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Comments on Newfoundland Power's 2022 Capital Budget Application

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1 INTRODUCTION

Newfoundland Power ("NP") filed its 2022 Capital Budget Application ("2022 CBA") with the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB" or "Board") dated May 18, 2021. After reviewing the 2022 CBA, Bernard Coffey, on behalf of the Newfoundland and Labrador Consumer Advocate ("CA") retained Elenchus Research Associates Inc. ("Elenchus") to prepare a report[1] assessing NP's 2022 capital budget taking into account the following perspectives:

1. The Generally Accepted Regulatory Principles ("GARP") that are applicable to reviewing the capital plans of regulated monopolies.
2. The standard practice of the Canadian economic regulators that set rates for electric utilities for reviewing the capital budgets of the utilities they regulate.
3. The trends in NP's annual capital expenditures (i) applied for, and (ii) approved, as compared to the corresponding trends of other regulated electric utilities across Canada.
4. The prospective impact on trends in capital expenditures as a result of the increased reliance on non-wires alternatives ("NWAs") such as distributed energy resources ("DERs"), including (i) distribution-connected and behind-the-meter renewable generation (e.g., solar) and storage, (ii) automated load control, and (iii) behavioural incentives such as demand response programs and time-of-use rates.

The report contains four additional sections. Section 2 provides an overview of Generally Accepted Regulatory Principles within the context of the regulatory regime that guides the Board's processes and decisions. This review includes more detailed review of the regulatory standard of prudence that is relevant for the current proceeding.

Section 3 identifies certain challenges that are relevant to prospective prudency reviews.

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[1] The report has been prepared by John Todd, President of Elenchus with the assistance of Andrew Blair. More information on Elenchus and resumes are available at www.elenchus.ca.

Section 4 presents information on the regulatory reviews of the capital programs of NP and some other Canadian distributors of electricity.

The conclusions of the report are contained in section 5. The key conclusions are:

- NP has not identified a reasonable range of alternative solutions for all capital projects included in the 2022 CBA.
- NP has not identified all relevant information for a reasonable range of alternatives to the capital projects included in the 2022 CBA.
- In the absence of consideration of a reasonable range of alternative solutions based on all relevant information, it is not possible to determine whether the planned investments are the least cost options.
- NP's approach to the economic evaluation of alternatives is consistent with the inherent incentive for an investor-owned utility to prefer alternatives that require high levels of capital investment, as evidenced by the focus on high capital cost project alternatives with minimal consideration of the industry modernization trend that is turning to lower capital cost, more flexible alternatives, including DERs.

2 RELEVANT GENERALLY ACCEPTED REGULATORY PRINCIPLES

It is generally accepted by regulators, regulated utilities and other stakeholders that the ratemaking process should be based on a set of clearly defined principles. While the phrasing and detail of these principles vary across jurisdictions, in part due to the distinct legislative frameworks that each regulator must operate within, the approaches are sufficiently consistent to have given rise to what are often referred to as "generally accepted regulatory principles" ("GARP").

These principles provide guidance for the ratemaking process which starts with the determination of costs that should be recoverable in rates. An important component of recoverable costs is the allowed rate base. The rate base is determined in large part by the capital expenditures that have been approved by the regulator and have not yet been fully amortized – that is the net book value of capital assets.[2]

The most commonly used reference for defining the objectives of public utility ratemaking is the seminal work of James Bonbright. Chapter 16 (pages 383-384) of the Second Edition[3] sets out ten "attributes of a sound rate structure".[4]

Revenue-related Attributes:

1. *Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality or safety.*

2. *Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.*

3. *Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity.*

Cost-related Attributes:

4. *Static efficiency of the rate classes and rate blocks in discouraging wasteful use of the service, while promoting all justified types and amounts of use:*

   (a) in the control of the total amounts of service supplied by the company;

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2 A utility's rate base typically includes additional items that must be financed on an ongoing basis such as working capital.

3 *The Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports, pages 383-4. The first edition was published in 1961.

4 There have been significant changes in the electricity market since the publication of Bonbright's Second Edition 33 years ago, including widespread competition in the generation sector, retail competition, the emergence of renewable energy generation, and the development of DERs. These changes have implications for the application of the principles to reflect the current market and resource realities (see for example, Rábago, Karl R. and Radina Valova, "Revisiting Bonbright's principles of public utility rates in a DER world", The Electricity Journal, 31 (2018) 9-13) that are consistent with the issues raised in this report.

(b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. *Reflections of all of the present and future private and social costs and benefits occasioned by the service's provision (i.e., all internalities and externalities).*

6. *Fairness of the specific rates in the apportionment of total cost of service among the different ratepayers, so as to avoid arbitrariness and capriciousness, and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).*

7. *Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no inter-customer burdens).*

8. *Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.*

Practical-related Attributes

9. *The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.*

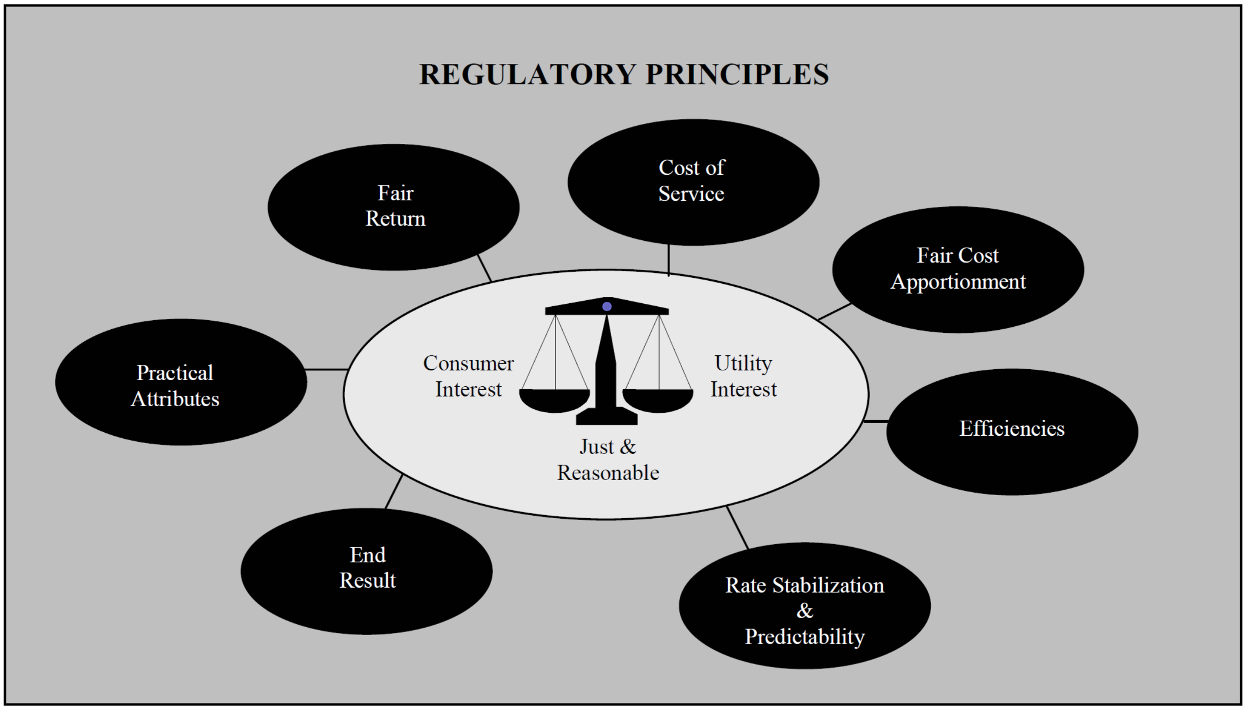
10. *Freedom from controversies as to proper interpretation.*

The PUB summarized its view of the "fundamental principles which are used by regulators as a guide or roadmap to rational decision-making" in Order No. P.U. 19 (2003).[5] This roadmap provides a clear and concise restatement of the ten Bonbright principles that Elenchus evidence has cited as an excellent example of a Canadian regulator providing an unequivocal endorsement of these principles. The Order includes the schematic

[5] The section of Order No. P.U. 19 (2003) discussing regulatory principles is reproduced as Appendix A to this report for easy reference.

(reproduced in Figure 1) that presents a visual summary of the need to balance the interests of consumers and utilities in applying these principles in specific circumstances.

Figure 1 – Regulatory Principles Schematic



Elenchus notes that the PUB subsequently issued Capital Budget Guidelines, Policy Number 1900.6, Revision date October 2007 ("Guidelines") that reflect the regulatory framework set out in Order No. P.U. 19 (2003). For example, the Guidelines include the following Policy Statement:

> *In fulfilling its mandate with respect to the supervision of the capital expenditures of a utility the Board balances the interests of consumers and the utility in the context of the applicable legislative provisions. In balancing these interests the Board is committed to the efficient and effective review and approval of expenditures in keeping with the provision of least cost reliable service.*[6]

As the Guidelines make clear in section IV, Purpose, it only "sets out the format, process, schedule and obligations of the utility and participating parties". It does not include the tests that are to be used in determining whether a capital expenditure will be approved.

[6] Capital Budget Guidelines, Policy Number 1900.6, Revision October 2007, section III.

However, it is evident that the tests for approving capital expenditures must reflect the regulatory principles set out in Order No. P.U. 19 (2003).

Although the identified regulatory principles are relevant in deriving a sound rate structure, not all are relevant considerations for purposes of reviewing a capital program such as that presented in NP's 2022 CBA. In Elenchus' view, the key principles that are relevant to reviewing capital expenditure are contained in the second and sixth principles set out in Order No. P.U. 19 (2003).

