Office of the Consumer Advocate

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November 6, 2025

Board of Commissions of Public Utilities
120 Torbay Road, P.O. Box 2140
St. John' s, NL AlA 5B2

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Dear Ms. Galarneau:

Re: Newfoundland Power's 2026 Capital Budget Application
- Submission of the Consumer Advocate

On June 27, 2025, Newfoundland Power ("NP") submitted to the Public Utilities Board (the "Board") its 2026 Capital Budget Application ("NP 2026 CBA" or "Application"). The Application seeks Board approval for the following (Application, para. 2):

a) proposed single-year 2026 capital expenditures in the amount of $75,158,000 comprising projects and programs costing in excess of $750,000;
b) proposed single-year 2026 capital expenditures of $10,212,000 comprising projects and programs costing $750,000 and under;
c) proposed multi-year projects commencing in 2026 with capital expenditures of $6,131,000 in 2026, $40,848,000 in 2027 and $8,040,000 in 2028; and
d) ongoing multi-year projects previously approved in Order No. P.U. 2 (2024) and Order No. P.U. 27 (2024) with capital expenditures of $46,442,000 in 2026 and $9,816,000 in 2027 (the "Previously Approved Multi-Year Projects").

Thus, the Application entails capital expenditures of $196,647,000 consisting of $140,389,000 in new expenditures in 2026, 2027 and 2028, and $56,258,000 for projects that were previously approved by the Board. The Application is also requesting the Board to fix its average rate base for 2024 in the amount of $1,357,191,000 (Application, para. 9(c)).

The Application process has included two rounds of Requests for Information (RFIs).

The Board directed intervenors to file submissions on the Application by November 6, 2025. This document is the Consumer Advocate's submission. What follows consists of five sections:

Context; Documentation Governing Utility Capital Budgets; Issues Relevant to the Application; Commentary on Specific Programs and Projects; and Summary.

1. CONTEXT

As the Board assesses NP's Application, it should take the overall context into account.

The broad context is alarming. The Island Interconnected System (IIS) is facing a **capital cost crisis.** The Muskrat Falls Project was extraordinarily costly and has reliability issues. Also, the Reliability and Resource Adequacy Study (RRAS) process suggests that billions of dollars in new spending is needed for capacity additions and that the costly Holyrood thermal generation station may have to continue to generate electricity beyond 2030. Hydro's recent Build Application contains just two of the three components of the RRAS's "minimum" investment required expansion path. The cost of those two components is estimated at approximately $2 billion (Build Application, Application para. 12) which is substantially more than the estimate of $1.2 to $1.6 billion from the RRAS process (2024 Resource Adequacy Plan Revisions 2, Executive Summary, p. vii). Considering the cost and supply chain issues faced by the electricity sector generally, the actual cost could turn out to be much higher. Moving from the minimum investment required expansion path to the RRAS's reference case involves billions more.

This looming capital cost crisis reflects Newfoundland and Labrador Hydro's past decisions and future plans. It was not caused by NP. However, there are actions that NP can take to help avoid or mitigate the potentially devastating costs for its customers. A change in rate design is pivotal with respect to the Application as it can mitigate its capital expenditures.

With respect to those capital expenditures, the following points are relevant.

a) In light of large recent and forecast rate increases, it is ever more important for electricity consumers that expenditures by a utility be subject to transparent, effective oversight. It is noteworthy that the most recent 7% retail rate increase effective July 1, 2025 does not recover all of the revenue requirement approved by the Board in its decision on NP's 2025-2026 General Rate Application (GRA).

b) In Order No. P.U. 36(2021) in regards to the burden of the cost of the Muskrat Falls Project, it is stated, "*The Board believes that, given the circumstances, both Newfoundland Power and Hydro should renew their efforts to provide evidence which demonstrates that every effort is being made to reduce costs for customers while ensuring the continued provision of reliable service.*"

c) In spite of these rate pressures and the Board's direction to reduce costs, the Application seeks Board approval for new capital expenditures of $140,389,000.

d) Capital expenditure adds to rate base, which adds to costs for customers and those costs are further increased with any increase in NP's approved rate of return on rate base. In

that regard, recent growth in NP's has been high. Based on values of the rate base (CA-NP-002), its annual growth rates for 2023 to 2027F are:

2023	7.34%
2024	3.35%
2025F	6.40%
2026F	3.81%
2027F	4.43%.

e) NP's intends to grow its capital budgets over the next 5 years, averaging about $172 million annually from 2026 through 2030 (Application, 2026 – 2030 Capital Plan, page 1). NP's plan is to increase capital expenditure from $137.9 million in 2026F to $155.3 million in 2027, to $192.6 million in 2028 and then $227.7 million in 2029 (2026-2030 Capital Plan, Appendix A, page 1). Such huge increases in capital expenditures must be paid for by customers and will surely add to NP's rate base. Unless these capital expenditures reduce NP's operating costs, the burden on consumers will continue to grow.

f) NP has for the last decade provided service at a superior level of reliability. In terms of SAIFI it is at least as good as the average of Electricity Canada Region 2 utilities, and it is substantially better than the Region 2 average for SAIDI (2026 Capital Budget Overview, Figures 2 and 3). More spending is not needed to address any deficiency in reliability.

g) Capital spending is very profitable and low-risk for NP. As shown in CA-NP-092, NP's capital budgets are expected to increase its after-tax return on equity by $2.8 million in 2026, $2.4 million in 2027, $3.3 million in 2028, $4.6 million in 2029 and $3.5 million in 2030. These returns are paid by NP customers.

h) The sheer scale of NP's Application for $140,389,000 in new capital expenditures and the trajectory of its capital budget expenditures over the coming years are very concerning. Ratepayers are entitled to complete justification from NP for its expenditures to ensure that the Electrical Power Control Act, 1994 is complied with and that NP is delivering power to consumers in the province at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.

