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NEWFOUNDLAND POWER
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HAND DELIVERED

August 5, 2019

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

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

Ladies and Gentlemen:

Re: 2018 Hydro Cost of Service and Rate Design Review Application ("the Application")

Please find enclosed the original plus 13 copies of Expert Evidence of Mr. Larry Brockman of Brockman Consulting.

The enclosure is intended to provided the Board with additional evidence to assist it in considering the Application.

We trust the foregoing and enclosed are found to be in order. However, if you have any questions whatsoever, please feel free to contact us.

Yours very truly,

Gerard M. Hayes
Senior Counsel

Enclosures

c. Shirley Walsh
Newfoundland and Labrador Hydro

Paul Coxworthy
Stewart McKelvey

Senwung Luk
Labrador Interconnected Group

Dennis Browne, QC
Browne Fitzgerald Morgan & Avis

Gregory Moores
Iron Ore Company of Canada

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5609 • FAX (709) 737-2974 • ghayes@newfoundlandpower.com

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 (the "*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the "*Act*");

AND IN THE MATTER OF an Application by Newfoundland and Labrador Hydro ("Hydro") for approval of revisions to its Cost of Service Methodology pursuant to Section 3 of the *EPCA* (the "Cost of Service Methodology Application") for use in the determination of test year class revenue requirements reflecting the inclusion of the Muskrat Falls Project costs upon full commissioning.

Prefiled Evidence of

Larry Brockman

Testimony on Behalf of Newfoundland Power

Brockman Consulting

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At the hearing into the Newfoundland and Labrador Hydro Cost of Service Methodology Review, the Cost of Service Expert Evidence in this report will be adopted by Larry Brockman, President of Brockman Consulting based in Atlanta, Georgia.

A witness profile for Larry Brockman follows.

Larry Brockman

President of Brockman Consulting

Atlanta, Georgia

Larry Brockman has over 40 years' experience as a power system planning engineer, rate designer, regulatory staff member and consultant, and specializes in regulatory and generation planning assistance and analysis, as well as the analysis of competitive generation markets.

Mr. Brockman has appeared before the Board of Commissioners of Public Utilities of Newfoundland and Labrador on numerous occasions as an expert witness. He has presented evidence on behalf of Newfoundland Power Inc. concerning cost of service, rate design and least cost planning in Newfoundland and Labrador Hydro's 1990, 1992, 2001, 2003, 2006, and 2013 general rate applications, as well as in Newfoundland and Labrador Hydro's 1992 generic cost of service hearing, the 1995 Rural Rate Inquiry and Newfoundland and Labrador Hydro's 2009 and 2013 Applications concerning Industrial Rates and the Rate Stabilization Plan.

Mr. Brockman has also appeared as an expert witness on cost of service and rate design on behalf of Newfoundland Power in the 1996 and 2003 Newfoundland Power general rate applications.

Mr. Brockman also provided expert evidence on behalf of Newfoundland Power in the Board's 2014 Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System and Newfoundland and Labrador Hydro's 2013 RSP Surplus Refund Application.

A more detailed description of Mr. Brockman's professional background is provided as Appendix A to this evidence.

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1.0 INTRODUCTION

1.1 Background

The Board conducted its last major review of Newfoundland and Labrador Hydro's ("Hydro") cost of service methodology in 1992 ("the 1992 Cost of Service Review"). I submitted expert cost of service evidence before the Board in that proceeding on behalf of Newfoundland Power.[1] The Board's decisions in that proceeding have, for the most part, guided the cost of service methodology used by Hydro since that time.

Because of the material change in Hydro's forecast supply cost mix that would result following commissioning of the 824-megawatt Muskrat Falls generating facility, the Labrador Island Link transmission line ("LIL"), and the Labrador Transmission Assets ("LTA"), (hereinafter referred to, collectively, as "the Muskrat Falls Project"), and the interconnection of the island of Newfoundland to the North American grid, Hydro proposed to conduct a cost of service methodology review (the "Cost of Service Methodology Review") following its 2013 general rate application. In the April 11, 2018 Settlement Agreement in relation to Hydro's 2017 general rate application, it was agreed that Hydro would file an application no later than November 15, 2018 for a Cost of Service Methodology Review.[2]

On November 15, 2018, Hydro submitted its application for revisions to its cost of service methodology, reflecting the inclusion of the costs of the Muskrat Falls Project (the "Application"). The evidence filed by Hydro in support of the Application consisted of Hydro's *2018 Cost of Service Methodology Review Report* dated November 15, 2018 (the "Hydro COS

1 *Testimony of Larry Brockman*, Hydro 1992 Cost of Service Investigation, August 1992.
2 The April 11, 2018 Settlement Agreement was filed as Consent #1 in Hydro's 2017 General Rate Application proceeding.

Report"), and a report of Hydro's cost of service consultant, Christensen Associates Energy Consulting ("Christensen"), titled *Cost-of-Service Methodology Review: Revised Version* dated November 15, 2018 (the "Christensen Report").

In July 2019, the Board filed an amended report, dated June 27, 2019, from its consultant, Brattle Group, Inc. ("Brattle"), titled *Embedded and Marginal Cost of Service Review – Amended Report* (the "Brattle Report").[3] The Brattle Report reviews Hydro's proposed revisions to its cost of service methodology, and proposes that certain of Hydro's proposals be accepted, but recommends alternate treatment of certain issues.

1.2 Cost of Service Concepts

The Application is principally concerned with Hydro's cost of service methodology. A brief overview of cost of service methodology concepts and principles follows.

Purpose and Principles of Cost of Service Studies

Cost of service studies are performed for several reasons. The National Association of Regulatory Utility Commissioners ("NARUC") *Electric Utility Cost Allocation Manual* published in 1992 (the "NARUC Manual") is a generally-accepted reference for the industry methods used to perform a cost of service study.[4] Perhaps owing to its breadth, and the fact that it was a result of a diverse range of industry input, it has not been revised since 1992. At page 12, the NARUC Manual states the purpose of a cost of service study as follows:

3 Brattle's initial report titled *Embedded and Marginal Cost of Service Review*, dated May 3, 2019, was filed by the Board on May 10, 2019.

4 The NARUC Manual is publically available on the NARUC website: http://www.naruc.org.

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirements for the monopoly services offered by a utility operating in both monopoly and competitive markets.
- To separate costs between different regulatory jurisdictions.

There are two major types of cost of service studies: embedded cost of service studies and marginal cost of service studies. An embedded cost of service study deals with the costs of existing utility plant and operating expenses. A marginal cost of service study deals with the future costs of meeting additional electric energy and demand requirements.

The use of cost of service studies to allocate revenue responsibility derives from the generally accepted principles of good rate design. James Bonbright was one of the first to codify these principles in his classic book, *Principles of Public Utility Rates*.[5] These principles are generally accepted by utility regulatory bodies in North America as a cornerstone of good ratemaking.

[5] *Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, Public Utilities Reports, Inc., Arlington, Virginia, 1988.

Bonbright's principles which relate to cost of service studies are:

- Effectiveness in yielding total revenue requirements.
- Fairness in the apportionment of total costs of service among the different ratepayers.
- Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.

Embedded cost of service studies are completed primarily to achieve the goal of fairness and avoidance of undue discrimination in the apportionment of revenue responsibility to rate classes. Marginal cost of service studies are performed primarily to assist in designing rates that are economically efficient.

Bonbright's principles of fairness in the apportionment of costs and the NARUC principle of attributing costs based upon how customers cause costs to be incurred are inextricably inter-twined. In fact, the principle of causality (or cost causation) is almost universally claimed in attempts to justify various cost of service methodologies as fair. The principle of cost causality states that the costs should be assigned according to load and customer characteristics that cause the costs to go up or down.[6] Cost causation, or the principle of cost causality, is mostly referred to in the classification stage of a cost of service study.

[6] The principle of causality is also heavily referenced and relied upon in the US Federal Energy Regulatory Commission's major orders on transmission ratemaking, including Order 888 and 1000.

Components of Cost of Service Studies

The NARUC Manual identifies three major steps in the cost allocation process: the "functionalization" of investments and expenses, cost "classification", and the "allocation" of costs among customer classes.[7] Before embarking on those three steps, however, a "systemization" decision may be required as to what portion of a utility's assets should be included in the cost of service study.

