Office of the Consumer Advocate

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November 3, 2022

Board of Commissions of Public Utilities
120 Torbay Road, P.O. Box 2140
St. John's, NL A1A 5B2

Attention: G. Cheryl Blundon, Director of Corporate Services / Board Secretary

Dear Ms. Blundon:

Re: Newfoundland Power's 2023 Capital Budget Application
Submission of the Consumer Advocate

On June 29,2022, Newfoundland Power ("NP") submitted to the Public Utilities Board (the "Board") its 2023 Capital Budget Application ("NP 2023 CBA"). That application seeks Board approval for 46 projects and programs. NP has previously received approval from the Board for $19.7 million in capital expenditure for 2023. The NP 2023 CBA is seeking approval for new capital expenditures of:[1]

(i) $93,292,000 in single-year 2023 capital expenditures
(ii) $10,483,000 for four multi-year projects commencing in 2023
(iii) $10,645,600 for the same four multi-year projects in 2024.

Thus, approval is being sought for $103,775,000 for 2023 and $10,645,600 for 2024 for a total of $114,420,600. An amount of $19,688,000 was previously approved for NP for 2023. The total expenditure for 2023 would be $123,463,000 if the Board approves this Application.

The Board directed intervenors to file submissions on the NP 2023 CBA by November 3, 2022. This is the Consumer Advocate's submission.

1. Opening Remarks

NP's application comes at a time of massive spending on the province's electricity system. The inclusion of the Muskrat Falls Project ("MFP") in rates will have a profound impact on electricity rates. The latest capital cost estimate for the MFP is $13,400 million.[2] Hydro's *Reliability and Resource Adequacy Study – 2022 Update* (*RRAS-2022 Update*) indicates that owing to continuing issues with the MFP, especially the Labrador-Island Link (LIL), the Holyrood TGS may be kept in service until 2030. Costs for Holyrood if required to operate in generation mode through 2030 are $1,013 million ($140 million for capital, $176

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1 NP-2023 CBA, Capital Budget Overview, page 1 and Appendix A, page 4.
2 NL Hydro CEO Jennifer Williams says the revised cost of the hydroelectric project which has met repeated delays and is now dealing with challenges involving GE's software is up from $13.1 billion to $13.4 billion. https://vocm.com/2022/06/17/muskrat-falls-revised-cost/#:~:text=The%20total%20cost%20is%20now,increase%20of%20about%20%24300%20Million.

million for operating costs and $697 million for fuel).[3] Further, Hydro is proposing to construct Unit 8 at the Bay d'Espoir hydro generating station at a capital cost of $522 million. Also, Hydro has submitted a 2023 CBA with a proposed capital spend of $612 million in the period 2023 to 2027 and indicates that in its deferral accounts the forecast amount owing by customers by year-end 2022 is $336.7 million (CA-NLH-098 from Hydro's 2023 CBA).[4] Including the capital budget amounts anticipated by NP in its 2023 CBA for the next five years (2023-2027) of $651 million (NP 2023 CBA), total expenditures for the undertakings listed above is about $16,521,300,000.[5]

This is a staggering amount of money in a jurisdiction with about 280,000 electricity consumers[6] equating to an average of $59,005 for each electricity customer in the province. These costs will place an enormous burden on the people of this province. The government's rate mitigation plan has yet to be defined[7] but, regardless, ratepayers will pay the bulk of the cost of these programs. As well, we note that $2 billion of the federal government's rate-mitigation assistance is repayable with interest, which will be a burden for ratepayers.[8]

These are difficult circumstances for ratepayers. Therefore, NP, as well as NL Hydro, ought to be doing as much as it possibly can to ease the cost burden on ratepayers. NP ought to be focusing on finding ways to reduce costs and limit capital expenditures to what is absolutely necessary and fully justified. In particular, capital expenditures add to rate base.[9] And NP's rate base has been rising at a much higher rate than the general price level over the past twenty years. Table 1 compares the increases in the two. Clearly, the rate base has grown much more than the price level. Had it grown at the same rate, electricity rates would have been lower.

Table 1

	2021 compared to 2001	***2021 compared to 2011***
NP Rate Base[10]	120.7%	37.3%
Price Level (as measured by GDP Deflator)[11]	53.1%	19.5%

For an intervenor, it is challenging to determine which, if any, of NP's proposed capital projects are premature, unnecessary or inadequately justified. Within regulatory process, there is an information

3 See Reliability and Resource Adequacy Study – 2022 Update, Volume III – Long-term Resource Plan, Tables 8 and 9.

4 Assuming $70 million equates to a 1% increase in rates means the deferral accounts will result in a 4.8% increase in rates at year-end 2022.

5 Excludes $13.4 million for Holyrood TGS capital projects that are accounted for in both the Reliability and Resource Adequacy Study – 2022 Update and the 2023 CBA.

6 https://www.gov.nl.ca/iet/energy/electricity/#:~:text=Publications-,Overview,Hydro%20serve%20about%20280%2C000%20customers.

7 Hydro indicates that it cannot submit its next GRA until the details of the government's rate mitigation plan are finalized (CA-NLH-016 from Hydro's 2023 CBA).

8 Government of Newfoundland and Labrador, Technical Briefing Rate Mitigation, July 28, 2021, and https://vocm.com/2022/02/14/federal-and-provincial-governments-update-muskrat-rate-mitigation-process/.

