multi-Year Rate Plan for 2020 through 2024, Annual Review for 2024 Rates,* which was filed with the British Columbia Utilities Commission ("BCUC") on August 4, 2023 (the "2024 Rates Review"). The filing was filed in compliance with BCUC Order G-166-20, which approved a Multi-Year Rate Plan ("MRP") for FortisBC for the years 2020 to 2024. As provided on page 1 of the filing, in accordance with the MRP, an annual review process is required to set rates for each year of the MRP. The Flow-Through Deferral Account is discussed on pages 115 to 120 in the filing.

110 See page 115 of FortisBC's filing.

111 See Table 12-2 on pages 117-118 of FortisBC's 2024 Rates Review for further details on the specific variances within these components that are included in Flow-Through Deferral Account.

112 See the BCUC's *Decision and Orders G-165-20 and G-166-20*, June 22, 2020, Order Number G-166-20.

113 See, for example, page 7 of FortisBC's 2024 Rates Review.

FortisBC for the flow-through of annual variances in its revenues is not commonly used by investor-owned electric utilities in Canada.[114]

4.3 DMI Account

Brattle recommends that the DMI Account should be modified to remove the incentive threshold related to peak demand. The account would still exist to capture variances from actual to test year demand costs. To support this recommendation, Brattle provides that incentives related specifically to demand cost management are not common amongst investor-owned Canadian electric utilities and recognizes that Newfoundland Power has limited ability to manage its demand costs.[115]

Brattle's findings are consistent with the Company's evidence in its GRA in support of its proposal to reduce the incentive amount to a set amount of ±$500,000,[116] as well as the findings in the Jurisdictional Report that incentive amounts are not commonplace for investor-owned electric utilities in Canada.

In Newfoundland Power's view, the ±$500,000 threshold on the DMI Account approved by the Board in Order No. P.U. 3 (2025) is reasonable. However, the Company takes no issue with Brattle's recommendation on the DMI Account and considers it a reasonable alternative to the current approach. Newfoundland Power does observe, as discussed in section 3.2, if the incentive was removed, it could allow for the combination of the ESCV Account and DMI Account that would more generally align with industry practice.

4.4 Weather Normalization

Finally, Brattle recommends that the Board require Newfoundland Power to file a report as part of its next GRA providing a detailed explanation of its WNR methodology for both the Degree Day Component and the Hydro Component. In support of its recommendations, Brattle provides the review is warranted given the time since the last such review, the unique structure of Newfoundland Power's WNR compared to other investor-owned Canadian electric utilities, and the statement that it is not evident to Brattle that the Hydrology component should be included in the WNR. Brattle also suggests it would be beneficial for the Board to separate the two calculations included in the WNR for the potential to create incentives for Newfoundland Power to maintain efficient and low-cost hydroelectric facilities.[117]

Sections 2 and 3 of this report, along with Attachment A, reviews each component of the Company's WNR and provides details on both. The report also compares Newfoundland Power's supply cost recoveries and weather normalization practices to other Canadian utilities. The report finds the following with respect to the Company's cost recoveries and practices associated with weather normalization:

- The continued operation of both the Degree Day Component and the Hydro Component are appropriate and necessary for Newfoundland Power to fully recover its purchased power costs, consistent with Canadian utility practice.[118]

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114 Jurisdictional Report, section 3.4.
115 Brattle Report, page 14.
116 See the Company's *2025/2026 GRA, Volume 1: Application, Company Evidence and Exhibits, 3.4.2 Demand Management Incentive,* page 3-50.
117 Brattle Report, page 15.
118 See sections 2.4 and 3.3 of this report.

- The core assumptions used in the Degree Day Component of the WNR are reasonable. While reasonable, the Company plans to analyze what impact changing from a 30-year average to a 10-year average may have on its weather normalization adjustments and test year forecasts to further explore that alternative approach.[119] Newfoundland Power will provide the results of that analysis in its next GRA.

- Opportunities exist to simplify the Hydro Component of the WNR and the regulatory filings associated with its operation and disposition, better aligning with industry practice.[120]

- There is an opportunity to simplify the disposition of the WNR.[121] As part of its next GRA, Newfoundland Power plans to propose an amendment to its Rate Stabilization Clause to transfer the year-end balance in the WNR to the RSA each December 31st and no longer file an annual application consistent with the Rate Stabilization Clause.[122]

- Incentive thresholds on purchased power cost variances are not common utility practice. The review finds that the Company is the only electric investor-owned utility that has an incentive threshold on its purchased power costs. Creating further incentive thresholds would, in Newfoundland Power's view, be contrary to Canadian utility practice.

With respect to the Company's maintaining and operating its hydro facilities in an efficient manner, Newfoundland Power provides the following:

- The Company has a legislative obligation to operate its generation facilities in the most efficient manner.[123] Newfoundland Power's plant availability has averaged 95% over the last decade. The operation and maintenance of the Company's hydro facilities is reviewed by the Board as part of its GRA and Capital Budget Application processes.

- The operation of the Company's hydro plants is coordinated with Hydro to ensure the economic dispatch of generation on the Island Interconnected System.[124] To meet system reserve requirements, Hydro dispatches Newfoundland Power's hydro plants in accordance with its BA-P-012 (T-001) Operating Reserves procedure.[125] The procedure outlines 12 sequential steps to be taken to ensure adequate capacity is available to meet system reserve requirements. Maximizing Newfoundland Power's hydro generation is the second step of Hydro's 12-step resource dispatching sequence. This confirms the role of the Company's hydro plants as an economic source of energy and generating capacity.[126]

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119 See section 3.3 of this report. The temperature balance point of 18 ºC will also be further analyzed to confirm it remains appropriate.
120 See section 3.3 of this report.
121 *Ibid*.
122 *Ibid*.
123 Section 3(b)(i) of the *Electrical Power Control Act, 1994.*
124 Over the three-year period, 2022 to 2024, Hydro requested Newfoundland Power to maximize its generation 182 times. This demonstrates the limited autonomy the Company has over the operation of its hydro facilities.
125 The BA-P-012 (T-001) Operating Reserves procedure outlines the requirements to assess and maintain sufficient operating reserve to meet current and anticipated customer needs under normal operating conditions and for specific contingency situations that result in reductions in resources. The procedure was most recently filed as PUB-NLH-002, Attachment 1 as a part of Hydro's *Reliability and Resource Adequacy Study* review.
126 It also confirms that Hydro has a degree of control over the dispatch of Newfoundland Power's hydro plants.

- Newfoundland Power completes upgrades to increase the efficiency of its plants where possible.[127] This typically occurs during the refurbishment of hydro plants, which are subject to Board approval.[128] Further, Newfoundland Power completes any refurbishment of its plants after the spring run-off to minimize the amount of spill associated with completing the planned work.[129] In addition, the Company maintains and refurbishes its hydro plants to reduce the risk of unplanned work which can lead to spills.[130]

4.5 Other

Excess Earnings Account

Brattle recommended that it would be beneficial if the Excess Earnings Account was based on Newfoundland Power's approved return on equity rather than its return on rate base.[131] However, Brattle noted that this issue has been previously considered by the Court of Appeal of Newfoundland and Labrador, and that the Court determined there are limits on the Board's jurisdiction in this matter. Newfoundland Power agrees with Brattle's finding that the issue has been previously considered by the Court of Appeal of Newfoundland and Labrador and therefore does not need to be assessed as part of this report.

Total Deferral Account Coverage

Brattle also provided its assessment of Newfoundland Power's total deferral account coverage compared to other investor-owned Canadian electric utilities. Brattle found that: "NP [Newfoundland Power] has a similar amount and treatment of deferral coverage to other utilities. However, many of these other utilities have some form of incentive regulation that requires them to find efficiencies for large portions of their costs. NP lacks this additional incentive to reduce costs and find efficiencies while also benefiting from a similar amount of deferral account coverage."[132]

In Newfoundland Power's view, Brattle's analysis oversimplifies the regulatory framework used in each jurisdiction to suggest a particular form of regulation requires utilities to find cost efficiencies, while another form of regulation lacks the additional incentive for the utility to find efficiencies.[133] Brattle does not appear to consider the local circumstances that gave rise to the approach to regulation in each jurisdiction.[134] In the Company's view, regulators across Canada strive to ensure customer electricity rates reflect efficient utility operations by working within the rate-setting framework permitted by their local legislation.[135]

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[127] For example, see Order No. P.U. 38 (2025), page 10, line 39 to page 11, line 28 regarding the approval of Newfoundland Power's project to automate the operation of the outlet gate as part of the *Mount Carmel Pond Dam Refurbishment* project approved by the Board in the previous year.
[128] *Ibid*.
[129] For example, see the *Lookout Brook Hydro Plant Refurbishment* project filed as part of the Company's *2024 Capital Budget Application*.
[130] For example, see Newfoundland Power's *2026-2030 Capital Plan*, notably sections 2.4.5 and 3.3.5 and Table A-5 in Appendix A.
[131] Brattle Report, page 20.
[132] *Ibid*., page 24.
[133] See, for example, the response to Request for Information NP-PUB-004 filed as part of Newfoundland Power's 2025/2026 GRA.
[134] *Ibid*.
[135] This is reflective of the power policy set out in each province. In most cases, including Newfoundland and Labrador, the power policy makes specific reference to operational efficiency requirements.

In Newfoundland and Labrador, the Board tests operational efficiencies through the review of utility general rate and capital budget applications which are filed with the Board on a routine basis.[136] The Board has also established a range of return on the utility's rate base, which provides an incentive for the utility to find operational efficiencies between rate reviews which are ultimately passed on to the benefit of customers in the next rate-setting process.[137]

Newfoundland Power observes that the range of returns on equity ("ROE") are significantly larger in Performance Based Ratemaking ("PBR") and Multi-Year Rate Plan ("MRP") jurisdictions than in more traditional COS jurisdictions.[138] In theory, the larger range, along with prolonged period between general rate proceedings, can provide a larger incentive to a utility to find cost efficiencies. Ultimately, Newfoundland Power is regulated under a COS model as established by provincial legislation. While other forms of utility regulation may provide opportunities, a review of the established rate-setting framework in the province is outside of the scope of this review.

Finally, Brattle's finding that "*NP lacks this additional incentive to reduce costs and find efficiencies while also benefiting from a similar amount of deferral account coverage*" does not fully consider how cost recovery is regulated in each jurisdiction in Canada. An example would be a comparison of 2024 cost recovery between FortisBC under its MRP framework and Newfoundland Power under its COS model. For 2024, Newfoundland Power had a more limited ability to recover its costs without a fulsome regulatory review as compared to FortisBC.

Under the MRP approach, FortisBC's 2024 revenue deficiency was recovered through an annual customer rate change.[139] Revenue requirement items contributing to FortisBC's 2024 revenue deficiency included sales, depreciation, operating expenses and return on rate base.[140] In comparison, the recovery of Newfoundland Power's 2024 revenue deficiency was limited to only the return on rate base component of its revenue requirement.

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136 GRAs are typically filed every three years, and capital budget applications are filed annually.