Functionalization is the process of assigning company investment and operating costs to specified utility functions of: (i) production (generation) or purchased power; (ii) transmission; (iii) distribution; (iv) customer service and facilities; (v) administrative and general.[8] Functionalization will generally follow standard accounting designations. However, at times there will be exceptions. In such cases, the purpose of the asset or expense, not the accounting treatment, must drive the distribution of the functional costs for the cost study.[9]

Classification is a refinement of functionalized costs. Cost classification identifies the usage characteristic – demand, energy, customer – for which functionalized dollars are spent. Revenue requirements in the production (generation) and transmission functions are classified as demand-related and/or energy-related.[10] Judgment is also exercised in determining an appropriate classification. When making such judgments it is helpful to return to basic principles, including that of cost causality to attribute costs to different categories of customers based on how those customers cause costs to be incurred.[11]

[7] NARUC Manual, page 12.
[8] NARUC Manual, page 33.
[9] NARUC Manual, page 19.
[10] NARUC Manual, pages 20-21.
[11] NARUC Manual, page 38.

Allocation is the last stage in the cost of service methodology. In the classification stages we generally use the principle of causality (or some other agreed-upon concept) to decide the cause of various costs on the system. That is, we decide what proportion of the costs are attributable to the rate classes' demands, energy, number of customers, or other characteristic. We then allocate the functionalized and classified costs to the rate classes based on the proportion of each characteristic each class contributes to the system.[12]

1.3 Overview of Evidence

This cost of service review was occasioned principally as a result of the impending commissioning of the Muskrat Falls Project and the interconnection of the Island Interconnected system to the North American grid. In this proceeding, the Board will consider for the first time how the assets comprising the Muskrat Falls Project should be treated for cost of service purposes. This will require the Board to assess, among other things, the cost causality underlying the decision to construct the Muskrat Falls generating facility and the associated LIL and LTA transmission assets.

The cost causality principle is based on the idea that costs should be assigned according to load and customer characteristics that cause the costs to go up or down. It is Hydro's evidence that the basis for proceeding with the Muskrat Falls Project was the long-term fuel cost savings associated with replacing the energy supply from Holyrood with lower cost hydroelectric energy from Muskrat Falls. In that regard, the Board will be required to determine the portion of Muskrat Falls Project costs that is to be classified as energy-related and the portion that is to be classified as demand-related.

[12] NARUC Manual, page 22.

In the Application, Hydro proposes to maintain the existing cost of service treatment of the majority of its assets. For the most part, cost of service methodology changes proposed in the Application are related to changes associated with the Muskrat Falls Project and the interconnection. In this report, I have not included detailed commentary on matters where no change in methodology has been proposed by Hydro, or recommended in the Brattle Report.

2.0 The Muskrat Falls Project

The Muskrat Falls Project was sanctioned by the Government of Newfoundland and Labrador in December 2012.[13] Once it is commissioned, the full costs of the Muskrat Falls Project are mandated to be recovered by Hydro in Island Interconnected rates charged to the appropriate classes of ratepayers.[14]

The current capital cost estimate of the Muskrat Falls Project is $10.1 billion. The full cost, including interest during construction and capitalized financing costs, is projected at $12.7 billion.[15] Annual operating and maintenance costs associated with the Muskrat Falls Project are estimated to be approximately $106 million.[16] Recovery of these costs represents a significant change in Hydro's cost to provide service to customers. This proceeding is the first time Muskrat Falls Project costs will be considered by the Board from a cost of service perspective. The Board will also consider the cost of service treatment of net export revenues related to Muskrat Falls.

In the Hydro COS Report, Hydro provides recommendations on how Muskrat Falls Project costs will be treated for cost of service purposes. Hydro's cost of service recommendations for the Muskrat Falls Project costs are summarized in Table 1.

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[13] Government of Newfoundland and Labrador News Release: *Government of Newfoundland and Labrador Announces Sanction of the Muskrat Falls Development*, December 17, 2012.
[14] Government of Newfoundland and Labrador Order in Council OC2013-343.
[15] Nalcor Energy, *Muskrat Falls Project Monthly Report, May 2019*, July 23, 2019, page 7.
[16] See Information Request PUB-Nalcor-050, Attachment 1, page 13 of 34, filed in relation to the Board's Rate Mitigation Options and Impacts Reference.

Table 1
Muskrat Falls Project
Cost of Service Recommendations - Hydro

Cost	Functionalization[17]	Classification[18]	Allocation[19]
Muskrat Falls Generation	Generation	Equivalent Peaker 20% attributed to Demand 80% attributed to Energy	Coincident Peak Allocator for Demand Annual Energy Allocator for Energy
LIL and LTA	Generation	Equivalent Peaker 20% attributed to Demand 80% attributed to Energy	Coincident Peak Allocator for Demand Annual Energy Allocator for Energy

In the Brattle Report, Brattle provides their view of the appropriate treatment of Muskrat Falls Project costs. Brattle's cost of service recommendations for Muskrat Falls Project costs are summarized in Table 2.

Table 2
Muskrat Falls Project
Cost of Service Recommendations - Brattle[20]

Cost	Functionalization	Classification	Allocation
Muskrat Falls Generation	Generation	System Load Factor 45% attributed to Demand 55% attributed to Energy	Coincident Peak Allocator for Demand Annual Energy Allocator for Energy
LIL and LTA	Transmission	100% Demand	Coincident Peak Allocator for Demand

Hydro and Brattle agree that the costs of the Muskrat Falls generating facility ("Muskrat Falls Generation") should be functionalized as generation. Hydro and Brattle also agree on how the energy and demand costs for Muskrat Falls should be allocated between Newfoundland Power and the Island Industrial customers. Hydro and Brattle disagree on the method for determining

17 Hydro COS Report, page 8, lines 6-8.
18 Hydro COS Report, page 10, line 1 to page 11, line 10.
19 Hydro COS Report, page 13, line 3 to page 15, line 8.
20 Brattle Report, pages 5-6, Table 1.

how much of the Muskrat Falls Generation costs should be classified as energy-related, and how much should be classified as demand-related.

Hydro and Brattle also disagree on the functionalization and classification of the costs of the LIL and the LTA. Hydro recommends that LIL and LTA costs be functionalized and classified in the same manner as the Muskrat Falls Generation costs. Brattle recommends that the costs of the LIL and LTA should be functionalized as transmission, and classified as 100% demand-related.

2.1 Muskrat Falls Generation Costs

I agree with Hydro's proposal that Muskrat Falls Generation costs should be functionalized as generation. In my opinion, this is consistent with generally-accepted cost of service principles and practices as outlined by NARUC.[21] It is also consistent with the Board's previous determinations with regards to Hydro's cost of service methodology.[22]

While Hydro and Brattle agree that Muskrat Falls Generation costs should be classified using energy-weighted approaches, they disagree on the specific method. Hydro recommends that power purchase costs resulting from the Muskrat Falls Project be classified using the equivalent peaker method.[23] This results in approximately 20% of the Muskrat Falls Generation costs being classified as demand-related, and approximately 80% being classified as energy-related.[24]

[21] NARUC Manual, pages 18-19.

[22] In February 1993, the Board provided a report to the Minister of Mines and Energy which provided the foundation for Hydro's existing cost of service methodology. In subsequent general rate applications, the Board approved refinements to the methodology established in 1993.

[23] Hydro COS Report, page 10, lines 2-5. The equivalent peaker methodology is effectively based on an estimate of the cost per kW of a new peaking unit compared with the cost per kW of the new base load generation unit giving consideration to the life-cycle of the two facilities. The portion of the cost in excess of the cost of the peaking unit is treated as energy-related.

[24] Hydro COS Report, page 11, Table 1.

It is Hydro's evidence that the Muskrat Falls Project was selected as the least cost option for replacing the Holyrood Thermal Generating Station ("Holyrood") primarily based on fuel savings over the long term. The equivalent peaker method deems that the costs of constructing the Muskrat Falls Project that are in excess of the cost of constructing a new peaking unit were incurred to meet energy requirements. Given Hydro's stated basis for developing the Muskrat Falls Project, I agree with Hydro's view that its proposal to use the equivalent peaker method to classify the related costs reflects the causality of its investment decision.[25]

Brattle recommends the system load factor approach to classification of Muskrat Falls Generation costs as opposed to the equivalent peaker approach recommended by Hydro.[26] The system load factor approach results in approximately 45% of the Muskrat Falls Generation costs being demand-related and approximately 55% being energy-related.[27]

Brattle provides five reasons for preferring the system load factor approach over the equivalent peaker method for the classification of Muskrat Falls Generation costs.