In sum, ratepayers are now being required to pay for the Muskrat Falls Project and the Board has called on the utilities to reduce costs. However, Hydro is seeking to spend billions on new capacity for the IIS and NP's Application envisions substantial growth in its capital expenditures. All that capital spending, if approved, would be an enormous burden on consumers. NP should do its part in averting a cost crisis for consumers. In these circumstances, it is not unreasonable to expect that, for 2026, NP's proposed capital budget can be strategically reduced with minimal impact on reliability. Additionally, NP should consider a longer-term

strategy for managing its capital assets and orientating its capital expenditure plans to help mitigate the severe challenges facing the IIS.

2. DOCUMENTATION GOVERNING UTILITY CAPITAL BUDGETS

The Board issued Provisional Capital Budget Application Guidelines ("Provisional Guidelines") on December 20, 2021 (effective January 2022). The cover letter to the Provisional Guidelines states (page 1) "*The Board is enclosing provisional Capital Budget Application Guidelines to be used in 2022 for the 2023 capital budget applications as well as other matters related to the Board's oversight of utility capital expenditures.*" NP appears to believe that the Provisional Guidelines are relevant to its 2026 CBA, but Hydro indicates (CA-NLH-013 pertaining to Hydro's 2026 CBA) that while the Board issued correspondence on June 12, 2023 which directed the utilities to utilize the Provisional Guidelines for the 2024 Capital Budget Application, there has been no direction from the Board respecting the 2025 and 2026 CBAs.

The Provisional Guidelines state (pages 1 and 2):

> "*The Board considers the interests of both customers and utilities in determining whether proposed capital expenditures should be approved. Appropriate capital spending is in the interest of both customers and utilities as customers benefit from a utility which is well positioned to provide safe, reliable and adequate service and utilities benefit when the rates to be paid by customers are reasonable and just. Cost, performance and risk are among the factors considered by the Board in determining whether capital expenditures are appropriate and necessary to ensure the delivery of power to customers at the lowest possible cost consistent with reliable service.*"

According to NLH-NP-001,

> *Newfoundland Power does not currently have the software or data necessary to calculate the risk mitigation or reliability improvement values of capital expenditures. Options to derive such values are among the matters being assessed by the Company as part of its ongoing asset management review.*

It is interesting that NP uses the words "*among the matters being assessed*". Yet, NP initiated its asset management review in 2022,[1] and three years later, has not introduced a single change to its asset management practices as a result of that review. It seems that NP will act only if directed by the Board.

In CA-NP-014, NP provides a list of items in its 2026 CBA that are not in compliance with the Provisional Guidelines. The list covers 3 pages. NP states (CA-NP-015b):

> *"To attain strict compliance with the risk quantification provisions currently outlined in the Appendix A of the Capital Budget Application Guidelines (Provisional), Newfoundland*

[1] Balancing Cost & Reliability over the Long-Term, Scope of Work dated October 15, 2025 (page 3).

Power will need to: (i) complete its Asset Management Technology Replacement project; (ii) utilize the technology and accrue data for several years; (iii) acquire and implement dedicated statistical risk modeling software; and (iv) integrate the risk management data into Newfoundland Power's capital planning."

Therefore, almost 4 years after the Provisional Guidelines were issued and three years after NP initiated work on its asset management review, NP does not meet the requirements sets out in the Provisional Guidelines, and suggests it will not be in a position to meet the requirements for several more years, and possibly never given that NP is "***assessing***" whether risk mitigation should be incorporated in its asset management review.

There is an information asymmetry in the CBA process that gives NP a significant advantage over the Board and intervenors. The Board must level the playing field by "compelling" the utilities to meet the requirements set out in the Provisional Guidelines. The intervenors and the Board are impaired in assessing the merits of a capital project or program without quantification of the risk mitigation and reliability improvement provided by the capital project or program.

In sum, NP admits that it is not meeting the requirements set out in the Provisional Guidelines, and by extension, is not meeting the requirements set out in legislation. The Board must correct this situation.

RECOMMENDATION 1: The Board should finalize the Capital Budget Application Guidelines requiring the utilities to quantify risk and reliability improvements associated with the projects included in their capital budgets beginning with the 2027 Capital Budget Applications.

3. ISSUES RELEVANT TO THE APPLICATION

The most important aspect of a capital budget application review is that the burden of proof is on the utility to prove that a capital project or program is needed. NP agrees. It states (NP 2021 CBA: CA-NP-128) "*It is Newfoundland Power's position that the onus is on the utility to fully support with evidence the expenditures proposed in its capital budgets*". NP bears the burden of establishing that each proposed project meets the Board's prudency test.