9 As shown in CA-NP-097's Table 1, rate base very closely approximates net plant investment.

10 According to CA-NP-097, the rate base was $545.162 million in 2001, $876.356 million in 2011 and, subject to Board approval, $1,202.946 million in 2021.

11 According to CA-NP-125, the GDP deflator was 0.64 in 2001, 0.82 in 2011 and 0.98 in 2021.

asymmetry that favours the applicant. The Board's consultant, Midgard, alludes to the information asymmetry as follows: [12]

> *To function effectively and ensure the necessary tension between interests, a capital budget approval process requires the applicant to provide complete and accurate supporting information for the planned investments. It is important to recognize that even if the application is full, complete and accurate, a significant informational asymmetry always exists between the applicant (i.e., utility) and the intervenors and regulatory Board.*

Moreover, in this application process, the Board declined to proceed with an oral hearing as requested by Consumer Advocate. This meant that intervenors did not have the opportunity to cross-examine NP witnesses to gain a complete understanding of merits of the 46 projects included in its application.

Nevertheless, we were able to identity six projects/programs in NP's 2023 CBA that are not sufficiently justified to merit Board approval and should be either deferred or not allowed.

2. Projects in the Application That Have *Not* Been Adequately Justified

At least 6 projects in NP's 2023 CBA have not been sufficiently justified to warrant Board approval. This section discusses each individually but before doing so, makes three points for the Board to take into consideration with respect to the entire application.

First, in addition to net present value (NPV), payback periods provide useful information to the Board and intervenors. NP argues that payback periods have several shortcomings relative to NPV and should not be the sole criterion for judging the merits of a project. However, there is no disputing that payback periods are a ***valid consideration*** in an economic analysis. The Harvard Business School states:[13]

> *The shorter the payback period, the better. And it "obviously has to be shorter than the life of the project - otherwise there's no reason to make the investment." If there's a long payback period, you're probably not looking at a worthwhile investment.*
>
> *Payback is often used to talk about government projects or relatively risky projects that are capital intensive.*

In short, a long payback period suggests greater risk and uncertainty, which should be incorporated into project analysis.

Second, the continuing increases in NP's capital spending, including the expected $33 million increase (from $43 million in 2022 to $76 million in 2025, a 77% increase) in the renewal category is a serious concern. NP will continue to increase capital spending unless the Board takes action. NP ought to focus its proposed asset management review toward meeting the requirements set out in the Provisional Capital Budget Application Guidelines.

12 See October 29, 2020 report by Midgard Consulting Inc. titled "Capital Budget Application Guideline Review", page 18.

13 https://hbr.org/2016/04/a-refresher-on-payback-method

Thirdly, interest rates are on the rise. Higher rates may affect NP's cost of debt, which would eventually have to be borne by ratepayers. So, the cost of capital expenditures today should be scrutinized not just with respect to current rates but what they might be over the life of new capital additions.

2.1 **LED Street Light Replacement Program**

NP proposes to spend $5,453,000 on its LED Street Light Replacement Program (LED Program) in 2023. That expenditure is part of a plan to accelerate the replacement of all HPS streetlights by the end of 2026. The plan requires additional capital expenditures of $5,507,387 in 2024, $5,544,690 in 2025 and $5,584,101 in 2026.[14] Thus, the four-year capital cost is $22,089,017. The 2023 CBA is seeking approval of $5,453,000 for 2023; presumably NP intends to seek approval for the other years in subsequent CBAs.

The alternative to the LED Program identified by NP is the replacement of HPS streetlights at the end of service life (HPS Program). The capital cost for the HPS Program would be $674,810 in 2023.[15] That is approximately $4.8 million less than the capital cost of the LED Program for 2023.

NP provided an analysis (PUB-NP-007, Attachment A) in which the NPV of the LED Program's costs, including capital cost, over the 33-year period, 2023 to 2055, is $21,991,140 whereas the HPS alternative's NPV of cost over the same time period is higher, at $26,302,543. However, up to 2041, the HPS alternative has a lower NPV cost than that of the LED program. In short, the LED program has a lengthy payback period of approximately 19 years, i.e., it takes 19 years for the LED program's cost to become lower than the HPS Program's cost, both in NPV terms. The sources of the LED Program's longer-term lower cost are the avoided cost of electricity, which reflects the LED streetlights' lower electricity consumption, and maintenance cost.

The high upfront four-year capital cost of the LED Program of approximately $22.1 million, versus the HPS Program's capital cost of approximately $2.7 million for the same four-year period, and its lengthy payback period are concerns. While the payback period is not the standard or sole criterion for investment decision-making, it does provide useful information. A lengthy payback period is suggestive of greater risk because generally the further into the future the greater the uncertainty of forecasts. Additionally, much higher upfront capital costs of LED streetlights place an immediate and heavier burden on ratepayers in return for the prospects of gains after almost 20 years.

To explore the LED Program further, NP was asked through the RFI process to repeat its analysis to take two key sensitivities into account (CA-NP-130). These relate to the discount rate and the marginal costs of energy and capacity on which the avoided cost of electricity is based.