Firstly, Brattle recommends that Hydro's existing practice of classifying generation based on system load factor should be applied to Muskrat Falls Generation in the absence of evidence that the equivalent peaker approach is unequivocally superior.[28] Brattle agrees that both the system load factor and equivalent peaker method have merit as energy-weighted approaches to

[25] See Hydro COS Report, page 10, line 19 to page 11, line 7 and the Response to Request for Information PUB-NLH-037.
[26] System load factor refers to the ratio of the average load over a designated period to the peak demand occurring in that period.
[27] Brattle Report, page 31, Table 4.
[28] Brattle Report, page 33, lines 1-4.

classification. Brattle believes both approaches are reasonable; however, they do not believe that one way is unequivocally superior to the other.[29]

I disagree with Brattle on this point. As a generation planner, it is my opinion that, from a cost causality perspective, the equivalent peaker method is the superior classification method for Muskrat Falls Generation costs. This is because the equivalent peaker method is directly related to the cost of the mix of generation upon which generation planning decisions are made.

In my opinion, while no embedded cost of service method for classifying generation costs is perfect, the equivalent peaker method best reflects the planning decisions that go into creating a modern least-cost electrical system. While the system load factor method does include an energy weighting, it is not rooted in cost causality.

Secondly, Brattle reasons that system load factor is more straightforward to implement and is not dependent upon and sensitive to key assumptions and input values that are required for the equivalent peaker approach.[30] In my view, however, the comparative simplicity of the load factor method is not a sufficient justification for choosing it over a superior method. While the equivalent peaker method may require key estimates to determine accurate energy and demand weightings, determining the reasonableness of such estimates is within the Board's expertise.

Thirdly, Brattle argues that, because the energy component of the equivalent peaker methodology is effectively a residual cost, the inclusion of such items as cost overruns can

[29] Brattle Report, page 32, lines 4-7.
[30] Brattle Report, page 33, lines 7-9.

distort the energy and demand weightings.[31] I agree that, under the equivalent peaker method, cost overruns on the Muskrat Falls Project will tend to increase the portion of the costs classified as energy-related. In my view, however, this is consistent with the causality of the Muskrat Falls Project. In my experience, it is more common that large generation projects built to lower energy costs will experience significant cost overruns, as compared to peaker projects, which tend to be less complex, and take far less time to construct.

Despite the impact of cost overruns on the cost of Muskrat Falls Generation, the use of the equivalent peaker method results in a lower percentage of energy-related cost than historically associated with Holyrood. According to Hydro's evidence, energy-related costs associated with Holyrood for the 2004, 2007, and 2015 test years were in the range of 82% to 86%, and demand-related costs were in the 14%-18% range.[32]

Brattle also argues that the equivalent peaker method would assign less of the Muskrat Falls generation costs to demand compared to the system load factor approach, thus diluting peak-reducing demand price signals. In other words, lower demand charges under the equivalent peaker approach would provide less of a disincentive to consumption during peak demand periods.[33] In my opinion, it is fundamental that cost of service methodology reflect causality. It is not a function of a cost of service study to artificially inflate either the demand or energy charges to encourage or discourage consumption. The question of price signals is a matter of rate design, which is a separate issue.

31 Brattle Report, page 36, lines 1-6.
32 Hydro COS Report, page 11, lines 5-7, and Hydro's response to Request for Information PUB-NLH-037, page 2 of 5.
33 Brattle Report, page 36, lines 11-16.

Brattle's final stated reason for recommending the system load factor method instead of the equivalent peaker method is related to the structure of the Muskrat Falls power purchase agreement (the "PPA").[34] The PPA effectively requires payments based on recovery of Muskrat Falls capital costs over a 50-year period, as well as annual operating and maintenance costs. The PPA is not based on the amount of energy Hydro consumes.[35] In my opinion, the form of the PPA does not reflect the causality of the decision to construct the Muskrat Falls Project, and therefore should not influence the choice of cost of service methodology.

In the 1992 Cost of Service Review, I recommended the equivalent peaker methodology as the most appropriate way to classify Hydro's generation. At the time, the Board chose not to adopt the equivalent peaker method, citing two specific challenges: (i) the value to be assigned to the peaker used as a proxy for investment in capacity; and (ii) the degree to which economic assumptions affecting past planning decisions would have to be rediscovered and incorporated in the method in order to reach reasonable and equitable decisions.[36] With respect to those challenges, I agree with Christensen's assessment that the issues of "computational challenge, and plant vintage and valuation issues" are of less concern with respect to the Muskrat Falls Project, since the computations pertain to a plant of current vintage.[37]

Although I recommended that the equivalent peaker method be applied to all of Hydro's hydraulic plant in 1992, I accept that the Board's concern regarding computational and valuation

[34] Brattle Report, page 36, line 19 to page 37, line 8.

[35] The Muskrat Falls Power Purchase Agreement was filed as Attachment 8 to the response to Request for Information PUB-NLH-004.

[36] Report of the Board of Commissioners of Public Utilities to the Honourable Minister of Mines and Energy, Government Of Newfoundland and Labrador on a Referral by Newfoundland and Labrador Hydro for the Proposed Cost of Service Methodology, February, 1993, pages 33-34.

[37] Christensen Report, page 17, lines 9-13.

challenges related to plant vintage remains valid with respect to Hydro's older generation assets. I therefore agree that Hydro's existing hydraulic assets should continue to be classified using system load factor.

2.2 LIL and LTA Costs

The LIL and LTA are transmission lines that are necessary to deliver and optimize production from the Muskrat Falls generating facility. Hydro proposes that the costs of the LIL and LTA be functionalized and classified in the same manner as Muskrat Falls Generation costs. They propose the LIL and LTA be functionalized as generation, and the costs classified as demand or energy-related using the equivalent peaker method. This would result in approximately 20% of LIL and LTA costs being classified as demand-related, and 80% being classified as energy-related. Brattle, on the other hand recommends an entirely different treatment. Brattle recommends functionalizing the LIL and LTA as transmission and classifying the costs as 100% demand-related.

I support Hydro's proposal. In my opinion, Hydro's proposal that the LIL and LTA be functionalized and classified as proposed in the same manner as the Muskrat Falls Generation is supported by the principle of cost causality. Hydro's proposal is also consistent with the existing cost of service treatment of those transmission lines on the Island Interconnected system that are considered to be "generator leads". It is also consistent with the cost of service treatment of similar transmission facilities in Manitoba.

Cost Causality

In my opinion, cost causality is the key principle to be considered in the cost of service process. For the generation function, consideration of cost causality involves a determination of the basis of the utility's decision to invest in a specific generation asset.[38]

It is Hydro's evidence that the Muskrat Falls Project is an integrated project that was selected as the least-cost alternative to replace Holyrood, primarily based on the projected fuel cost savings over the long term. From a cost causality perspective, Hydro therefore considers it reasonable that most of the Muskrat Falls Project costs be considered energy-related.[39]

As a generation planner, I agree with the following assessment by Christensen of the LIL and LTA:

> "…the existence of the LIL and LTA is driven by energy and associated fuel cost savings, as planned: fuel costs, not capacity, are highly specific to location – in the immediate case, the unique physical features and properties of MF beget fuel cost savings, in service of the IIS, mainly the customers and load of the Avalon Peninsula. If it were just capacity that had been needed, Hydro would, as a matter of least cost, have built/installed capacity in close proximity to the loads to be served."[40]

From a planning perspective, it is useful to compare the cost of the capacity of the LIL to the cost of capacity of an equivalent peaker. The estimated cost of the 900-megawatt LIL is approximately $3.7 billion.[41] If the line is functionalized as Transmission and classified as being 100% demand-related, the capacity cost of the LIL alone would be over $4,100/kW. This compares to Hydro's estimated cost of $3,500/kW for an equivalent peaker combustion turbine.[42]

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38 NARUC Manual, page 38.
39 Hydro COS Report, page 11, lines 1-7.
40 See the response to Request for Information PUB-NLH-034, page 5 of 6, lines 19-25.
41 Nalcor Energy, *Muskrat Falls Project Monthly Report, May 2019*, July 23, 2019, page 7.
42 3.7 billion / 900 MW = $4,111/kW. See Hydro's COS Report, Exhibit 1, Page 2 of 3, for Hydro's estimate of an equivalent peaker combustion turbine.

