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*"), as amended, and regulations thereunder; and;

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

Requests for Information

by the Labrador Interconnected Group

LAB-NLH-001 to LAB-NLH-029

June 10, 2019

<u>Requests for Information Regarding</u>

LAB-NLH-1. Re: 2018 Cost of Service Methodology Review Report, p. 7 (18 pdf)

Citation:

> **3.1 Systemization**
>
> Hydro proposes to maintain separate cost of service studies for the Labrador Interconnected System and the Island Interconnected System for use in determining customer rates. This approach is consistent with the Government direction exempting customers on the Labrador Interconnected System from paying costs related to the Muskrat Falls Project.

a) In this section, Hydro does not make explicit reference to Section 2 of the Christensen Associates Energy Consulting ("CAES") study presented as Appendix A of the filing (pages 6-9, pages 62-65 pdf), which makes a similar recommendation. Does Hydro adopt all of the reasoning set out by CAES in this section?

Preamble:

> In Section II.B of the Brattle Group report prepared for the Board (pages 12-14, pages 16-18 pdf), the Brattle Group recommends that Hydro "plan for and prepare a single integrated system for COS purposes in future GRA proceedings".

b) How does Hydro respond to the points made in this section by the Brattle Group?

LAB-NLH-2. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 8 (64 pdf)

Citation:

> **Discussion/Analysis.** It appears that Hydro can resolve this issue in two ways that potentially lead to similar outcomes. First, the COS methodology could retain separate treatment of the two interconnected systems, <u>based on the belief that all new and future assets and expenses will be readily separable by service territory</u>. This would be computationally simple in the short run and would conform to cost assignment requirements. Second, the COS methodology could unify the two areas but retain separate rate classes based on geography, thus retaining the ability to allocate costs in the mandated fashion. <u>This alternative might more readily accept future cost allocation in cases of assets or expenses that both regions must share</u>. If this unification is not performed, then a "jurisdictional" assignment of costs must continue. (underlining added)

a) Does Hydro envisage significant costs in the coming years that would be shared by the Island and Labrador regions? If so, please describe these costs, their magnitudes and the likely dates when they would appear.

b) With regard to the second methodology described in the citation:

   i. Please describe the Board's precedents regarding the use of separate rate classes based on geography; and

   ii. Please describe the methodology that Hydro would use to establish rates in each of the two regions, and the extent to which that methodology would resemble the first methodology described in the citation.

LAB-NLH-3. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 8 (64 pdf)

Preamble:

> In Section II.B of the Brattle Group report prepared for the Board (pages 12-14, pages 16-18 pdf), the Brattle Group recommends that Hydro "plan for and prepare a single integrated system for COS purposes in future GRA proceedings". More specifically, Brattle states:
>
> > In our opinion, given that the two systems have been interconnected via the LIL, viewing the LIS and the IIS as a single integrated system for COS purposes would be beneficial going forward and can be done while still adhering to the relevant policy constraints that exist. It is quite common in COS studies to reflect relevant policy constraints—such as exempting (mandating) that certain classes of customers avoid (pay) for specific assets or expenses as is currently the case with the Muskrat Falls project—without the need to have separate COS studies to accommodate such policy considerations. In the present case, Hydro can straightforwardly accommodate the aforementioned policy constraints within an integrated system for COS purposes. For example, the COS study can retain separate rate classes based upon geography and the costs of the Muskrat Falls project could be assigned 100% to customers who reside within the Island Interconnected system—an approach that is an option that CAEC raised (at 8). <u>The benefits of a single integrated system for COS purposes is that it will more readily accommodate the changing nature of the systems going forward in which future assets and expenses will more likely be shared among regions compared to the system before the LIL. While that will not happen immediately, over time, one would expect more of Hydro's assets to be used to provide services in both territories and it would be more straightforward to treat both areas as one independent area for COS purposes</u>. (underlying added)

a) In Hydro's view, are Brattle's statements that "future assets and expenses will more likely be shared among regions compared to the system before the LIL" and that "over time, one would expect more of Hydro's assets to be used to provide services in both territories" well founded? Please explain your response.

b) Does CAEC share Brattle's view that "future assets and expenses will more likely be shared among regions compared to the system before the LIL" and that "over time, one would expect more of Hydro's assets to be used to provide services in both territories"?