The NP analysis used a discount rate of 5.81%, which is NP's current weighted average cost of capital (WACC); note that NP's approved 2022 rate of return on rate base is higher, at 6.61% (P.U. 3(2022) p.20). That WACC is based on NP's 3.608% cost of debt, 8.5% return on equity, and capital structure of 55% debt and 45% equity. This discount rate was used to determine NPV over the 33-year period of the analysis. That may not be the appropriate choice. In its 2022 GRA NP had sought, but did not obtain, a 9.8% return on equity. Also, interest rates have risen over the course of this year. Before the end of October the Bank of Canada in incremental steps had increased its policy interest rate by 3.5 percentage points to 3.75% from 0.25%. In response to CA-NP-129b, NP indicated that its most recent debt issue

14 Response to PUB-NP-007, Attachment A, Table 2.

15 PUB-NP-007, Attachment A, Table 1.

yields 4.198%, which is higher than the 3.608% cost of debt in its current WACC and that debt issue was made in April 2022, when the Bank of Canada policy rate was just 1%.[16] Consequently, a sensitivity analysis was requested for the discount rate.

NP used forecasts of the marginal cost of energy and the marginal cost of capacity in its estimation of avoided electricity costs. For the years 2023-2040, NP used the forecasts from the *Marginal Cost Study Update – 2021* (March 7, 2022) and for later years assumed that those marginal costs would increase at the same rate as the Conference Board of Canada's long-term forecast for the GDP deflator. In response to CA-NP-128c, NP calculated the correlation between the marginal cost of energy and GDP deflator forecasts as well as the correlation between the marginal cost of capacity and the GDP deflator forecasts for the period 2023 to 2040. The results indicate that these marginal costs are actually negatively correlated with the GDP deflator (i.e., they tend to move in opposite directions) with the correlation between the marginal cost of capacity and the GDP deflator close to zero. These results are inconsistent with NP's assumption that marginal costs increase at the same rate as the forecast of the GDP deflator after 2040, which was the assumption used in the NPV analysis for the years 2041 to 2055. Moreover, 2041 is the year that the Churchill Falls Contract expires. That could dramatically change the marginal costs of energy and capacity on the Island system if transmission is put in place. Consequently, a sensitivity analysis for the avoided cost of electricity was requested for 2041 to 2055.

The results of the requested sensitivity analysis, as provided by NP in response to CA-NP-130b, are presented in Table 2 below. That table also contains NP's core results as contained in its response to PUB-NP-007, see row labelled "NP Core Results." The sensitivity results are based on various discount rates and a common assumption that avoided electricity costs after 2040 are 50% less than used to derive the core results.[17] The discount rates go as high as 8.5%, which may seem high, but the analysis covers a long time and we note that in 2013 the allowed rate of return on NP's rate base was 7.92% within a range of 7.74% to 8.10%; P.U. 23(2013).

Table 2

Scenario	***HPS Program***	***LED Program***	***LED Advantage***[18]	***Payback Year***
NP Core Results (as in response to PUB-NP-007 Revised-Attachment A) based on 5.81% discount rate	$26.3	$22.0	$4.3	2041
Sensitivity[19]				
5.81% and 50% lower electricity cost post 2040	$28.3	$24.5	$3.7	2041
6.5% and 50% lower electricity cost post 2040	$26.5	$24.2	$2.3	2042
7.0% and 50% lower electricity cost post 2040	$25.3	$24.0	$1.3	2047
7.5% and 50% lower electricity cost post 2040	$24.3	$23.8	$0.5	2050
8.0% and 50% lower electricity cost post 2040	$23.3	$23.6	-$0.3	Never
8.5% and 50% lower electricity cost post 2040	$22.4	$23.4	-$1.1	Never

16 https://www.bankofcanada.ca/core-functions/monetary-policy/key-interest-rate/

17 When only the alternate discount rates results are used then the sensitivity analysis is more favourable to the LED Program, see NP's response to CA-NP-130a Attachments A to E.

18 This is the excess of the NPV of cost of the LED Program over the HPS Program. A negative number indicates the HPS Program has the lower cost.

19 Theses sensitivity results correspond to Attachments F, G, H, I, J and K, in NP's response to CA-NP-130b.

In addition, NP provided two other sets of results that were not requested.

First, included in its response to CA-NP-128c, NP provided a NPV analysis that assumes zero avoided electricity cost savings in 2042 and thereafter for both options. At a 5.81% discount rate, the results favour the LED Program but by a smaller margin than in NP's Core Results; the NPV advantage declines to $3.3 million for the LED Program rather than $4.3 million as indicated in Table 2. NP did not provide NPV magnitudes corresponding to the other higher discount rates.

Second, in response to CA-NP-130, NP also included results corresponding to the sensitivity cases given in Table 2 but based on two assumptions favourable to the LED program. Specifically, it reduced the assumed LED failure rate to one-tenth of that previously used and applied cost inflation to the non-labour materials.[20] The inclusion of the inflation assumption mainly drives up the capital cost of the HPS program, while the assumed lower failure rate reduces the post-2027 capital cost, retirement cost, and taxes & net salvage cost of the LED Program.[21]

Those two assumptions underlying the second scenario are questionable. If the much lower LED failure rate is more accurate than the one used in NP's analysis then why was it not used when NP provided an update as requested by PUB-NP-007? Also, it is not clear if the new lower failure rate assumed for LED streetlights is based on long-term data on experience in Newfoundland's climatic conditions. Similarly, if the application of inflation to non-labour materials costs was more appropriate then, again, why did NP not make that change in its response to PUB-NP-007? Moreover, NP does not provide evidence to support the assumption of increasing costs of non-labour materials. The opposite may be the case for LED streetlights, and they appear to be the bulk of the capital costs. The City of Portland stated:

> *The cost of LED fixtures has dropped considerably over the last 15 years. In 2000, each of the ECobra fixtures cost about $500. Today, they are $124. As these lights become the technology of choice for street lighting, costs are expected to continue to decrease.*[22]

And in 2020, the president of Halifax-based LED Roadway Lighting Ltd. stated:

> *Over the years, we've watched the efficiency of LEDs steadily increase and the electronics used to power them, have become very competitively priced. Once the volume started to build, the prices started to drop. Ten years later, we're now selling our LED lights for less than 10% of what we charged in the beginning.*[23]

It is possible that the trend in the purchase cost of LED streetlights has changed or that the cost is experiencing a spike due to supply chain problems but NP has offered no evidence of such. In fact, our most recent evidence is from NL Hydro in its response to CA-NLH-107 in its 2023 CBA. If the information in the quotes given above are still valid then NP should have reduced the purchase cost of the streetlight fixtures rather than increased them.

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20 See Table 3 in NP's response to CA-NP-130.

21 See response to CA-NP-130, Attachment L.

22 City of Portland, Green Purchasing Case Study, Residential LED Street Lights, December 2018 at https://www.portlandoregon.gov/brfs/article/474134

23 Export Development Canada, "Lights and insights: Streetlight company expands into new solutions," December 2020. https://www.edc.ca/en/blog/led-roadway-lighting-cleantech-export-star.html.

Turning back to Table 2, it is clear that lower post-2040 electricity marginal costs and higher discount rates reduce or, at higher discount rates, eliminate the LED Program's advantage over the HSP alternative. Even in the most favourable case, it takes about 19 years for net cost savings to begin to be realized. Also, there are two other considerations that favour the HSP alternative.

- ***Technological improvements***. Under HPS Program, a HPS streetlight would be replaced by a LED fixture only at the end of the HPS streetlight's service life. That means it would take many years for all of them to be replaced. However, it is reasonable to expect that a replacement made in, say, 10 or 20 years' time will be superior to the currently available LED streetlights. Thus, replacing streetlights in accordance with HPS end-of-service life could lead to more efficient, higher quality, and possibly cheaper replacements being installed over much of the 33-year time frame.

- ***Anti rate-mitigation effect***. One of the impacts of the LED Program is the avoided electricity cost. Those avoided costs are NP's savings from reduced purchases from NL Hydro and they are based on estimates of Hydro's marginal costs. However, Hydro's revenues can be expected to fall by more than that because saved electricity would be exported.[24] To make up the lost revenue, Hydro's rates would have to be increased. This is simply the opposite effect of electrification where higher island electricity purchases generate more revenue for Hydro than had the electricity been exported. Any extra burden on Island ratepayers of the anti rate-mitigation effect due to the LED Program is not considered in NP's NPV analysis.

In addition, the *RRAS 2022 Update* complicates a comparison between the LED Program and the HPS Program. That Update indicates that the Holyrood TGS will have to be relied upon much longer than previously planned, possibly to 2030, and that additional generation capacity will have to be added to the Island system by 2030.

It now seems that the Holyrood TGS could be operating in a base-load role for winters up to as late as 2030. This will presumably have an upward impact on marginal energy and capacity costs. On the other hand, once new additional on-Island capacity is in place by 2030, and if by that time the LIL is operating reliably at its 824MW capacity then there could be a large reduction in marginal costs. In short, the marginal cost profile of the Island system may be very different from that in *Marginal Cost Study Update – 2021* on which NP based its comparative analysis of the streetlight programs. If the reliance on the Holyrood TGS is significant and lasts until 2030 then conservation becomes more beneficial, which tends to favour the accelerated replacement of streetlights (i.e., the LED Program). On the other hand, if new Island capacity by 2030 lowers marginal costs more than had been assumed then the post-2030 avoided-electricity-cost benefits of the LED program could go down. Thus, new estimates of marginal costs are needed. Those new estimates should be included in a revised comparative analysis.

In light of all the issues raised above, NP has failed to adequately justify its request for the LED Program capital expenditures for 2023. Prudence is called for here. There should be a reversion to the HPS Program for 2023. Customers would not experience any reduction in service because faulty streetlights would either be repaired or replaced with LED lights; capital expenditure, for which ratepayers must pay,

24 In response to CA-NP-131, NP agrees that Hydro's revenue would fall as a result of the LED Program and that the saved electricity could be exported. It does not compare the lost revenue with the revenue earned from exporting.

would be reduced substantially; and NP would have the option of applying for a re-start of the LED program in 2024 or later. In the interim, NP could re-do its NPV analysis and address issues raised in this submission, e.g., LED failure rate for the Island climate, interest rate considerations, LED streetlights purchase cost trends and, especially, changes to Hydro's marginal costs profile.

Recommendation: The Board should ***not*** approve the expenditure of $5.453 million for the LED Program as requested in NP's 2023 CBA. NP indicates in PUB-NP-007 (Attachment A, Table 1) that the alternative is to spend $0.675 million for the HPS program for 2023.

2.2 **Electric Vehicle Charging Network**

NP's 2023 CBA proposes to spend $594,000 on three EV charging stations. Each station would consist of a fast charger and a level 2 charger. The purpose of these charging stations is to encourage more purchases of EVs. This expenditure is consistent with NP's Electrification Conservation and Demand Management Plan: 2021-2025, (the 2021 ECDM Plan) which has not been approved but is still under consideration by the Board. A parallel ECDM Plan by NL Hydro is also still under consideration by the Board.