> *2. Cost of Service*
>
> *Under this principle a utility is permitted to set rates that allow the recovery of costs for regulated operations, including a fair return on its investment devoted to regulated operations - no more, no less. Costs should be:*
>
> - *<u>prudent</u>;*
> - *used and useful in providing the service;*
> - *assigned based on cause (causality);*
> - *incurred and recovered (matching costs and benefits) during the same period; and*
> - *reflective of private/social costs and benefits occasioned by the service.*
>
> *6. <u>End Result</u>*
>
> *<u>In compliance with the legislation, the end result must be fair, just and reasonable from the perspective of both the consumer and utility</u>.*
>
> [emphasis added]

2.1 THE REGULATORY STANDARD OF PRUDENCE

Central to any review of capital expenditures, including the current regulatory review of NP's 2022 CBA, is the first bullet that appears under the Cost of Service principle which asserts that the costs associated with an expenditure that is to be recovered from ratepayers must be prudent.

The concept of determining whether a cost incurred by a regulated utility was prudently incurred is embedded in the review processes of all Canadian regulators.[7] The PUB examined the regulatory standard of prudence quite thoroughly in the matter of *A Prudence Review by the Board of Certain Projects and Expenditures of Newfoundland and Labrador Hydro*, Decision and Order of the Board Order No. P.U. 13(2016) ("Prudence Review Order").

The Prudence Review Order includes a discussion in section 4.1 of the Regulatory Framework that was applicable. This discussion is consistent with the discussion of the regulatory framework contained in Order No. P.U. 19(2003). Furthermore, it sets out the legislative context:

> *The Board regulates Hydro pursuant to the provisions of the Electrical Power Control Act, 1994, SNL 1994, Chapter E-5. I (the "EPCA") and the Public Utilities Act, RSNL 1990, Chapter P-47 (the "Act"). The regulatory policy framework set out by the legislation requires the Board to balance the interests of Hydro and its customers.*[8]

It then quotes section 4 of the EPCA which includes the following:

> *(b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner*
>
> *(i) <u>that would result in the most efficient production, transmission and distribution of power</u>,*
>
> *(ii) that would result in consumers in the province having equitable access to an adequate supply of power,*
>
> *(iii) <u>that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service</u>,*

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[7] Exceptions exist in some jurisdictions where selected costs are deemed to be prudent by legislation.

[8] Order No. P.U. 13(2016), page 4, lines 8-11. It is my understanding that the relevant provisions of the EPCA apply equally to both Newfoundland and Labrador Hydro ("NLH") and NP.

> *(iv) that would result in, subject to Part II, a person having priority to use, other than for resale, the power it produces, or the power produced by a producer which is its wholly- owned subsidiary,*
>
> *(v) where the objectives set out in subparagraphs (i) to (iv) can be achieved through alternative sources of power, with the least possible interference with existing contracts,*[9]

Based on the commentary in Order No. P.U. 13(2016), Elenchus concludes that the PUB's stated approach is consistent with what we observe as the standard approach of other Canadian regulators. Consistent with GARP, regulators expect the utilities they regulate to adopt the least cost option for meeting the needs of their customers (primarily adequate and reliable service) unless a higher cost is justified as necessary to meet specific government policy objectives (e.g., renewable targets) or to achieve identified and quantified external benefits. Being the least cost option is a key consideration in determining that a capital investment is prudent.

As Order No. P.U. 13(2016) observes, the prudence standards adopted by the Board are generally accepted by regulators across Canada.

> *The standards or tests for determining prudence have been discussed in several jurisdictions. While the standards may be described differently among the various jurisdictions, there are certain common principles.*[10]

This comment is made by the Board in reference to the prudence review standard that it set out in its Terms of Reference for that review.

> *The Board set out in the Terms of Reference the regulatory framework and standards for Liberty to use in its prudence review. The regulatory framework requires that utility management act prudently in making decisions and taking (or deciding not to take) actions that involve or affect assets, personnel, and operations related to the provision of service to customers. Management's decisions and actions must focus*

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[9] Order No. P.U. 13(2016), page 4, lines 28-40, emphasis added.

[10] Order No. P.U. 13(2016), page 6, lines 22-24.

on promoting the delivery of safe, adequate, reliable, and least-cost service to their customers. Prudent decisions and actions require that management follow specific practices:

1. *identify all relevant information*
2. *identify a reasonable range of alternative solutions*
3. *test those solutions by applying criteria and values consistent with delivery of safe, adequate, reliable and least-cost service*
4. *choose an option that falls within the range of those properly determined to be reasonable*
5. *act with the level of dispatch and care consistent with the timing needs for making a decision or taking action*[11]

Elenchus observes that while the prudence review standard was set out by the PUB for its retrospective review of selected capital and operating costs incurred by NLH, standard regulatory practice applies the same concepts of prudence for the prospective review of proposed expenditures as it does for a retrospective review. The primary difference between a prospective review and a retrospective review is that the latter may be constrained by the no-hindsight concept discussed below. This concept is not relevant for a prospective review since the expenditures have not been committed.

In the view of Elenchus, because the no-hindsight principle is a consideration in retrospective reviews, it is extremely important that the prudence review standard for a prospective review be no less stringent than the prudence review standard that is applied for retrospective reviews of similar expenditures. The symmetry of prospective and retrospective prudence standards is critical because advance regulatory approval of an expenditure will provide support for the case that the expenditure was prudent given the information that was available at the time that the investment decision was made (i.e., recognizing the no-hindsight test). Hence, in order to reasonably balance the interests of the utility and its customers, it is desirable to reduce the risk of retroactive cost

[11] Order No. P.U. 13(2016), page 6, lines 6-20.

disallowances by ensuring that all elements of the prudence review standard have been met before capital expenditures receive regulatory approval. This approach is also in the interest of customers because it reduces the risk that an investment that would not meet the prudence review standard, if stringently applied, is allowed into rate base.

The relevant applicability of the no-hindsight principle was explicitly addressed in Order No. P.U. 13(2016).

> *The Nova Scotia Utility and Review Board further determined that the definition of imprudence, while it may vary among jurisdictions, has the following fundamental principles:*
>
> - *Were the utility's decisions unreasonable in the context of information that was known (or should have been known) at the time?*
> - *Did the utility act in a reasonable manner and use a reasonable standard of care in its decision-making process?*
> - *The imprudency test should relate to the circumstances at the time in question and not to hindsight.*[12]

In Part Three: Discussion and Board Findings of Order No. P.U. 13(2016), the PUB provided additional clarification of the prudence review standard that it deemed to be applicable in light of court decisions that were released during the proceeding.

The PUB noted that following points.

> - *The Court recognized in both decisions that a prudence review is a valid and widely accepted tool with which regulators assess whether costs incurred by a utility are just and reasonable.*[13]

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[12] Order No. P.U. 13(2016), page 6, lines 36-44, emphasis added. The general applicability of these principles is discussed on the next page of the Order.

[13] Order No. P.U. 13(2016), page 37, lines 20-22.

- *The Court also confirmed that a regulatory tribunal has discretion in how it chooses to assess prudence, except where the legislation under which the tribunal operates expressly requires a specific methodology.*[14]
- *Also, the Court found that, while the prudence test is normally applied to capital costs, there is no reason it cannot be applied to operating costs as well.*[15]

…

- *In Ontario (Energy Board) the Court differentiated between types of cost under review, specifically whether the cost was a committed or a forecast cost:*

  [82] Forecast costs are costs which the utility has not yet paid, and over which the utility still retains discretion as to whether the disbursement will be made. A disallowance of such costs presents a utility with a choice: it may change its plans and avoid the disallowed costs, or it may incur the costs regardless of the disallowance with the knowledge that the costs will ultimately be borne by the utility's shareholders rather than its ratepayers. By contrast, committed costs are those for which, if a regulatory board disallows recovery of the costs in approved payments, the utility and its shareholders will have no choice but to bear the burden of those costs themselves. This result may occur because the utility has already spent the funds, or because the utility entered into a binding commitment or was subject to other legal obligations that leave it with no discretion as to whether to make the payment in the future, [Fn. 56: Ontario (Energy Board), *paragraph* 82 *(Appendix* A of *Hydro's Submission)]*[16]

- *Similarly, the Court stated in Atco Gas;*

  As explained in OEB, understanding whether the costs are committed or forecast may be helpful in reviewing the reasonableness of a regulator's

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[14] Order No. P.U. 13(2016), page 37, lines 22-24.

[15] Order No. P.U. 13(2016), page 37, lines 24-26.

[16] Order No. P.U. 13(2016), page 37, lines 31-41.

> *choice of methodology: see para. 83. Committed costs are those costs that a utility has already spent or that were committed as a result of a binding agreement or legal obligation that leaves the utility with no discretion as to whether to make the payment in the future: para. 82. If the costs are forecast, there is no reason to apply a no-hindsight prudence test because the utility retains discretion whether to incur the costs: para. 83. By contrast, the no-hindsight prudence test may be appropriate when the regulator reviews utility costs that are committed. [Fn. 57: Atco Gas, paragraph 48; Hydro's Submission, page 4]*[17]
>
> - *As will be explained, particularly with regard to committed capital costs, prudence review will often provide a reasonable means of striking the balance of fairness between consumers and utilities. [Fn. 58: Ontario (Energy Board), paragraph 104 (Appendix A of Hydro's Submission)]*[18]

The Board concluded its discussion of the prudence review standard as follows:

> *The Board is satisfied that a no-hindsight methodology is appropriate in reviewing the prudence of the costs at issue here and that this approach is fair to both the utility and consumers. The Board also notes that no party suggested another methodology or test should be applied. In assessing whether particular costs are reasonable and prudent, the Board will therefore consider information that was known or ought to have been known by Hydro at the time of the decision or action, whether Hydro's decision or action was reasonable in the circumstances, and whether it was within the range of reasonable alternatives a utility would choose. Hindsight will not be used in determining the prudence of costs under review.*[19]

Elenchus concludes that in order for the PUB's review of NP's 2022 CBA to be consistent with both generally accepted prudency review standards and the Board's own stated prudency review standards, the following questions need to be addressed fully.