LAB-NLH-4. Re: 2018 Cost of Service Methodology Review Report, p. 7 (18 pdf), note 16

Citation:

> Hydro recommends that the power purchase costs resulting from the Muskrat Falls Project (Muskrat Falls Generation, LIL and LTA assets) be functionalized as generation;

Preamble:

> In Section II.C.1of the Brattle Group report prepared for the Board (pages 15-19, pages 19-23 pdf), the Brattle Group recommends that the LIL and LTA assets be functionalized instead as transmission.

How does Hydro respond to the points made in this section by the Brattle Group?

LAB-NLH-5. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 30 (86 pdf)

Citation:

> **Sub-functionalization**
>
> **Generator Interconnection Facilities.** In the past, utilities have often functionalized generator interconnection facilities and their associated costs as transmission. However, more recently, some electricity service providers have been assigning all-in financial costs to the generation function. Additionally, the U.S. FERC has set up specific features for the assignment of all-in costs of interconnection facilities to the individual generators obtaining interconnection services. Such functional assignment is facilitated by a bright line of demarcation that is immediately observable: Interconnection facilities are built to connect generation to the grid; flows are one way; facilities are sized according to the capability of the relevant station.

a) Please provides references to the orders referred to in which FERC has set up specific features for the assignment of all-in costs of interconnection facilities to the individual generators obtaining interconnection services.

b) Based on the bright-line of demarcation referred to, would the LIL be considered a Generator Interconnection Facility by the FERC? Please explain your response.

LAB-NLH-6. Re: 2018 Cost of Service Methodology Review Report, p. 10 (21 pdf)

Citation:

> **3.3.2 Classification Recommendation – Muskrat Falls Project Power Purchases**
>
> Hydro recommends the use of the equivalent peaker methodology for classification between demand and energy for the classification of power purchase costs resulting from the Muskrat Falls Project. CA Energy Consulting recommended the equivalent peaker approach rather than the other traditional cost of service classification approaches.

Preamble:

> In Section II.D.2.a of the Brattle Group report prepared for the Board (pages 27-37, pages 31-41 pdf), the Brattle Group recommends that Hydro use the system load factor approach instead. It also raises concerns about the inclusion of the LIL and LTA cost in the equivalent peaker calculations.

How does Hydro respond to the points made in this section by the Brattle Group?

LAB-NLH-7. Re: 2018 Cost of Service Methodology Review Report, p. 14 (25 pdf);

Citation 1:

> Hydro plans to evaluate if it is practical to employ a peak allocation approach based on the percentage of load by class in the highest 50 hours of the winter season. Hydro currently uses this approach. This analysis would provide additional information to evaluate the reasonableness of the current 1 CP allocation approach. Hydro plans to report to the Board on the analysis results in its next GRA.

Citation 2 (Appendix A, CAEC Report, page 13 (page 69 pdf)):

> An alternative might be to use a method applied at Manitoba Hydro, which makes use of the fifty highest demand hours of the winter. Such a measure requires recording and averaging much more data, but is likely to be stable and to capture behavior in the many hours associated with peak demand. Taking this approach to its logical conclusion, one might consider utilizing a marginal cost-based combined classification and allocation approach, which includes all hours, and uses marginal cost to value each hour. Section 3.3 discusses this approach.