137 See, for example, Order No. P.U. 36 (1998-99), where the Board approved an increase in the range of return on Newfoundland Power's rate base from 24 basis points to 36 basis points. In that order, the PUB stated on page 70: "*The introduction of an expanded range of 36 basis points will provide an incentive for the company to improve productivity and will allow for some variation in financial variables other than those adjusted by the formula.*"

138 At the time of the Company's 2025/2026 GRA, the following was observed. In Ontario, the range of ROE is ±300 basis points. In Alberta, the range of ROE is ±200 basis points. If a utility's actual ROE is between 200 and 400 basis points higher than the ROE used to set customer rates, the utility retains 60% and customers receive 40% of the incremental earnings in that range. For earnings more than 400 basis points above the rate-setting ROE for that year, the utility retains 20% and customers receive 80% of incremental earnings. For FortisBC, any actual earnings below or above the mid-point ROE in that year are shared 50/50 with customers through the symmetrical Earnings Sharing Mechanism. Further, the MRP allows for a plan off-ramp to be triggered if earnings in any one year vary from the ROE by more than ±150 basis points. This compares to ranges on ROE in traditional COS jurisdictions of ±25 basis points to +35 basis points for Nova Scotia Power and Maritime Electric, respectively, as well as ±18 basis points on return on rate base for Newfoundland Power.

139 See, for example, section 1.5 on page 7 of FortisBC's *Multi-Year Rate Plan for 2020 through 2024, Annual Review for 2024 Rates,* August 4, 2023.

140 *Ibid*.

5.0 RESPONSE TO THE BOARD'S LETTER

In its letter dated April 10, 2025, the Board noted that actual stream flows have been below normal stream flows every year since 2015 and the cumulative difference over the period 2015 to 2024 period was 10.1% below normal. The Board stated its concern that the current normal hydroelectric production may be too high and requested that this matter be addressed in Newfoundland Power's review of its normal hydroelectric production. As noted by the Board, and as outlined in this report, base customer rates reflect normal hydro production, with the Hydro Component of the WNR providing recovery of any variance from that normal through the annual July 1st customer rate adjustment.[141]

Newfoundland Power engages Hatch Ltd ("Hatch") to complete a study of the Company's hydroelectric normal production every 5 years. The next 5-year study is scheduled to be filed with the Board in 2027, based on actuals up to 2025. During its last review, Hatch noted that *"It is possible that physical, operational, and hydrological changes in the systems over the years have resulted in some "drift" despite the model revisions made during successive reviews, and that some of the models would benefit from recalibration. It is recommended that model calibration be reassessed during the next review."*

As recommended by Hatch, model calibration will occur as part of the ongoing 5-year review. This includes movement to a new modern modelling system that has been deployed by Hatch and detailed review of underlying inputs and assumptions being used to estimate Newfoundland Power's hydroelectric normal production.[142] The model will be calibrated on an individual plant basis by comparing the simulated and recorded generation for a period that is most representative of current conditions (e.g. the most recent 10 years compared to 30+ year averages used in previous studies).[143]

The Company anticipates the review will provide for a lower hydroelectric normal production. Consistent with the other potential revisions to Newfoundland Power's supply cost mechanisms as a result of this review, the Company will put forward the revised hydroelectric normal production in its next GRA, to begin with its next test year. This will allow all revisions to the WNR, and notably the Hydro Component of the WNR, to be considered together and be implemented in an efficient manner.

In terms of future reviews of Newfoundland Power's hydroelectric normal production, the Company anticipates continuing its 5-year reviews and providing those reviews in the subsequent GRA filing.[144]

141 Variance, in dollars, were larger over the historical period up to 2024 due to the wholesale rate in place at that time. It is anticipated, based on the new wholesale rate, that dollar variances will be significantly less. For example, in 2025 the transfer to the Hydro Component of the WNR was $2.3 million (see Table 6 in this report). Under the previous wholesale rate, the transfer would have been an estimated $19.5 million.

142 This includes a review of the correlation between inflows and generation.

143 For example, total precipitation in St. John's over 2015 to 2025 period has been approximately 3% lower on average compared to the previous 20-year average. Moving to a more recent historical average would be consistent with the Company's approach in other areas. In its *2022/2023 GRA*, Newfoundland Power reduced its historical average used to determine its native load from 15-years to 5-years to better reflect current conditions. Further, following this review, the Company plans to assess the reasonableness of using a 10-year historical average associated with the Degree Day Component of the WNR.

144 This approach would be consistent with the approach used to review its depreciation expense.

6.0 CONCLUSION

Newfoundland Power's supply cost mechanisms remain appropriate and necessary to ensure the Company fully recovers its power supply costs. The jurisdictional review shows that regulatory mechanisms that permit full recovery of energy supply costs by investor-owned electric utilities are commonplace in Canada.

Based on Newfoundland Power's review, the results of the Jurisdictional Report, as well as with consideration of the recommendations of Brattle and the Board's letter dated April 10, 2025, the Company plans to bring forward the following proposals in its next GRA:

- Revisions to its Rate Stabilization Clause to provide for the disposition of the year-end balances in the DMI Account and WNR on December 31st on an annual basis.[145]

- Revisions to the Hydro Component to the WNR to set the normal equal to the test year figure, eliminating the need for annual updates.

- Potential revisions in the determination of the Company's hydroelectric normal associated with the Hydro Component of the WNR.[146] The potential change in the hydroelectric normal will be based on a study completed by Hatch.

The planned, and potential, revisions to Newfoundland Power's supply cost mechanisms will better align their operation with industry practice, improve regulatory efficiency associated with their balance disposition and ensure the normals used in the WNR are reasonable.

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145 These revisions will be proposed in conjunction with the planned revisions to the Rate Stabilization Clause associated with the ESCV Account, DMI Account, and WNR outlined in the *Return on Rate Base Report* filled with the Board on March 31, 2026. See pages 7 and 8 of that report for further details.

146 As outlined in section 3.3 of this report associated with the Degree Day Component of the WNR, Newfoundland Power also plans to analyze what impact changing from a 30-year average to a 10-year average may have on its weather normalization adjustments and test year forecasts to further explore that alternative approach. The temperature balance point of 18 ºC will also be further analyzed to confirm it remains appropriate. The Company will provide the results of these analyses in its next GRA.

2025 Weather Normalization Reserve Details

Attachment A: 2025 Weather Normalization Reserve (“WNR”) Details

Degree Day

To demonstrate how weather normalization adjustments are determined, Table 1 provides the calculation of the 2025 weather normalization adjustments for the domestic electric heat (“EH”) customer class in the St. John’s area with explanations of each component.[i]

Table 1:
Example Calculation of Weather Normalization Adjustments for 2025
Domestic EH Customer Class, St. John’s Area

Month	**HHD Difference**[ii] (A)	**Coefficient**[iii] (B)	**Customers**[iv] (C)	**Normalization Adjustment (kWh)**[v] (D)
Sales				
January	50	1.557	89,680	7,023,478
February	(12)	1.557	89,804	(1,705,863)
March	88	1.557	89,934	12,350,402
April	24	1.557	89,937	3,304,753
May	(9)	1.557	90,154	(1,305,439)
June	96	0.779	90,139	6,722,594
July	-	-	90,174	-
August	-	-	90,357	-
September	10	0.779	90,380	724,717
October	12	1.557	91,210	1,704,168
November	27	1.557	91,202	3,834,041
December	3	1.557	91,648	371,009
Total Sales Adjustment				**33,023,860**
Purchased Power				
January	50	1.632	89,680	7,362,246
February	(12)	1.632	89,804	(1,788,143)
March	88	1.632	89,934	12,946,109
April	24	1.632	89,937	3,464,154
May	(9)	1.632	90,154	(1,368,405)
June	96	0.816	90,139	7,046,850
July	-	-	90,174	-
August	-	-	90,357	-
September	10	0.816	90,380	759,672
October	12	1.632	91,210	1,786,366
November	27	1.632	91,202	4,018,971
December	3	1.632	91,648	388,905
Total Purchased Power Adjustment				**34,616,725**
Net Normalization (Total Sales - Total Purchased Power)				**(1,592,865)**

Hydro Component

The following provides the calculation of the Hydro Component of the WNR for 2025 with explanations of each component.[vi]

Table 2:
Calculation of the Hydro Component
2025

		January to March & December	April to November
Actual hydro inflows (GWh)[vii]	A	157.5	152.1
Normal hydro inflows (GWh)[viii]	B	137.3	279.5
Hydro inflows variance (GWh)	**C = A - B**	**20.2**	**(127.4)**
Wholesale second block energy rate (¢/kWh)[ix]	D	96.980	33.540
Hydro inflows variance ($000s)	E = C x D	1,959	(4,273)
Total transfer [$1,959 + ($4,273)][x]	**F**		**(2,314)**

Explanations

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i Weather normalization adjustments are determined by customer rate class, by area. See Newfoundland Power's *Application for Approval of Balance in Weather Normalization Reserve, Schedule A, Appendix B* for the sales normalization adjustments for 2025. Table 1 provides the determination of the 2025 sales normalization adjustment of 33,023,860 kWh for Rate Code 112 (Domestic EH) which agrees to page 1 of Appendix B. Revenue weather normalization adjustments are determined by multiplying the kWh adjustments by the base customer energy rate for that rate class approved by the Board for that month. Similarly, *Application for Approval of Balance in Weather Normalization Reserve, Schedule A, Appendix C* provides the purchased power normalization adjustments for 2025. Table 1 provides the determination of the 2025 purchased power normalization adjustment of 34,616,725 kWh for Rate Code 112 (Domestic EH) which agrees to page 1 of Appendix C. Purchased power expense weather normalization adjustments are determined by multiplying the kWh adjustments by the second block wholesale rate approved by the Board for that month.

ii Actual Heating Degree Days ("HDD") less Normal HDD. Normal HDD are a 30-year average of HDD.

iii The coefficients are determined using multiple linear regression analysis, a statistical technique that identifies mathematical relationships between a dependent variable (e.g., monthly electricity sales) and one or more independent variables (e.g., weather data). The resulting coefficients represent the impact of one unit of abnormal weather on energy usage. Since the impact of weather on energy usage varies seasonally, the Company coefficients vary in the months of June to September compared to October to May.

iv Number of customers in the Domestic EH customer class in the St. John's area at the end of each month.

v D = A x B x C.

vi For further details of the Hydro Component of the WNR for 2025, see Newfoundland Power's *Application for Approval of Balance in Weather Normalization Reserve, Schedule A, Appendix D.*

vii Actual production plus change in hydro storage equals actual hydro inflows.

viii Normal hydro inflows total of 416.8 GWh (137.3 GWh + 279.5 GWh) per *Newfoundland Power's Normal Hydroelectric Production* for 2025 letter filed with the Board on February 21, 2025.

ix See Order No. P.U. 1 (2025), Schedule A, page 4.

x Difference of $2 from Table 6 in the report due to rounding.

Jurisdictional Review of Supply Cost Mechanisms

Jurisdictional Review of Supply Cost Mechanisms

Prepared for:

Newfoundland Power Inc.
March, 2026

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Table of Contents

1. Introduction

1.1. Background and Purpose

This Jurisdictional Review of Supply Cost Mechanisms ("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 that Newfoundland Power file a report reviewing its supply cost mechanisms with the PUB on or before December 31, 2025. The Board subsequently extended the deadline for submission of this report to March 31, 2026. The report is required to include a review of the recommendations in the Brattle Review, as well as a jurisdictional review.