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[17] Order No. P.U. 13(2016), page 38, lines 1-10.

[18] Order No. P.U. 13(2016), page 38, lines 25-27.

[19] Order No. P.U. 13(2016), page 39, lines 31-38.

1. **Has a reasonable range of alternative solutions been identified?** The alternatives considered will normally include (i) design alternatives, (ii) technological alternatives, (iii) the deferral alternative, and (iv) the do nothing alternative. It will normally be expected that all alternatives that do not have unacceptable implications in terms of maintaining an adequate, reliable and safe supply of power be considered in a cost-benefit analysis that compares the feasible alternatives.

2. **Has all relevant information been identified?** If there are significant gaps in the information identified and used in the comparison of alternatives, the utility's burden of proof will not have been met. Ideally, significant information gaps can be addressed and the comparison of alternatives updated on a timely basis to permit the regulator to make a decision that is fully informed. If there is a compelling reason to proceed with a proposed investment when the burden of proof has not been met (e.g., a proposed capacity upgrade is proposed on a "just-in-time" basis, or to address a serious safety issue, leaving insufficient time to address the information gaps), it would be reasonable for the regulator to relieve itself of the no-hindsight limitation on a retrospective review by advising the utility that approval is not unconditional. In other words, if the utility has not met its burden of proof although it could have with a more complete analysis of alternatives, it may be required to proceed with its planned investment knowing that there may be a retrospective review that will take into account what the utility "should have known" in advance of its decision. While this caveat is relevant for retrospective reviews in any case, an explicit warning by the regulator that the utility had not met its burden of proof would provide the regulator with greater latitude to disallow a cost subsequently.

3. **Is the planned investment the least cost option?** There is a regulatory requirement to limit cost recovery to the least cost option unless the utility provides a compelling rationale for choosing a more expensive alternative. In some cases, such as consideration of Non-Wire Alternatives (NWAs) to traditional capacity enhancements, the comparison of alternatives will require scenario analysis that includes an

assessment of the risks and uncertainty for the reasonable alternatives.[20] Scenario analysis is particularly important in cases where the alternatives have significantly different investment horizons, or significantly different proportion of capital and operating costs. For example, an alternative with a short service life may offer significant value in terms of future flexibility (option value) that justifies a higher total cost over the service life of the longest-lived alternative. In these types of comparisons of alternatives, the assumptions used regarding long term trends in the inherently uncertain demand for grid electricity and the differences in cost trends for the alternatives can be the primary determinant of the relative cost as measured using either a net present value ("NPV") or levelized cost calculation.

4. **Does the utility's approach to the economic evaluation of alternatives reflect the inherent bias for an investor-owned utility to prefer alternatives that require high levels of capital investment?** There is an extensive academic literature addressing the Averch-Johnson Effect[21] ("A-J Effect") that details the financial incentive for regulated utilities to seek to maximize their reliance on capital investment, which earns a return under the traditional rate-base rate-of-return rate-setting model (thereby increasing shareholder profit) rather than operating costs which are passed through in rates with no markup that enhances profits. Regulatory recognition of this bias has been an important driver for regulators in many jurisdictions around the world to adopt various forms of incentive regulation (a.k.a., performance based regulation) which

[20] NWAs can also serve to reduce costs by enabling a utility to defer a larger investment. Deferring a larger investment may be particularly beneficial if there is uncertainty about the assumptions driving the need for the larger investment, such as the adoption rate of heat pumps, the adoption rate of self-generation (reducing demand), the adoption rate of EVs (increasing demand), or the rate at which cost will decline for emerging technologies.

[21] This label has arisen since the concept rose to prominence as a result of the 1962 article: Averch, Harvey; Johnson, Leland L. (1962). "Behavior of the Firm Under Regulatory Constraint". American Economic Review. 52 (5): 1052–1069. JSTOR 1812181. The following contemporary non-technical description of the A-J Effect (also known as goldplating) can be found in Wikipedia.

> *The Averch–Johnson effect is the tendency of regulated companies to engage in excessive amounts of capital accumulation in order to expand the volume of their profits. If companies' profits to capital ratio is regulated at a certain percentage then there is a strong incentive for companies to over-invest in order to increase profits overall. This investment goes beyond any optimal efficiency point for capital that the company may have calculated as higher profit is almost always desired over and above efficiency.*

mitigates the A-J Effect.[22] In the absence of some form of incentive regulation, regulators must rely on a formalized capital review process, either along the lines of the CBAs undertaken by the utilities regulated by the PUB, or through similar reviews of proposed capital expenditures as part of a general rate application that reviews test year operating, maintenance and administration (OM&A) costs as well as proposed capital expenditures.

Many regulators have adopted incentive regulation because they have also been concerned about the information asymmetries that are inherent in the traditional regulatory process since the applicants have significant control over the information provided to the regulator. Incentive regimes are designed to reward utilities for identifying and implementing opportunities for increased operational efficiencies. This approach is based on the principle that the utility is in the best position to find efficiencies and will do so when appropriate incentives are in place. In the absence of the financial incentives that are relied on by the various forms of incentive regulation, the primary tools available to economic regulators are expenditure caps on the allowed capital budget envelope (and in some cases on specific major projects) and disapproval or deferral of specific proposed projects.

3 THE CHALLENGES OF PROSPECTIVE PRUDENCY REVIEWS

It has long been recognized that regulators face several challenges in conducting prudency reviews, including:

- Forecasts are inherently uncertain (costs, customer demand, weather, etc), and
- Rate base rate of return regulation creates a bias (the A-J Effect discussed above) for regulated utilities to favour capital expenditures over operating and

[22] The original version of incentive regulation was developed by Stephen Littlechild, a UK Treasury economist in the 1980s. Since then, it has been applied to all privatized British network utilities. For a relatively recent overview of performance based regulation ("PBR") see: Elenchus Research Associates, Inc., Report for the Régie de l'énergie, Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Québec Distribution and Transmission Divisions.

maintenance (non-capitalized) expenses and to maximize the capital expenditures on which they earn a return.

Adding to these traditional challenges are the potential impacts of the current transformation of the electricity market that is undermining some of the central assumptions embedded in the traditional approach to conducting the economic analysis of capital projects involving long lived assets.

3.1 THE EVOLVING PERSPECTIVE ON THE USEFUL LIFE OF ASSET

Since the emergence of the regional monopolies that have dominated the electricity sector in generation, transmission and distribution of electricity in Canada and other developed countries, regulators have required these monopolies to demonstrate that they have appropriately sought to minimize costs by requiring utilities to provide a comparison of the costs of the reasonable alternatives (generally, in the form of a business case for the proposed investment). The comparison of alternatives has typically relied on economic analysis methods that assume that grid assets will remain used and useful for the full duration of the expected service life of the assets considered. No distinction was drawn between the economic life of an asset and its physical life. This approach was reasonable when technological alternatives to the grid did not exist, or were uneconomic in most circumstances. However, it is not reasonable at this time when technological advancement and declining DER costs are transforming the electricity sector.

The validity of this assumption is becoming doubtful, however, due to the declining relative cost of behind the meter self-generation and storage, the expanding adoption of behavioural incentives such as demand side management and demand response programs, and increased accessibility to automated load control technologies. These developments reduce both the capacity and the energy requirement for grid-dependent electricity. Put simply, the grid and the utilities that supply customers with electricity through the grid are facing a future where customers have increasingly attractive competitive alternatives to the grid.

One of the implications of the modernization of the grid is that the expected service, of physical, life of capital assets, which in many cases may reasonably be expected to be half a century or more, will not be relevant for the economic analysis used to compare investment alternatives. If a significant proportion of customers adopt non-grid options for their electricity supply in the coming decades, some of the existing grid assets will become stranded as demand for grid-dependent supply shrinks.[23] For example, self-generation and storage, perhaps using a combination of solar power, battery backup and fuel cell technologies, could encourage grid independence. A driver of grid independence, in addition to price, could be the increased reliability that could result from not relying on a grid that is vulnerable to weather incidents and storm damage. Reliability will become a more powerful driver if climate change results in continued increases in the frequency and severity of the kind of storms and fires that threaten trees and above-ground wires.

Given the increasing uncertainty about the long-term value of traditional generation, transmission and distribution grid assets, prudence dictates that options that are less vulnerable to stranding should be given preference over traditional assets, even if their expected cost is modestly higher based on a scenario in which market disruptions are more benign than the more dire scenarios that can be envisioned. The comparison of alternatives needs to move from a simplistic NPV analysis to scenario analyses that will help avoid the most severe risks of harm to future generations of ratepayers. The worst scenario for future ratepayers and shareholders is one in which utilities commit to expensive long-lived assets that end up being underutilized or abandoned. A scenario that involves stranded assets raises serious policy questions in terms of who should bear the cost of the stranded assets: investors, ratepayers or government.