Such a costly line would never be built simply to serve demand. In my opinion, classifying these costs as 100% demand-related is not consistent with the cost causality principle.

Brattle considers the issue of cost causality somewhat differently. It appears that, from Brattle's perspective, the fact that the decision to proceed with the Muskrat Falls Project was based on the projected fuel cost savings over the long term bears no relevance to the functionalization or classification of the LIL and LTA. It is Brattle's view that "the primary driver of a transmission facility's costs (i.e., the cost causality) is its size, i.e., its maximum capability to transfer energy at any point in time."[43] Accordingly, Brattle recommends that, should the Board accept the LIL and LTA as functionalized to generation, they both be classified as demand-related.[44]

In my opinion, the primary driver of the costs of the LIL and LTA is not their design capacity. While it is true that, for a transmission line of a given length, the cost will vary according to the design capacity of the line, the most significant contributor to the cost of the LIL and LTA are the lengths of the lines and the terrain over which they traverse, factors which are a direct result of the location of the Muskrat Falls generating facility.[45]

As noted by Hydro, "the main drivers of the LIL cost is the fact that the LIL is connecting remote generation to the Alternating Current grid of the Island Interconnected system."[46]

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43 See responses to Requests for Information CA-PUB-004 and NP-PUB-001.

44 Brattle Report, page 19, lines 3-5.

45 The LIL traverses approximately 1,100km from the Muskrat Falls generating station in central Labrador to the Soldiers Pond HVdc converter station near St. John's and includes a 35 km marine cable crossing at the Strait of Belle Isle. The LTA consists of two 250km 315kV HVac transmission lines in central Labrador between Muskrat Falls and Churchill Falls.

46 See response to Request for Information PUB-NLH-034, page 3 of 6, lines 21-25.

Regarding the LTA, I agree with Hydro's view that, because its purpose relates to maximizing generation output for transfer over the LIL to the Island, it should also be considered the same as the Muskrat Falls generating facility for cost of service purposes.[47]

Brattle further recommends that the costs of the LIL and LTA be removed from the equivalent peaker calculation. In my view, however, the cost causality of the Muskrat Falls generating facility extends to the LIL and LTA, which would not have been constructed but for the construction of the generating facility itself. Because the costs of the LIL and LTA were incurred in furtherance of the long term fuel cost savings associated with the replacement of Holyrood energy, those costs ought to be included in the equivalent peaker calculation.

Previous Board Determinations

Hydro's position on the functionalization of the LIL and LTA as generation is consistent with the cost of service treatment recommended by the Board in its report on the 1992 Cost of Service Review (the "1993 Cost of Service Report"). The Board stated as follows:

> "It is a fair presumption that Hydro developed hydraulic sites because they offered capacity and energy at least cost, and that where such sites were remote from the transmission system, the cost of transmission between the site and the grid was included in the economic evaluation. Under such circumstances it is the Board's opinion that the transmission from site to grid should be classified in accordance with the generation itself."[48]

[47] See response to Request for Information PUB-NLH-034, page 4 of 6, lines 2-3.
[48] 1993 Cost of Service Report, pages 44-45.

The 1993 Cost of Service Report also stated:

> "In the Board's opinion all lines, terminal stations and ancillary equipment dedicated to the service of a generating station should be classified in conformity therewith.
>
> > Recommendation 15:
> > That transmission lines and substations in the Island Interconnected System used ***solely or dominantly for the purpose of connecting remotely-located generation to the main transmission system*** be classified in the same manner as the generating stations they serve. ***(emphasis added)***
> >
> > Recommendation 16:
> > That all other transmission be classified 100% to demand."[49]

Based on the information provided in Hydro's evidence in this proceeding, including the Christensen Report, it is my opinion that the LIL and the LTA transmission assets were constructed solely or dominantly for the purpose of connecting the remotely-located Muskrat Falls generating facility to the Island Interconnected grid.[50] In my opinion, functionalizing the LIL and LTA as generation, and classifying the costs associated with the transmission lines in the same manner as the Muskrat Falls generating facility is consistent with the recommendations in the 1993 Cost of Service Report.

Taken in combination, Brattle's cost of service recommendations for the Muskrat Falls Generation and the LIL and LTA turns the Board's historical split between demand and energy for a large portion of the Island Interconnected power supply on its head. Brattle's recommendations result in 80% of the Muskrat Falls project being classified as demand-related.[51] The effect is largely driven by Brattle's recommendation to classify LIL and LTA as

[49] 1993 Cost of Service Report, page 45-46.
[50] See response to Request for Information PUB-NLH-034.
[51] See response to Request for Information PUB-NLH-37, page 1 of 5, Table 1.

100% demand and the fact that the combined cost of the LIL and LTA is almost equal to the cost of the Muskrat Falls generation facility.[52]

The LIL and LTA are an integral part of the Muskrat Falls Project. Given that these combined assets were constructed primarily to save on energy, the end result of Brattle's recommendation does not seem reasonable.

The FERC

Development of the Muskrat Falls Project including the associated interconnections between the Island Interconnected system and the Quebec and Nova Scotia transmission systems using the LIL, LTA, and Maritime Link, enables both the export and import of wholesale electricity by means of the North American electricity grid. To participate in the North American wholesale electricity markets, open and non-discriminatory access to the Newfoundland and Labrador transmission system must be provided. This requirement is established by the Federal Energy Regulatory Commission ("FERC").[53]

In accordance with the direction of the provincial government, the Board has approved, on an interim basis, certain policies and procedures, and transmission rates and rate methodologies, relating to the transmission of electricity over the Province's high voltage transmission system.[54] In addition, the *Electrical Power Control Act, 1994* has been amended to include a requirement

[52] The Muskrat Falls generating facility is estimated to cost approximately $5.5 billion. The LIL and LTA are estimated to cost approximately $3.7 billion and $0.9 billion, respectively. ($3.7 billion + $0.9 billion) / $5.5 billion = 0.84. Cost estimates are sourced from the Nalcor Energy, *Muskrat Falls Project Monthly Report, May 2019*, July 23, 2019, page 7.

[53] The FERC is an independent agency of the United States Department of Energy. Its responsibilities include regulation of the transmission and wholesale sales of electricity in interstate commerce in the United States.

[54] See Order No. P.U. 3 (2018).

for open, non-discriminatory and non-preferential access on the integrated electricity system.[55] The stated purpose of these developments is to ensure consistency with the principles of open transmission access adopted by the FERC.[56]

In its discussion of Hydro's proposal to functionalize and classify the costs of the LIL and LTA in the same manner as the Muskrat Falls Generation, Brattle referred to the FERC's definition of a transmission system, and raised the matter of FERC requirements related to open access transmission service.[57] However, Brattle's evidence does not point to a specific FERC requirement that all transmission assets subject to open access transmission requirements be functionalized or classified in a particular manner.[58]

It is Hydro's evidence that functionalizing the LIL and LTA is not limited by FERC requirements. In Hydro's view, the Board has the authority to establish the cost of service functionalization and classification of Hydro's assets. It is Hydro's evidence that the FERC "does not prescribe how transmission rates are to be calculated; its only requirements with respect to transmission rates are that all customers receiving the same service should be charged the same rate and that the methodology for rate design be transparent."[59]

The FERC does not have regulatory jurisdiction in Canada. Although, as a practical matter, compliance with specific FERC requirements may be necessary to ensure electricity produced in

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55 *Electrical Power Control Act, 1994*, Section 3 (b)(iv.1).
56 Government of Newfoundland and Labrador News Release: *Government Adopts Open Access Framework for Transmitting Electricity, March 26, 2018.*
57 Brattle Report, page 16, line 4 to page 19, line 2.
58 In fact, Brattle acknowledges the Board may approve Hydro's proposal to functionalize the LIL and LTA as generation. (See Brattle Report, page 19, lines 3 - 5).
59 See the response to Request for Information NP-NLH-006.

Canada can be exported to markets in the United States.[60] My review of Canadian regulatory practice suggests the Board would have the authority to functionalize, classify, and allocate costs as it deems appropriate, subject to the requirement that access be open to all who may require transmission service, and that the terms be non-discriminatory. For example, the Island Regulatory and Appeals Commission of Prince Edward Island, in a 2018 open access transmission tariff decision, accepted the evidence of regulatory experts that the FERC will defer to the decision of the local regulator "as long as the overarching issue of service comparability and non-discriminatory access is met."[61]

There is no evidence in this proceeding that Hydro's proposed cost of service treatment of the Muskrat Falls Project is in conflict with FERC requirements with respect to open access transmission service. It is my opinion that there are characteristics of the Muskrat Falls Project that would support a departure from the treatment of transmission lines under FERC jurisdiction.