Citation 3 (Appendix A, CAEC Report, page 23 (page 79 pdf)):

> Manitoba Hydro constitutes an interesting special case. Until recently the utility applied a "weighted energy" allocator to generation costs, which consists of marginal cost-based allocation of generation services. (Manitoba Hydro also utilized a variant of the process in allocating transmission costs.) In a recent COS methodology proceeding, the utility argued for retention of its weighted energy allocator. However, the Public Utilities Board of Manitoba (Manitoba Board) found that the allocator lacked elements of demand, a shortcoming that it felt was determinative. As a result, it required Manitoba Hydro to adopt a system load factor approach. The demand allocator that it recommended is a "winter CP" formulation in which usage in the fifty winter hours with the highest demand is to be averaged to produce class peak period usage totals. Curiously, the weighted energy (marginal cost) approach could readily have been retained had marginal cost included both energy and reserves instead of energy alone.

a) Please provide references to Manitoba Hydro documents that explain in detail how it implements (or implemented) this approach.

LAB-NLH-8. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 15 (71 pdf)

Citation:

> One implication of the substitution of Muskrat Falls for Holyrood generation under the assumption of SLF classification is that the demand composition of generation revenue requirements may rise substantially. This change may or may not reasonably represent the change in cost causality due to the substitution of Muskrat Falls for Holyrood but it would likely shift the cost burden in the direction of peak-coincident classes or customers.

Preamble:

> In Section II.D.2.a of the Brattle Group report prepared for the Board (pages 27-37, pages 31-41 pdf), the Brattle Group recommends that Hydro use the system load factor approach instead.

How does CAEC respond to the arguments presented by the Brattle Group in support of the use of the system load factor approach?

LAB-NLH-9. Re: 2018 Cost of Service Methodology Review Report, p. 6 (17 pdf)

Citation:

> **2.4 Export Sales**
>
> Hydro forecasts that export revenues will result from available Recapture Energy, ponding activities, exports to avoid spill, and due to the fact that its current forecast load requirements from Muskrat Falls generation are less than its contacted entitlement provided in Schedule 2 of the Muskrat Falls PPA Schedule 2 [sic]. The sharing of the net revenues from these exports need to be considered in the cost of service methodology. The cost of service methodology does not deal with other rate mitigation funds that may be provided from other sources.

a) Please specify, for each of the various categories of exports mentioned in the citation, if the energy to be exported belongs to Hydro, to Muskrat Falls Corporation (MFC), or to other entities.

b) For categories in which the energy does not belong to Hydro, please explain whether it is Hydro's understanding that the Board has jurisdiction with respect to the resulting revenues, and how these revenues would be applied to Hydro's revenue requirements in the cost of service methodology.

LAB-NLH-10. Re: 2018 Cost of Service Methodology Review Report, p. 18 (29 pdf)

Citation:

> **3.11 Allocation of Net Export Revenues**
>
> Hydro recommends:
>
> > (i) net export revenues be used to reduce the Muskrat Falls supply costs to be recovered through the rates of customers on the Island Interconnected System;
> >
> > (ii) net export revenues be classified in the same manner as the classification of the Muskrat Falls Project costs in the cost of service study; and
> >
> > (iii) net export revenues be included in the test year cost of service study for rate making with variations from forecast net export revenues be dealt with through a deferral account mechanism.
>
> Hydro plans to include any revenues that result from the sale of carbon credits, due to the closure of Holyrood, in net expert [sic] revenues.

a) Please specify how "net export revenues" are defined.

b) Please explain the relationship between the “net exports revenues” discussed in section 3.11 and the “export revenues” discussed in section 2.4. Insofar as this distinction affects the responses provided to LAB-NLH-004, please explain how.

c) In the event that export of hydraulic power results in the creation of carbon credits in the importing regions, please indicate how the resulting revenues will be attributed.