In order to manage long term risk, the economic analysis of alternatives could include scenario analysis that examines the implications of a reasonable range of different assumptions regarding costs trends and the economic (as opposed to physical) life of the alternative assets being evaluated. This scenario analysis would provide more complete information for purpose of a prudence review.

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[23] This possibility is the basis of concerns about the so-called “death spiral”. If grid throughput declines, utilities will only be able to recover their fixed embedded cost by increasing rates for the remaining throughput. Rate increases will increase the benefit to customers of grid defection, thereby exacerbating the problem.

3.2 <u>An Illustration of the Impact: Sandy Brook</u>

NP confirms in NLH-NP-020: *The economic analysis of the Sandy Brook Plant Penstock Replacement project includes a study period of 50 years, the expected service life of the new penstock*. (page 1, lines 20-21)

The traditional approach to the economic analysis prepared by regulated utilities to justify capital investments has been to assume that the expected <u>service</u> life of a capital asset corresponds to its expected <u>physical</u> life. NP uses this approach for the economic analysis of its capital projects including the Sandy Brook Plant Penstock Replacement.

If the PUB determines it is prudent for the economic analysis to assume that the Sandy Brook Plant, once the Penstock replacement project has been completed, (i) will be used and useful for 50 years, and (ii) will have an economic value consistent with NP's long term projection, then NP's economic analysis would provide a relevant benchmark for assessing the prudence of the investment based on the information that is currently available (i.e., at the time NP committed to the investment). In other words, unequivocal acceptance of NP's economic analysis will provide NP with a strong basis for arguing in the future that its decision was prudent and, in accordance with the no-hindsight principle, should not be questioned and disallowed in the future, regardless of how future growth of DERs may reduce both the need for, and the value of, the capacity and energy that will be provided by the project.

In Elenchus' view, current uncertainty about the role of traditional grid power supply resources, such as the Sandy Brook Hydro Plant, in 20, 30, 40 or 50 years makes it critically important to ask whether all specific practices listed in the above-quoted discussion of the Prudence Review Standard in Order No. P.U. 13(2016) have been fulfilled. In particular, as stated in the Order (quoted above):

> *Prudent decisions and actions require that management follow specific practices:*
>
> *1. identify all relevant information*
>
> *2. identify a reasonable range of alternative solutions*

With respect to the first "specific practice", Elenchus notes that NP appears to have dismissed any recognition that there is a risk that DERs will disrupt the sector in developed countries (or at least in Newfoundland) and that consumers in Newfoundland will increasingly opt for non-grid supply in the coming half-century. NP's view is exemplified in its response to CA-NP-090 (c) which asked whether NP is "concerned about the utility death spiral". NP states:

> *c) Newfoundland Power is not currently concerned about the utility death spiral. [Fn. 3: Newfoundland Power considers the 'utility death spiral' to refer to a scenario in which declining utility energy sales lead to higher customer rates necessary to recover a utility's costs. Higher customer rates, in turn, lead to a further decline in energy sales which require further increases in customer rates.]*

In the view of Elenchus, NP's absence of concern is quite reasonable if the comment is intended to apply only to the next few years; however, it seems naive if NP is suggesting that the same lack of concern is reasonable and prudent in terms of the next half-century, or even for the next decade.

In recent years, the view that electricity disruption is imminent and unavoidable has moved from being an outlier to being mainstream. To illustrate the point that NP's view is disconnected from reality, Elenchus notes that:

> *On June 2, 2021, the Canadian Electricity Association hosted its annual Regulatory Forum in collaboration with Canada's Energy and Utility Regulators (CAMPUT) and Natural Resources Canada (NRCan). The theme for the event was Electricity Regulation & the Four Disruptors – Decarbonization, Decentralization, Digitalization and Democratization, and focused on dialogue between key stakeholders on how electricity regulation can be modernized under the pressure of profound disruption.*[24]

The Key Takeaways Summary for this session observed that:

> *For utilities, they need to find a way to see the change that is needed as an opportunity rather than simply taking a risk averse view to it. The electrification of vehicles, and so many other related technologies present the opportunity of a lifetime*

[24] Background section of the Key Takeaways Summary prepared by the CEA's expert viewer, Ted Ferguson, Chief Sustainability Officer for the Delphi Group that was circulated to participants. The participant list included at least six NP employees.

for the sector. New innovations such as 'non-wire' solutions, energy storage, leveraging big data and sensor technology, all need to be done more quickly to create the pathway for the 4D's to be successful. And success needs to have utilities square in the centre of the ecosystem, as an enabler and not a barrier. Getting the 4D's right can mean that the electricity sector enables multiple positive drivers of progress for society and the economy.[25]

It went on to conclude:

Thus, if the key players can embrace the reality of the dramatically changing landscape and approach the challenge with a collective will to work together for a positive outcome, then much could be accomplished. Intentional investments of time, programs and policies need to be generated in Canada. Each stakeholder in the electricity industry needs to ask themselves, where else can I be collaborating, innovating, and modernizing our outlook on the need for change in the sector.[26]

The potential impact of the disrupters addressed at the CEA session is not a new discovery. The September 26, 2018 edition of Energize Weekly reviewed a report that included the following comments:

As electric utilities grapple with the challenges posed by significant revenue losses caused by the growth of distributed generation, the century-old business model utilities have long used to generate returns on their investments will die if utilities don't change their ways, according to an industry survey for a new report by Black & Veatch.

The 2018 Strategic Directions: Electric Report[27] *polled the nation's electric utilities on several issues, including the so-called "utility death spiral" created by advancements in distributed energy resources (DER) and consumer demand for cleaner energy. A whopping 71 percent of utilities said they believe the death spiral is a real and possible*

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[25] Ibid., page 2.

[26] Ibid., page 2.

[27] The report is available to subscribers at https://www.bv.com/resources/2018-strategic-directions-electric-industry-report.

> *outcome if the industry fails to implement alternative energy solutions and/or regulations fail to recognize flexibility.*
>
> *"In an industry with more than 130 years of history, including four decades of fundamental transformational changes, we now find ourselves at a new pivot point," the report noted.*
>
> *Centralized power is losing its relevance in a world with a preference for cheaper distributed generation. Commercial and industrial customers are now potential competitors, and the power they produce can be an extra source of revenue for their businesses.*
>
> *According to the report, 47.8 percent of utilities believe the utility death spiral is a real and potential outcome if utilities fail to add alternative energy solutions to their generation mix, 39 percent said the death spiral is a likely outcome if regulatory models don't start reflecting market flexibility, and 28.9 percent said the death spiral is not real because the adoption rate of new generation is too slow versus the value of traditional generation.*
>
> *"The reality is that utilities still bear significant fixed costs," according to the report. "A real market need still exists for conventional generation because renewables are intermittent, not to scale in many cases and not quite to grid parity on marginal cost."*
>
> *But the death spiral should be a concern for utilities with small service areas with high rates, because the cost of renewable energy is getting less expensive and its reach is widening, the report noted.*
>
> *"There is immense value in connecting DER to the utility network, and it is a natural fit for utilities to deploy DER as part of their resource mix," the report found. "But this won't happen equally across the board; some will adapt easily, while others will not or cannot."*
>
> *The power sector is being reinvented to accommodate a renewable and digital revolution that has spawned new expectations from consumers.*

While predicting an imminent death spiral for electric utilities is certainly premature, in Elenchus' view: (i) it is imprudent to assume that current levels of demand for grid power cannot diminish over the next half-century, and (ii) that even if levels of demand for grid power do not diminish, the value of electricity capacity and energy on the grid will increase along with inflation, which is the assumption used in NP's economic analysis of the Sandy Brook Plant Penstock Replacement project.[28]

In Elenchus' view, the comments on the Sandy Brook Plant Penstock Replacement project can be generalized to all future potential long-lived investment in any generation, transmission or distribution project. Alternatives either exist or are being developed for lower cost alternatives to traditional capacity enhancements throughout the grid. DERs, including NWAs such as behind-the-meter generation and storage, demand response programs, automated load control, etc. will make the power system of tomorrow almost unrecognizable to the power system engineers trained only in traditional assets.

If the demand for grid power diminishes in the future due to customers migrating to self-generation as is widely expected, the shortened economic lives of existing assets will put upward pressure on levelized costs. The long-term value of the energy and capacity that will be provided by the Sandy Brook Plant Penstock Replacement project is further undermined by the potential availability of Churchill Falls power after 2041. This power may become available to serve Newfoundland at extremely low cost causing the value of Sandy Brook to decline to close to zero. No scenario analysis has been done by NP to consider the implications for the economics of project if it is redundant after 2041.

As shown in Table 1, the levelized revenue requirement of the Sandy Brook Plant Penstock Replacement project increases as the service life decreases. If the plant has no value after 2041, the levelized revenue requirement will be 3.87¢ rather than 3.22¢, a 20% increase in the levelized revenue requirement.

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[28] Predicting future demand for grid power, as distinct from the total electricity consumption, is particularly difficult at this time. In the coming decades, significant increases in the penetration of self-generation by all classes of customers is a near certainty. However, policies that are responding to the challenges of climate change are expected to drive policies that drive electrification in the transportation sector and other sectors that are reliant on fossil fuels. The impact of electrification on grid demand is uncertain, however, since hydrogen technologies (e.g., hydrogen fuel cell vehicles) have the potential to disrupt reliance on the grid in the next few decades. The evolving disruptors that make investments that are justified on the basis of benefits three or four decades into the future are particularly problematic.