This Review has been prepared for Newfoundland Power to assist the utility in preparing the broader report identified in Order No. P.U. 3 (2025) referenced above. The Review is focused primarily on completion of a jurisdictional scan of relevant utility supply cost mechanisms, including a comparison of the specifics and outcomes of Newfoundland Power's supply cost mechanisms to those of peer utilities. Limited comments have been included in Section 4.1 of the Review regarding the Battle Review, specifically to highlight insights from this Review which are relevant to the individual recommendations made.

1.2. Review Structure

This Review is structured as follows:

- **Peer Group Selection**: A description of the criteria used to select peer utilities for the purpose of completing the Review, as well as ancillary peer groups identified for the purpose of reviewing specific elements of supply cost mechanisms in Canada.
- **Supply Cost Mechanism Review**: Presentation of the research results of this Review, examining the supply cost mechanisms of Newfoundland Power and peer utilities on an area by area basis. The presentation of research results on each area is followed by an analysis of trends amongst the utilities examined.
- **Comparison of Peer Utilities to Newfoundland Power**: Summary conclusions regarding the comparability or non-comparability of Newfoundland Power's supply cost mechanisms to those of peer utilities, both with respect to outcomes and mechanics. This section also discusses findings which are specifically relevant to the recommendations of the Brattle Group *Report on Newfoundland Power's Deferral Accounts* submitted to the Board April 24, 2024 in the proceeding to review Newfoundland Power's 2025-2026 General Rate Application.

- **Conclusions**: Concluding statements regarding the consistency of Newfoundland Power's supply cost mechanisms to those of relevant Canadian utilities.

1.3. Utilis Consulting Inc.

Utilis is a 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[2] 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 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.

Preparation of this Review was completed in consultation with **Andrew Mandyam** and **Bruce Bacon.**

Andrew Mandyam is a Founder and Partner at Utilis, and a former utility executive and leader of the regulatory and finance functions for one of Canada's largest energy distributors. Andrew's deep regulatory expertise is augmented by his experience leading complex regulatory processes at the intersection between executive leadership and on-the-ground regulatory practice.

Bruce Bacon has worked in Canadian energy regulation and rate-making for over 40 years; having acted as a consultant in the preparation of the Ontario Energy Board's Cost Allocation Model, and assisted in

[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

[2] AI functionality referenced is relied upon strictly in the identification of relevant resources. All materials were reviewed and analyzed by Utilis Consulting in the preparation of this Review

the preparation of well over 100 distribution cost of service rate applications for over 45 utilities. Bruce's boundless curiosity and joy of problem-solving, augmented by his significant experience, make him an ideal thought-partner in efforts to tackle tough challenges and formulate new ideas.

2. Peer Group Selection

The objective of successful peer group selection for this Review was to identify reasonably comparable Canadian electric utilities to assess the specifics of their supply cost recovery mechanisms against those of Newfoundland Power. The objective of the peer group selected was to ensure an appropriate diversity of Canadian jurisdictions and utilities was encompassed, and was not intended to provide an exhaustive list of all relevant or comparable utilities in Canada.

Further, in light of the specifics of Newfoundland Power's supply cost mechanisms, additional focus was placed on ensuring the Review adequately assessed weather normalization and hydrological adjustment mechanisms active in Canada for the purpose of comparison. In order to achieve these objectives, Utilis identified three distinct groups for the purpose of completing the Review. The first group includes a diverse collection of utilities chosen for their comparability to Newfoundland Power for the purpose of researching and comparing supply cost mechanisms overall ("Main Peer Group"). The second group was chosen specifically for the purpose of assessing weather normalization of revenues and weather normalization methodologies, and was expanded from the Main Peer Group for the purpose of ensuring sufficient weather-sensitive utilities were included ("Weather Normalization Peer Group"). The final group was selected explicitly to research and compare regulated utilities with hydro-electric generation facilities, and excludes non-relevant members of the Main Peer Group ("Hydrological Adjustment Peer Group").

2.1. Main Peer Group

The Main Peer Group relied upon to assess comprehensive supply cost mechanisms consists of a cross-section of Canadian electric utilities with reasonably comparable characteristics to Newfoundland Power. Specifically, Utilis considered the following attributes in selecting the Main Peer Group:

- **Investor-Owned Utilities:** Priority was given to utilities which are investor-owned, as opposed to operating as publicly owned entities;
- **Size and Function:** 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 supply cost mechanisms used in Ontario are directed by the Ontario Energy Board and are highly consistent across both large and small utilities. Utilities selected were also tailored to ensure the utilities carried out an electricity distribution function connected to end-use customers, comparable to Newfoundland Power's function;

- **Geography:** A cross-section of Provincial jurisdictions was sought out to canvass the different approaches approved by different economic regulators in Canada. The Main 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 structures which reflect the types of mechanisms in place where no single entity is responsible for all generation, transmission, distribution, and collection of revenue from customers;

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

Table 1: Main Peer Group for Review of Supply Cost Mechanisms

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[3]	Ontario Energy Board	Investor-owned
ATCO Electric	Alberta Utilities Commission	Investor-owned
FortisAlberta	Alberta Utilities Commission	Investor-owned
FortisBC Inc.	British Columbia Utilities Commission	Investor-owned

[3] Supply cost mechanisms employed in Ontario are generic to all Ontario electricity distributors regulated by the Ontario Energy Board, with rare variation driven by utility-specific circumstances. As such Algoma Power, regardless of size comparability, represents a proxy for all Ontario electricity distributors. Further, unlike most electricity distributors in Ontario Algoma Power is investor-owned, rather than municipally-owned

2.2. Weather Normalization Peer Group

Newfoundland Power exhibits a high penetration of electric heating, resulting in greater weather-sensitivity than is typical amongst other Canadian electric utilities which may otherwise be comparable from a supply cost mechanism perspective. To accommodate this difference and ensure the weather normalization practices of Newfoundland Power are sufficiently compared to those of other regulated utilities in Canada, a weather normalization peer group was established. This group maintained all members of the Main Peer Group, but was expanded to include natural gas utilities within Canada, for whom energy consumption varies considerably based on weather in a manner consistent with Newfoundland Power.

Table 2: Additional Weather Normalization Peer Group Members

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
ATCO Electric	Alberta Utilities Commission	Investor-owned
FortisAlberta	Alberta Utilities Commission	Investor-owned
FortisBC Inc.	British Columbia Utilities Commission	Investor-owned
ATCO Gas	Alberta Utilities Commission	Investor-owned
AltaGas	Alberta Utilities Commission	Investor-owned
Energir	Regie l'energie	Investor-owned
Enbridge Gas	Ontario Energy Board	Investor-owned
Pacific Northern Gas Ltd.	British Columbia Utilities Commission	Investor-owned
FortisBC Energy Inc.	British Columbia Utilities Commission	Investor-owned

2.3. Hydrological Adjustment Peer Group

Newfoundland Power owns and operates regulated hydroelectric generation facilities which are used for the purpose of supplying power to customers, substantially augmented by energy supply purchases made from Newfoundland and Labrador Hydro. This characteristic is not common amongst utilities which are otherwise comparable to Newfoundland Power for the purpose of assessing broader supply cost mechanisms. To accommodate this difference and ensure the hydrological adjustment practices of Newfoundland Power are sufficiently compared to those of other regulated utilities in Canada, a hydrological adjustment peer group was established. This group maintains the members of the Main Peer Group which operated regulated hydro-electric generation facilities (i.e. Newfoundland Power, Nova Scotia Power, FortisBC Inc.), eliminates all other members of the Main Peer Group, and is expanded to include crown corporations which operate hydro-electric generation facilities.

Table 3: Additional Hydrological Adjustment Peer Group Members

Utility	Regulator	Ownership
Newfoundland Power	Newfoundland & Labrador Board of Commissioners of Public Utilities	Investor-owned
Nova Scotia Power	Nova Scotia Energy Board	Investor-owned
FortisBC Inc.	British Columbia Utilities Commission	Investor-owned
Newfoundland and Labrador Hydro	Newfoundland & Labrador Board of Commissioners of Public Utilities	Crown Corporation
New Brunswick Power	New Brunswick Energy & Utilities Board	Crown Corporation
Ontario Power Generation	Ontario Energy Board	Crown Corporation
Manitoba Hydro	Manitoba Public Utilities Board	Crown Corporation

3. Supply Cost Mechanism Review

The following sub-sections present distinct areas of review examined, wherein the pertinent details of each peer utility are presented, followed by analysis of consistency and trends amongst the peer group, inclusive of Newfoundland Power.

3.1. Passthrough Outcomes

The following table summarizes the degree to which, and the high-level mechanisms through which, each of the utilities in the Main Peer Group achieve full passthrough of supply costs:

Table 4: Passthrough Outcome Comparison

Utility	Details
Newfoundland Power	Full passthrough, with the exception of a Demand Management Incentive, is achieved through a series of discrete adjustments and accounts. Variations in energy costs for degree day normalization and hydro production equalization are entered in the Weather Normalization Reserve. Variations in demand costs from test year incurred, subject to a risk/reward incentive, are entered in the Demand Management Incentive Account. Variations in energy costs from test year are entered into an Energy Supply Cost Variance Account. The balances in the Weather Normalization Reserve, the Demand Management Incentive Account and the Energy Supply Cost Variance Account are transferred to the Rate Stabilization Account for disposition to or collection from customers.
Nova Scotia Power[4]	Full passthrough is achieved annually through the Fuel Adjustment Mechanism, which establishes a Base Fuel Cost per kWh to be charged to customers, and subsequently records variances in Base Fuel Cost Revenues and actual fuel costs in a given year for recovery through Fuel Adjustment Mechanism riders. Base Fuel Costs can be established in a General Rate Application or through a Fuel Adjustment Mechanism adjustment process every second year. Recovery of a given year's variance takes place over a 2-year cycle, with the second year dedicated to clearing any variance between forecast and actual disposition driven by billing determinant variances.
Maritime Electric[5]	Full passthrough is achieved through the Energy Cost Adjustment Mechanism, which sets a Base Rate for energy supply over a multi-year term aligning with Maritime Electric's General Rate Application cycle. Actual annual energy supply costs are compared to Base Rate Revenue to determine any variance between supply driven revenues and costs. Variances are placed in deferral for future recovery, which typically occurs in a General Rate Application but can be requested out-of-cycle (e.g. 2022 relating to 2021 energy supply costs). Recovery is achieved

[4] Nova Scotia Utility and Review Board, 2024 Fuel Adjustment Mechanism Decision, 2024 NSUARB 71; Nova Scotia Utility and Review Board, 2025 Fuel Adjustment Mechanism Decision, 2025 NSUARB 33; Nova Scotia Utility and Review Board, 2020–2021 Fuel Adjustment Mechanism (FAM) Audit Decision, 2024 NSUARB 34
[5] Island Regulatory and Appeals Commission (IRAC), Order UE21-05: ECAM Review; Island Regulatory and Appeals Commission (IRAC), Maritime Electric 2023–2025 General Rate Application, June 20, 2022