Christensen considers the LIL and LTA to be "Special Purpose Transmission Facilities" that are required to facilitate energy transfers from the combined Churchill Falls and Muskrat Falls generation facilities.[62] Christensen states that the decision to functionalize a line as generation includes considerations such as the nature of the power flow and the sizing of the transmission line. If virtually all power flow is in one direction (generator to the main grid), and the line is sized with the specific generator's capacity in mind, then functionalization as generation is justifiable.[63]

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[60] The FERC's policies do require that utilities they regulate document a reasonable and non-discriminatory cost of service policy. Presumably, reciprocity would require similar reasonable non-discriminatory and documented procedures from NLSO.

[61] See The Island Regulatory and Appeals Commission *Order UE18-05*, July 26, 2018, page 14, paragraph 90.

[62] Christensen Report, page 33, line 20 to page 36, line 8.

[63] See also the response to Request for Information NP-NLH-014.

I agree. Similar considerations are reflected in the results of the 2016 Manitoba Public Utilities Board cost of service review of Manitoba Hydro, which is discussed in the following section of my report.

With regard to energy classification of transmission lines, not all transmission lines in the US are treated as demand-related. FERC allows the California ISO (CAISO) and its utilities to treat certain transmission lines in California as energy-related. Although California transmission lines are more heavily integrated into the grid, there are a number of high-voltage DC lines built to the Pacific Northwest for the predominant purpose of bringing low-cost hydro power to Southern California. To simplify the way the FERC-approved transmission rates for these California lines are determined, the total costs of the lines are added up for all the utilities and then divided by the energy expected to flow over them. Transmission rates in the New York ISO area also contain a significant energy component.[64]

Manitoba Hydro Cost of Service Review

A cost of service review carried out by the Manitoba Public Utilities Board in 2016 considered the cost of service treatment of certain Manitoba Hydro generation and transmission facilities that share similarities with the Muskrat Falls Project. Both systems include: (i) large hydroelectric generating facilities; and (ii) transmission lines designed to transmit power over long distances from the hydroelectric generating facilities to the load centres.[65]

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[64] California ISO, *Review Transmission Access Charge Structure – Issue Paper*, June 30, 2017, page 12.

[65] The Manitoba Hydro system includes three hydroelectric generating facilities located on the Nelson River (Kettle, Long Spruce, and Limestone). A fourth, the Keeyask hydroelectric generating station, is currently under construction. The Bipole I, Bipole II, and Bipole III HVdc transmission lines bring power from these generating stations to load centres located in southern Manitoba.

In Order No. 164/16 – Order in Respect of a Review of Manitoba Hydro's Cost of Service Study Methodology (the "Manitoba COS Order"), the Manitoba regulator recognized cost causation as the paramount principle in determining the appropriate cost of service methodology.[66]

The Manitoba COS Order included a detailed review of the functionalization of the Northern Collector System transmission lines.[67] The Manitoba Board found that all Northern Collector System transmission lines including Bipole I and Bipole II should be functionalized as generation since they act "as extensions of the northern generators, not as networked transmission." The Manitoba Board also found that Bipole III should be functionalized as generation since it provides generation reliability to Bipole I and Bipole II and not reliability to the networked transmission system.[68]

The Manitoba Public Utilities Board classified the Northern Collector System transmission lines with both an energy and demand component using system load factor, which is in accordance with the classification methodology used for other Manitoba Hydro functionalized generation costs.[69] The Manitoba COS Order does not appear to have interfered with Manitoba Hydro's exports of power into the US.[70]

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66 Cost causation, as defined by the Manitoba Public Utilities Board, takes into consideration both how an asset is planned and how that asset is used. This takes into account how an asset fits into Manitoba Hydro's current system planning, as well as the current use. See Manitoba Public Utilities Board Order No. 164/16 dated December 20, 2016, page 27 of 116.

67 The Northern Collector System is a series of wires, transformers, switches, and stations that transmit electricity from Manitoba Hydro's three hydroelectric generating stations on the Lower Nelson River. The Northern Collector System includes the Bipole I, Bipole II, and Bipole III HVdc transmission lines.

68 Manitoba Public Utilities Board Order No. 164/16 dated December 20, 2016, page 56 of 116.

69 Manitoba Public Utilities Board, Order No. 164/16, December 20, 2016, page 56 of 116.

70 See Manitoba Hydro – Power Sale Arrangements at: https://www.hydro.mb.ca/corporate/electricity_exports/power_sale_arrangements/

Brattle has pointed out certain differences between the Muskrat Falls Project and the Manitoba Hydro system, including that the lines are entirely radial and that Manitoba Hydro has not functionally separated its generation activities from its transmission activities except for its power marketing activities.[71] In my opinion, from a cost of service perspective, these distinctions do not negate the fundamental similarities.

2.3 Treatment of Net Export Revenues

The interconnection of the Muskrat Falls Project, together with the Maritime Link, will facilitate the export of electricity from Hydro to Nova Scotia and beyond.[72] Hydro recommends using net export revenues to reduce Muskrat Falls Project costs and to classify the revenues in the same way that Muskrat Falls Project costs are classified.[73] I agree with this approach, since it effectively offsets the costs associated with the Muskrat Falls Project in a manner that avoids cross-subsidization between customer rate classes. Brattle also supports Hydro's recommendation in this regard.[74]

To account for annual variances in the amount of net export revenues received from one year to the next, Hydro recommends using a deferral account that adjusts for variations from forecast net export revenues included in a test year cost of service study.[75] Brattle raises a concern over the uncertainty of Hydro's test year export credits, and recommends the use of a rider to facilitate true-ups between rate cases, with no less than annual frequency.[76]

[71] See the response to Request for Information NLH-PUB-007.
[72] Hydro's recommendation includes costs relating to Muskrat Falls Generation, the LIL, and the LTA. See Hydro COS Report, page 6, lines 20-26.
[73] Hydro COS Report, page 18, lines 12-17.
[74] Brattle Report, page 10, lines 2-5.
[75] Hydro COS Report, page 18, lines 18-20.
[76] Brattle Report, page 61, lines 4-7.

In my opinion, the methodology proposed by Hydro is straightforward and practical to administer. Furthermore, the deferral account methodology can be completed in a way that ensures net export revenues are properly applied against the costs of the Muskrat Falls Project for each customer rate class.

3.0 Other Proposed Changes to Cost of Service Methodology

In addition to the introduction of assets included in the Muskrat Falls Project, Hydro has proposed certain other changes to its cost of service methodology. These include changes related to: (i) transmission lines TL-234 and TL-263; (ii) Holyrood; and (iii) wind purchases. My views on these proposed changes are discussed in the following section.

3.1 TL-234 and TL-263

Prior to the integration of the Maritime Link, Hydro's transmission lines TL-234 and TL-263 functioned as a radial transmission system connecting the Granite Canal and Upper Salmon hydroelectric facilities in central Newfoundland to Hydro's 230 kV transmission system. Both TL-234 and TL-263 were considered generator leads, and functionalized as generation in Hydro's previous cost of service studies.

To facilitate the export of power from the Muskrat Falls Project to Nova Scotia, transmission line TL-269 was constructed from Granite Canal to Hydro's Bottom Brook terminal station on the west coast of Newfoundland.[77] The completion of TL-269 integrates TL-234 and TL-263 into Hydro's 230 kV network transmission system.

Hydro recommends that the functionalization of TL-234 and TL-263 change from generation to transmission to reflect the changing function of these transmission lines with the integration of

[77] TL-269 is owned by NSP Maritime Link Incorporated. A HVdc transmission line from Bottom Brook to Nova Scotia completes the interconnection between the Newfoundland and Nova Scotia electricity systems. See Newfoundland and Labrador System Operator (NLSO) Report – *2018 Annual Planning Assessment* (Doc # TP-R-011), May 4, 2018, page 3, for a map of the Newfoundland and Labrador Interconnected System. The report is available at: https://www.oasis.oati.com/NLSO/index.html.

the Muskrat Falls Project and the addition of the Maritime Link to Nova Scotia.[78] Brattle agrees with this change.[79]

I agree that the addition of TL-269 from Granite Canal to Bottom Brook line has changed the function of the TL-234 and TL-263 from generation to transmission. TL-234 and TL-263 are no longer radial generation lines whose main purpose or function is to bring the generation to the load centers. Instead, they serve a broader function as part of the integrated transmission grid. I agree that TL-234 and TL-263 should be functionalized as transmission.