The Consumer Advocate has consistently opposed the entry of NP and NL Hydro into the EV charging station market. In particular, the Consumer Advocate has argued against utility ownership of charging stations as a regulated undertaking with capital costs and any operating losses being funded by the general ratepayer. Other reasons for opposing utility ownership and operation of EV charging stations were given in the Consumer Advocate's submission to the Board of March 1, 2021 in relation to NP's 2021 ECDM Plan, and again in a submission dated September 22, 2021 with respect to 2021 Supplemental Capital Expenditures for Utility-Owned EV Charger Infrastructure, which the Board had removed from the 2021 ECDM Plan and treated separately.

While the Board has yet to make a decision on NP's 2021 ECDM Plan (as well as Hydro's associated Plan), the Board did approve the 2021 supplemental application, which was for capital expenditure by NP on 10 charger stations; see Board order P.U. 30(2021).[25] In its Reasons for Decision Order No. P.U. 30(2021), the Board stated (p.13):

> *...the Board would like to highlight that the approval of the supplemental 2021 EV charging station capital expenditures is based on the unique circumstances in the province at this time. The circumstances surrounding electrification programming are rapidly changing and this may require different approaches in the future with respect to EV charging station capital expenditures. In future years the utilities will have to demonstrate that further capital expenditures for additional EV charging stations are justified in the circumstances.*

Circumstances have changed dramatically. In a letter, dated July 8, 2022, to the Board regarding NP and NL Hydro's ECDM Plans, the Consumer Advocate raised, among other things, the question of proceeding with electrification should the LIL not be available to eliminate reliance on the Holyrood TGS as a base-load generator during the winter months. Now, we have new information indicating that the LIL will not be reliably available for some time. The *RRAS-2022 Update* implies that there is a much

25 Capital expenditures were also approved for NL Hydro for nine EV charging stations.

greater chance of that being the case than when the Board issued P.U. 30(2021). In the new circumstances, Holyrood will likely be needed for base load in the winter months for several years. If so, then EVs would run on electricity generated by burning oil, which is both dirty and expensive. Such an outcome is completely contrary to the objective of electrification.

The *RRAS-2022 Update* strikes at the rationale for all electrification initiatives until the LIL and other Muskrat Falls issues are resolved. No more electrification measures should be undertaken for as long as the Holyrood TGS serves as a base-load facility for the high-load winter months. On this basis, NP's request for approval of capital expenditure for EV charging stations should not be granted.

While the findings of the *RRAS – 2022 Update* are pivotal, there are other concerns that reinforce the recommendation not to approve those capital expenditures. They are summarized below.

- The capital cost of the EV charging stations is much higher than estimated in NP's 2021 ECDM Plan. In response to CA-NP-133, NP indicated that the capital cost is 33% more. This is an extra cost that will be borne by ratepayers under current arrangements.

- There is more scope for the private sector to enter the public EV charging market. Federal mandates for EV purchases will have effect in the near future; at least 20% of new light-duty vehicle sales must be zero-emission vehicles by 2026.[26] Moreover, in September 2022, the Canada Infrastructure Bank announced a new $500 million fund to assist private business investment in charging infrastructure for zero-emissions vehicles.[27] If NP and NL Hydro were not to enter this market any further then these developments would incentivize private business entry prior to 2026.

- The pricing for use of EV charging stations is an unresolved issue. If the utilities were generating enough revenue from government incentives and purchases of electricity by EV owners at utility-owned charging stations then this would not be an issue. However, that is not the case. In response to CA-NP-179e, NP indicates that costs will be recovered from the Electrification Cost Deferral Account. And in response to CA-NP-179 NP indicates that it does not set its price for EV charging with an aim to recover cost, but copies the prices charged elsewhere in Atlantic Canada. Setting a price based on what occurs somewhere else where circumstances may be very different is not appropriate. The Board should establish the price with an aim to striking a balance between the burden on the main beneficiaries, i.e., customers of EV charging stations, and other ratepayers.

Recommendation: The Board should ***not*** approve the $594,000 for EV charging stations.

2.3 Transmission Line 55L Rebuild

NP's CBA is seeking approval to rebuild transmission line 55L. The capital cost is $10.6 million over two years: $5.3 million in 2023 and $5.3 million in 2024. The application is seeking approval for both years.

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26 Automotive News Canada, March 29, 2022. https://canada.autonews.com/government-regulations/canadas-climate-plan-includes-ev-sales-mandate-increased-rebates
27 https://cib-bic.ca/en/medias/articles/cib-launches-500-million-charging-and-hydrogen-refuelling-infrastructure-initiative/

In report 3.1 - 2023 Transmission Line Rebuild, it is stated (section 6.0):

> *Transmission Line 55L is a radial line that is critical to the delivery of reliable service to approximately 3,400 customers in the Placentia area. The line was constructed in 1971, is not built to current design standards, and is experiencing significant levels of deterioration. The line's sub-standard design and deteriorated condition have caused equipment failures, which have resulted in customer outages and significant maintenance costs.*

The report notes the following with respect to outages on this transmission line:

- A "*severe storm event*" in 2017 resulted in customers experiencing a 4.5-hour outage.
- A "*similar outage due to a wind storm in 2020, resulting in a total of approximately 817,000 customer minutes of outage*."
- "*Over the last two decades, customers served by Transmission Line 55L have experienced over 10 million minutes of outage*."