Table 1 – Levelized Sandy Brook Revenue Requirement Scenarios

Service Life		Levelized Rev. Req. (¢/kWh)[29]
50 Years	2022-2071	3.22¢
40 Years	2022-2061	3.28¢
30 Years	2022-2051	3.44¢
20 Years	2022-2041	3.87¢

The risk of diminished consumption causing higher levelized costs can be lessened with shorter-term projects, without precluding the flexibility to respond to increased grid demand if that is the future reality. Planning for multiple short-term projects allows more flexibility to match future projects to updated requirements whether actual consumption tracks above or below current projections. Multiple smaller projects also allow near-term capital costs to be deferred. There may be lower revenue requirements even if the total cost of the alternative projects is greater than committing to a long-term asset.

As an illustrative example, consider the proposed Sandy Brook project and two consecutive utility-scale distributed energy resource alternatives, each with half the service life of the Sandy Brook project.[30]

[29] The levelized revenue requirement does not include operating costs after the end of the service life. The 20 Years scenario also excludes planned capital investments in 2046 and 2047.

[30] This simplified example uses a 5.81% discount factor and straight-line depreciation. The capital cost for the Distributed Energy Resource Project #2 assumes 1% annual cost reductions from technological improvements. Decommissioning costs incurred to address safety risks to employees, the general public and wildlife after plant shutdown are not considered in this analysis since the present value of those costs are assumed to be consistent over time and would be incurred in either scenario.

Table 2 – Illustrative Example: Two 25-Year DER Projects

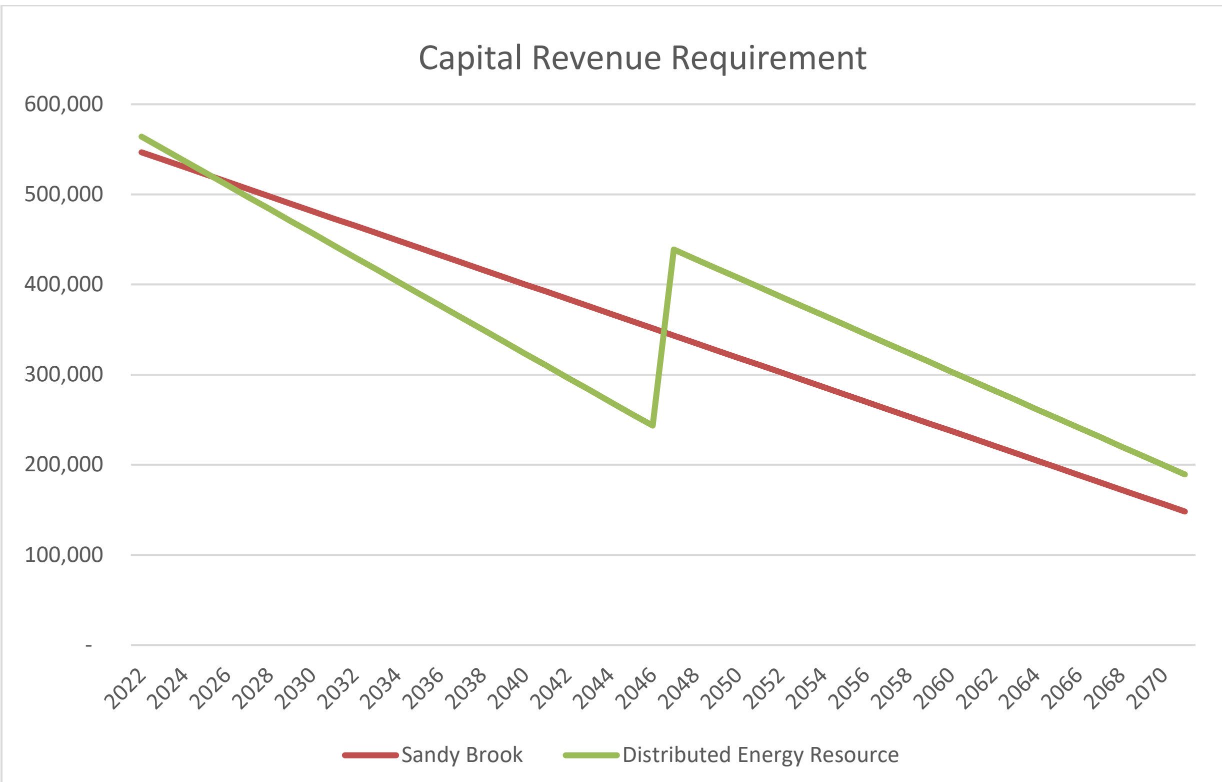
	Sandy Brook	Distributed Energy Resource Project #1	Distributed Energy Resource Project #2	Total DER Projects, #1 and #2
Service Life	50 years	25 Years	25 years	50 years
Year	2022-2071	2022-2046	2047-2071	2022-2071
Capital Cost	$7,000,000	$5,250,000	$4,472,473	$10,222,473
Total Capital Revenue Requirement	$17,370,850	$10,092,975	$7,850,532	$17,943,507
PV of Capital Revenue Requirement	$7,132,980	$5,928,495	$1,032,629	$6,961,124
Levelized Capital Rev. Req. (¢/kWh)	1.692¢	1.749¢	0.305¢	1.651¢

The sequential DER projects result in a lower long-term cost whether calculated in terms of the PVs of the options or the 50-year levelized cost. Despite higher capital costs and higher capital revenue requirements, the hypothetical DER projects have a lower net present value of capital revenue requirements than the Sandy Brook project over the full 50-year planning horizon due to the assumed cost reductions before an investment in DER Project #2 is required.

A more significant consideration when comparing a long-lived asset to an alternative with a shorter life, such as the hypothetical DER project in the table above, is the option value provided by the more flexible alternative. That is, it leaves open the option of not undertaking the second investment in 25 years if changes in NP's customer requirements render it uneconomic compared to alternatives that are available in 2047. This could be the case if adoption of self-generation, or other measures, have significantly reduced the demand for grid power. It also leaves open the option of increasing or decreasing the scale of the DER options developed over the planning period as well as the option of utilizing excess power from other committed supply options such as Muskrat Falls.

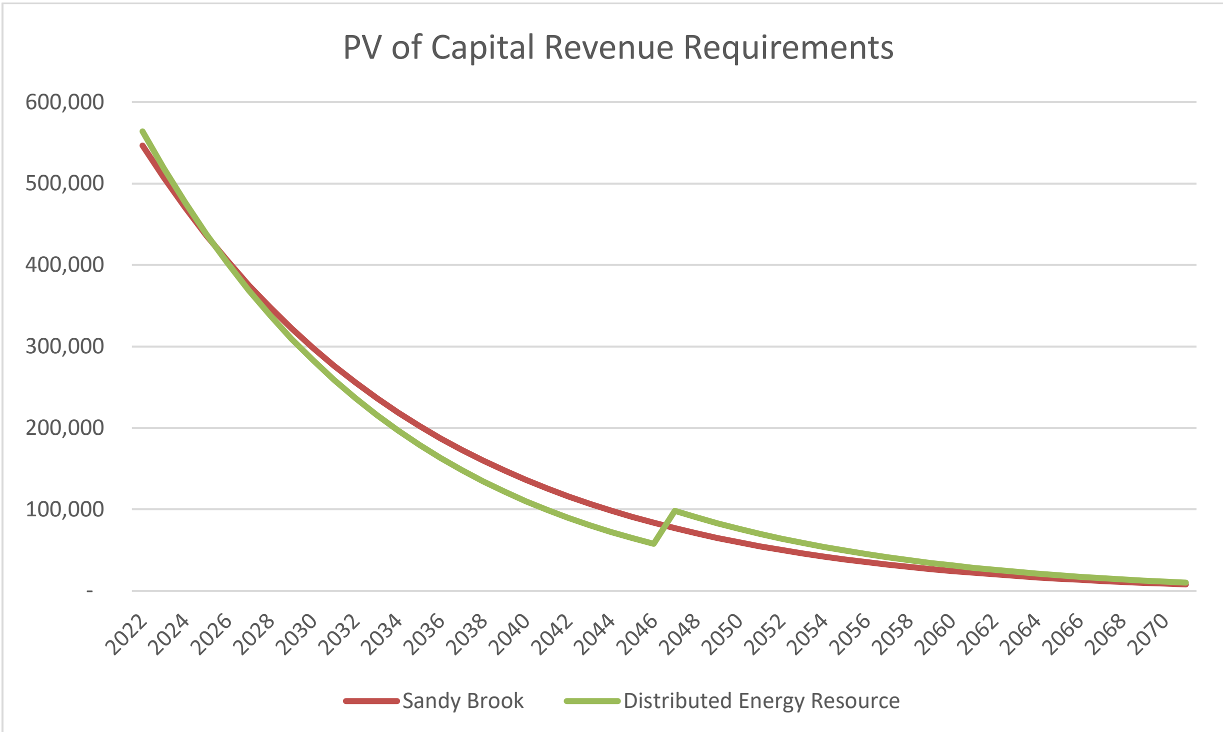
Illustrative annual revenue requirements for the Sandy Brook project and the combined DER projects are provided in Figure 1. The graph does not include the possibilities that could arise from the option value of the DER alternative. There are many possibilities including the capital revenue requirement line dropping to zero in 25 years. This flexibility favours consideration of short-term alternatives even if the short-term levelized cost exceed the theoretical levelized cost of the proposed project.