Utility	Details
	through rate riders applicable to the Energy Cost Adjustment Mechanism deferral, where any remaining balances after planned disposition remain in the account balance for future disposition.
Algoma Power[6]	Full passthrough is achieved through two variance accounts generically established for all Ontario electricity distributors; 1588-RSVA Commodity and 1589-RSVA Global Adjustment, which together record all supply costs and revenues. The division of supply costs between the two accounts relates to Ontario's electricity generation being a mix of a wholesale market for electricity (1588) and contracts and other costs controlled by the Independent Electricity System Operator (1589). Supply-specific rates are established by the Ontario Energy Board for implementation by distributors, creating a distinct pool of revenues to compare against supply costs. All supply costs and revenues recorded by distributors are netted against one another, and the resulting variances are recorded in Accounts 1588/1589. Similar accounts exist for transmission charges and other system charges billed to and by distributors. These accounts are targeted for disposition on an annual basis, in a largely mechanistic manner.
ATCO Electric[7]	Full passthrough of supply costs is effectively not necessary for Alberta electricity distributors. Customer billing in Alberta is carried out by third-party energy retailers (electric, gas or dual-fuel) responsible for entering into energy commodity agreements with customers, or the supplier of last resort serving the same function. As such, transmission and distribution charges are added to and collected via retailer bills to customers, as opposed to the other way around as is typically the case in Canadian jurisdictions which allow for third-party energy retailers. As a result of this arrangement, distributors are not responsible for paying the cost of power, nor are they responsible for collecting revenues related to the cost of power.
FortisAlberta[8]	Per the above, full passthrough of supply costs is effectively not necessary for Alberta electricity distributors.
FortisBC Inc.[9]	Full passthrough is achieved through the Flow-through Deferral Account; a broad true-up mechanism applicable to numerous items deemed to be outside the control of management, which are not subject to other discrete deferral or variance accounts. Any variance in power supply expense relative to forecast in a given year is entered into the Flow-through Deferral Account for disposition in future years. Notably, another entry in the Flow-through Deferral Account provides for variances in utility revenue driven by customer count and load variances relative to forecast. As such variances in revenues notionally dedicated to recovery of energy supply

[6] Ontario Energy Board, EB-2025-0054: Algoma Power 2026 Incentive Rate-setting Mechanism Application, Application and Evidence, August 14, 2025

[7] Alberta Utilities Commission (AUC) – Rate of Last Resort (ROLR) – Fact Sheet (information card explaining the default "Rate of Last Resort" for Alberta customers, including its approval by the Commission in Decision 29204-D01-2024); Utilities Consumer Advocate (Alberta) – Understanding Your Bill – Residential Electricity; Alberta Utilities Commission (AUC) – Decision 27388-D01-2023: 2024-2028 Performance-Based Regulation (PBR) Plan for Alberta Electric and Gas Distribution Utilities

[8] Ibid.

[9] British Columbia Utilities Commission, FortisBC Inc. 2020–2024 Multi-Year Rate Plan Application, BCUC Filing B-1; British Columbia Utilities Commission, FortisBC Inc. 2025/2026 Rate Application, B-2 Filing

Utility	Details
	expenses are recorded in the Flow-through Deferral Account as an inherent component in the broader entry relating to revenue variances.

Amongst the Main Peer Group analyzed in this Review, all utilities achieved the full passthrough of supply costs to customers with the sole exception of Newfoundland Power's Demand Management Incentive, as discussed in Section 3.5 Supply Cost Incentive Mechanisms within this Review. Aside from this atypical item, all supply costs across all utilities are recovered from customers based on actual costs incurred.

Utilis observes that while all of the supply cost mechanisms analyzed shared the same end-state of achieving the full passthrough of actual energy supply costs to customers, the manner through which this passthrough is achieved varies considerably across the Main Peer Group. Several utilities (i.e. Nova Scotia Power, Maritime Electric, FortisBC Inc.) utilize broad mechanisms which capture variances in energy supply costs as a whole for recovery from (or credit to) customers in the future, while others (i.e. Newfoundland Power and Algoma Power) utilize a series of more discrete adjustments and accounts. ATCO Electric and FortisAlberta do not require or implement a passthrough mechanism.

Utilis expects the mechanisms employed to achieve the full passthrough of energy supply costs are responsive to the specific circumstances of each jurisdiction and utility in question. In the case of Algoma Power for example, Ontario distributors generally operate distinctly from the Province's transmission and generation assets, and regulatory mechanisms have evolved to accommodate this separation. Distinct charges are included on customer bills to separately recover the cost of generation, transmission, and distribution, as each of these revenue streams must ultimately be dispersed to a different participant within the electricity sector. The discrete tracking of revenues allows for discrete comparison of such revenues to invoices from providers to Algoma Power (i.e. transmission providers and commodity providers), and allows for clear and transparent tracking of variances in both the parts and whole of energy supply costs.

Similarly, Newfoundland Power is subject to the Demand Management Incentive, which lends itself to the tracking and identification of demand supply cost variances separately from energy supply cost variances. Newfoundland Power further operates on a weather normalized basis in recognition of its high heating load, which also lends itself to distinct adjustment. Finally, Newfoundland Power does not establish a charge or rate which is distinct to energy supply costs; instead embedding energy costs within its broader rate structure designed to recover its Cost of Service on a forecast basis. Nova Scotia Power and Maritime Electric have established similar, simplified mechanisms wherein a base energy supply rate is calculated and used to determine the variance between forecast and actual energy supply costs, despite no distinct energy supply cost charge being in place.

FortisBC Inc.'s operation under a much broader mechanism for the purpose of achieving the full passthrough of energy supply costs is consistent with the utility's rate framework of full revenue decoupling. Given the entire revenue envelope of FortisBC Inc. will be trued-up based on variations between forecast and actual customer count and load, there is no need to establish a base energy supply rate for the purpose of truing up supply cost variances, nor is there a need to make any revenue entry or adjustment specific to supply-dedicated revenues. FortisBC's entry to its Flow-through Deferral Account is a simple entry equal to the difference between forecast and actual supply costs, as any corresponding variance in revenue will be captured in the utility's broader revenue decoupling entry to the Flow-through Deferral Account.

3.2. Energy Price Normalization

The following table summarizes the manner in which each member of the Main Peer Group normalizes the price paid per unit of energy consumed as part of their supply cost mechanisms:

Table 5: Energy Price Normalization Comparison

Utility	Details
Newfoundland Power	In order to calculate entries into the Energy Supply Cost Variance Account Newfoundland Power calculates the difference between the 2nd block charge per kWh and the calculated ¢/kWh for wholesale energy forecast for the Test Year. This is necessary because Newfoundland Power does not have a distinct category of revenue dedicated to energy supply costs, and thus must calculate energy price differential (in addition to volume differential) in order to generate an adjustment that increases or decreases revenue to achieve full passthrough of supply costs.
Nova Scotia Power	Entries into the Fuel Adjustment Mechanism implicitly include energy price normalization. Fuel Adjustment Mechanism entries are calculated based on the difference between Base Fuel Cost Revenues and Actual Fuel Costs, where Base Fuel Cost Revenues are determined by multiplying the Base Fuel Cost per kWh by actual kWh billing determinants charged. As such, Fuel Adjustment Mechanism entries could be expressed either as a dollar-amount variance (i.e. Base Fuel Revenues vs Actual Fuel Costs), or a kWh price variance (i.e. Base Fuel Charge vs. Actual Fuel Costs divided by Actual kWh billing determinants).
Maritime Electric	Entries into the Energy Cost Adjustment Mechanism implicitly include energy price normalization. Energy Cost Adjustment Mechanism entries are calculated based on the difference between Base Rate Revenues and Actual Energy Supply Costs, where Base Rate Revenues are determined by multiplying the Base Rate by actual kWh billing determinants charged. As such, Energy Cost Adjustment Mechanism entries could be expressed either as a dollar-amount variance (i.e. Base Rate Revenues vs Actual Supply Costs), or a kWh price variance (i.e. Base Rate vs. Actual Supply Costs divided by Actual kWh billing determinants).
Algoma Power	Explicit energy price normalization is not required by Algoma Power or other Ontario electricity distributors. Algoma Power bills distinct energy supply cost rates designed to recover energy supply costs from customers, and can directly compare the revenues received from these rates to costs incurred for corresponding energy supply costs on an actual basis. Entries to Accounts 1588/1589 are equal to the difference between revenues and costs, with no need to explicitly calculate differences between forecast and actual rates for energy supply on a discrete basis.

Utility	Details
ATCO Electric	Price normalization is not required, as customer billing is completed by third-party energy retailers; relieving the distribution utility of the need to manage supply revenues and costs.
FortisAlberta	Price normalization is not required, as customer billing is completed by third-party energy retailers; relieving the distribution utility of the need to manage supply revenues and costs.
FortisBC Inc.	Explicit price normalization is not required. FortisBC Inc. can enter the full cost variance of energy supply costs without requiring adjustments to revenue specific to energy supply, in light of the broader revenue coupling and true-up structure under which FortisBC Inc. operates.

The principal driver for the use or non-use of explicit energy price normalization across the Main Peer Group is driven by the utility's approach to accounting for revenues dedicated to recovering energy supply costs, and the true-up of variances in such revenue.

Newfoundland Power, Nova Scotia Power, and Maritime Electric all rely implicitly or explicitly on energy price normalization within their energy supply cost mechanisms as a means to avoid the need to explicitly adjust or account for revenues specific to energy supply cost recovery. In all three cases, to the degree variances in energy supply costs are driven solely by variances in kWh billing determinants relative to forecast, such variances will inherently be captured through revenues from customers (i.e. more or less kWh used by customers will drive both costs and revenues up or down in tandem). The missing component in achieving full passthrough of energy supply costs is a true-up of differences in energy cost per kWh. For Newfoundland Power, this is achieved by multiplying actual normalized kWh energy purchases by the variance in energy cost per kWh. For Nova Scotia Power and Maritime Electric, this is achieved by multiplying forecast $/kWh by actual kWh billing determinants, and establishing the dollar-amount variance between this calculated amount and actual energy supply costs incurred. The three calculations are materially the same in intent and outcome, by providing an adjustment to supply-cost dedicated revenues such that they equal to supply costs incurred.

Algoma Power and FortisBC Inc. do not require an explicit adjustment to normalize for supply cost prices per kWh, however in both cases price normalization is implicitly accomplished through application of their respective mechanisms. With respect to Algoma Power and other Ontario electricity distributors, the discrete receipt and tracking of supply costs and supply revenues allows for the two totals to be compared directly, with resulting variances entered into Accounts 1588/1589 for disposition to ratepayers.[10] With respect to FortisBC Inc., the full cost variance of energy supply costs is booked to the Flow-through Deferral Account alongside variances in revenues driven by billing determinant variances; implicitly inclusive of revenues notionally dedicated to recover supply costs. No reconciliation between the two is required, as it is understood that customers will ultimately bear the actual cost of energy supply costs, and will also bear the risk/reward of billing determinant-driven variances in revenue. In both instances,

[10] Comparable treatment is applied to transmission charges and other upstream charges associated with energy supply

customers pay the actual cost of energy supply without requiring an explicit normalization of $/kWh energy supply costs paid by the utility.