LAB-NLH-11. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 75 (131 pdf)

Citation:

> **Background.** Upon completion of the Muskrat Falls project, Hydro will find itself with an exportable surplus of energy and new outlets for those exports, thanks to construction of the LIL and ML dc lines. By contractual requirement, Island Interconnected customers must pay all the costs of these facilities. Operationally, Hydro will determine how much power Nalcor Energy Marketing (NEM) will have available for export. NEM will sell the power and remit the net revenues from the sale to Hydro.

a) Please clarify the precise meaning of “net revenues” in the citation.

b) Please clarify by virtue of what statute, regulation or policy NEM will remit the net revenues from the sale of exported Muskrat Falls power to Hydro.

LAB-NLH-12. Re: 2018 Cost of Service Methodology Review Report, p. 20 (31 pdf)

Citation:

> Table 4 shows that the projected 2021 revenue requirement for the Island Interconnected System is approximately $575 million higher (more than double) than that of the projected 2019 Test Year revenue requirement. The primary changes are increase in power purchases costs of approximately $667 million (net of Hydro export revenues), and a decrease in fuel costs of approximately $100 million. The 2021 projected revenue requirement excludes other rate mitigation that may be provided.

a) Please provide similar tables for 2023, 2025 and 2030, assuming no substantive changes other than the expected costs related to the Lower Churchill Project.

d) Please make and explain any assumptions necessary to make these calculations possible.

LAB-NLH-13. Re: 2018 Cost of Service Methodology Review Report, Exhibit 2, page 8 of 10 (48 pdf)

Preamble:

> The Exhibit shows that the Labrador Interconnected Revenue Requirement after Deficit and Revenue Credit Allocation in 2021 (col. 6) would be slightly lower than revenues under current rates (col. 2).

Is it appropriate to conclude that Labrador Interconnected rates are expected to be lower in 2021 than they are today? If not, please explain why.

LAB-NLH-14. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 20 (76 pdf)

Citation:

> Marginal cost-based methods take advantage of the emergence of sophisticated techniques for measuring or estimating cost over hourly (and even finer) time intervals. The development of wholesale markets for energy, reserves services, and capacity, along with advances in internal cost computation advances, provide the means to project marginal costs over forward periods. This means that estimating the cost to serve a class of customers can be calculated by developing hourly marginal costs and applying them to hourly load profiles. The result is an annual total marginal cost for each class (and then a sum across classes representing the utility as a whole). <u>By calculating each class's share of the utility total, one can derive a cost allocator applicable to generation services.</u>
>
> Using this approach, it is no longer necessary to infer demand and energy classification results. Instead, the derived marginal cost shares are applied directly to financial costs of generation. From a conceptual or methodological point of view, this approach has a virtue of taking account of customer behavior in all the hours of the year, in contrast with traditional CP methods on the demand side that typically make use of a very limited number of hours.

Please provide a numerical example, or a reference with detailed examples and explanations, to illustrate how this approach would be used in practice.

LAB-NLH-15. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 21 (77 pdf)

Citation:

> Marginal cost-based allocation of embedded costs may seem to be novel, but variants of this approach have been in use for many years in a number of regulatory jurisdictions. West coast U.S. utilities have used this approach for twenty years.

Please provide copies of or links to documents from these West Coast utilities describing their approach to marginal cost-based allocation of embedded costs.

LAB-NLH-16. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 30 (86 pdf)

Citation:

> Marginal cost-based allocation can be used in the Labrador Interconnected system as well, following the Muskrat Falls in-service date. This would require that projections of marginal cost for Labrador be developed, presumably based on a process similar to that used for the Island Interconnected system.

Please elaborate on the implications for Labrador rates if marginal cost-based allocation were used.