This section identifies matters that illustrate how NP does not adequately meet the burden of proof requirement in its 2026 CBA.

a) ***Limited control by NP senior management over capital spending.*** According to CA-NP-011b, "*With respect to the 2026 Capital Budget Application, there is no documentation from senior management specifically relating to the budget control, prioritization and cost efficiencies in the light of the rate pressures brought on by the Muskrat Falls Project, Newfoundland Power's 2025/2026 GRA and Hydro's Build Application.*" It seems that rate pressures are not a concern of NP senior management.

b) Inadequate planning. In P.U. 3(2025) (page 71) the Board states:

> "*The Board believes that Newfoundland Power should develop an overall plan as to how it approaches the balance of cost and reliability, identifying issues and challenges that may have significant potential implications for its system and customers. Newfoundland Power should consider strategies and approaches to assess and manage these issues in a comprehensive, coordinated way and should communicate effectively with the Board in relation to these efforts. This would provide both transparency and clarity for the Board and customers with respect to Newfoundland Power's plans and policies.*"

According to CA-NP-028 (pertaining to NP's 2025 CBA), NP has not produced a 5-year Distribution Expansion Plan. In the absence of such a strategic plan, it is not possible to determine if the capital budget application adequately addresses and assesses the needs of NP's customers, particularly as they relate to government net-zero emissions and electrification efforts and customer willingness to pay. In the response to CA-NP-165 (pertaining to NP's 2024 CBA) NP confirms "*that its current practices do not fully incorporate integrated distribution system planning.*" Integrated distribution system planning is in the best interests of customers and necessary if the Board is to determine whether proposed capital projects and programs provide least cost supply in an environmentally responsible manner.

On October 15, 2025, NP issued a document entitled "Balancing Cost & Reliability over the Long-Term, Scope of Work". It is understood that this document was submitted in response to the Board Order on the 2025-2026 GRA to provide a scope of work for development of a Strategic Plan. The scope of work provided in the document indicates that NP will hire a consultant to tell it how to plan its system.

The proposed work includes a jurisdictional scan and compilation of risks that could impact NP and its customers. Does NP need to consult Ontario and other provinces to determine what it needs to do to provide quality distribution service to its customers in NL? Does NP not know what risks are on the horizon that will impact its customers? Is strategic planning not a core activity of a distribution company? Neither does a Strategic Plan need to identify costs in other jurisdictions as indicated in the proposed scope of work.

A Strategic Plan should include sections on the current system, future forecasts, capital investment projects, reliability and modernization initiatives, and financial analysis. Regulatory filings made with public service commissions often follow a standard, detailed structure. A typical table of contents for a strategic Distribution Plan is provided in the Appendix to this submission.

Numerous distribution companies have made publicly available 5-year electricity distribution plans or similar documents including, but not limited to, the following. It is

noteworthy that Michigan utilities have been required to file 5-year plans since 2018, 7 years ago.[2]

- **National Grid:** A 2023 DSIP Update is publicly available, detailing its distributed system implementation plans.
- **EPCOR Electricity Distribution Ontario Inc.:** A "2023–2027 Distribution System Plan" has been published.
- **DTE Electric and Consumers Energy:** These Michigan-based utilities were required to file 5-year plans by the Michigan Public Service Commission in 2018.
- **Dominion Energy:** Virginia regulators oversee Dominion's long-term plan, which outlines how the utility will meet energy demands and carbon reduction standards.
- **Hawaiian Electric:** Documents on its "Distribution Planning Methodology" are publicly available and cover its planning process and future goals.
- **PG&E Corporation:** This utility has been required to file plans related to distribution system planning.
- **San Diego Gas & Electric (SDG&E):** Publishes its "Electric Distribution Design Manual," which contains relevant information on its system design.

Under the current structure of the power sector in NL, NP performs the roles of both distribution operator and supplier. The distribution operator function includes management of the physical delivery of electricity via the distribution wires and substations. The distribution supplier function includes management of the commercial aspects of power delivery and may include rate options such as time-of-use rates and demand control, energy efficiency, customer-owned generation, and other behind-the-meter alternatives such as fuel cells and batteries. These supplier activities require installation of smart meters. In electricity markets with retail competition, the two functions are separate with the operator function regulated and the supplier function deregulated.

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https://www.google.com/search?q=which+utilities+have+5+year+electricity+distribution+plan+table+of+contents&sca_esv=7ea9874e2de762c7&rlz=1C1UEAD_enUS1049US1049&sxsrf=AE3TifMILalwvgLyqUUSsqrlhUWz78N-eA%3A1760794226923&ei=cpbzaPGEOIiu5NoPy52QiQM&ved=0ahUKEwjxhazT7a2QAxUIF1kFHcsOJDEQ4dUDCBA&uact=5&oq=which+utilities+have+5+year+electricity+distribution+plan+table+of+contents&gs_lp=Egxnd3Mtd2l6LXNlcnAiS3doaWNoIHV0aWxpdGllcyBoYXZlIDUgeWVhciBlbGVjdHJpY2l0eSBkaXN0cmlidXRpb24gcGxhbiB0YWJsZSBvZiBjb250ZW50c0juTVDvEFi_QXABeACQAQCYAYABoAGzDqoBBDE2LjW4AQPIAQD4AQGYAgigAoEGwgIOEAAYgAQYsAMYhgMYigXCAggQABiwAxjvBcICCxAAGIAEGLADGKIEwgILEAAYsAMYogQYiQXCAgUQABjvBcICCBAAGIAEGKIEwgIIEAAYogQYiQXCAgQQIRgKmAMAiAYBkAYHkgcDMy41oAf0QrIHAzIuNbgH_QXCBwUwLjYuMsgHEg&sclient=gws-wiz-serp

NP falls well short of meeting the distribution supplier function. It appears far more interested in the distribution operator function as witnessed by the fact that it does not have a Strategic Plan and apparently requires the help of a consultant to develop such a plan. NP's interest in the distribution operator, or wires, function is likely driven by profits which are well-defined: NP receives a return on all capital expenditures. The profits associated with the distribution supplier function are not as well-defined. Cost recovery associated with behind-the-meter alternatives such as time-of-use rates, while consistent with the interests of customers, is not necessarily in the best interests of NP's shareholder.