3.3. Demand Cost Normalization

The following table summarizes the manner through which each of the Main Peer Group conduct demand cost normalization as part of their supply cost mechanisms:

Table 6: Demand Cost Normalization Comparison

Utility	Details
Newfoundland Power	Newfoundland Power conducts demand normalization through the Demand Management Incentive Account. Specifically, Newfoundland Power converts both forecast and actual Demand Cost billed by Newfoundland and Labrador Hydro into a ¢/kWh value based on actual normalized kWh purchases. The difference between forecast and actual demand ¢/kWh is multiplied by actual kWh purchases, to determine the appropriate entry to the Demand Management Incentive Account (prior to incorporation of the risk/reward incentive amount).
Nova Scotia Power	Nova Scotia Power does not complete explicit demand normalization. Rather, any variance in demand charges paid will be incorporated into broader variances in Actual Fuel Costs, which are subsequently trued-up through the Fuel Adjustment Mechanism.
Maritime Electric	Maritime Electric does not complete explicit demand normalization. Rather, any variance in demand charges paid will be incorporated into broader variances in Actual Energy Supply Costs, which are subsequently trued-up through the Energy Cost Adjustment Mechanism.
Algoma Power	Algoma Power does not complete explicit demand normalization. Rather, any variance in demand charges paid will be incorporated into costs booked to Algoma Power's supply cost accounts (including accounts dedicated to transmission costs, which are billed on the basis of monthly peak demand). All variances between costs and revenues in these accounts are subsequently cleared to customers.
ATCO Electric	Demand cost normalization is not required, as customer billing is completed by third-party energy retailers; relieving the distribution utility of the need to manage supply revenues and costs.
FortisAlberta	Demand cost normalization is not required, as customer billing is completed by third-party energy retailers; relieving the distribution utility of the need to manage supply revenues and costs.
FortisBC Inc.	FortisBC Inc. does not complete explicit demand cost normalization. Rather, any variance in demand charges paid will be incorporated into costs booked to the Flow-through Deferral Account, and will subsequently be cleared to customers.

All of the utilities within the Main Peer Group[11] achieve the same end of full passthrough of actual demand costs to customers, however only Newfoundland Power employs an explicit normalization of demand charges separate and apart from broader supply cost mechanisms. Under Newfoundland Power's current construct, this separation appears to exist for two reasons. First, the Energy Supply Cost Variance Account calculation relies on the 2nd block wholesale ¢/kWh rate of Newfoundland and Labrador Hydro in order to complete energy price normalization and ensure customers pay the actual cost of energy per kWh. The cost of demand charges are not included in Newfoundland and Labrador Hydro's wholesale ¢/kWh rates, and as such the Energy Supply Cost Variance calculation does not account for variances in demand and demand charges. Second, Newfoundland Power's Demand Management Incentive is explicitly tied to demand (kW), as opposed to supply costs as a whole. The separate adjustment of demand charges is expected to be conducive to the separate and transparent implementation of this incentive mechanism.

3.4. Revenue Decoupling

The table below demonstrates the degree to which each of the utilities in the Main Peer Group incorporate revenue decoupling into their rate-making constructs, defined as the separation of cost recovery from non-weather-related billing determinant variances:

Table 7: Revenue Decoupling Comparison

Utility	Details
Newfoundland Power	Newfoundland Power bears the revenue risk/reward of non-weather-related billing determinant variances.
Nova Scotia Power	Nova Scotia Power bears the revenue risk/reward of non-weather-related billing determinant variances.
Maritime Electric	Maritime Electric bears the revenue risk/reward of non-weather-related billing determinant variances.
Algoma Power[12]	Like all Ontario electricity distributors, Algoma Power has transitioned to a fully fixed charge for residential customers, which can be viewed as partial revenue decoupling. Algoma Power continues to bear the revenue risk/reward of non-weather-related billing determinant variances (i.e. customer count for residential customers, and customer count and demand or consumption for non-residential)
ATCO Electric	ATCO Electric bears the revenue risk/reward of non-weather-related billing determinant variances.
FortisAlberta	FortisAlberta bears the revenue risk/reward of non-weather-related billing determinant variances.

[11] With the exception of ATCO Electric and FortisAlberta, which does not require a supply cost mechanism
[12] EB-2012-0410, Board Policy: A New Distribution Rate Design for Residential Electricity Customers, April 2, 2015

Utility	Details
FortisBC Inc.	FortisBC Inc. operates under full revenue decoupling, with revenues trued-up through the Flow-through Deferral Account alongside some depreciation expense, insurance premiums, income and property taxes, and certain forecast operations and maintenance expense.

Revenue decoupling is not the norm amongst the Main Peer Group, with only Algoma Power (as a proxy for all Ontario electricity distributors) employing partial revenue decoupling, and FortisBC Inc. employing full revenue decoupling.

With respect to Algoma Power, the Ontario Energy Board issued direction to all Ontario electricity distributors in 2015 to begin transitioning residential customers toward a rate structure under which distribution charges were collected entirely through fixed monthly charges, with no corresponding energy or demand-based billing determinant. This revenue decoupling approach remains partial however, as transmission charges, energy charges, and rate riders for recovery of various regulatory balances remain billed to residential customers on the basis of energy (kWh) billing determinants, and most other customer classes continue to be billed distribution charges on the basis of both fixed charges and energy or demand billing determinants.

With respect to FortisBC Inc., it is a risk/reward policy choice of the British Columbia Utilities Commission to allow the utility to operate under a revenue decoupling rate-setting model. FortisBC Inc. is required, via the Flow-through Deferral Account, to return any incremental revenues to customers driven by incremental billing determinants, while receiving the benefit of recoveries from customers when revenues are lower than forecast. Further, the Flow-through Deferral Account, which is not FortisBC Inc.'s only deferral or variance account, captures other notable expenditure variances for items such as Clean Growth Project depreciation expense, and some operating and maintenance expenditures such as insurance premiums and EV charging station operating costs. This relatively extensive approach to revenue decoupling sets FortisBC Inc. apart from its peers in the Main Peer Group.

3.5. Supply Cost Incentive Mechanisms

The following table summarizes incentive mechanisms specific to supply costs amongst the Main Peer Group:

Table 8: Supply Cost Incentive Comparison

Utility	Details
Newfoundland Power	Newfoundland Power is subject to a Demand Management Incentive which up until 2025 was equal to a threshold of +/- 1% of test year wholesale demand costs. Any variance up to the threshold was borne by the utility, either as incremental earnings (in the event of lower demand costs than forecast) or reduced earnings (in the

Utility	Details
	event of higher demand costs than forecast). As of the 2025 test year, the threshold for this incentive has been revised to +/- $500,000 CAD.
Nova Scotia Power[13]	Beginning in 2009 Nova Scotia Power had in place an incentive mechanism whereby the utility retained 10% of the variance between forecast and actual fuel costs as an increase to earnings (where fuel costs were lower than forecast) or decrease to earnings (where fuel costs were higher than forecast). The incentive mechanism was subject to a cap of $5 million CAD. This incentive mechanism was discontinued effective 2017.
Maritime Electric	Maritime Electric does not have an incentive bearing risk or reward associated with energy supply costs.
Algoma Power	Algoma Power does not have an incentive bearing risk or reward associated with energy supply costs.
ATCO Electric	ATCO Electric does not bill customers or manage energy supply costs, and as such does not have an incentive bearing risk or reward associated with energy supply costs.
FortisAlberta	FortisAlberta does not bill customers or manage energy supply costs, and as such does not have an incentive bearing risk or reward associated with energy supply costs.
FortisBC Inc.[14]	FortisBC Inc. proposed a Power Supply Incentive in its 2020 to 2024 Multi-year Rate Plan, wherein the first $7.5 million of savings in power purchase expenses relative to forecast would be exclusively to the benefit of customers, while any reduction beyond this amount would be allocated 90% to customers and 10% to the utility as an incentive. The British Columbia Utilities Commission denied this request.

Newfoundland Power's Demand Management Incentive is atypical across the Main Peer Group, with no other utility currently implementing an incentive mechanism for management of supply costs. While one such mechanism existed amongst the Main Peer Group in the past, the current paradigm appears to treat energy supply costs as pure passthrough items, wherein customers bear the actual cost of supplied energy regardless of whether it is higher or lower than forecast.

Though active incentives for portfolio or cost management in energy supply are not the norm, economic regulators continue to maintain focus on utilities' prudent management of the supply cost function on behalf of customers.

In justifying its proposal for a Power Supply Incentive, FortisBC Inc. submitted that the incentive would "…encourage [FortisBC Inc.] to increase efficiency, reduce costs, and enhance performance management

[13] Nova Scotia Power, 2020–2022 Rate Stability Plan Application
[14] British Columbia Utilities Commission, Decision and Orders G-165-20 and G-166-20 on FortisBC Inc. 2020–2024 MRP, April 2020

with respect to its power supply portfolio management."[15] In denying FortisBC Inc.'s request, the British Columbia Utilities Commission agreed with intervenors that ongoing active management of power supply costs was already a priority of FortisBC Inc.; representing normal stewardship of the utility business.[16]

In its Decision regarding Nova Scotia Power's 2020-2021 Fuel Adjustment Mechanism Audit, the Nova Scotia Energy Board[17] issued a disallowance of supply cost recovery of approximately $2 million. The Nova Scotia Energy Board found that Nova Scotia Power's actions were imprudent, and contributed to an oil spill at the utility's Tuft's Cove generating facility resulting in $157,921 in re-dispatching costs and approximately $1.8 million in unnecessarily uninsured operating costs incurred by Nova Scotia Power as a result of the incident.[18] The Nova Scotia Energy Board's Decision highlights that aside from explicit incentives relating to the management of supply costs, all utilities are expected to exercise prudence in the process of managing supply costs in the standard course of operating a utility business.

3.6. Weather Normalization of Revenue & Methodological Assessment

As noted in Section 2, a Weather Normalization Peer Group was prepared for the purpose of examining weather normalization to ensure the capture of relevant regulatory practices in Canada, even where such practices may be implemented within utilities which are not directly comparable to Newfoundland Power (e.g. natural gas utilities). Weather normalization was assessed across jurisdictions in two ways within this Review; the degree to which (and mechanisms through which) utilities do or do not normalize revenues for weather, and a general review of weather normalization methodologies.

<u>Weather Normalization of Revenue</u>

The table below analyzes mechanisms through which utilities do or do not normalize revenues for weather variation relative to weather-normal. For clarity, all of the utilities analyzed normalize for weather with respect to supply costs, as weather-driven variances in supply costs will be recovered on a passthrough basis consistent with broader practices for recovery of supply costs. This section presents the degree to which the utilities analyzed normalize revenues, particularly non-supply related revenues, for variances in weather. As a matter of context, for electric utilities the penetration of electric heating by provincial jurisdiction is also presented, as the prevalence of electric heating significantly impacts the degree to which an electric utility's revenues are sensitive to weather variances. No similar information is presented

[15] British Columbia Utilities Commission, FortisBC Inc. 2020–2024 Multi-Year Rate Plan Application, BCUC Filing B-1, Page C-167

[16] British Columbia Utilities Commission, Decision and Orders G-165-20 and G-166-20 on FortisBC Inc. 2020–2024 MRP, April 2020, Pages 164-165

[17] Previously the Nova Scotia Utility and Review Board

[18] Nova Scotia Utility and Review Board, 2020–2021 Fuel Adjustment Mechanism (FAM) Audit Decision, 2024 NSUARB 34, pages 5-6

for gas utilities included within the Weather Normalization Peer Group, as all natural gas utilities are assumed to have revenue sensitivity to weather.