<u>Figure 2 – Sandy Brook and DER Alternative Capital Revenue Requirements</u>



The present value of these projects is provided in Figure 3. Again, the potential option value of alternatives with shorter lives are not shown here.

<u>Figure 3 – PV of Sandy Brook and 25-Year DER Capital Revenue Requirements</u>



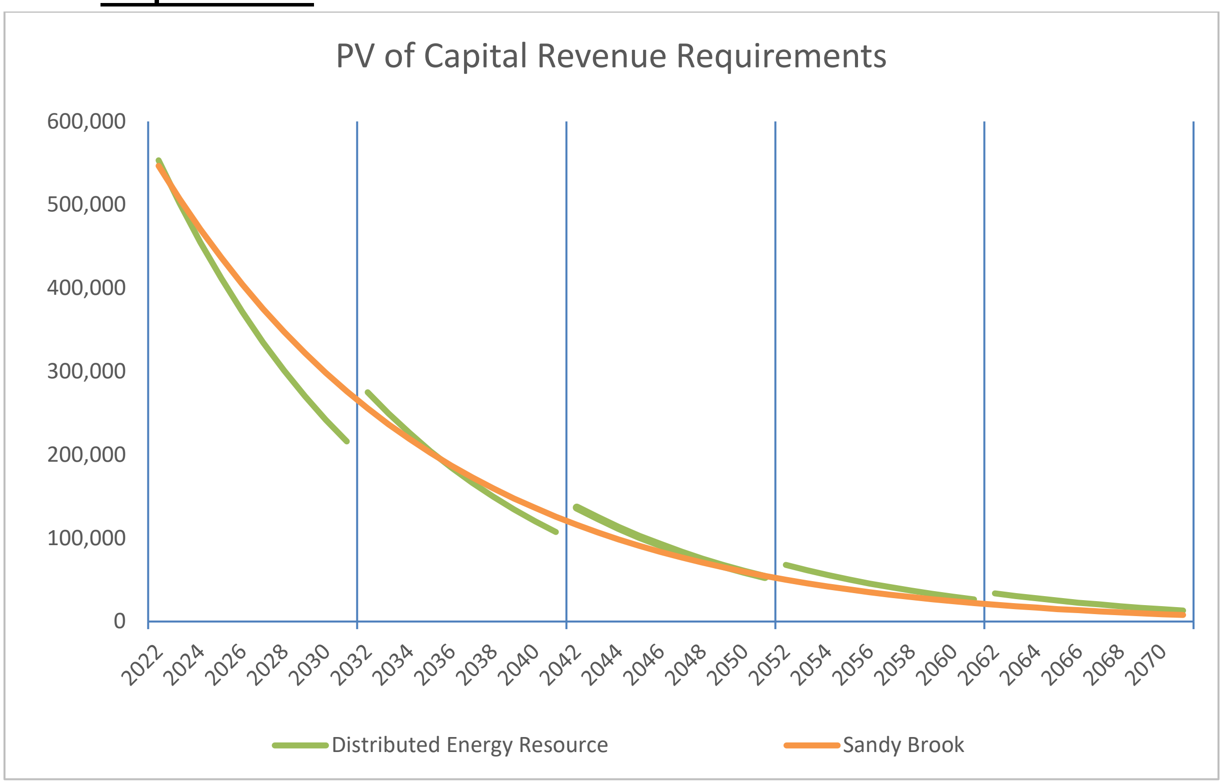
To illustrate the potential benefit of the more flexible alternatives in a world where future grid demand is uncertain, Table 3 below is presented. It is based on a hypothetical utility-scale DER alternative that relies on five consecutive 10-year DER projects where the cost of similarly sized projects is declining by 1% annually. Each of the five projects would only proceed if the capacity and energy it would provide is actually required at the time of committing to the next 10-year project.

The combined DER project has a lower levelized capital revenue requirement despite total capital costs that are more than twice the Sandy Brook project. If the need for generation does not materialize, Sandy Brook would become a stranded asset and the present value of Sandy Brook capital-related revenue requirements project cannot be avoided. The hypothetical alternative of a series of DER projects would allow NP to avoid the costs associated with later projects if the need does not materialize. This optionality is illustrated in Figure 4, in which the vertical lines represent potential off-ramps.

Table 3 – Illustrative Example: Five 10-Year DER Projects

Project	Service Life	Capital Cost	PV of Capital Rev. Req.	Levelized Capital Rev. Req. (¢/kWh)
Sandy Brook	**2022-2071**	**$7,000,000**	**$7,132,980**	**1.692¢**
DER Total	**2022-2071**	**$14,458,364**	**$7,051,734**	**1.673¢**
DER Project A	2022-2031	$3,500,000	$3,657,639	0.868¢
DER Project B	2032-2041	$3,165,337	$1,818,029	0.431¢
DER Project C	2042-2051	$2,862,674	$903,651	0.214¢
DER Project D	2052-2061	$2,588,951	$449,160	0.107¢
DER Project E	2062-2071	$2,341,401	$223,255	0.053¢

Figure 4 – PV of Sandy Brook and 10-Year DER Capital Revenue Requirements



This consideration of the potential benefit of alternatives that provide option value over the expected operating life of a long-lived capital asset such as Sandy Brook underlies the importance of assessing the reasonableness of alternative assumptions regarding the extent to which the growth of customer-owned DERs is likely to reduce the demand for grid capacity and hence the value of new or renewed capacity over the expected service life used in the economic analysis (i.e., 50 years).

Limiting consideration of alternatives to what has been traditionally viewed as "good utility practice"[31] may have been prudent in the past. But that does not suggest that the same approach in the future, or even in the present, is prudent. This conclusion is unavoidable if the PUB determines that the prudent economic life to use for a capital asset can be shorter than its physical, or potential service, life.

In Elenchus' view, preparing an economic analysis that assumes the asset will be used and useful until the 2070's is risky. If there is no feasible alternative to a proposed project for meeting service obligations, it may be prudent to proceed with that option. However, if there are feasible alternatives, careful examination of more than the NPVs or levelized cost of the alternatives is needed to identify the alternative that best serves the interest of ratepayers as well as the utility.

3.3 RECOGNIZING TOTAL BILL IMPACT

The Board's prudence review standard as set out in Order No. P.U. 13(2016) included:

> *prudent decisions and actions require that management follow specific practices:*
>
> *…*
>
> *3. test those solutions by applying criteria and values consistent with delivery of safe, adequate, reliable and least-cost service*

In the view of Elenchus, the concept of least-cost service in this statement relates to the total cost to customers, not just the cost incurred directly by NP that will be recovered from customers. This interpretation appears to be the intent of section 4 of the EPCA which includes:

[31] A fairly standard definition of "good utility practice can be found in Annex B Definitions, page 1 of PJM TSDS Technical Requirements.

(b) all sources and facilities for the production, transmission and distribution of power <u>in the province</u> should be managed and operated in a manner

<u>(i) that would result in the most efficient production, transmission and distribution of power</u>,

[emphasis added.]

A comprehensive view is also consistent with the regulatory principles set out in Order No. P.U. 19 (2003), which include under Cost of Service that "costs should be … reflective of private/social costs and benefits occasioned by the service."[32]

For this reason, an economic analysis that meets the PUB's test of prudence by identifying <u>all relevant information</u> would have to quantify the net costs to be recovered from customers that will be avoided, not just the costs avoided by NP. This distinction is important, for example, in assessing the avoided capacity and energy costs that are attributed to a capital project such as Sandy Brook. NP's economic analysis appears to quantify the reduction in its payments to NLH based on the implicit assumption that the costs that will have to be recovered by NLH from its other domestic customers will not be impacted. However, under the more realistic assumption that NLH's cost are mostly fixed and export revenue will not increase significantly when sales to NP decline, a portion of NP's reduced payments to NLH will be offset by an increase in the costs that NLH will recover from its in-province customers. As a consequence, in the long run the NLH costs that will be passed through to NP customers will offset a portion of the savings assumed in NP's economic analysis. Furthermore, any increase in cost recoveries from other in-province customers will offset the assumed provincial benefit of the cost avoided by NP as a result of any project that reduces NP's reliance on NLH for capacity and energy.

Put in other terms, NP can be viewed as a self-generating customer of NLH that is analogous to any other utility's customers that are investing in behind-the-meter self-generation capacity. For example, a large customer of any utility may find it attractive to invest $1 million in self-generation that reduces its monthly bill by $100,000. From the customer's perspective, it will save $1.2 million annually, a very attractive return on

[32] Order No. P.U. 19 (2003), page 15.

investment. However, since the utility's costs are almost entirely fixed and cannot be reduced when the customer reduces its demand, the investment in self-generation may constitute uneconomic bypass. That is, from a societal perspective there may be virtually no costs avoided that offset the expenditure of $1 million to provide the new behind the meter capacity; hence, the new capacity may simply strand some of the existing capacity of the utility.[33] Uneconomic bypass benefits the individual customer despite increasing the total cost of power in the province; hence, the saving is achieved by shifting some of the utility's recoverable costs to other customers. In contrast, by definition, economic bypass results in lower total costs being incurred by the utility and the customers that are bypassing the grid. The cost of the bypass facilities exceeds the avoided cost of the utility.