In short, owing to the absence of a coordinated 5-year distribution expansion, or strategic, plan, NP fails to meet the burden of proof requirement. A proper distribution planning process was needed five years ago rather than five years into the future, and should be a requirement before the Board approves funds in NP's capital budgets.

RECOMMENDATION 2: The Board should order Newfoundland Power to complete a Strategic Distribution Plan prior to submission of its 2027 Capital Budget Application.

c) ***Value of major project upgrades***. CA-NP-224, Attachment A (pertaining to NP's 2025 CBA) shows that in 12 of 23 cases, SAIDI actually worsened following Substation Refurbishment and Modernization projects. In spite of NP's large capital budgets in recent years, equipment failures are increasing, and in many cases, reliability has actually worsened following major project upgrades. This suggests that the capital budgets are improperly prioritized and have not met the burden of proof requirement. NP senior management is not exercising control over capital spending in order to optimize rate impacts on customers.

d) ***Inadequate assessment of alternatives for Replacement Meters and New Meters programs.*** NP continues to use AMR (Automatic Meter Reading) meters rather than AMI (Advanced Metering Infrastructure, or smart meters) even though 8 of the other 9 Canadian provinces (89%) have either installed, or have plans underway, to install smart meters (CA-NP-248f pertaining to NP's 2025 CBA). In CA-NP-078a it is stated "*Newfoundland Power considers the fact that approximately 80 percent of the utilities surveyed had either replaced their bill design solution in the past five years or were planning to do so within the next two to three years as indicative that the Company's planned approach to bill design and delivery aligns with industry best practice.*" It is interesting that NP considers 80% to be a significant figure when it comes to bill design, but does not consider it significant that 89% of the other Canadian provinces are installing smart meters.

   AMR metering is not compatible with time-varying rates, and has numerous deficiencies compared to smart meters. NP continues to state than AMI, or smart meters, are not least cost, but acknowledges (CA-NP-095c) that it "*has not previously completed a fulsome business case for AMI.*" How can NP assert that AMI technology

is not least cost when it has not assessed the numerous benefits of smart meters, which according to New Brunswick Power, include:[3]

a. Reduced Manual Meter Reading and Meter Service Orders;
b. Avoided Meter Replacement Costs;
c. Conservation Voltage Reduction;
d. High Bill Alert Service;
e. Distribution Network Losses;
f. Meter Accuracy Losses;
g. Avoided Cost of Load Research Program;
h. Avoided Cost of Net Metering Program;
i. Avoided Cost of Meter Services Manager Salary;
j. Avoided Cost of Meter Reading Vehicles[4];
k. Outage Restoration (Crew management);
l. Reduced Customer Inquiries;
m. Avoided Cost of Handheld System;
n. Unbilled/Uncollectable Accounts;
o. Avoided Cost of Meter Reading Supervisor; and
p. Reduced Overtime for Meter Service Orders.

The New Brunswick Power study of AMI identified 12 additional customer and societal benefits that were not quantified such as "*time-varying rates, which can provide significant benefits to customers and NB Power by providing more efficient price signals, and geographically-targeted demand-side management (DSM) programs, which can avoid or defer costly transmission & distribution ("T&D") investments based on AMI-derived visibility into grid needs and patterns.*"

NP acknowledges (CA-NP-080) "*Advanced Metering Infrastructure ("AMI") technology has the potential to enhance decision-making, emergency response and resource management.*" Further, in CA-NP-082 NP states "*Yes, Advanced Metering Infrastructure ("AMI") technology could allow the Company to identify customers who are experiencing outages and are therefore "not electrically connected to the system.*"

In spite of this, NP has not filed a study including even a preliminary assessment that quantifies the benefits of AMI. When asked (CA-NP-095e) "*What studies are being advanced by NP that will "help quantify the potential benefits of an AMI implementation*" NP was able to cite only "*demand response initiatives such as time-varying rates*". New Brunswick Power justified smart meters six years ago without even quantifying load shifting benefits (CA-NP-248f pertaining to NP's 2025 CBA).

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[3] New Brunswick Power filed evidence with the New Brunswick Energy and Utilities Board on August 1, 2019, "Advanced Metering Infrastructure Capital Project. https://www.nbpower.com/media/1489724/nbp0103.pdf

[4] And fuel to power the vehicles used for meter reading.

As noted by Util-Assist, NL Hydro's metering consultant (see CA-NLH-012, Attachment 1 pertaining to NL Hydro's 2025 CBA, Section 2 – Technology and Trends) "*the trend amongst utilities in Canada and really across North America is toward the deployment of AMI. Drive-by AMR meter reading is something that electric utilities are moving away from and not towards. As the utility industry is searching for ways in which to improve Customer Experience, drive-by metering does the opposite in that it improves the utility's experience while preventing any meaningful impact to the customer.*"

While the preceding quote was directed to Hydro, it is equally applicable to NP. Indeed, this is the most disappointing aspect of NP's refusal to embark on a smart metering program – the failure to consider improving customer experience.

In spite of numerous submissions by the Consumer Advocate on behalf of customers, the utilities refuse to even undertake a preliminary assessment that places a value on the numerous benefits of smart meters relative to the outdated AMR technology now in use. At this point in time, however, further assessment may no longer be necessary. Hydro's consultant has recommended AMI and AMI is now widely used in North America, largely displacing AMR. Moreover, the Island system is facing a capital cost crisis that can be mitigated by AMI in combination with a more appropriate retail rate structure and other behind-the-meter alternatives.