Table 9: Weather Normalization of Revenue Comparison

Utility	Details	Jurisdictional Electric Heat Penetration[19] (Electric Utilities Only)
Newfoundland Power	To complete the Degree Day Normalization portion of the Weather Normalization Reserve, Newfoundland Power multiplies the coefficient of each weather variable by the variance in that weather variable relative to normal. The three variables relied upon are Heating Degree Days ("HDD"), Cooling Degree Days ("CDD") and wind speed. Newfoundland Power relies on the standard balance point for HDD and CDD of 18°C.	85%
Nova Scotia Power[20]	Nova Scotia Power does not have a weather normalization mechanism applicable to its revenues, and as such the utility wears the revenue risk and reward of weather-driven variances in billing determinants.	65%
Maritime Electric[21]	Maritime Electric employs a Weather Normalization Reserve which provides revenue adjustments accounting for the difference between actual revenues and weather-normal revenues. In 2024 Maritime Electric submitted a Comprehensive Review of the Weather Normalization Reserve Account proposing to modify the mechanism to a) adjust the balance point for deriving HDD from 18°C to 12°C and b) put in place a sales ratchet to limit debits and credits in certain circumstances. Specifically, where HDD and Sales vary in the same direction (i.e. both below or both above forecast), the Weather Normalization Reserve would continue to function as anticipated; crediting or debiting customers. However, where HDD and Sales move in opposite directions (i.e. sales are above forecast despite lower HDD, or sales are below forecast despite higher HDD) no debit or credit would be issued. Maritime provides rationale for the proposed change, and suggests it is in a period of transition due to a substantial increase in residential electric heating. A regulatory Decision regarding Maritime's proposed changes to the Weather Normalization Reserve remains pending as of the date this research was completed.	66%
Algoma Power	Algoma Power does not normalize revenues for variations in weather. Algoma Power's sensitivity to weather variances is reduced due to the	26%

[19] Statistics Canada. Table 38-10-0286-01, Primary heating systems and type of energy. Based on 2023 statistics by Province; may not reflect individual utilities with precision

[20] Nova Scotia Energy Board – Nova Scotia Power, M12349, 2025 Load Forecast Report

[21] Maritime Electric Company Limited: Comprehensive Review of the Weather Normalization Mechanism and Reserve, September 27, 2024

Utility	Details	Jurisdictional Electric Heat Penetration[19] (Electric Utilities Only)
	Ontario Energy Board policy which requires residential distribution rates to be charged via a fixed monthly charge with no variable billing determinant.	
ATCO Electric	ATCO Electric does not normalize revenues for variations in weather.	14%
FortisAlberta	FortisAlberta does not normalize revenues for variations in weather.	14%
FortisBC Inc.	While FortisBC Inc. does not explicitly normalize revenues for weather, all revenues are subject to variance true-up via the utility's Flow-through Deferral Account. This treatment normalizes for all variances in revenue, including weather-driven variances.	52%
Energir[22]	Energir's revenues are normalized for weather based on a combination of temperature and wind-speed, via the temperature and wind rate stabilization adjustment recorded in the Deferred Expense Account (CFR - Stabilisation tarifaire de la température et du vent). Net changes in this account balance are amortized and recovered from customers.	N/A
ATCO Gas[23]	ATCO Gas implements a Weather Deferral Account via its Rider W, applicable to its North and South service territories, respectively. Entries to the Weather Deferral Account are calculated monthly based on variations between actual per customer consumption and weather-normal per customer consumption. Where the total balance for either the North or South service territories exceeds $7 million, ATCO Gas will initiate disposition of the variance to customers via a 12 month rider. At the time of approval of the Weather Deferral Account, $7 million represented a variance of approximately 10% in normalized weather forecasts.	N/A
AltaGas[24]	AltaGas (now APEX Utilities) does not have an explicit weather normalization account or rate rider, however the utility operates under a revenue-per-customer cap rate-setting framework such that revenues are largely decoupled from weather-driven billing determinant variances. Financial statements and return-on-equity are however presented on a weather normalized basis.	N/A
Enbridge Gas[25]	While Enbridge Gas does not currently have an explicit weather-normalization mechanism, both its legacy entities (Enbridge Gas	N/A

[22] Régie – Énergir 2025–2026 cause tarifaire, R-4287-2024; Régie – Énergir 2025–2026 cause tarifaire, R-4287-2024, RÉPONSE D'ÉNERGIR, S.E.C. (ÉNERGIR) À LA DEMANDE DE RENSEIGNEMENTS NO 2 DE l'AHQ-ARQ; Régie – Énergir Cause tarifaire 2024-2025, R-4257-2024

[23] AUC Decision 23643-D01-2018, August 23, 2018; AUC Decision 2014-263 – ATCO Gas North 2014 Weather Deferral Account Rider W

[24] AUC Decision 27388-D01-2023, October 4, 2023; Financial Statements: APEX Utilities Inc. for the nine months ended September 30, 2022

[25] Ontario Energy Board, EB-2025-0155, Application, Exhibit C, Tab 2, Schedule 17; Ontario Energy Board, EB-2025-0064, Application, Exhibit 8, Tab 2, Schedule 3; Ontario Energy Board, EB-2022-0200 Application, Exhibit 3, Tab 2, Schedule 3

Utility	Details	Jurisdictional Electric Heat Penetration[19] (Electric Utilities Only)
	Distribution Inc. and Union Gas Limited) relied upon differing Normalized Average Use true-up mechanisms, which recorded variances driven by differences in the average use per customer relative to historical averages. Enbridge Gas has currently proposed a Straight Fixed Variable with Demand rate design approach in Phase 3 of its rebasing application addressing rate design and other matters. If approved, this approach would mitigate Enbridge Gas's exposure to weather-driven revenue variance relative to present day.	
Pacific Northern Gas Ltd.[26]	Pacific Northern Gas Ltd. normalizes revenues for both weather and non-weather variances in consumption amongst residential and small commercial customers through its Revenue Stabilization Adjustment Mechanism, which implements rolling credits or debits to customers via rate riders. While this mechanism encompassing the impacts of weather-driven variances in consumption, it is not explicitly derived on the basis of weather-related calculations.	N/A
FortisBC Energy Inc.[27]	While FortisBC Energy Inc. does not explicitly normalize revenues for weather, the utility uses a combination of the Flow-through Deferral Account (as utilized by FortisBC Inc.) and a Revenue Stabilization and Adjustment Mechanism, which specifically normalizes revenues for per customer consumption in the residential and commercial customer classes. Variations in customer count and industrial consumption are captured in the Flow-through Deferral Account. Taken together, this treatment normalizes for all variances in revenue, including weather-driven variances.	N/A

While there is significant variance amongst the 13 utilities identified above, some trends can be observed. Of the 13, 7 effectively normalize revenues for weather, 3 have partial revenue decoupling mechanism which limit their sensitivity to weather-driven revenue variances, and 3 do not normalize revenues for weather.

The list of utilities above that normalize revenues for weather includes Newfoundland Power, Maritime Electric, FortisBC Inc., Energir, ATCO Gas, Pacific Northern Gas Ltd., and FortisBC Energy Inc. As previously described, the total revenues of FortisBC Inc. are subject to a Flow-through Deferral Account which will inherently capture any weather-driven variances in revenue. This same mechanism, with additional

[26] BCUC Order G-339-23 RE: Pacific Northern Gas Ltd. 2023-2024 Revenue Requirement Application, December 11, 2023; BCUC – Pacific Northern Gas Ltd.: Application for Acceptance of 2024 Consolidated Resource Plan, June 28, 2024

[27] BCUC Decision G-86-15 / FortisBC Energy 2015 Annual Review, May 27, 2015; FortisBC Energy Inc. Management Discussion & Analysis for the year ended December 31, 2024; FortisBC Energy Inc.: Application for Approval of a Certificate of Public Convenience and Necessity (CPCN) for the Okanagan Capacity Upgrade (OCU) Project (Application), January 13, 2021, pages 21-22

nuance for residential and commercial customers, applies to FortisBC Energy Inc.'s gas distribution business, with the same outcome of normalizing weather-driven variances in revenue. Similarly, while Pacific Northern Gas Ltd.'s Revenue Stabilization Adjustment Mechanism is not explicitly calculated on the basis of weather variance, its effect is to normalize revenues for variances in weather. The remaining 4 utilities (i.e. Newfoundland Power, Maritime Electric, Energir, ATCO Gas) rely on explicit mechanisms which normalize revenues for weather. Of note, these 4 utilities are sensitive to temperature driven load.

The three utilities with partial revenue decoupling mechanisms limiting their sensitivity to weather-driven revenue variances are Algoma Power, AltaGas and Enbridge Gas. Like all of the utilities in the Main Peer Group, Algoma Power's energy supply costs are subject to comprehensive passthrough treatment; providing a baseline of protection from weather variance. Algoma Power has additional protection from weather-driven revenue variances, as all residential customers in Ontario were transitioned to fully fixed distribution charges in the 2010's and early 2020's. While AltaGas does not have an explicit weather normalization adjustment, the utility operates under a revenue cap per customer framework, which effectively normalizes distribution revenues for variations in energy consumption; substantially limiting the impacts of weather on utility revenues and earnings. Finally, while Enbridge Gas does not presently normalize revenues for weather, the utility has consistently implemented a Normalized Average Use methodology to adjust revenues from residential and small commercial customers for weather; substantially reducing the impact of weather on utility revenues.

Finally, Nova Scotia Power, ATCO Electric and FortisAlberta do not normalize revenues for weather variances, and do not have revenue decoupling mechanisms comparable to those described above. With respect to the latter two, it is expected such normalization has been deemed unnecessary due to their relatively low exposure to weather-driven revenue variances.

Weather Normalization Methodologies

The table presented below summarizes the core assumptions of each utility[28] analyzed for weather normalization, regardless of whether the utility does or does not ultimately use its weather normalization techniques to adjust revenues. The analysis provided focuses on the weather variables used in weather normalization, the time-based data relied upon to establish weather normal averages, and the temperature balance point for HDD and CDD where applicable.

Table 10: Weather Normalization Methodology Comparison

Utility	Weather Variables	Average to Established Weather Normal	Temperature Balance Point (HDD/CDD)
Newfoundland Power	HDD, CDD, Wind speed	30 year average	18°C

[28] Algoma Power, ATCO Electric, FortisAlberta, and FortisBC Inc. have been excluded from this analysis, as utilities that are not weather-sensitive, and do not employ explicit weather normalization methodologies

Utility	Weather Variables	Average to Established Weather Normal	Temperature Balance Point (HDD/CDD)
Nova Scotia Power	HDD, CDD, Wind speed. Cloud cover analyzed but dismissed as a variable	10 year average, with 30 year data used to inform a long-term warming trend regression	18°C
Maritime Electric	HDD. CDD analyzed but dismissed as a variable	10 year average	12°C
Energir	HDD, Wind speed	30 year average	13°C
ATCO Gas	Average of daily temperature by month, by weather zone, with weather zone-specific maximum temperature for adjustment purposes	10 year average	N/A Max temperatures range from ~14-16°C depending on weather zone
AltaGas	HDD	20 year rolling average	15°C
Enbridge Gas	HDD	50/50 Hybrid of 10 year moving average and 20 year trend for Central Zone, 10 year moving average for other zones	15°C
Pacific Northern Gas Ltd.	Consumption forecasting is based on application of forecast use per account multiplied by forecast customer count. Use per account relies on Navigator Energy and Emissions Simulation Suite, which incorporates weather parameters	Unknown; varies based on inputs to Navigator model	18°C
FortisBC Energy Inc.	Daily demand and local mean daily temperature are compared on a per customer basis to establish a linear regression. The process separates weather sensitive consumption from baseload, and determines the slope relationship between temperature and consumption to determine average use per customer	2 years of temperature and consumption data. Use per customer is averaged across 3 years	N/A

With respect to weather variables used, HDD presents itself as the most consistently relied upon metric to measure weather for the purpose of determining weather-normal; relied upon by 6 of the 9 utilities analyzed (i.e. Newfoundland Power, Nova Scotia Power, Maritime Electric, Energir, AltaGas, Enbridge Gas). 3 of the 6 also incorporate wind speed into their weather-normal calculations (i.e. Newfoundland Power, Nova Scotia Power, Energir). CDD are actively used only by Newfoundland Power and Nova Scotia

Power within the utilities analyzed, with Maritime Electric having tested this weather variable for use and determined it to be immaterial.