Elenchus notes that there is an incentive for customers to undertake investments that result in uneconomic bypass when the electric utility's rate design recovers a portion of its fixed costs through variable capacity and energy charges. This is the standard approach to rate design that is a legacy of the monopoly world.[34] Traditional regulated rate designs are based on cost allocation studies that identify unavoidable capacity-related and energy-related costs as a basis for setting rates that recover costs through variable capacity and energy charges in order to satisfy the equity principles that are central to the Bonbright principles, as set out in section 2. This incentive for uneconomic bypass is an important driver for the customer investments in DERs that are disrupting the electricity sector in jurisdictions around the world. The result is that self-generation may result in bill reductions that exceed the utility's avoided costs. As long as this rate design persists, and the cost of self-generation and storage continue to decline, the stranding of assets such as Sandy Brook is a foreseeable development, which in the

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[33] This issue was addressed by Elenchus in a report prepared by Elenchus for SaskPower entitled Review of SaskPower Capacity Reservation Service (CRS) Rates.

[34] A classic monopoly can set rates that are "equitable" as determined by a cost allocation study that is designed to recover historic embedded costs since customers cannot turn to competitive options that are priced on the basis of future-oriented marginal costs. A key driver in the efforts to modernize market structures and regulatory regimes has been the growing pressure being faced by utilities from market-price innovative new technologies. Utilities are responding by shifting in the market-based pricing to the extent permitted by their regulators. The controversial decision of the Ontario Energy Board to require all distributors to adopt fully fixed rates for the recovery of distribution costs is an example of this shift in approach. See Ontario Energy Board (EB-2012-0410) Board Policy, *A New Distribution Rate Design for Residential Electricity Customers*, April 2, 2015.

extreme, raises the possibility of the feared "death spiral". It is this looming reality that is the driver behind views such as the earlier quotes from the Key Takeaways Summary from the CEA conference and the article from Energize Weekly.

4 Capital Expenditure Approvals of Canadian Utilities

NP's response CA-NP-001 shows that there are two years in which NP's approved capital expenditures differed from requested capital expenditures in the past 25 years. The Board disallowed 0.9% of requested capital expenditures in NP's 2003 CBA and disallowed 3.15% of requested capital expenditures in NP's 2004 CBA. Approved amounts were equal to requested amounts in all other years. To provide some context for this observation, Elenchus has identified examples of disallowances in other jurisdictions.[35] It may be noted that in other Canadian jurisdictions utility capital plans are typically included in rate applications as opposed to being addressed in separate applications. Capital projects must be deemed to be prudent in order for the related test year costs to be recovered in rates.

Hydro One, Ontario's largest distributor, typically has 5-year distribution rate applications in which its capital budget is reviewed by the Ontario Energy Board ("OEB"). In its most recent application, the OEB disallowed a total of $300 million in capital expenditures over the 2018 to 2022 period. This disallowance represented a 8.4% reduction in its requested 5-year capital budget. The OEB stated that its decision reflects "the need for Hydro One to improve customer consultation and investment planning processes, finding ways of doing more work for less, executing the work program as planned, and improving performance relative to its peers."[36]

Hydro Quebec has annual distribution rate applications which include a review of its capital budget by the Régie de l'énergie ("Régie"). In its 2017-18 decision, the Régie

[35] Public utility boards often approve only revenue requirements and do not make specific disallowances to capital budgets.

[36] Ontario Energy Board, EB-2017-0049 Decision and Order, page 3

disallowed $31 million in capital expenditures for that year, approximately 4% of Hydro Quebec's capital budget. The Régie's decision stated that Hydro Quebec did not provide sufficient justification for increasing investment levels, particularly growth in the maintenance of assets, quality improvement, and demand growth asset categories.[37]

In 2018, NB Power applied to the New Brunswick Energy and Utilities Board ("NBEUB") for approval of an Advanced Metering Infrastructure ("AMI") multi-year project as part of its 2018/19 General Rate Application. NB Power applied for a capital expenditure of $26.2 million in 2018/19 ($90.7 million total) to implement the new meter infrastructure. The AMI project, representing 7.3% of NB Power's proposed 2018/2019 capital budget and part of its planned budget in subsequent years, was not approved by the NBEUB and the test year costs were disallowed. The NBEUB stated that a positive business case was not established in that proceeding so the application did not satisfy the prudency of the AMI project. NB Power subsequently submitted an application for the AMI project with an improved business case and supporting evidence which was approved by the NBEUB.[38] The NBEUB was satisfied that the renewed application demonstrated that the project was prudent and in the public interest.

5 CONCLUSIONS

In section 2 of this report, Elenchus concluded that:

> *in order for the PUB's review of NP's 2022 CBA to be consistent with both generally accepted prudency review standards and the Board's own stated prudency review standards, the following questions need to be addressed fully.*
>
> 1. *Has a reasonable range of alternative solutions been identified?*
> 2. *Has all relevant information been identified?*
> 3. *Is the planned investment the least cost option?*

[37] Régie de l'énergie, D-2018-025, R-4011-2017

[38] This proceeding (Matter No. 452) was separate from NB Power's annual rate proceedings.

> 4. *Does the utility's approach to the economic evaluation of alternative reflect the inherent bias for an investor-owned utility to prefer alternatives that require high levels of capital investment?*

Based on the evidence on the record to date (NP's 2022 CBA and the responses to RFIs) Elenchus has the following comments with respect to the four questions identified in section 2, above, that need to be answered before a credible case can be made that the PUB's stated prudency review standards have been met.

1. Has a reasonable range of alternative solutions been identified?

The evidence to date indicates to Elenchus that NP is excluding consideration in its 2022 CBA of alternatives that merit at least preliminary inclusion in "a reasonable range of alternative solutions". It follows that this test has not been met.

Elenchus has not attempted to identify excluded alternatives that could be considered within the reasonable range of alternatives for each project included in the 2022 CBA. NP is in a far better position to do that once it adopts a more open view of reasonable alternatives.

Elenchus' view is based in part on NP RFI response CA-NP-114 (b):

> *The purpose of NWA solutions is to reduce load at a given power transformer, substation or distribution feeder to avoid exceeding capacity ratings resulting in necessary infrastructure upgrades. [Fn. 10: California's Distribution Investment Deferral Framework recognizes that NWA solutions are not capable of addressing specific utility infrastructure projects such as repair or replacement of damaged/deteriorated infrastructure, non-capacity related reliability issues and dedicated infrastructure required to serve customers. These types of projects would require pursuing traditional poles and wires solutions. See Distribution Infrastructure Deferral Framework and Distribution Deferral Advisory Group meeting, December 12, 2016, presentation by Pacific Gas and Electric, San Diego Gas and Electric and California Edison.] Based on this definition, Newfoundland Power has only 1 capital project in its 2022 Capital Budget Application that could be addressed with NWA solutions: the Feeder Additions for Load Growth project.*

This response indicates that NP takes a very limited view of the role of NWAs in the modern electricity grid. This constrained view drives a preference for traditional, long-lived capital-intensive alternatives for meeting the needs of customers. Many jurisdictions have initiated processes to integrate DERs into the planning and development processes for the electricity grid and the market that they regulate. For example, the process that is referred to in NP's RFI response was background for a Proposed Decision[39] issued by the California Public Utilities Commission ("CPUC") last year.[40]

The CPUC Proposed Decision cites a Wood Mackenzie report[41] in its discussion of DER growth expectations which observes that:

> *In the United States, DERs, including battery storage, customer-sited solar, demand-side management, and electric vehicle (EV) infrastructure are on track to reach 387 GW of cumulative installed capacity by 2025. By comparison, the current combined coal and nuclear power capacity in the United States is substantially less at about 330 GW. Customer-sited solar, residential load-management potential, battery storage, and EV infrastructure is expected to account for more than 90 percent of DER capacity installed through 2025.*

The CPUC Proposed Decision also notes that "Wood Mackenzie defines DERs as having the following characteristics: 'grid connected,' 'customer-sited,' MW restricted, and with a 'voltage range'." This projection may not be indicative of the growth of DERs that should be expected by 2025 in the NP service area. However, in the view of Elenchus, it would be naïve to assume that there will not be significant transfers of technological and policy from the United States to Canada generally and to Newfoundland specifically in the coming decades. While there will almost certainly be a lag of a few years from the

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[39] CPUC, Order Instituting Rulemaking to Modernize the Electric Grid for a high Distributed Energy Resources Future.

[40] The New York Public Services Commission has taken a different approach to stimulating grid modernization. It has developed a comprehensive approach to valuing DERs using what it calls The Value Stack which is used to compensate projects based on when and where they provide electricity to the grid and compensation is in the form of bill credits. The value is determined by a DER's (i) Energy Value (LBMP), (ii) Capacity Value (ICAP), (iii) Environmental Value (E), (iv) Demand Reduction Value (DRV) and (v) Locational System Relief Value (LSRV).

[41] Wood Mackenzie, "United States distributed energy resources outlook: DER installations and forecasts 2016-2025E", 18 June 2020.

implementation of new technologies and polices in leading jurisdictions such as California, new proven technologies will become available to, and adopted by, Canadians long before the end of the service life of grid assets build by NP in the 2020's. All utilities, including NP, need to recognize that significant change is coming within the next decade, or two at most, before committing to further traditional investments in grid infrastructure.

An important reason for immediately expanding the scope of the alternatives considered (i.e., by taking into account the benefit of low capital investment alternatives to traditional capital projects) is that commitments to old technologies that will only be economic if they remain used and useful for several decades can be reduced. Utilities can instead focus on assets that allow them to maintain flexibility to modernize and better serve their customers without stranding significant capital assets.