On closer examination, the image presented by NP is less worrisome than presented. The severe storm event in 2017 was classified as a significant event so was not included in NP's SAIDI and SAIFI statistics (CA-NP-169). NP indicates in CA-NP-172 that there have been no outages on this line since the last inspection. NP shows that SAIFI for this line has been 1.0 in 4 of the past 10 years, and 0 in the other 6 years (CA-NP-176) meaning there has been a total of 4 outages on this line in the past 10 years.

In CA-NP-176 NP states "*The Company does not rely on reliability indices, which are lagging indicators, to justify capital upgrades on its transmission system. Doing so would result in a poor quality of service being experienced by large numbers of customers*." If NP does not rely on reliability indices, then why did NP provide historical outage information in the Application and state as part of the justification for the project that equipment failures have resulted in customer outages?

With respect to maintenance of line 55L, costs have averaged only $30,340/year over the past 10 years (CA-NP-176), and less than $30,000/year since 2018 (CA-NP-109). One would expect that a deteriorated line would have required much higher maintenance costs, particularly in more recent years.

The evidence relating to reliability and maintenance costs does not support NP's claim that "*The line's sub-standard design and deteriorated condition have caused equipment failures, which have resulted in customer outages and significant maintenance costs.*"

Further, NP has not quantified: 1) the risk of project deferral, 2) the expected improvement in reliability, and 3) the expected improvement in maintenance costs as requested in CA-NP-176. In Schedule B (page iii) it is stated "*Newfoundland Power does not currently have the data or software necessary to provide calculations of risk mitigation or reliability improvement.*" NP notes that it has "*developed a methodology to provide consistency in its assessment of risks across projects and programs*", but as NP points out, this is not a quantification of the risk of project deferral, and in the opinion of the Consumer Advocate, has numerous deficiencies and provides little useful information. NP does not quantify the expected improvement in maintenance costs owing to the project, stating only that operating and maintenance costs are expected to be improved. It is not clear why NP is unable to quantify the cost improvements.

NP conducts annual inspections of line 55L "*In accordance with its Transmission Inspection and Maintenance Practices*" (NLH-NP-031). Under this program NP has had to replace only 8 poles in the past 5 years, and none since the last inspection, and there have been no outages of the line since the last inspection (CA-NP-172). But the 2022 inspection "*determined that the line had deteriorated to the point that 253 of 490 poles on the line required replacement. In addition, 61 structures were identified as either having deteriorated insulators, crossarms, or hardware deficiencies*." What has happened in the past year that elevated the number of required pole replacements to 253 when they have been averaging only 1.6 pole replacements per year over the past 5 years? Did a significant storm damage these poles? It seems unlikely since there have been no outages of the line since the last inspection and NP offers no evidence to support such a claim. Was there a sudden wood boring insect infestation? Again, NP offers no such evidence.

Neither is it clear why the entire line must be replaced rather than only the damaged poles. In CA-NLH-074b (Hydro's 2023 CBA) Hydro was asked:

> *If Hydro determined that, for example, 50% of the wood poles on a transmission line were deteriorated and required replacement, would Hydro replace the entire line or only the 50% of the poles that were deteriorated and required replacement?*

Hydro responded:

> *If 50% of the wood poles on a transmission line were found to be deteriorated through condition assessment procedures established under the wood pole program, Hydro would perform a cost-benefit analysis to determine whether the whole line should be replaced. However, Hydro has never encountered such a high pole-rejection rate in a single inspection cycle and does not expect to, based on condition assessments completed to date.*

Indeed, it is difficult to understand how such a high pole-rejection rate can occur in a single inspection cycle. It is understood that Hydro will be submitting to the Board a further update on its Wood Pole Line Management Program reflecting data obtained through the program's first 20 years (CA-NLH-041 from Hydro's 2023 CBA). It appears that NP's Transmission Inspection and Maintenance Practices program is suspect and in need of help. It would be wise for the Board to defer any approvals of NP's Transmission Line Rebuild Program until the results of Hydro's update are filed and NP develops a Transmission Inspection and Maintenance Practices program that reflects industry best practice.

In summary, the Line 55L Rebuild project has not been adequately justified by NP and that two-year project, entailing $5.3 million in each of 2023 and 2024, should be deferred.

Recommendation: The Board should ***not*** approve $10,612,000 million ($5.328 million in 2023 and $5.284 million in 2024) for the Transmission Line 55L Rebuild project. The Board should direct NP to continue to maintain the line and incorporate information gleaned from Hydro's Wood Pole Line Management Program Update in its Transmission Inspection and Maintenance Practices program.

2.4 <u>Distribution Reliability Initiative – Feeder SUM-01 Refurbishment</u>

The cost of the project to refurbish distribution feeder SUM-01 is $1,671,000 ($656,000 in 2023 and $1,015,000 in 2024). In report 1.1 - Distribution Reliability Initiative it is stated (section 7.0):

> *The Company reviewed the performance indices and Responder data for distribution feeder SUM-01 to identify the cause of the poor service reliability experienced by customers on New World Island. An engineering assessment determined that capital upgrades to replace deteriorated conductor, address other deficiencies and install downline reclosers would address the poor service reliability experienced by these customers. A two-year project is proposed to address these deficiencies at a total cost of $1,671,000.*

In CA-NP-176, NP indicates that this is the only project included in its 2023 CBA that is justified on the basis of improvements in SAIDI and SAIFI. NP goes on to say, "*This project involved rebuilding a section of distribution feeder SUM-01 which is among Newfoundland Power's worst performing feeders.*"

Although this project is being justified on the basis of SAIDI and SAIFI improvements, NP does not specify the criteria used to determine when a feeder requires refurbishment. NP indicates that it uses reliability criteria to decide if an engineering assessment is warranted (CA-NP-157). However, the engineering assessment documented in section 3.3 of report 1.1 has done little more than suggest the feeder is in poor condition and "*is becoming more susceptible to failure when exposed to wind, ice and snow loading.*" The same can be said about every feeder on the system – all feeders are more susceptible to failure when exposed to wind, ice and snow loading over time. Such an assertion is not evidence.

