Embedded and Marginal Cost of Service Review

PREPARED FOR

Newfoundland and Labrador Board of Commissioners of Public Utilities

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I. Introduction

A. Background

The Newfoundland and Labrador Board of Commissioners of Public Utilities ("the Board") retained the Brattle Group, Inc. ("Brattle") to review Newfoundland and Labrador Hydro's ("Hydro") Embedded Cost of Service ("ECOS") Methodology Report, which proposes changes to the ECOS methodology for use in the determination of test year class revenue requirements reflecting the inclusion of the Muskrat Falls Project costs.[1]

The Muskrat Falls project consists of the hydroelectric generating station at Muskrat Falls as well as the Labrador-Island Transmission Link ("LIL") and the Labrador Transmission Assets ("LTA").[2] The generation facilities at Muskrat Falls have a capacity of 824 MW and Hydro anticipates that it will produce first power in 2019, with full service in Q3 of 2020.[3] The LIL is a 1,100 km, ±350 kV 900 MW HVDC transmission line between Muskrat Falls located in the Labrador Interconnected System ("LIS") and Soldiers Pond located in the Newfoundland Island Interconnected System ("IIS"). The LTA consists of two parallel 315 kV HVAC transmission lines that run 250 km between

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[1] See 2018 Cost of Service Methodology Review Report ("Embedded Cost Methodology Review") filed by Hydro on November 15, 2018. Hydro's report is accompanied by a report by Christensen Associates Energy Consultants, LLC ("CAEC") ("CAEC Embedded COS Report").

[2] Hydro will obtain energy, capacity, ancillary services and GHG credits through a Power Purchase Agreement between it and the Muskrat Falls Corporation. According to Exhibit 2, p. 1, of Hydro's Embedded Cost Methodology Review. The Muskrat Falls power purchases account for approximately $293 million of the test year revenue requirement compared to a total revenue requirement of approximately $1,169 million, or approximately 25 percent of the test year revenue requirement.

[3] See, Reliability and Resource Adequacy Study, Volume I: Study Methodology and Proposed Planning Criteria, November 16, 2018 ("Reliability and Resource Adequacy Study, Volume I"), p. 2, lines 8-10.

Muskrat Falls and Churchill Falls. In addition to customers on the LIS and the IIS, Hydro serves customers in 21 isolated systems on the coasts of Newfoundland and Labrador who receive their power from diesel generators operated locally.[4]

In 2013, the anticipated commissioning of the Muskrat Falls project led Hydro to propose in its amended General Rate Application ("GRA") to conduct a Cost of Service Methodology review prior to its next GRA. As stated in the Supplemental Settlement Agreement dated September 28, 2015:

> The Cost of Service Methodology Review to be completed in 2016 will include a review of: (i) all matters related to the functionalization, classification and allocation of transmission and generation assets and power purchases (including the determination whether assets are specifically assigned and the allocation of costs to specifically assigned assets) and (ii) the approach to CDM cost allocation and recover.[5]

In its application, Hydro is proposing changes to the Cost of Service Methodology for use in determining test year class revenue requirements that reflect the inclusion of the Muskrat Falls Project costs. The changes that Hydro is recommending are the following:[6]

1. *Functionalization of Hydro's TL-234 and TL-263 change from generator leads to common high-voltage transmission;*
2. *Functionalization of Holyrood Unit 3 as transmission after the unit is permanently converted into the role of synchronous condenser;*
3. *Power purchase costs resulting from the Muskrat Falls Power Purchase Agreements and the Transmission Funding Agreements be functionalized as generation;*

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[4] See https://www.nr.gov.nl.ca/nr/energy/electricity/index.html.

[5] Delays to the Muskrat Falls Project led to delays in the Cost of Service Methodology Review.

[6] We took the list of recommended changes from the letter accompanying the Embedded Cost Methodology Review, p. 6-7.

4. *Classification between demand and energy for the power purchase costs resulting from the Muskrat Falls Power Purchase Agreements and the Transmission Funding Agreement to be 20% demand-related and 80% energy-related based on the equivalent peaker methodology;*

5. *Classification between demand and energy for the power purchase costs to the Island Interconnected system for Recapture Energy be based on system load factor;*

6. *Classification between demand and energy for the Holyrood Thermal Generation asset costs should be based on a forecast test year capacity factor and its fuel cost would continue to be classified as an energy cost;*

7. *Classification of the cost of wind purchases be 22% demand-related and 78% energy-related;*

8. *The use of indexed asset costs in operating and maintenance cost allocations in the determination of specifically assigned charges subject to a further review in the next GRA;*

9. *To discontinue the generation credit agreement between Hydro and CBPP upon full commissioning of the Muskrat Falls Project;*

10. *That net export revenues available will:*

    a. *Be used to reduce the Muskrat Falls supply costs to be recovered through the rates of customers on the Island Interconnected System;*

    b. *Be classified in the same manner as the classification of the charges from the Transmission Funding Agreement and the Muskrat Falls PPA included in the cost of service study; and*

    c. *Be included in the test year cost of service study for rate making with variations from forecast net revenues be dealt with through a deferral account mechanism to be developed by Hydro for the Board's review at the next GRA.*

In this report, we review and opine on these proposed changes by Hydro to the Cost of Service Methodology.

In addition to the ECOS, Hydro submitted a Marginal Cost of Service ("MCOS") Study update.[7] The Board has also asked us to review and opine on Hydro's MCOS Study methodology.

B. Summary of Opinions and Recommendations

In Table 1 below and in the text that follows, we summarize our recommendations on Hydro's ECOS methodology as it pertains to systemization, functionalization, classification, and allocation. We also summarize our recommendations regarding several other relevant cost of service issues in the table. Our recommendations in navy italics indicate differing opinions from those of Hydro.