LAB-NLH-17. Re: 2018 Cost of Service Methodology Review Report, p. 4 (15 pdf)

Citation:

> Following the commissioning of the Muskrat Falls Project, Newfoundland and Labrador will have an inter-provincial transmission system fully interconnected with Quebec, Nova Scotia, and the broader North American electric grid. This development gives rise to the <u>obligation</u> for Hydro and its affiliated transmission owners to provide open, non-discriminatory access to transmission service on transmission lines used for inter-provincial trade by third parties. This <u>requirement</u> is established by the Federal Energy Regulatory Commission ("FERC"), which is an independent agency that regulates the transmission of electricity in the United States. <u>To meet the FERC requirement of reciprocity, Hydro must provide comparable open access to transmission service over the interprovincial transmission system within Newfoundland and Labrador</u>. From a cost of service perspective, FERC requires that Hydro record its transmission costs in a manner that can be used in the determination of open access transmission tariffs.

> On December 21, 2017, OC2017-380 directed the Board to adopt a policy that the submissions of the Newfoundland and Labrador System Operator ("NLSO") relating to the transmission of electricity over the Province's high voltage transmission system be approved on the following terms: (i) the pro-forma Transmission Service Agreements, and attached rates and rate methodology, be approved on an interim basis; and (ii) the Transmission Policies and Procedures and Code of Conduct for transmission system operations to be adopted by the NLSO be approved until such time as the Board reviews the interim proposals.
>
> In Order No. P.U. 3(2018), the Board approved, on an interim basis, the pro-forma Transmission Service Agreements, the NL Transmission Policies and Procedures and the Code of Conduct for NL Transmission System Operations, effective February 9, 2018. (underlining added)

a) Please explain the source of this "obligation" or "requirement". Does it flow from statute or regulation, or from the fact that Hydro or its affiliates takes transmission service from other entities that either are subject to FERC jurisdiction or have adopted FERC-compliant Open Access Transmission Tariffs (OATTs) that contain said reciprocity provisions? Please provide details with respect to your response.

b) In Hydro's view, do the pro-forma Transmission Service Agreements, the NL Transmission Policies and Procedures and the Code of Conduct for NL Transmission System Operations adopted effective February 9, 2018 meet the minimum standards for an OATT set out in FERC's Order 890 or subsequent orders? If not, does Hydro intend to seek Board approval for an OATT that meets FERC's minimum requirements as set out in these orders? If so, when?

LAB-NLH-18. Re: 2018 Cost of Service Methodology Review Report, p. 5 (16 pdf)

Citation:

> Prior to the annual publishing of a new rate for Labrador Industrial Customers, Hydro is required to make a submission regarding the proposed rate to the Minister of Natural Resources for review.

Please provide copies of the annual submissions regarding the proposed rate for Labrador Industrial Customers provided to the Minister of Natural Resources for each of the last five (5) years.

LAB-NLH-19. Re: 2018 Cost of Service Methodology Review Report, p. 6 (17 pdf)

Citation:

> OC2013-343 also requires that any expenditures, payments or compensation paid directly or indirectly by Hydro under an agreement or arrangement to which the Muskrat Falls Exemption Order applies, shall be included as costs in

> Hydro's cost of service, without disallowance, to be recovered through Island Interconnected System customer rates. To enable Hydro to fully recover annual costs resulting from charges related to the Muskrat Falls Project will require Hydro to establish a supply cost recovery mechanism to deal with such cost variances. This matter was reflected in the Supply Cost Mechanism review filed with the Board in June, 2016. Hydro will propose revisions to its supply cost recovery mechanisms in a future GRA along with its proposals to permit the recovery of Muskrat Falls Project costs through customer rates.

Please provide copies or links to the Supply Cost Mechanism review filed with the Board in June 2016, as well any orders issued by the Board in this regard.

LAB-NLH-20. Re: 2018 Cost of Service Methodology Review Report, p. 7 (18 pdf), note 16

Citation:

> When Hydro filed its cost of service methodology report in 2016, Hydro believed that transmission line TL-248 from Deer Lake to Massey Drive would need to change in functionalization from a generator lead to a common transmission asset. However, because TL-248 is not a portion of a 230 kV loop, the transmission tariff does not consider TL-248 a common transmission asset.

Please explain what has changed since 2016 leading to the change in point of view described in the citation.