RECOMMENDATION 3: The Board should order Newfoundland Power to move to AMI technology and begin installing AMI as soon as possible before the end of 2026. To that end, NP should provide an implementation plan to the Board by March 1, 2026.

e) ***Falling behind other provinces***. New Brunswick Power filed evidence with the New Brunswick Energy and Utilities Board on August 1, 2019 entitled Advanced Metering Infrastructure Capital Project which states (page 5) "*The pace of technological change has been increasing and will continue to increase.* ***NB Power believes that continuing to plan on the basis of making investments in traditional utility assets in the face of such change may not be prudent and reasonable.***" (emphasis added)

Nova Scotia Power states on its website "*Globally, the electrical grids that have served us over the past century are evolving through new technology into "smart grids". Smart grids offer a future in which individual pieces of the electrical system - including "smart devices" in customers' homes and businesses - can communicate with one another, so that the entire electrical system works together to use energy more efficiently. This means lower overall costs for customers and a cleaner environment.*"

Yet NP continues business-as-usual, pouring considerable amounts of capital into its traditional utility assets in the absence of a planning approach that would result in lower overall costs for consumers and a cleaner environment. NP cannot evolve its distribution system into a "smart grid" without smart meters. New Brunswick Power recognized this 6 years ago. Owing to NP's outdated planning approach, NL continues to fall behind other jurisdictions.

In a monopoly jurisdiction such as NL where both the distribution operator and supplier functions are combined, the regulator must ensure that customer interests are served. Customer interests are not being served as witnessed by the following:

i) NP indicates (CA-NP-100a) "*There are no projects or programs in the 2026 Capital Budget Application that reduce customer reliance on the grid.*"
ii) The utilities have done very little to promote customer-owned generation. According to CA-NP-100b "*As of the end of 2024 there were 55 net metering projects in service in Newfoundland Power's service territory, with a total capacity of 602 kW.*" This is a paltry effort by the province's utilities. In comparison, Nova Scotia's total net-metered solar installations exceeded 11,000 in 2024, surpassing the 2023 total by 27%. The total net-metered solar capacity in Nova Scotia now exceeds 100 MW. Including non-net-metered Community Solar, behind-the-meter solar, and Solar Electricity for Community Buildings Projects, the province's total solar capacity is approximately 120 MW (120,000 kW).[5] New Brunswick has 1,350 net metering customers producing more than 17 MW of green capacity and avoiding 17,000+ metric tons of greenhouse emissions.[6] While electricity prices are currently higher in Moncton, NB and Halifax, NS at 16.8 cents/kWh and 19.19 cents/kWh, respectively (compares to 15.79 cents/kWh in St. John's, NL)[7], electricity prices on the Island are forecast to increase to 25 cents/kWh by the mid-2030s, thus providing a significant incentive to customers to install their own generation.
iii) NP agreed to conduct a Load Research Study and a Retail Rate Design Review in a Settlement Agreement relating to its 2023-2024 General Rate Application signed on November 22, 2021. Four years later, NP has yet to offer a single new rate design. Improvements to rate design based on marginal costs are needed more than ever in light of the massive capital expenditures on capacity contemplated in the RRAS. A more efficient pricing regime would help delay or reduce those costly additions to the IIS's capacity. It is crucially important that a new retail rate design be adopted as soon as possible. Once AMI is in place that design could then be further enhanced.
iv) It is not clear (CA-NP-101) that Hydro and NP are working together to develop a power system expansion plan that best meets the needs of customers. A coordinated plan is necessary given that Hydro has identified a need for capacity and energy additions to

[5] https://www.linkedin.com/posts/davidbrushett_nova-scotia-power-released-its-2024-net-metering-activity-7311069451045486592-Pus-/
[6] https://www.nbpower.com/en/products-services/net-metering/
[7] https://www.fraserinstitute.org/sites/default/files/2025-03/energy-costs-and-canadian-households-how-much-are-we-spending-2025.pdf

the power system in the early 2030s. In fact, as already noted, although NP serves the vast majority of customers in the province, it does not have a Strategic Distribution Plan.

v) Hydro and NP have not yet updated the five-year conservation, demand management and electrification ("CDME") plan for the years 2026 to 2030. The updated CDME is expected to be completed by year-end 2025 (CA-NP-051a).

vi) It is not clear when, if ever, customers will reap benefits of NP's asset management review. NP is currently unable to quantify the risk of not proceeding with a capital project or program; neither can NP quantify the reliability improvement resulting from a capital project or program. However, the review is not being undertaken in response to the requirements of the Provisional Capital Budget Application Guidelines that were issued by the Board almost 4 years ago. According to CA-NP-094, the asset management review is being undertaken in response to the "*end of vendor support for the current system.*"

In short, NP is doing little to improve the customer experience and reduce the impact of its capital programs on rates, and is not likely to do so until the Board directs it to. NP must make substantial efforts to incorporate behind-the-meter alternatives and smart grid applications such as smart meters.

4. COMMENTARY ON SPECIFIC PROGRAMS AND PROJECTS

As stated earlier, there is an information asymmetry that makes it challenging to effectively evaluate NP's proposed spending. Nevertheless, we have identified capital expenditures of particular concern. For some of these expenditures, we offer observations on specific programs and projects for the Board to take into account when it assesses them. Next, there are some programs and projects for which we offer explicit recommendations.

First, there are some the programs and projects for which we have concerns and urge the Board to more closely scrutinize them. They follow.