2. Has all relevant information been identified?

Elenchus has not examined the alternatives that NP included in its economic evaluations of all capital projects included in the 2022 CBA for the purpose of identifying information deficiencies. However, as noted above, it appears to Elenchus that NP has not approached the economic analysis of the projects by identifying and evaluating "a reasonable range of alternative solutions". Unless NP can demonstrate through further disclosure and discovery that (i) it has considered a reasonable range of alternatives and (ii) those alternatives are not preferable to the proposed projects taking into account both costs and uncertainty with respect to the long-term value of the proposed projects, it follows that all relevant information has not been identified and included as is necessary to identify the least cost option and therefore prudent alternative.

One obvious information deficiency is consideration of the impact on the total bill of customers if capital projects such as the Sandy Brook Plant Penstock Replacement project constitute uneconomic bypass of NLH. It appears that NP has not addressed the question as to whether any reduction in the NP portion of the customer bills will be offset by increases in the pass-through of NLH costs, resulting in increases in total customer bills. This undesirable outcome will result if the reduced supply of capacity and/or energy from NLH to NP reduces NLH revenues by an amount that exceeds the sum of the reduction in NLH costs and the increase in NLH's export revenues.

3. Is the planned investment the least cost option?

As indicated by the preceding comments, it is impossible to know whether the planned investments are the least cost options in the absence of evidence that a reasonable range of alternatives have been identified and assessed based of all relevant information.

In Elenchus' view, it would be desirable for NP to conduct its planning on the basis of an integrated resource plan (IRP) that determines the least cost supply scenario based on the recognition that generation, demand-side management (DSM) and DERs are supply options that will increasingly be substitutable in the next few decades (i.e., over the planning horizon for projects such as Sandy Brook). All relevant projects providing generation, transmission or distribution capacity should be consider in the IRP.

4. Does the utility's approach to the economic evaluation of alternatives reflect the inherent bias for an investor-owned utility to prefer alternatives that require high levels of capital investment?

The apparent preference of NP for traditional capital-intensive alternatives over NWAs may be indictive of this behaviour. A more complete comparison of alternatives would help determine whether lower cost alternatives with low capital costs have been avoided, reflecting the bias referred to as the A-J Effect.

The lack of effort that has been made to explore NWAs is suggestive that NP may have a bias that is resulting in higher total costs than would result from the adoption of more flexible alternatives that would involve lower commitments to long-lived, high capital cost alternatives. At a minimum, long-lived capital projects that have greater risk of stranding should be evaluated using a differentiated discounted risk premium that reflects the high level of stranding that will ultimately have to be borne by customers, shareholders or taxpayers. It would be interesting to know the risk premium that would be expected by investors if it were determined in advance that any unrecovered costs due to stranding would be their responsibility (i.e., stranded costs would not be backstopped and hence recoverable from either ratepayers or taxpayers).

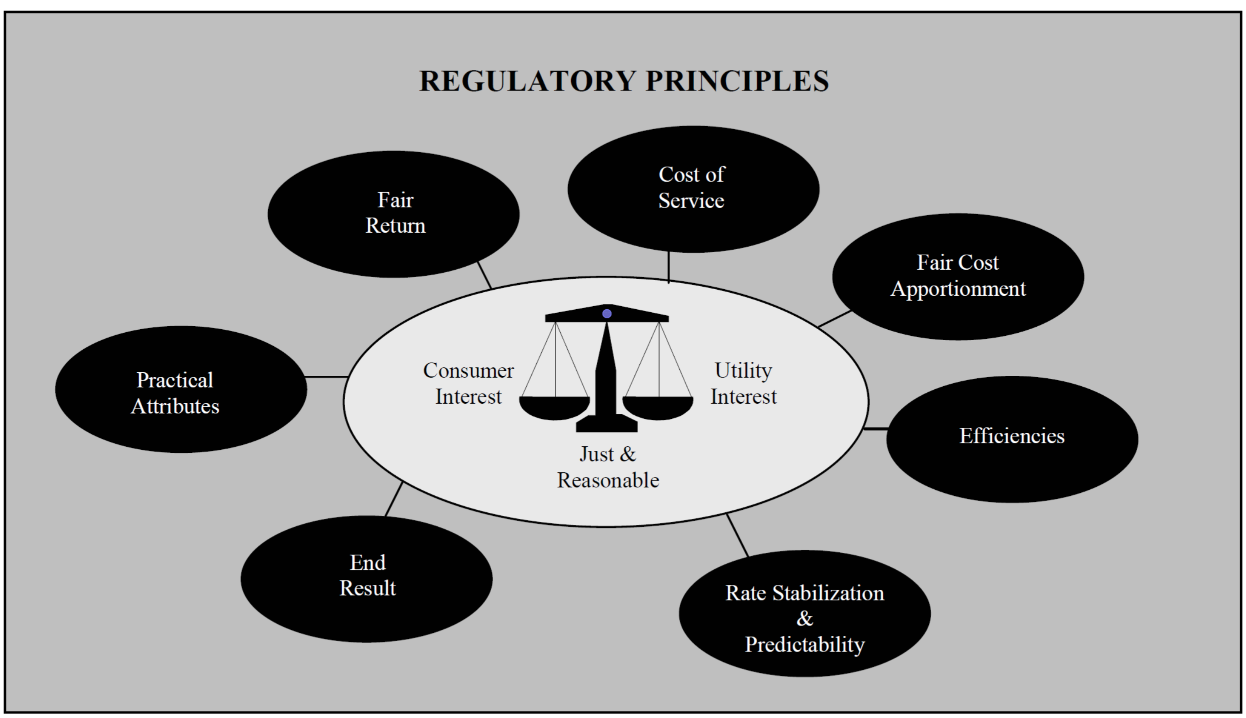
APPENDIX A: EXCERPT FROM P.U. 19 (2003)

The following excerpt is from pages 14 to 17 of Newfoundland and Labrador, Board of Commissioners of Public Utilities, 2003 General Rate Application filed by Newfoundland Power Inc., Decision and Order of the Board, Order No. P.U. 19 (2003), June 20, 2003.

3. Regulatory Principles

Sound regulatory practices encompass fundamental principles which are used by regulators as a guide or roadmap to rational decision-making. As stated in the Bonbright J. C., Danielsen A.L, Kamerscen D.R., Principles of Public Utility Rates (Arlington: Public Utilities Reports, Inc., 1988): "We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict." These are commonly referred to as Bonbright's principles and are specifically outlined on pages 383-384 of his book.

Section 4 of the EPCA directs the Board to apply tests that are consistent with generally accepted sound public utility practice. The Board sets out the following principles for purposes of its regulatory framework:



1. *Fair Return*

   Regulated utilities are given the opportunity to earn a fair rate of return. To be considered fair, the return must be:

   - *commensurate with return on investments of similar risk;*
   - *sufficient to assure financial integrity; and*
   - *sufficient to attract necessary capital.*

   The fair return principle is consistent with both Section 80(1) of the Act and Section 3(a)(iii) of the EPCA.

2. *Cost of Service*

   Under this principle a utility is permitted to set rates that allow the recovery of costs for regulated operations, including a fair return on its investment devoted to regulated operations - no more, no less. Costs should be:

   - *prudent;*
   - *used and useful in providing the service;*
   - *assigned based on cause (causality);*
   - *incurred and recovered (matching costs and benefits) during the same period; and*
   - *reflective of private/social costs and benefits occasioned by the service.*

3. *Fair Cost Apportionment*

   Fairness of specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness, capriciousness, inequities or discrimination. Under this principle, customers in similar situations should be treated equally (horizontal equity), while those in different situations should be treated differently (vertical equity). This principle would not deny cross-subsidization of rates among customers of equal circumstances but such subsidization should not cause undue discrimination. The principle of horizontal equity (i.e. equals treated equally) is set forth in Section 73(1) of the Act which *requires that "all tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, …". Furthermore, the aspect of undue discrimination also has statutory reinforcement in Section 3(a)(i) of the EPCA which declares it to be "…the policy of the province that the rates to be charged ………should be reasonable and not unjustly discriminatory."*

4. *Efficiencies*

   Rate classes and rate blocks should discourage wasteful use of service while promoting all types and amounts of use that are economically justified. Greater efficiency should also be employed in promoting innovation and responding economically to changing demand and supply patterns.

5. *Rate Stability and Predictability*

   Rates and revenues should be stable and predictable from year to year with a minimum of unexpected changes seriously adverse to either ratepayers or utility companies. This principle may justify smoothing out increases to avoid sharp rate climbs or temporary fluctuations. The emphasis using this standard relates to the timing of rate implementation.

6. *End Result*

   In compliance with the legislation, the end result must be fair, just and reasonable from the perspective of both the consumer and utility.

7. *Practical Attributes*

   Rates should be simple, understandable and publicly acceptable with a minimum of controversy upon implementation.

While setting out these principles may be useful to ensure full consideration of all the issues, the Board notes that at times they may contain ambiguities, conflict with legislation, be inconsistent and/or hold different priorities. The real challenge for the Board, in keeping with its legislative mandate, is to balance ofttimes competing objectives *within the regulatory environment to ensure a set of sound and reasoned decisions serving the interests of both consumer and utility alike.*

During rate proceedings the Board is often petitioned by intervenors and presenters to consider the customers' ability to pay when setting rates for various classes of customers and service. While cross subsidization of a group of customers contributing toward the cost of service assigned to another group of customers is a common regulatory practice, the ability of an individual customer to pay for the electrical service consumed is not considered by the Board in setting rates. Without compelling change in either legislation, public policy or structure of regulation, the Board will continue to pursue generally accepted regulatory principals as outlined above which does not incorporate ability to pay among its criteria for rate setting.