LAB-NLH-21. Re: 2018 Cost of Service Methodology Review Report, p. 20 (31 pdf)

Citation:

> The key financial forecast assumptions included in the 2021 illustrative revenue requirement are: …
>
>> (ii) The TFA and PPA payments estimated for 2021 have been determined consistent with a Nalcor long-term financial plan prepared in September 2018;

a) Please explain why and how the TFA and PPA payments depend on a Nalcor long-term financial plan.

b) Please provide a copy of the referenced Nalcor long-term financial plan.

LAB-NLH-22. Re: 2018 Cost of Service Methodology Review Report, Exhibit 2, page 3 of 10 (43 pdf)

Preamble:

> Column 7 for lines 8 and 9 shows a Revenue to Cost Coverage (RCC) of 0.19 for Island Isolated, and of 0.31 for Labrador Isolated.

Please explain the reasons why the RCC is substantially lower for Island Isolated than it is for Labrador Isolated.

LAB-NLH-23. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 13 (69 pdf)

Citation:

> **Discussion/Analysis.** The composition of Hydro's generation assets and expenses will change significantly after 2020, with the introduction of Muskrat Falls' 824 MW of new installed hydraulic capacity (790 MW of firm capacity), linked to the Island and to the Eastern Interconnection by undersea dc lines. The addition of Muskrat Falls to the Hydro system facilitates the eventual retirement of the Holyrood thermal generation unit.

Please indicate the source for the affirmation that Muskrat Falls will provide 790 MW of firm capacity.

LAB-NLH-24. Re: 2018 Cost of Service Methodology Review Report, Appendix A, Cost of Service Methodology Review, Christensen Associates Energy Consulting (CAEC), Nov. 15, 2018, page 15 (71 pdf)

Citation:

> However, Muskrat Falls is on the mainland, connected to the Island's customers via an HVdc line that may encounter transmission constraints.

Please explain under what circumstances the HVdc line connecting Muskrat Falls to the Island's customers may encounter transmission constraints.

LAB-NLH-25. Re: Marginal Cost Study Update – 2018 – Summary Report, Nov. 15, 2018, page 4 (8 pdf), Table 1 and Note 7

Preamble:

> Table 1 indicates a net capacity addition of 72 MW by 2021, taking into account 900 MW from the LIL, minus 80 MW losses and 158 MW for the Emera entitlement. Note 7 indicates that the 900 MW of the LIL consists of a "Combination of recapture energy from Churchill Falls and Muskrat Falls generation".

a) Please specify the amount of recapture energy from Churchill Falls which is considered by Hydro to constitute firm capacity for the IIS.

b) Please indicate the assumption regarding the amount of cryptocurrency mining loads in Labrador underlying this estimate of available recapture energy.

c) Please specify the amount of Muskrat Falls generation which is considered by Hydro to constitute firm capacity for the IIS.

d) Please break down your estimate of the amount of Muskrat Falls generation which is considered by Hydro to constitute firm capacity for the IIS into:

    i) The amount of generation that can be relied upon at system peak produced by the Muskrat Falls Generating Station, and

    ii) the amount of power from the Churchill Falls Generating Station, additional to recapture energy, which is considered by Hydro to contribute to firm capacity at the IIS system peak by virtue of the Water Management Agreement between Nalcor and CF(L)Co.

LAB-NLH-26. Re: Marginal Cost Study Update – 2018 – Summary Report, Nov. 15, 2018, Appendix A (Christensen Associates Energy Consulting, Cost Estimates and Methodology for Generation and Transmission Services, 2021-2029, page 5 (27 pdf).