As noted in CA-NP-176, NP has not quantified: 1) the risk of project deferral, 2) the expected improvement in reliability, and 3) the expected improvement in maintenance costs. As noted earlier (section 2.3 of this submission), "*Newfoundland Power does not currently have the data or software necessary to provide calculations of risk mitigation or reliability improvement*" and NP's risk matrix does not quantify the risk of project deferral. Neither does NP quantify the expected improvement in maintenance costs owing to the project.

NP did not canvas customers served by the feeder about service reliability or the value they place on improved reliability. NP does not track customer complaints relating to reliability of this feeder. This information was requested in CA-NP-176, but was not provided. The cost to refurbish the feeder was identified, but the information necessary to justify the project and gauge its merits was not. There is no way for intervenors to judge if refurbishing this feeder is more desirable than refurbishing any other feeder on the system. Given the importance of reliability to customers, and NP's position that the project is justified on the basis of improved reliability, the project cannot be approved. The justification for this project is sorely deficient.

Recommendation: The Board should ***not*** approve $1,671,000 to refurbish distribution feeder SUM-01.

2.5 Distribution Feeder Automation – Installation of Downline Reclosers

NP proposes to install 17 downline reclosers under its Distribution Feeder Automation program at a cost of $1,054,000 in 2023. Schedule B (pages 12-16) in the Application addresses the Distribution Feeder Automation program. The justification for the expenditure follows:

> *The Distribution Feeder Automation project is required to provide customers with reliable service at the lowest possible cost as it will support maintaining Newfoundland Power's efficiency and effectiveness in response to customer outages.*

On page 14 of Schedule B NP states:

> *The 2023 Distribution Feeder Automation project is consistent with the approach Newfoundland Power adopted in 2020 and Recommendation 2.4 of The Liberty Consulting Group's Report on Island Interconnected System to Interconnection with Muskrat Falls addressing Newfoundland Power.*

In CA-NP-045 NP was asked with respect to the reclosers project if either Liberty or NP considered cost relative to service improvement. The response states "*Yes, both Liberty and Newfoundland Power considered cost relative to service improvement ...*". However, Liberty recommended (Footnote 3):

> *Investigate the installation of downstream feeder reclosers for the purpose of improving distribution SAIFI and SAIDI indices, in addition for reducing cold load pick up difficulties, with priorities given to feeders based on installation costs versus anticipated avoided customer interruptions.*

Therefore, Liberty did not consider cost, but recommended that NP consider cost by prioritizing feeders based on installation costs versus anticipated avoided customer interruptions. NP was asked if it carried out the analysis recommended by Liberty (CA-NP-177) and responded:

> *Newfoundland Power has not completed the analysis identified in this Request for Information. The Company is not installing downline reclosers for the purposes of improving distribution SAIFI or SAIDI.*

So, NP is justifying the project on the basis that it "*is required to provide customers with reliable service at the lowest possible cost as it will support maintaining Newfoundland Power's efficiency and effectiveness in response to customer outages*" and uses Liberty's recommendation to support the project, but then states that the project is not being pursued to improve SAIDI and SAIFI as recommended by Liberty, and that it did not carry out the cost analysis recommended by Liberty. Could an argument to justify a project be any more convoluted?

In CA-NP-045 NP states "*The Company's plan balances the cost of installing downline reclosers and anticipated avoided customer interruptions by applying deployment scenarios*." On page 12 of Schedule B NP describes the deployment scenarios as follows:

(i) Scenario 1 – Deployment of a single downline recloser such that approximately one third of the feeder load is downstream of the downline recloser, and the remaining two thirds of the load is upstream.
(ii) Scenario 2 – Deployment of multiple downline reclosers on a feeder such that approximately one third of the feeder load is downstream of the first downline recloser, one third of the load is between the first and second downline recloser, and the remaining one third of the load is upstream of the second downline recloser. This is typically used for larger feeders with the highest number of customers.
(iii) Scenario 3 – Deployment of downline reclosers at normally open tie locations on feeders that have downline reclosers installed.

These scenarios make no mention of the words "cost" or "reliability". The deployment scenarios do not justify the project and provide no useful information to the Board upon which to gauge the merits of the project. The deployment scenarios do not quantify the expected improvement in reliability resulting from the project. The risk associated with project deferral is not quantified (the cost resulting from a failure multiplied by the probability of failure); neither are improvements in operating and maintenance costs quantified (see sections 2.3 and 2.4 of this submission, and CA-NP-176). As already noted, NP does not canvas its customers about service reliability or the value they place on improved reliability, and does not track customer complaints relating to reliability (CA-NP-176). The cost of the program is identified, but the information necessary to justify the project and gauge its merits is not, and NP did not conduct the cost/benefit analysis recommended by Liberty (CA-NP-151). The evidence necessary to justify this project is sorely deficient.