In contrast, the methodologies used by ATCO Gas and FortisBC Energy Inc. rely on average temperatures, with the former relying on the average of daily averages by month, and the latter relying on mean daily temperatures. While the use of average temperature differs in approach from relying on HDD or CDD, ATCO Gas's methodology incorporates temperature maximums which are expected to have a similar effect as HDD.[29] The weather variables relied upon by Pacific Northern Gas Ltd. are included within its forecasting software, and could not be retrieved to inform this research.

With respect to the amount of data relied upon to establish weather normal, measured in number of years, considerable variance is observed across the utilities analyzed. The use of a 10 year average to establish weather-normal emerges as a minimum length of time where basic averaging is relied upon to establish weather-normal. While FortisBC Energy relies on only two years of data, the objective of its methodology is to determine average use per customer for load forecasting purposes, and is not explicitly aimed at establishing weather-normal. Conversely, Newfoundland Power and Energir rely on 30 year averages to establish weather normal, AltaGas relies on a 20 year average, Enbridge Gas incorporates a 20 year average alongside other methodologies on a blended basis, and Nova Scotia Power relies on a 10 year average with 30 years of data to inform a long-term warming trend.

Finally, with respect to temperature balance points 3 of the 7 utilities relying on HDD[30] use the historical standard of 18°C; Newfoundland Power, Nova Scotia Power and Pacific Northern Gas Ltd. Of note, for both Enbridge Gas and Maritime Electric the transition away from 18°C for the purpose of establishing HDD is a relatively new development. Enbridge Gas first proposed a change to 15°C in its 2024 rebasing application, filed October of 2022, while adjudication of Maritime's HDD balance point change to 12°C is ongoing as of the completion of this research.

3.7. Hydrological Normalization

As noted in Section 2, a Hydrological Adjustment Peer Group was utilized for the purpose of examining hydrological normalization to ensure the capture of relevant regulatory practices in Canada, even where such practices may be implemented within utilities which are not directly comparable to Newfoundland Power (e.g. Crown Corporations). The mechanisms applicable to each utility are summarized in the table below:

[29] Any temperature above the HDD balance point temperature registers a value of 0. In a similar manner, the average temperature relied upon by ATCO Gas cannot exceed the maximum per weather zone specified. In both instances temperatures in excess of the balance point or maximum temperature register the same as if the value were equal to the balance point or maximum temperature

[30] While Pacific Northern Gas does not rely on HDD in the same manner as the other 6 HDD-reliant utilities, it does identify 18°C as the balance point relied upon for heating load analysis

Table 11: Hydrological Adjustment Comparison

Utility	Details
Newfoundland Power	As part of its Weather Normalization Reserve, Newfoundland Power calculates a Hydro Production Equalization Transfer, which calculates the impact on energy costs resulting from variances in hydraulic flows into its hydroelectric generation facilities. The Hydro Production Equalization Transfer accounts for the reality that any reduction to hydroelectric generation within Newfoundland Power's owned generation facilities resulting from lower hydraulic flows will necessitate incremental energy supply purchases, and vice versa. Newfoundland Power calculates the variance in monthly hydraulic flows relative to average based on hydraulic studies completed approximately every 5 years.
Nova Scotia Power[31]	The Fuel Adjustment Mechanism accounts for variations in power purchases as well as variations in fuel quantities and costs. The fixed cost of hydroelectric generating units are recovered via Cost of Service, and as such while the notional revenues intended to recover the cost of these facilities may vary with customer consumption, they largely do not vary with production. To the degree hydrological flows and thus hydroelectric generating output are below forecast, the difference must be made up with incremental fuel or power purchase costs, which will be subject to true-up via the Fuel Adjustment Mechanism. For this reason, an additional hydrological adjustment would be redundant. Base energy cost forecasts are informed by hydrological flows, and forecast hydrological flows are included in Nova Scotia Power's forecasting system Plexos. Hydrological flow forecasts are based on a rolling 23-month average specific to the generating unit.
FortisBC Inc.[32]	FortisBC Inc. owns 4 hydroelectric generation facilities, however these are controlled and dispatched by BC Hydro in exchange for entitlement purchases. These purchases are included with FortisBC Inc.'s power supply expense, and are thus subject to the Flow-through Deferral Account. As such, no additional adjustment for hydrological flows is required given the Flow-through Deferral Account trues up all power supply expense variances.
Newfoundland and Labrador Hydro[33]	Newfoundland and Labrador Hydro historically relied on a Rate Stabilization Plan for the purpose of capturing variances, which incorporated an adjustment for Hydraulic Variance to keep Newfoundland and Labrador Hydro financially whole where lower hydraulic flows resulted in incremental fuel costs associated with Holyrood generating station. In 2021 the Rate Stabilization Plan was replaced by the Supply Cost Variance Deferral Account which, among other items, captures variances in both Holyrood fuel costs, other supply costs, and variances in revenue due to load

[31] Nova Scotia Utility and Review Board (NSUARB) – Fuel Adjustment Mechanism (FAM) Overview and FAQ;
[32] British Columbia Utilities Commission (BCUC) – Order G-340-23: FortisBC Inc. 2024 Annual Review of Rates – Decision and Order, December 12, 2023
[33] Newfoundland & Labrador Board of Commissioners of Public Utilities (PUB) – Implementation of the Rate Mitigation Plan – NL Hydro Filing, October 22, 2024; Newfoundland & Labrador Board of Commissioners of Public Utilities (PUB) – NL Hydro – Supply Cost Variance Deferral Account Report (September 2025), filed October 23, 2025; Newfoundland & Labrador Board of Commissioners of Public Utilities (PUB) – NL Hydro – Application for the Recovery of Deferred 2024 Isolated Systems Supply Costs, March 12, 2025; Newfoundland & Labrador Hydro – Schedule of Rates, Rules and Regulations, August 2024

Utility	Details
	variance. In light of these adjustments, a Hydraulic Production Variance adjustment is no longer required for Newfoundland and Labrador Hydro, as other items in the Supply Cost Variance Deferral Account capture all variances in costs which would be anticipated to be incurred as a result of variation in hydrological flows supporting hydro-electric generation.
New Brunswick Power[34]	The cost of New Brunswick Power's hydroelectric generation facilities are included within rate base and operating expenditures underpinning revenue requirement and rates. New Brunswick Power has an Energy Supply Cost Variance account which tracks and clears the difference between actual and budgeted monthly supply costs, subject to a $5 million incentive threshold, for energy sold to in-province customers. New Brunswick Power also has an Electricity Sales and Margin Variance Account, which is calculated as the sum of out-of-province gross margin variance, load-price variance, and load-volume variance. This too is subject to a $5 million incentive threshold. Between these two mechanisms, variances in both costs and revenues are trued-up for New Brunswick Power, obviating the need for an explicit Hydrological Adjustment.
Ontario Power Generation[35]	Ontario Power Generation has a Hydroelectric Water Conditions Variance Account, which captures variances resulting from actual production amounts at hydro facilities relative to reference production values, based on changes in actual water conditions. This is completed by entering actual flow values into the production forecast models used to calculate the approved production forecast. The comparison is based on monthly averages, and for older facilities relies on historical 2014/2015 values, while newer facilities (21 of the 48) rely on computer models to forecast production. In addition, Ontario Power Generation has a Surplus Baseload Generation Variance Account to compensate the utility for foregone generation in instances where hydroelectric facilities are forced to spill water due to demand constraints limiting the system's ability to receive incremental generation. Water conveyance restraints, production capability constraints (e.g. unit outage), and contractual obligations are excluded from this calculation.
Manitoba Hydro[36]	Manitoba Hydro is highly sensitive to variations in hydrological flows, however it does not have a distinct deferral, variance or true-up mechanism related to these flows. The utility generates substantial revenues from ex-Provincial sales of electricity, principally from hydro-electric generation. A severe drought in 2021 pushed the utility from projected net income of $177 million, to a loss of $190 million. Manitoba filed an interim rate application in the fall of 2021 to mitigate these losses, however the application did not explicitly create or propose a mechanism which would mathematically make-up prior losses. Rather the application sought a balance between rate increases and the impact of the loss, requesting a 5.0% increase to rates. The Manitoba Public Utilities Board approved a

[34] New Brunswick Energy & Utilities Board (NBEUB) – NB Power 2026–2027 General Rate Application – Main Evidence: Variance Treatment

[35] Ontario Energy Board, EB-2013-0321, Ontario Power Generation Payment Amounts Application, September 27, 2013; Ontario Energy Board, EB-2020-0290, Revised Final Draft Rate Order for Payment Amounts, January 19, 2022; Ontario Energy Board, EB-2023-0336, Application for Market Renewal Program, December 13, 2023

[36] Manitoba Public Utilities Board (MPUB) – Order 9-22, 2022

Utility	Details
	3.6% increase, which was subsequently challenged with a Motion to Vary which was denied. Substantially higher-than-average hydrological flows in 2022 subsequently made up for the 2021 loss. Manitoba previously relied on a 100-year data set to forecast hydrological flows, but moved to a 40-year data set submitting that this more accurately measures recent weather trends. Manitoba Hydro still relies on its 100+ years of historical data for the purpose of long-term planning and understanding extreme weather.

Amongst the utilities analyzed, only Newfoundland Power and Ontario Power Generation have in place active hydrological adjustment mechanisms to adjust revenues for hydraulic flow. The two mechanisms bear similarities, with both approaches relying on forecasting models which translate the difference between actual and forecast hydrological flows into produced power at their respective hydroelectric facilities. While Ontario Power Generation relies on computer models to forecast hydraulic flows for newer facilities, 27 of its 48 facilities continue to rely on average observed hydraulic flows in 2014/2015. Newfoundland Power in comparison updates benchmark hydraulic flows with greater frequency of approximately every 5 years.

The most common arrangement observed amongst the peer group is the use of broader true-up mechanisms which obviate the need for a specific hydrological adjustment mechanism, with Nova Scotia Power, FortisBC Inc., Newfoundland and Labrador Hydro, and New Brunswick Power all taking this approach. While each true-up mechanism uniquely reflects the circumstances of the utility in question, in all cases an explicit hydrological adjustment would be redundant. While New Brunswick Power has both cost and revenue variance incentives in place, these incentives appear specifically responsive to the context of New Brunswick Power's scale and business as a vertically-integrated utility. These incentive mechanisms may be more appropriately described as limitations to the full revenue coupling which would otherwise occur in their absence, as opposed to active incentives.

Finally, Manitoba Hydro is more exposed to variations in hydraulic flows than peers. While Manitoba Hydro is a regulated Crown Corporation and does not have formal, pre-cast risk mechanisms specific to hydraulic flows, recent history demonstrates that the Provincial Government and Manitoba Public Utilities Board will act, within reason, to assist the utility in managing unusually large variations in hydraulic flows and revenues.