3.2 Holyrood

In this Application, Hydro is proposing to change the basis of classification of Holyrood thermal generation from an historical 5-year average capacity factor to a forecast test year capacity factor. This accounts for the changing role of Holyrood following the completion of the Muskrat Falls Project.[80] I agree with Hydro's proposal to use a test year forecast capacity factor.

Once the Muskrat Falls Project is fully commissioned and operating reliably, Hydro intends to decommission Holyrood. Unit 3 at Holyrood ("Holyrood 3") will be retained to operate as a synchronous condenser only. Hydro indicates that the role of Holyrood will change, and the plant will cease to perform as a generating unit. Hydro has recommended that, once Holyrood 3 is permanently converted to a synchronous condenser, it be functionalized as transmission.[81]

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[78] Hydro COS Report, page 7, lines 8-11.
[79] Brattle Report, page 19, line 17.
[80] Hydro COS Report, page 12, lines 1-7.
[81] Hydro COS Report, page 8, lines 15-16.

Brattle recommends that the portion of rate base and depreciation associated with Holyrood's use as a generator continue to be functionalized as generation, but that the capital additions and operations and maintenance costs associated with Holyrood 3's use as a synchronous generator be functionalized as transmission.[82]

Brattle appears to be trying to keep the costs of Holyrood's depreciation and rate base reflective of their original use as a generator, while reflecting any costs going forward in accordance with their new function of transmission. I do not feel it is necessary to keep reflecting any remaining rate base and depreciation costs as generation, once the function of the unit has changed. In my opinion, since the generator and control equipment will be re-purposed as part of the transmission system, its functionalization should reflect that.

Synchronous condensers are used to help control voltage during high and low load periods on a transmission system. As such, they are an integral part of the transmission system and should be treated as such. I agree with Hydro's recommendation that, once Holyrood 3 is converted into a synchronous condenser only, it be functionalized as transmission and classified as demand-related.

3.3 Wind Purchases

Under Hydro's existing cost of service methodology, purchases from the two wind farms on the island are classified as 100% energy-related. In 2018, Hydro's planning group conducted a study of wind availability during peak periods.[83] The study concluded that the effective load carrying

[82] Brattle Report, page 20, line 10-18.
[83] Hydro's *Effective Load Carrying Capability Study – Newfoundland and Labrador Hydro Wind Turbines*, November 2018, was filed as Attachment 1 to the response to Request for Information CA-NLH-011.

capability ("ELCC") of the existing wind generation on the Island Interconnected system was approximately 12 MW, or 22%, based on an installed capacity of 54 MW.[84]

Prior to this proceeding, there was no evidence that wind power was reliably available during peak periods. Hydro's study shows that wind purchases can be relied upon for peak demand about 22% of the time. The Application proposes that Hydro's wind purchases be classified as 22% demand-related and 78% energy-related, reflecting the results of the study.[85]

Based on the results of Hydro's study, I agree with Hydro's proposal to classify wind purchases as 22% demand and 78% energy.

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[84] See the response to Request for Information CA-NLH-011, Attachment 1, *Effective Load Carrying Capability Study – Newfoundland and Labrador Hydro Wind Turbines*, November 2018, page 6, lines 1-2.

[85] Hydro COS Report, page 12, lines 9-12.

4.0 Other Cost of Service Issues

In addition to the cost of service treatment of Muskrat Falls Project costs, and the other cost of service methodology changes Hydro has proposed, certain other issues relating to Hydro's cost of service methodology have been raised by Brattle. These include Hydro's systemization methodology, the functionalization of transmission lines, the classification of diesel and gas turbine fuel, marginal cost based allocation and the Corner Brook Pulp and Paper ("CBPP") generation credit.

4.1 Systemization

Systemization is the process of determining which assets, costs, and revenues from a utility's total assets, costs and revenues should be included in a given cost of service study. Hydro recommends maintaining its existing systemization methodology which includes separate cost of service studies for the Labrador Interconnected System and the Island Interconnected System for use in determining customer rates.[86] Brattle recommends that Hydro plan and prepare a single integrated system for cost of service purposes in future general rate applications.[87]

Brattle is not recommending changes to Hydro's systemization methodology at this time. In my view, either separate or combined cost of service studies will yield the same result if they are properly performed. Hydro has indicated that Brattle's proposal is not fully explained.[88] I recommend that Hydro consult with Brattle to clarify their recommendation, and report on the

[86] Hydro COS Report, page 7, lines 21-22.

[87] In the response to Request for Information NLH-PUB-005, Brattle suggests that "there may be certain generation costs such as overhead, administrative and general, etc., which, in a future integrated COS might be treated differently than in the current COS."

[88] See response to Request for Information PUB-NLH-033.

costs and benefits of Brattle's recommendation so the issue can be considered in Hydro's next general rate application.

4.2 TL-243 and TL-247

Transmission lines TL-243 is a radial transmission line that connects the Hinds Lake hydroelectric generating station to Hydro's 230 kV transmission system. Similarly, transmission line TL-247 is a radial transmission line that connects the Cat Arm hydroelectric generating station to Hydro's 230kV transmission system. Hydro currently considers these transmission lines to be generator leads and has historically functionalized them as generation.[89]

Brattle disagrees with Hydro's current practice of functionalizing TL-243 and TL-247 as generation. Furthermore, Brattle recommends a general review of Hydro's transmission assets for possible re-functionalization as transmission. In support of its argument, Brattle refers to the FERC open access transmission policy. Brattle states:

> "Concerning all of Hydro's assets that provide interconnection into the transmission system, we recommend a general review of these assets for possible refunctionalization as transmission. As already noted, it appears that Hydro uses whether the asset can be associated with loop flow on the transmission network as its criterion for transmission functionalization. As the U.S. Federal Energy Regulatory Commission's open access transmission policy no longer deems that as the sole basis for determining if an asset should be treated as a component of the transmission system, and thus, have a transmission tariff, it seems appropriate to review Hydro's current functionalization of such assets."[90]

I disagree with Brattle's recommendation that TL- 243 and TL-247 should be functionalized as transmission. Nor do I believe a general review as proposed by Brattle is necessary. TL-243 and

[89] See response to Request for Information PUB-NLH-032.
[90] Brattle Report, page 20, lines 1-8.

TL-247 do not function as networked transmission lines. Judging from Hydro's transmission system schematics, and Hydro's evidence, these lines function essentially as generator leads.[91] Furthermore, there is no evidence filed in this proceeding that functionalizing TL-243 and TL-247 as transmission is necessary to meet legislative requirements or FERC's open access transmission policy.

Since these lines are still essentially generator leads, I agree with Hydro's recommendation that TL-243 and TL-247 should remain functionalized as generation.

4.3 Fuel for Gas Turbines

Hydro proposes that it continue classifying Island Interconnected and Labrador Interconnected diesel and gas turbine units and variable fuel costs as demand. Brattle believes variable fuel costs should be classified as energy-related rather than demand-related, since the amount of fuel required varies with the amount of energy produced in these units.[92]

Hydro disagrees with Brattle's recommendation, and points to the Board's determination in the 1993 Cost of Service Report that the treatment of such fuel costs as demand-related costs would more adequately reflect cost causation. Hydro explains that the requirement to operate these units is not normally driven by the requirement to supply energy. Instead, the gas turbines and diesel units are operated for reliability considerations (i.e., to maintain operating reserves and to support system operating limits) consistent with the classification as demand-related operation.[93]

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[91] See Newfoundland and Labrador System Operator (NLSO) Report – *2018 Annual Planning Assessment* (Doc # TP-R-011), May 4, 2018, page 3, for a map of the Newfoundland and Labrador Interconnected System. The report is available at: https://www.oasis.oati.com/NLSO/index.html.
[92] Brattle Report, page 44, lines 9-11.
[93] See the response to Request for Information PUB-NLH-039.