Recommendation: The Board should ***not*** approve $1,054,000 to install 17 downline reclosers in 2023 under the Distribution Feeder Automation program.

2.6 <u>Substation Spare Transformer Inventory – Purchase Spare Transformer</u>

NP proposes to purchase a spare power transformer under its Substation Spare Transformer Inventory project at a cost of $1,500,000 in 2023. In report 2.2 - Substation Spare Transformer Inventory (Section 5.0) it is stated:

> *Newfoundland Power's customers are exposed to increasing risk of extended outages due to the failure of aging and deteriorated power transformers. An assessment of alternatives determined that procurement of spare power transformers has become necessary to maintain an adequate inventory of units that can be readily deployed in response to equipment failures. Maintaining a reasonable inventory of spare units is consistent with current utility practice, will help mitigate risks of extended customer outages and is necessary to continue delivering reliable service to customers at the lowest possible cost.*

NP states:

> *The Company maintains an inventory of spare power transformers to respond to failures and ensure the delivery of reliable service to customers. The Company's inventory of spare power transformers has historically relied on units that were removed from service due to load growth. The inventory is*

therefore limited and is expected to diminish going forward due to the current low-growth environment.

The Province's electricity sector is currently in a low-growth environment, but that is expected to change as a result of the government's zero-carbon effort and electrification. In the *RRAS – 2022 Update*, it is stated:

> *Electricity Canada has published that Canada will need 121 TWh of new supply just to replace carbon-based sources of electricity by 2035. This is equivalent to adding four Churchill Falls or 25 Muskrat Falls.*
>
> *That 121 TWh is based on current loads. Climate change action requires other industries to decarbonize and move to clean electricity sources. This means the current whole electricity sector will need to grow by a factor of 2 or 3, or more.*

It is puzzling that NP makes no mention of this in the Application because NP itself has proposed an electrification program to accelerate growth of electricity demand. Stagnant growth in electricity demand is not expected to continue, so any spare power transformers purchased could soon become stranded. In CA-NP-058 NP states:

> *Newfoundland Power plans to maintain an adequate inventory of spare transformers through the procurement of conventional spares that will be placed into service upon the failure of an in-service unit. Newfoundland Power will assess the condition of its spare transformers and its inventory requirements annually to determine the need for any additional spare units. The Company will seek Board approval of any additional spare units through future capital budget applications.*

Therefore, Board approval of the purchase of a spare transformer in this Application promises to lead to further capital spending on purchases of spare transformers in future applications.

If electrification (e.g., installation of home EV chargers) leads to an increase in electricity demand, there will continue to be a need to replace existing transformers with higher capacity transformers to meet the increased demand. This would mean a return to the past when there was no need to purchase individual spare transformers because the transformers that are replaced with higher capacity transformers would serve as spares, the same scenario that has been used by NP for many years.

Therefore, a clearer view of the impacts of electrification and the government's climate change initiative on electricity demand in the Province is needed before embarking on an expensive program to purchase individual spare transformer units that may soon become stranded assets. Increasing electricity demand as indicated in the RRAS – 2022 Update would enable NP to continue relying on transformers that are removed from service due to load growth to supplement its spare transformer inventory, and eliminate the need to purchase spare transformers.

Recommendation: The Board should ***not*** approve $1,500,000 in 2023 for the purchase of a spare power transformer.

3. Recommendations Summary

The Provisional Capital Budget Application Guidelines state:

> *Annual capital budget applications shall include comprehensive information and supporting documentation to enable the Board and interested persons to understand the nature, scope and justification of the proposed individual capital expenditures and the annual capital budget. The application must demonstrate that the proposals are reasonable and necessary for the provision of service at the lowest possible cost consistent with reliable service. The support provided should justify the proposed capital budget and each capital expenditure showing that all reasonable alternatives were considered, including the status quo and deferral.*

Further, as stated by NP (CA-NP-128 relating to NP's 2021 CBA) "*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.*"

This submission has identified six projects in NP's CBA 2023 which have not been sufficiently justified. Those projects are identified in Table 3. NP has failed to include comprehensive information and supporting documentation necessary to demonstrate that the projects are reasonable and necessary for the provision of service at the lowest possible cost consistent with reliable service.

Table 3

Proposed Project	***2023 Cost***	***2024 Cost***
LED Street Lighting Replacement Program	$5,453,000	
Electric Vehicle Charging Network	$ 594,000	
Transmission Line 55L Rebuild	$ 5,328,000	$5,284,000
Distribution Reliability Initiative - Feeder SUM-01 Refurbishment	$ 656,000	$1,015,000
Distribution Feeder Automation – Installation of Downline Reclosers	$ 1,054,000	
Substation Spare Transformer Inventory - Purchase Spare Transformer	$ 1,500,000	
Total	***$14,585,000***	***$6,299,000***

The LED Street Lighting Replacement program has an alternative, namely, the HPS Program. We ask that the Board approve NP's indicated funding for that alternative in the amount of $674,810 for 2023.

Thus, this submission calls for a reduction of $13,929,000 (= $14,585,000 - $674,810) from NP's request for approval of $103,675,000 for 2023 and a reduction of $6,299,000 from its request for approval of $10,645,600 for 2024.

Finally, NP's 2023 CBA also requested Board approval of a 2021 rate base in the amount of $1,202,946,000. This is a very large number. We reiterate our concern about high capital expenditures continuing to add to the rate base, the cost and risk of which are borne by ratepayers.

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

Yours truly,

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/bb

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