4. Comparison of Peer Utilities to Newfoundland Power

In review of the jurisdictional scan provided above across key categories impacting the supply cost mechanisms of utilities across Canada, the supply cost mechanisms of Newfoundland Power demonstrate broad consistency with those of other utilities, while demonstrating discrete points of divergence.

Areas of consistency between Newfoundland Power and the practices of other utilities analyzed can be summarized as follows:

- **Passthrough Outcomes:** Most notably, the combined Supply Cost Mechanisms of Newfoundland Power achieve the full passthrough of actual supply costs to customers; an outcome which is common to all of the Main Peer Group utilities analyzed in this Review. The sole exception to the full passthrough of costs is Newfoundland Power's Demand Management Incentive.

- **Energy Price Normalization:** Newfoundland Power's approach to the normalization of price paid for energy supply is consistent with the calculations employed by other utilities which require this calculation as part of their supply cost mechanisms; namely Nova Scotia Power and Maritime Electric. While others such as Algoma Power and FortisBC Inc. do not explicitly adjust for price in truing up supply costs, this is a result of the structural make-up of their broader supply cost mechanisms, and is not reflective of any inconsistency with the principles relied upon by Newfoundland Power.

- **Revenue Decoupling:** Newfoundland Power is firmly in the majority of the Main Peer Group analyzed in that it has not instituted full revenue decoupling, and it remains exposed to the risk/reward of non-weather variations in billing determinants. FortisBC Inc. stands apart relative to the other utilities analyzed as the only member of the Main Peer Group subject to a total revenue true-up via its Flow-through Deferral Account. Algoma Power and other Ontario electricity distributors have partial revenue decoupling via the transition of all residential customers to a fully fixed distribution charge, however the utility remains subject to the risk/reward of variations in customer count, as well as variance in demand or energy billing determinants for non-residential customers.

- **Weather Normalization of Revenues:** Newfoundland Power is in the majority of the utilities analyzed with respect to its normalization of revenues for weather, despite variances amongst peers' specific approach to normalization. Among the utilities analyzed, over half (7 of 13) normalize revenues for weather, while another 3 out of the 13 have partial revenue decoupling mechanisms which limit the degree to which their revenues are impacted by weather variances. Of the 3 utilities remaining, 2 of them have limited sensitivity to weather as electric utilities in Alberta where electric heating is limited.

In other areas of analysis there is a split amongst the peer utilities analyzed, such that the practices of Newfoundland Power are aligned with some, but not with others. These areas of mixed consistency across the peer utilities analyzed are largely centered around weather and hydrological adjustments, and can be summarized as follows:

- **Weather Normalization Methodologies:** Across the breadth of inputs and calculations within utility approaches to determine weather-normal there is considerable variation with respect to overall method, weather variables used, amount of data relied upon for averages (measured in number of years), and the temperature balance point for HDD and CDD. The use of HDD by Newfoundland Power is common amongst those analyzed, with 6 of the 9 utilities relying on this variable. However there is more variation amongst utilities with respect to the number of years of data relied upon to establish weather normal, and the temperature balance point used to establish HDD. Of note, two of the utilities which use HDD in determining weather-normal but do not use a temperature balance point of 18°C, have made or are making this transition only recently (i.e. Enbridge Gas and Maritime Electric).

- **Hydrological Normalization:** Newfoundland Power is in the majority of the utilities analyzed in truing-up costs and/or revenues to reflect variances in hydrological flows relative to normal. The mechanics employed by Newfoundland Power appear consistent with the principles and practices employed by Ontario Power Generation in this regard; the only other utility to have an active and separate adjustment for hydrological flows. This being said, an incremental 4 utilities in effect achieve the same end through broader passthrough mechanisms which obviate the need for a hydrological adjustment. Only Manitoba Hydro appears directly exposed to the risk/reward of variations from normal hydrological flows without regulated mitigation, however the provincial government and economic regulator have demonstrated a willingness to assist Manitoba Hydro in mitigating significant hydrological shortfalls in recent historical experience.

Areas in which Newfoundland Power is an outlier in its current practices include the following:

- **Demand Cost Normalization:** No other utility analyzed in the Main Peer Group completed the normalization of demand charges through a discrete mechanism separate and apart from broader energy supply costs. Structurally, the separate true-up of demand charges is required for Newfoundland Power as a result of the mathematical underpinning of its Energy Supply Cost Variance calculation, which relies on wholesale power rates (¢/kWh) that are exclusive of demand charge costs. Mathematically, this is not the case in other jurisdictions analyzed, where all supply costs are combined in the calculations to determine total variances in supply costs either as an aggregate dollar amount, or as a calculated cost per kWh. Consolidation of Newfoundland Power's demand normalization calculation would require revision to the calculations underpinning the Energy Supply Cost Variance Account. It may be the case however, that exclusion of demand normalization from other calculations provides greater transparency and tracking of Newfoundland Power Demand Management Incentive, as discussed below.

- **Supply Cost Incentive Mechanisms:** No other utility analyzed in the Main Peer Group has an active incentive mechanism applicable to the management of supply costs. While Nova Scotia Power historically had a mechanism which exposed the utility to the risk/reward of supply costs, this incentive was eliminated nearly a decade ago. As evidenced by the British Columbia Utilities Commission's decision to deny FortisBC Inc.'s request to reinstate a Power Supply Incentive, prudent management of energy supply costs is viewed as 'table stakes' for electric utilities in Canada.

4.1. Comments Regarding Brattle Group Report

In the proceeding to review Newfoundland Power's 2025-2026 General Rate Application the Board engaged the Brattle Group to prepare a *Report on Newfoundland Power's Deferral Accounts*, which was submitted April 24, 2024 ("Brattle Group Report"). Within the Brattle Group Report were 4 recommendations with respect to Newfoundland Power's supply cost mechanisms.

The Brattle Group Report recommendations pertaining to supply cost mechanisms are presented below, with additional comments in light of the research presented in this Review:

1. ***Power Supply Cost Mechanism Coverage:*** *[Newfoundland Power] has a similar amount of coverage for power supply cost recovery mechanisms compared to other investor-owned electric utilities, and the [Revenue Stabilization Account] is an appropriate mechanism for the disposition of account balances related to power supply costs.*
    a. **Comments:** The research included within this Review supports this conclusion and recommendation from the Brattle Group Report.

2. ***Energy Supply Cost Variance Deferral:*** *The Board should redefine the [Energy Supply Cost Variance] deferral to account for both the costs and revenues associated with energy supply. Amending the deferral account to track variance in both revenues and costs will limit the variability in [Newfoundland Power's] [Return on Equity] associated with energy supply and ensure the matching of costs and revenues by both being deferred.*
    a. **Comments:** The research included within this Review does not support a need to redefine the Energy Supply Cost Variance Account to include revenues associated with funding supply costs. The calculations underpinning Newfoundland Power's Energy Supply Cost Variance are consistent, albeit not exact to, those underpinning Nova Scotia Power's Fuel Adjustment Mechanism and Maritime Electric's Energy Cost Adjustment Mechanism. This recommendation of the Brattle Group Report points to the practices of FortisBC Inc. to substantiate the recommended approach. The research presented in this Review demonstrates FortisBC Inc. is operating under a fundamentally different rate-setting construct than Newfoundland Power, and may not be an ideal model for Newfoundland Power to emulate under its very different rate-setting construct.

3. ***Demand Management Incentive Account:*** *[The Brattle Group] recommends that the [Demand Management Incentive] Account should be modified to remove the incentive threshold related to peak demand. The account should still be maintained to capture variance from actual to test year demand costs via the calculation of the Demand-Supply Cost Variance. However, netting off the demand management incentive should no longer be included. If the Board wishes to incentivize reductions in peak demand, incentives to specific demand reduction programs through the existing Conservation and Demand Management Program should be considered instead.*
    a. **Comments:** The research included within this Review supports this recommendation of the Brattle Group, notwithstanding that subsequent to submission of the Brattle Group Report, the Board reduced the threshold on the Demand Management Incentive to a capped amount of $500,000 CAD.

4. ***Weather Normalization Reserve:*** *[The Brattle Group] recommend that the Board require [Newfoundland Power] to file a report as part of its next [General Rate Application] providing a detailed explanation of its Weather Normalization Reserve methodology for both its Degree Days Normalization and Hydrology Production Equalization. Included in this report should be a review of the model utilized to calculate the weather coefficients in both the Degree Days Normalization*

and Hydrology Production Equalization, the appropriateness of the weather variables included in the Degree Days Normalization as compared to other utilities weather normalization practices, the appropriateness of the Hydrology Production Equalization being included in the Weather Normalization Reserve, and the appropriateness of utilizing a Hydrology Production Equalization compared to other utilities' practices of hydroelectric production variation.

a. **Comments:** The research included within this Review is anticipated to aid Newfoundland Power and the Board in assessing the items raised in this area by the Brattle Group. The research presented in this Review indicates the use of a hydrological production adjustment is appropriate, and yields results comparable to those experienced by other utilities with hydroelectric production. This Review also highlights that while Newfoundland Power's weather normalization methodologies are consistent to those of other utilities, there is variation in the specific approaches used by utilities across Canada.

5. Conclusions

As shown in the preceding sections of this Review, the supply cost mechanisms employed by Newfoundland Power are broadly consistent with those of industry peers in Canada; more often varying in mechanics and jurisdictionally-specific characteristics than in principle or outcome. Critically, Newfoundland Power's supply cost mechanisms achieve the desired end of providing a full passthrough of costs for energy supply to customers, consistent with all other utilities analyzed.

Newfoundland Power is a notable exception in its application of a Demand Management Incentive specific to supply costs, which is not observed as active in any other member of the Main Peer Group. It is expected that this departure from common practice amongst other utilities in part explains Newfoundland Power's separate and explicit calculation of demand charge variances for the purpose of calculating passthrough adjustments to recover these charges, which is another way in which Newfoundland Power is atypical. To the degree there was not a Demand Management Incentive, this may open an opportunity for simplification of Newfoundland Power's broader supply cost mechanisms.

While the outcomes achieved by Newfoundland Power are highly consistent with those of others, it may be possible in the long-term to consolidate and simplify the various supply cost adjustments and mechanisms employed by Newfoundland Power. In so doing, the calculations relied upon by Nova Scotia Power and Maritime Electric, adjusted to reflect the specifics of Newfoundland Power, may be worthy of consideration as these mechanisms reflect a similar but simplified version of Newfoundland Power's Energy Supply Cost Variance, Demand Cost Variance, Degree Day Reserve and Hydro Production Reserve. A transition to an even simpler construct, such as Algoma Power wherein total energy supply costs and revenues can be directly compared to one another, may require foundational adjustments to rate structure and customer bill presentation.

All else equal the energy supply cost mechanisms of Newfoundland Power could be simplified relative to their current state, and the mechanisms of other utilities analyzed here demonstrate numerous potential approaches. However, at present Newfoundland Power's supply cost mechanisms are functioning effectively and appropriately to adjust for the items they were designed to adjust for, and achieve the full passthrough of supply costs to customers on an actual basis. Material modification of these constructs for the sake of regulatory efficiency is likely not warranted at this time, however incremental and non-disruptive adjustments could be considered provided they are assessed to be non-disruptive to apply.