- In Section 2.1 - 2026 Substation Refurbishment and Modernization, Appendix A (page 6) it is stated "*Equipment failure in the substation exposes all customers supplied by GPD Substation to the risk of extended outages. The time to restore service to customers would depend on the nature of the failure and could range from several hours up to 36 hours.*" This does not justify Substation Refurbishment and Modernization because as noted by NP (CA-NP-063), a single equipment failure could result in "*extended customer outages to all customers supplied by any of the 131 substations Newfoundland Power operates.*"

- In Section 2.1 - 2026 Substation Refurbishment and Modernization, Appendix A (page 6) it is stated "*The existing power transformer and voltage regulators in GPD Substation contain large amounts of insulating oil and lack standard spill containment.*" Spill containment is not justification for Substation Refurbishment and

Modernization because as noted by NP (CA-NP-064) 101 of its 191 power transformers and 12 of its 16 voltage regulator banks do not currently have spill containment.

- In Section 2.2 - Substation Power Transformer Strategy (page 2) it is stated "*A total of 91 power transformers in the Company's fleet, or approximately 48%, are aged 50 years or older, which is the upper limit of the typical industry experience.*" Further, it is stated (page 11) "*Of the 10 failures experienced over the last five years, three power transformers failed in service and the remaining seven were identified as being at imminent risk of failure through condition monitoring. Four of the 10 power transformers required replacement, while the remaining six were repaired and returned to service.*" As noted by NP (CA-NP-065) "*Five of the six power transformers that required replacement were less than 50 years old at the time of replacement.*" This suggests that age is not the determining factor for transformer replacement.

- Section 3. 1 - Transmission Line 100L Rebuild, Table 2 summarizes transmission line outages. CA-NP-070 asks how many customers were affected by these outages and for how long? NP states "*Three of the outages summarized in Table 2 resulted in outages to customers. The December 2023 outage resulted in 49,272 customer outage minutes. Additionally, the February 2013 and April 2015 outages were the result of widespread blizzard/severe weather events causing outages to numerous substations and transmission lines and resulting in outages to customers.*" What this shows is that transmission outages rarely result in customer outages and when they do, it is often a result of a severe weather event. NP does not plan its system to withstand severe weather events – to do so would be prohibitively expensive. NP does not include severe weather events in its outage statistics.

These specific concerns highlight the fact that the ability to quantify risk associated with a capital project is paramount. For an intervenor and the Board, it is challenging to determine which, if any, of NP's proposed capital projects are premature, unnecessary or inadequately justified. Within the regulatory process, there is an information asymmetry that favours the applicant. The fact that NP does not calculate a quantifiable risk mitigation value associated with its asset management program and does not have the data or software necessary to provide calculations of risk mitigation or reliability improvement puts intervenors and the Board at a significant disadvantage.

Next, we turn to programs and projects for which we give explicit recommendations.

a) ***Extensions, New services, New Meters and New Street Lighting.*** The Application requests funding for these four programs in the amounts of $16,747,000, $4,218,000, $701,000 and $2,425,000, respectively, which is $24,091,000 in total.

These expenditures are for new services and are all driven by requests from customers, or developers and contractors. In the case of the Extensions program, (CA-NP-026) requestors' contributions are required only in a limited number of cases as per NP's CIAC policy. However, amount paid for by CIAC is unknown since NP "*does not record customer contributions as being part of a specific capital program.*" For the Services program, (CA-NP-031), in general, as per CIAC policy, there is "*no contribution from the customer towards the capital cost.*" For New Street Lighting, the capital costs are "*indirectly recovered through customer rates*" (CA-NP-032).

In light of the considerable growth in NP's planned capital expenditures, it is worthwhile having NP require some capital contributions for its extensions, new services and new meters program. Such contributions would not be contrary to NP's legislative obligation "*to provide customers with equitable access to an adequate supply of power in a manner that is not unjustly discriminatory*" (CA-NP-111) as long as such capital fees are not unreasonable or onerous. The new customers are the main beneficiaries of the new services, and supply chain and cost pressures are making it ever more expensive to provide such services. Moreover, to the extent requestors contribute to capital costs of their new service requests, NP's rate base growth would be reduced, which reduces the cost for all customers of funding NP's return on rate base. It is not unreasonable to have requestors pay at least some minimal contribution towards the capital expenditure.

Contribution revenue could be set as a percentage of cost for each program. For instance, contributions for New Street Lighting could be a different percentage of cost than Extensions. And within each program, the fee could vary depending on the nature of the work and customer class. More generally, there needs to be a reasonable schedule of fees. Developing one should not be difficult or time-consuming. This may be a departure from traditional utility practice but with NP's plans for substantial increases in capital expenditure over the next four years, with Hydro wanting to undertake massive capital expenditures, the circumstances warrant it,

RECOMMENDATION 4: The Board should order NP to begin recording customer contributions to the specific capital programs with which they are associated.

RECOMMENATION 5: The Board should order NP to develop a set of fees to be paid as capital contributions for new capital expenditures based on specific requests and based on the principle that there should be at least a minimum capital contribution.

b) Customer Correspondence Modernization. The Application requests funding of $782,000 in 2026 and $1,175,000 in 2027 for this two-year project.

In Section 4.1 of the Application, Customer Correspondence Modernization Project, it is stated (page 2) "*Newfoundland Power conducts regular Customer Satisfaction Surveys to gather customer feedback on various service interactions. Feedback from these surveys has indicated that customers feel the current bill lacks clarity and functionality in several key areas.*" However, CA-NP-103a indicates that NP "*did not survey customers regarding the implementation of the Customer Correspondence Modernization project.*" Therefore, customers

were not made aware of the cost of the project and its impact on customer bills. Surely, that uncollected information would have been relevant.