I agree with Hydro's existing approach of classifying Island Interconnected and Labrador Interconnected diesel and gas turbine units and variable fuel costs as 100% demand-related. Gas turbines on these systems function primarily to manage peak load requirements and are operated when needed to serve demand.[94]

4.4 Marginal Cost Based Allocation Approach

Cost of service studies are of two types. Embedded studies allocate the utility's revenue requirement, while marginal cost studies allocate costs based on marginal consumption. In the 1992 Cost of Service Review, the Board approved the use of embedded cost of service studies for allocating costs to customers.[95] Hydro's consultant in this proceeding, Christensen, recommends the introduction of marginal cost-based allocation of costs "subject to Hydro's mastery of the technical challenges of marginal cost development."[96]

Hydro does not recommend the use of marginal costs in the allocation of costs in its cost of service study. Hydro indicates that no other Canadian utilities apply the marginal cost approach and has concerns relating to the complexity and understandability of marginal cost derivation relative to the traditional cost of service approaches.[97] Brattle also disagrees with the use of marginal cost-based allocation at this time.[98] I agree with Hydro and Brattle that marginal cost allocation should not be pursued at this time.

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[94] This differs from isolated diesel units that serve the entire load of an isolated community, both on-peak and off-peak. Such units should continue to be classified using system load factor as proposed by Hydro and recommended by Brattle.

[95] 1993 Cost of Service Report, page 8.

[96] Christensen Report, page 29, lines 16-20.

[97] Hydro COS Report, page 8, line 26 to page 9, line 24.

[98] Brattle Report, page 64, lines 15-18.

4.5 Corner Brook Pulp and Paper Generation Credit

Corner Brook Pulp and Paper's generation credit allows Hydro to call on CBPP to maximize its 60 Hz generation prior to increasing generation at Holyrood for system reasons and prior to starting its stand-by units. The benefits arising from the fuel cost savings that supported the generation credit are not expected to continue upon commissioning of the Muskrat Falls Project. Since Holyrood will no longer be operating as a generating unit once the Muskrat Falls Project has been fully commissioned, Hydro is proposing to work with CBPP to revise their arrangement to better reflect future savings.[99] In my opinion, this is appropriate.

[99] Hydro COS Report, page 17, line 17 to page 18, line 10.

5.0 Other Cost of Service Matters

The remaining proposals in the Application maintain the existing cost of service treatment. Brattle has not recommended any changes in relation to these matters.

In my opinion, Hydro's existing cost of service methodologies related to these matters continue to be appropriate:

1. Contributions from customers for new network additions.
2. Classification of existing hydraulic assets.
3. Rural deficit allocation.
4. Newfoundland Power's generation credit.
5. Conservation and demand management.
6. Allocation of functionalized generation and transmission costs.
7. Power purchases (excluding wind) should be classified using system load factor.
8. Isolated diesel units should be classified using system load factor with variable fuel costs classified as energy.
9. L'Anse Au Loup diesel generation assets classified as demand with variable fuel costs classified as energy.
10. Transmission assets specifically assigned to customers to continue to be specifically assigned.
11. Use of indexed asset costs in operating and maintenance cost allocations in the determination of specifically assigned charges.

6.0 Summary of Recommendations

Having reviewed all of the evidence filed in this proceeding, I offer the following recommendations with respect to Hydro's cost of service methodology:

Additions to Hydro's Cost of Service

1. Muskrat Falls Generation costs should be functionalized as generation and classified using the equivalent peaker method.
2. The Labrador Island Link (LIL) and Labrador Transmission Assets (LTA) should be functionalized as generation and classified using the equivalent peaker method.
3. Net export revenues should be included in the cost of service study and allocated in the same manner as Muskrat Falls Project costs. Variations from forecast should be dealt with through a deferral account mechanism.

Hydro's Other Proposed Changes to its Cost of Service Methodology

4. Transmission lines TL-234 and TL-263 should be functionalized as transmission.
5. Holyrood thermal generation should be classified using a test year forecast capacity factor.
6. Holyrood 3 costs should be functionalized as transmission and classified as 100% demand-related when it becomes a synchronous condenser.
7. Wind power purchases should be classified as 22% demand and 78% energy.

Other Issues

8. Hydro should investigate the costs and benefits of systemizing its cost of service studies in future cases as a single integrated system.
9. Transmission LTL-247 and TL-243 should continue to be functionalized as generation.
10. Labrador Interconnected system and Island Interconnected system diesel and gas turbine units should be classified as demand with variable fuel costs classified as demand.

APPENDIX A

LARRY B. BROCKMAN RESUME

President, Brockman Consulting

Qualifications Summary
Mr. Brockman has over 40 years' experience as a utility rate designer, planner, consultant, regulator, educator, and expert witness. He specializes in cost of service and rate design, strategic planning, regulatory assistance, competitive market assessments, bid evaluation processes, merger and acquisition analysis, and computer simulation, to help utilities meet their strategic goals and maintain competitive advantage.

Education
Mr. Brockman earned a bachelor's degree in engineering from the University of Florida in 1973. He subsequently completed 35 quarter-hours towards a master's degree in electrical engineering, with a minor in regulatory economics at the University of Florida.

Prior Experience
During his career, Mr. Brockman has performed, and managed a broad range of consulting projects, including:

Cost of Service and Rate Design
Numerous Cost of service and Rate Design projects for Canadian and US utilities, assisting the utilities with marginal and embedded cost-of-service and rate designs for their ability to meet the utilities' strategic and regulatory goals, and pass regulatory scrutiny. In many of these examinations, Mr. Brockman has appeared as an expert witness. These cases are delineated in the Appendix.

Co-Developer and Instructor of the Public Utilities Reports, industry short course on Rates and Regulation for 5 years. In these courses, Mr. Brockman taught hundreds of utility rate designers, regulators, attorneys and Commission staff the principles of rate design and regulation.

Review of a restructured utility's shared services costs of service separation study to allocate the costs between regulated and unregulated subsidiaries, and procedures for tracking the costs in the future.

Financial Analysis and Asset Valuation
Construction of detailed utility financial simulation models to forecast regional bulk-power prices and profits for Utilities and Independent Power Producers to judge market entry positions and create successful negotiating strategies for purchases and sales in unregulated generation markets.

A profitability study for an electric utility to assess effects on shareholder returns and economic value added (EVA), of various marketing activities of the utility. These studies resulted in re-engineering the marketing department to yield higher returns and be more consistent with corporate goals.

Several asset valuation studies for electric utilities to determine whether a market existed to sell existing generating assets, what they were worth, and whether they would be competitive with existing and new generation in the region. Results were presented to senior management and used to revise the strategic planning direction.

Competitive Market Assessments

Expert testimony to the Arkansas and Louisiana Public Service Commissions on the market clearing prices for generation in a competitive market, and the relative competitive positions of many of the generating companies in the SPP and ERCOT regions. To perform this work, Mr. Brockman used sophisticated computer models and a database containing over 120,000 MW of capacity in the region.

A study on the effects of retail competition on the states of North and South Carolina, presented to the South Carolina Legislature and performed for Carolina Power and Light Company. The study required research on the behavior of prices in other formerly regulated industries and detailed modeling of the market prices and financial effects on the utilities, as well as the effects on state and local taxes.

An independent review of the effectiveness and reliability of a large Mid-Western utility's Power Marketing and Purchases Department in deregulated generation markets, performed as a joint project with the utility and the state's attorney general.

Numerous market outlook and generator profitability studies of the ERCOT, Eastern Interconnect, and WSCC markets for merchant plant developers, using the GEMAPS transmission-constrained production cost simulation tool.

An analysis for a large Canadian utility of the profitability of increased transmission line investments to move power into various competitive markets in the US and Canada.

Computer Simulation of Power Systems

Mr. Brockman is an expert in the use of utility simulation software for: planning; operations; and financial analysis including: PROMOD; PROVIEW; PROSCREEN II; PMDAM; PROSYM; EVALUATOR; GEMAPS, IREMM, and several Power Flow programs.

Strategic Planning

A strategic planning project for a large South-Eastern electric utility identifying strengths, weaknesses, opportunities, and threats, in competitive open-access power markets. For each utility in the region, the project identified which customers would be gained and lost, and assessed the impacts of alternative transmission, and contracting strategies. The entire South Eastern US generating and major transmission systems were simulated. Over $1.5 Billion of potential customer revenue migration was identified at the client utility. Strategies for maintaining the utility’s profitability were recommended and accepted by senior management.