Citation:

> In brief, in the presence of competitive wholesale markets, the prices obtained reflect opportunity costs, in other words, the highest-valued use of marginal resources. Such result is fully consistent with least cost dispatch. Generally speaking, an opportunity cost approach is the preferred methodology, providing that service providers are actively engaged in competitive markets.

a) Please provide some guidance as to determining whether or not a service provider is "actively engaged in competitive markets". Should the determination be made based on:

- the quantity of off-system sales (and/or purchases) compared to on-system sales;
- the extent to which additional off-system sales are possible (i.e., the extent to which transmission paths would permit additional off-system sales);
- the extent to which off-system purchases are competitive with on-system generation or purchases; or

- other factors.

b) If possible, please provide quantitative benchmarks. For example, if a utility's off-system sales account for just 1% of its regulated sales and it has no off-system purchases, is it appropriate to base marginal costs on "opportunity costs" based on off-system market prices? What if off-system sales account for 5% of regulated sales, but no additional sales are possible due to congestion?

LAB-NLH-27. Re: Marginal Cost Study Update – 2018 – Summary Report, Nov. 15, 2018, Appendix A (Christensen Associates Energy Consulting, Cost Estimates and Methodology for Generation and Transmission Services, 2021-2029, page 9 (31 pdf).

Citation:

> The process of sizing facilities often favors oversizing beyond that which is needed during the early years of capacity life, as doing so reduces total facility costs in the long run over extended future years.

Does oversizing beyond that which is needed during the early years of capacity life reduce total facility costs in the long run in a context where load growth is flat, almost flat or declining, based for instance on expectation of dramatic rate increases?

LAB-NLH-28. Re: Marginal Cost Study Update – 2018 – Summary Report, Nov. 15, 2018, Appendix A (Christensen Associates Energy Consulting, Cost Estimates and Methodology for Generation and Transmission Services, 2021-2029, page 16 (38 pdf).

Citation:

> As mentioned, marginal energy and operating reserve costs for Hydro's Island Interconnected System is based on projections of NEISO energy and operating reserve prices, after accounting for path charges and Hydro's network losses.[29]
>
> Note 29: The analysis implicitly presumes that Hydro has sufficient capacity to sell power into the NEISO. However, there are occasional timeframes where such assumption may not hold owing to generation or capacity constraints. In addition, it is likely that, on occasion, Hydro will face NEISO energy prices sufficiently low that the sale of power into wholesale markets is not warranted, as path charges would negate all benefits arising from the sale.

a) Has CAES analyzed the expected number of hours per year during which Hydro will and will not be able to sell power into the NEISO, owing to generation or capacity constraints, or to unavailability of transmission capacity along the path? If so, please provide the results of this analysis. If not, please comment on the extent to which such an analysis might lead CAES to modify its estimates of Hydro's marginal costs.

b) Has CAES analyzed the expected number of hours per year during which NEISO energy prices are expected to be sufficiently low that the sale of power into wholesale markets is not warranted, as path charges would negate all benefits arising from the sale? If so, please provide the results of this analysis. If not, please comment on the extent to which such an analysis might lead CAES to modify its estimates of Hydro's marginal costs.

LAB-NLH-29. Re: Marginal Cost Study Update – 2018 – Summary Report, Nov. 15, 2018, Appendix A (Christensen Associates Energy Consulting, Cost Estimates and Methodology for Generation and Transmission Services, 2021-2029, page 22 (44 pdf).

Preamble :

> Figure 8 shows the monthly peak, off-peak and all-hours marginal transmission losses for the IIS for 2021. Values range from 8% to over 11%.

a) Are the marginal transmission losses shown in Figure 8 particularly high, compared to other systems of similar size with which CAES is familiar?

b) Is CAES familiar with the equivalent figures for the transmission systems through which Hydro's power would have to travel to reach the NEISO market? To the extent possible, please estimate marginal peak and off-peak transmission losses for January and for July, for :

   a. The Labrador and Hydro-Quebec transmission systems, and

   b. The Nova Scotia and New Brunswick transmission systems.

c) Please provide CAES' best estimate of the combined marginal transmission losses to reach the NEISO market for each of the two routes mentioned in the previous question.