The response to NLH-NP-025a indicates that in 2024, NP surveyed its customers on their overall level of satisfaction with the Company's current bill design and possible modifications to the bill design. In that survey (NLH-NP-025, Attachment A, page 7 of 24, B2), 82% of residential customers and 86% of business customers rated satisfaction with the current bill design at 7 or higher out of 10, and only 6% of residential customers and a mere 1% of business customers ranked their satisfaction at 4 or lower on a scale of 1 to 10. NP's claim that "*Feedback from these surveys has indicated that customers feel the current bill lacks clarity and functionality in several key areas*" is not significant enough to adversely affect customers' overall satisfaction. The survey evidence shows that vast majority of its surveyed customers are satisfied with the current bill design. There is no evidence that customers want to pay for changes in the bill design.

Going beyond the survey, there is no evidence of widespread dissatisfaction with the current bill design. When asked for the number of customers contacting NP to request changes to bill designs over the past ten years, NP was unable to give any (CA-NP-75(c)). Also, when asked whether any of the 11,000 calls received by NP between February 17 and March 7, 2025 involved requests to change bill design, NP was again unable to give an estimate. It appears that NP can offer no evidence that a significant number of customers want a change in bill design.

Customer Correspondence Modernization Project Appendix A provides calculation of the NPV of this project's impact on NP's after-tax earnings. It gives the NPV of NP's after-tax cash flow as $183.1 thousand. It also provides the associated corporate income tax (Column G) that accrues from NP increased earnings. The NPV of that amount, using NP's discount rate of 5.84%, is $78.5 thousand. Thus, the federal and provincial governments gain ($78.5 thousand) and NP shareholder gains ($183.1 thousand). Where is consumers' gain? There is no identified monetary benefit for the customers. All the net operating savings go to NP and governments.

It appears that NP's assessment of gains to customers is not monetary, but a better billing experience. NP states (Customer Correspondence Modernization, page 2) "*Newfoundland Power conducts regular Customer Satisfaction Surveys to gather customer feedback on various service interactions. Feedback from these surveys has indicated that customers feel the current bill lacks clarity and functionality in several key areas. This includes understanding individual energy usage, how weather affects consumption and costs, awareness of available services, simplification of payment options and the presentation of complex billing calculations. Customers also indicate that the readability and overall comprehension of the current bill is unclear and lacks certain key information. As a result, customers with billing questions or concerns often reach out to the Customer Contact Centre. Bill-related contacts account for over 20 percent of the total volume of calls, emails, and webchats received by the Company's Contact Centre each year.*"

Yet, as pointed out above, the vast majority of customers surveyed have indicated overall satisfaction with the current bill design and related correspondence, and NP has not been able to provide evidence of large number of unsolicited complaints from customers regarding bill

design. Additionally, the quote mentions that bill-related contacts account for more than 20% of communications received by its Contact Centre. But bill-related contacts are not the same as complaints about the design of the bill; the magnitudes of the amounts owing are the more likely motivation for these contacts. Moreover, no evidence has been presented to suggest that customers are unsatisfied with their experiences with NP's Contact Centre.

Finally, if the operating cost saving is modestly less than anticipated then the NPV becomes negative. According to CA-NP-079, if the saving turned out to be just 15% less than anticipated then the NPV of the after-tax cash flow becomes -$27.2 thousand. Considering that many customers might still want to communicate with the Contact Centre despite a new bill design, it is a distinct possibility that the operating cost savings may be less than anticipated.

In short, customers are largely content with the existing bill design and there is no evidence that they have been contacting NP to demand changes to it. The Consumer Advocate has not received any such complaints either. Even for NP, the NPV impact is small and could turn negative if cost savings are modestly less than anticipated.

RECOMMENDATION 6: The Board should not approve the Customer Correspondence Modernization project.

c) ***Mount Carmel Pond Feeder Extension CAB 01*** and ***Mount Carmel Pond Dam Fibre***. For these two related projects, the Application requests $1,346,000 and $150,000, respectively, for a total of $1,496,000.

Both projects are related to the Mount Carmel Pond Dam Refurbishment project that was approved in NP's 2025 Capital Budget Application. The refurbishment project included (i) replacement of the overflow spillway structure, (ii) enhancements to the public safety infrastructure and (iii) automation of the outlet gate including gate replacement (2025 Application, 4.1 Mount Carmel Pond Dam Refurbishment, p. 1). That Application also indicated NP's intent to submit distribution and telecommunications projects in its 2026 Capital Budget Application. So, these two projects in this Application were not considered in the 2025 Application and must be evaluated on their merits.

According to CA-NP-105(e) the feeder extension and the fibre optic cable are complementary. Both are needed in order to operate the outlet gate remotely. Without them the outlet gate would have to be operated manually as was past practice. However, with the improvements to the facilities due to the Refurbishment project, one might presume that the manual operation of the outlet will not be more onerous than in the past.

The apparent rationale for the total expenditure of $1,496,000 for feeder extension and fibre optic cable is labour-saving. Remote operation would eliminate the need for a two-hour return trip by vehicle to the gatehouse by staff based at NP's Mobile District Building, (2025 Application, 4.1 Mount Carmel Pond Dam Refurbishment, p.11). That trip consists of 22 km along Route 10 and then 13 km along a road that requires an off-road vehicle in the winter (CA-NP-042) for a total of 35 km. Thus, the return trip is 70 km.

The estimated labour cost of such a trip to adjust the outlet gate ranges from $203 during regular operations and $271 during overtime periods (CA-NP-105(d)).

NP was unable to say how many times since the start of operations in 1954 that the outlet gate was adjusted; NP indicated that it did not collect such statistics (CA-NP-042). When asked how many times in 2024 did manual adjustment of the outlet gate occur, NP gave the same answer. That is surprising. Would not asking staff based at the Mobile District Building in 2024 given a reasonable estimate?