Development of several successful strategies and power supply bid evaluation procedures in use at investor owned and rural electric cooperatives, to ensure that winning bids are consistent with the utility's business goals and objectives.

Operational Studies
A salt dome natural gas storage study for a South Central electric utility. The study identified the hourly operational characteristics necessary for favorable economics of the required storage facility. Estimated savings in excess of $100 Million were identified. The facility was constructed and has been successfully benchmarked against the study results.

Merger and Acquisition Analysis
Mr. Brockman has participated in several merger and acquisition studies assessing the production cost and planning and operational synergies arising from the merger. He testified before the FERC on the accuracy and appropriateness of the production costing computer simulations a merger application. He also participated in a regulated/non-regulated cost separation study for a shared services group of a major utility.

Expert Litigation Assistance
Project manager of an anti-trust case involving investigation of all phases of power supply planning covering a 40-year historical period and a successful defense against over $3 Billion damage suit involving alleged actions by an investor owned utility.

Managed a successful defense against a co-generator seeking to convince regulators that a utility's ratepayers should pay over $1.5 Billion in unnecessary and uneconomic new generation avoided costs

Project manager for a precedent setting FERC case defending a utility from an attempt to abrogate a long-term bulk power contract worth over $400 Million. Mr. Brockman's team was able to convince the FERC that contract abrogation was not in the public interest, that the plaintiff was not going bankrupt, and that the plaintiff's difficulties were the result of arbitrary and capricious state regulation.

Co-authored an investigation comparing the Prudence of the Georgia Power Vogtle Nuclear Units 3 and 4 with the South Carolina Summer units in 2016.

Prior Positions Held
Managing Consultant PA Consulting, 2000-2002. Mr. Brockman managed a group of consultants engaged in the analysis of transmission-constrained competitive generation markets, as well as managing several litigation cases involving electric utilities.

President of Brockman Consulting 1997-2000. Mr. Brockman assisted clients with strategic planning and regulatory assistance.

Managing Director and Vice President 1994-1996, EDS Management Consulting Services (formerly EMA). Responsible for the Atlanta consulting office, engaged in providing technical consulting services in planning, regulatory assistance, marketing, competitive assessments, reliability, bid evaluation, financial simulation, and expert testimony.

Vice President Energy Management Associates (EMA) Consulting Department 1985-1994. Started as lead consultant and rose to position of Vice President. Marketed and provided strategic planning, regulatory assistance, and operational consulting to electric and gas utilities worldwide.

Assistant Director Electric and Gas Department, Florida Public Service Commission 1981-1985. Supervised 48 employees engaged in all phases of electric and gas regulation. Made recommendations to the Commission on rate cases and resource planning dockets for all electric and gas utilities in Florida. Responsible for financial and management audit scopes, prudence reviews of rate base, expenses, revenue requirements, and final rate design. Also advised Commission on economic effects of regulatory and energy policy actions.

Corporate Planning Engineer 1979-1981, Gainesville Regional Utilities. Developed, analyzed, and presented to senior management and the City Council, ideas, plans, and studies affecting the growth, financial well-being and efficient operation of the city owned electric system. Performed detailed simulations and studies of new substations, transmission lines, voltage conversions, re-conductoring, and power factor correction. Mr. Brockman conducted public hearings and testified before the City Council on proposed transmission lines, substations, and rate designs.

Special Consultant 1979-1980, University of Florida Public Utilities Research Center. Under a grant from Florida Power Corporation and the Florida Public Service Commission, performed a detailed review of marginal cost study techniques for electric utilities and completed a marginal cost study for Florida Power Corporation.

Transmission Planning Engineer 1973-1976, Jacksonville Electric Authority. Responsible for bulk transmission planning, including extensive use of power-flow, fault current and transient stability computer programs. Chairman of the Florida Electric Coordinating Group’s Long Range Transmission Planning Task Force 1974.

Adjunct Faculty Member 1976, University of North Florida. Taught courses in industrial and commercial building wiring design and conformance with National Electrical Codes.

Expert Witness Appearances

City of Gainesville City Council, 1980, testified on behalf of Gainesville Regional Utilities concerning a joint utility and citizen’s collaborative effort on cost of service and rate design.

City of Gainesville City Council, 1981, developed and testified on a Long-Range Transmission and Distribution Plan and proposals to construct a new substation.

Florida Public Service Commission, Florida Power and Light, 1981 Docket No. 810002, Rate Case, testified on cost-of-service.

City of Tallahassee - Surcharge Outside the City Limits, 1983. Testified concerning marginal and embedded costs inside and outside the city limits.

Florida Public Service Commission, 1988, West Florida Natural Gas Company. Testified on cost-of-service and rate design and why the utility needed flexibility to meet competition.

Oklahoma Corporation Commission, 1988, Avoided Cost Proceeding. Testified on the appropriate use of computer models to determine avoided cost of generation.

Nova Scotia Board of Commissioners of Public Utilities, 1989, Nova Scotia Power Rate Case. Testified on cost of service and rate design.

Nova Scotia Board of Commissioners of Public Utilities, 1990, Nova Scotia Power Rate Case. Testified on integrated resource planning, cost of service and rate design.

Nova Scotia Board of Commissioners of Public Utilities, 1993, Nova Scotia Power Rate Case. Testified on cost of service and rate design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1990 Newfoundland and Labrador Hydro rate case. Testified on integrated resource planning and rate design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1992, Newfoundland and Labrador Hydro rate case. Testified on Cost of Service and Rate Design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1992, Generic Hearing on Cost of Service and Rate Design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1995, In the Matter of an Inquiry into Issues Relating to Rural Rate Subsidies.

Public Service Commission Colorado, 1994, testified on behalf of Public Service Company of Colorado on the proper use of dynamic programming models in the utility's integrated resource planning process.

Federal Energy Regulatory Commission, 1994, Merger Case, Testified on behalf of Central and Southwest utility concerning production cost merger benefits.

Nova Scotia Board of Commissioners of Public Utilities, 1995, Nova Scotia Power Rate Case. Testified on cost of service and rate design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 1996, Newfoundland Power Rate Case, testified on cost of service and rate design.

Arkansas Public Service Commission, 1997, Arkansas Power and Light Rate Case, testified concerning the market clearing prices for power in deregulated markets and the relative competitive positions of various generators in such markets.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2001, Newfoundland and Labrador Hydro rate case, on behalf of Newfoundland Power concerning Cost of Service and Rate Design.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2003, Newfoundland and Labrador Hydro rate case, on behalf of Newfoundland Power concerning rate design and marginal costs.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2003, Newfoundland Power rate case, concerning Cost of Service and Rate Design.

North Carolina Docket No. E-22, Sub 412. Draft testimony on behalf of Dominion North Carolina, February 2005, concerning rates to a large steel company. Case was settled before final evidence was submitted.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2006, Newfoundland and Labrador Hydro rate case, on behalf of Newfoundland Power concerning rate design and marginal costs.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2009, on behalf of Newfoundland Power concerning Newfoundland and Labrador Hydro's Industrial Rates.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2014, on behalf of Newfoundland Power concerning Newfoundland and Labrador Hydro's proposal for a refund of the Newfoundland Power RSP Surplus.

Board of Commissioners of Public Utilities of the Province of Newfoundland and Labrador, 2014 Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System, on behalf of Newfoundland Power.

Clients Mr. Brockman has Performed Consulting Services for Include:

Ahlstrom Pyro Power

Alabama Electric Cooperative

Alberta Power Company

Balch and Bingham

Black and Veatch

California Energy Commission

Carolina Power and Light Company

Central and Southwest Company

Central Vermont Power Company

Chugach Electric Cooperative

Cincinnati Gas and Electric Company

Citibank

Commonwealth Edison Company

Duke Power Company

Enron

Entergy

Florida Public Service Commission

Georgia Power Company

Gainesville Gas Company

Hawaiian Electric Company

Howery and Simon

Hydro One

McKinsey and Company

Mission Energy

Nevada Power Company

New Brunswick Power Company

New York State Electric and Gas

Newfoundland Power

Niagara Mohawk

Nova Scotia Power Company

Oklahoma Gas and Electric Company

Ontario Power Generation

Pacific Gas and Electric Company

Public Service Company of Colorado

Public Service Company of New Mexico

Rochester Gas and Electric

SCANA

Southern California Edison

Tampa Electric Company

The City of Austin

The Southern Company

TransEnergie

West Florida Natural Gas Company

The World Bank