If outlet-gate adjustment is required 50 times per year then, based on NP's estimated cost of $203 to $271 per trip, the associated annual labour cost to manually adjust the outlet gate would approximately range from $10,000 to $14,000 plus some mileage allowance for use of a vehicle. A capital expenditure of $1.5 million to save such annual cost is not close to be being justifiable. Even if 200 return trips for adjustment to the outlet gate were needed per year, the annual savings would be only around $40,000 to $55,000 plus some vehicle savings, which would still hardly justify a $1.5 million capital expenditure. This is speculation but the fact is that NP offered no benefit-cost analysis for these complementary projects.

These two project have not been justified, and there is no evidence that the benefits of the previously approved Refurbishment Project would be reduced without them.

RECOMMENDATION 7: The Board should not approve either the Mount Carmel Pond Feeder Extension CAB 01 project or Mount Carmel Pond Dam Fibre project.

5. SUMMARY

IIS electricity consumers face a very difficult future, especially if NL Hydro pursues its massive capital expenditure plans for the island. However, NP can play a significant role in helping consumers.

Beyond curtailing its capital expenditure growth, one crucially important action NP can take is to improve retail rate design. New rate design has the potential to contain growth in electricity consumption and, in particular, reduce peak loads. That could potentially delay or even eliminate some of Hydro's capital projects for the island, which NP's customers would otherwise have to pay for. Retail rates are not the subject matter of the Application but the scope for rate design improvements is limited, though not eliminated, by the lack of AMI. This submission therefore argues for a shift in NP's capital spending towards an immediate plan to implement AMI throughout the IIS. That should be done in conjunction with NP making substantial efforts to incorporate behind-the-meter alternatives and smart grid applications such as smart meters as part of a strategic Distribution Plan.

In terms of specific expenditure programs and projects, this submission raises several concerns for the Board to consider. Also, it recommends action on capital contributions for request-driven expenditures in order to reduce the growth in NP's rate base and thus the associated burden on

ratepayers. Finally, this submission identifies three capital expenditures projects that are not at all supported by reasonably convincing evidence and recommends that the Board not approve them.

Please contact the undersigned if you have any questions on this submission.

Yours truly,

Dennis Browne, KC
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cc

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APPENDIX

Illustration of a Table of Contents for a Strategic Distribution Plan[8]

1. Introduction

- **Executive summary**: An overview of the plan's purpose, key objectives, and projected outcomes for the next five years.
- **Background**: A description of the utility, its service area, and the regulatory context of the plan.
- **Mission and purpose**: The overall goals of the distribution system, including safety, reliability, affordability, and sustainability.

2. Current state of the distribution system

- **System description**: A detailed overview of the existing distribution network, including substations, primary and secondary circuits, and asset inventory.
- **Performance metrics**: An assessment of historical performance, focusing on reliability metrics like System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).
- **Operational challenges**: An analysis of current issues, such as aging infrastructure, areas of low reliability, and capacity limitations.

3. Forecasting and planning

- **Load and demand forecasting**: A detailed projection of future electricity demand, including the expected growth of Distributed Energy Resources (DERs), such as rooftop solar and electric vehicles.
- **Growth and modernization drivers**: An analysis of factors driving the plan, including state and federal energy policies, clean energy goals, and customer needs.
- **Forecasting methodology**: The process and models used to develop forecasts and analyze potential scenarios.

4. Capital investment plan

- **Capital projects overview**: A summary of planned capital expenditures for the 5-year period, often presented by project category.

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8 https://www.google.com/search?q=5+year+electricity+distribution+plan+table+of+contents&rlz=1C1UEAD_enUS1049US1049&oq=5+year+electricity+distribution+plan+table+of+contents&gs_lcrp=EgZjaHJvbWUyBggAEEUYOTIHCAEQABjvBTIHCAIQABjvBTIKCAMQABiABBiiBDIHCAQQABjvBTIKCAUQABiiBBiJBdIBCTI4NTYwajBqN6gCALACAA&sourceid=chrome&ie=UTF-8

- **Asset management**: Plans for the inspection, maintenance, repair, and replacement of aging infrastructure.
- **Grid modernization initiatives**: Investment plans for upgrading the grid with smart technologies, automation, and advanced metering infrastructure.
- **Distributed energy resources (DER) integration**: Plans for enabling the growth and seamless integration of DERs, including new infrastructure and operational models.
- **Maintenance and upgrade projects**: A categorized list of specific maintenance and upgrade projects, with details on drivers, timing, and cost.

5. Reliability and resilience

- **System reliability improvements**: Strategies for reducing the frequency and duration of power outages.
- **Grid resilience plan**: An assessment of grid vulnerabilities and planned investments to mitigate threats from extreme weather, cyber-attacks, and physical attacks.
- **Mitigation analysis**: An evaluation of the effectiveness of planned projects in addressing identified reliability and resilience risks.

6. Financial and regulatory considerations

- **Cost analysis**: A detailed breakdown of estimated capital and operational expenditures for the plan.
- **Financial plan**: An explanation of how the plan will be funded, including potential impacts on customer rates.
- **Budgeting process**: The process used for capital budgeting and securing funding for the plan.
- **Performance monitoring**: Metrics and methods for monitoring the performance of the distribution system and the plan's progress over the 5-year period.

7. Appendices

- **Work papers**: Supporting documentation and technical analyses related to forecasting and project planning.
- **Glossary**: A list of technical terms and acronyms used in the plan.
- **Project details**: Specifics on individual projects, including budgets and timelines.