[7] See Marginal Cost Study and Rate Structure Review ("Marginal Cost Study") filed by Hydro on November 15, 2018. Hydro's Marginal Cost Study is accompanied by a marginal cost report file by CAEC ("CAEC Marginal COS Report").

Table 1: Summary of Embedded Cost of Service Study Recommendations by Hydro and Brattle

Topic	Hydro Current	Hydro Proposed	Brattle Proposed
Systemization	• Separate LIS and IIS systems	• Separate LIS and IIS systems for current and future GRAs	• *Single integrated system for future GRAs*
Functionalization	• N/A	• Muskrat Falls PPA as generation	• Muskrat Falls PPA as generation
	• N/A	• LTA and LIL as generation	• *LTA and LIL as transmission*
	• TL-234 and TL-263 as generation	• TL-234 and TL-263 as transmission	• TL-234 and TL-263 as transmission
	• TL-247 and TL-243 as generation	• TL-247 and TL-243 as generation	• *TL-247 and TL-243 as transmission*
			• *A general review of Hydro's assets, which provide interconnection into the transmission system for possible refunctionalization as transmission*
	• N/A	• Holyrood 3 as transmission following conversion to synchronous condenser	• *Holyrood 3 capital additions and O&M costs for Holyrood 3 as synchronous condenser as transmission; current rate base and depreciation as generation*
	• Transmission assets specifically assigned to customers to be specifically assigned	• Transmission assets specifically assigned to customers to be specifically assigned	• Transmission assets specifically assigned to customers to be specifically assigned
	• Contribution from customers for new network additions be deducted from rate base	• Contribution from customers for new network additions be deducted from rate base	• Contribution from customers for new network additions be deducted from rate base

Classification	• N/A	• Muskrat Falls PPA using equivalent peaker	• *Muskrat Falls PPA using system load factor*
	• Existing hydraulic assets using system load factor	• Existing hydraulic assets using system load factor	• Existing hydraulic assets using system load factor
	• Holyrood using 5-year average capacity factor	• Holyrood using forecasted capacity factor	• Holyrood using forecasted capacity factor
	• N/A	• Holyrood Unit 3 as demand	• *Holyrood Unit 3 operating and incremental capital costs as energy; original capital costs and depreciation as demand*
	• Power purchases (excl. wind) using system load factor	• Power purchases (excl. wind) using system load factor	• Power purchases (excl. wind) using system load factor
	• Power purchases wind as energy	• Power purchases wind as 22% demand and 78% energy	• Power purchases wind as 22% demand and 78% energy
	• LIS and IIS diesel and gas turbine units and variable fuel costs as demand	• LIS and IIS diesel and gas turbine units and variable fuel costs as demand	• *LIS and IIS diesel and gas turbine units as demand with variable fuel costs as energy*
	• Isolated diesel units using system load factor with variable fuel costs as energy	• Isolated diesel units using system load factor with variable fuel costs as energy	• Isolated diesel units using system load factor with variable fuel costs as energy
	• L'Anse-au-Loup as demand with variable fuel costs as energy	• L'Anse-au-Loup as demand with variable fuel costs as energy	• L'Anse-au-Loup as demand with variable fuel costs as energy
	• N/A	• LIL using equivalent peaker	• *LIL as demand*
	• N/A	• LTA using equivalent peaker	• *LTA as demand*
Allocation	• Demand-related costs using 1-CP allocator • Energy-related costs using energy allocator	• Demand-related costs using 1-CP allocator • Energy-related costs using energy allocator	• Demand-related costs using 1-CP allocator • Energy-related costs using energy allocator

Other	• Rural deficit allocated using revenue requirement approach • CDM classified as energy	• Rural deficit allocated using revenue requirement approach • CDM classified as energy	• Rural deficit allocated using revenue requirement approach • *Maybe classify a portion of CDM as demand for future GRAs*
	• Use of indexed asset costs in operating and maintenance cost allocations in the determination of specifically assigned charges, until a reasonable alternative is developed	• Use of indexed asset costs in operating and maintenance cost allocations in the determination of specifically assigned charges, until a reasonable alternative is developed	• *Specifically assigned O&M charges should be tracked separately for each customer, use of indexed costs as interim basis per settlement agreement*
	• Newfoundland Power generation credit provided for both hydraulic and thermal generation	• Newfoundland Power generation credit provided for both hydraulic and thermal generation	• Newfoundland Power generation credit provided for both hydraulic and thermal generation
	• CBPP generation demand credit as demand	• CBPP generation demand credit as demand	• CBPP generation demand credit as demand
	• N/A	• Net export revenues to be included in the COS study with variations from forecast to be dealt with through a deferral account mechanism	• *Hydro establish rider for net export revenues; classify and allocate revenues in same manner as Muskrat Falls; establish periodic schedule for true-up, with frequency no less than annually*

To elaborate, our main opinions and recommendations regarding Hydro's Embedded Cost of Service Study are the following:

1. ***Systemization***: Our recommendation is for Hydro to plan for and prepare a single integrated system for COS purposes *in future* GRA proceedings and that it is not necessary to do so for this upcoming GRA.

2. ***Functionalization***: Concerning the functionalization of the Muskrat Falls project, our recommendations are:

    a. To functionalize generation facilities at Muskrat Falls as generation;

    b. To functionalize the LIL as transmission;

    c. To functionalize the LTA as transmission.

    We agree with Hydro's functionalization of TL-234 and TL-263, and Holyrood Unit 3, with the exception that the current rate base and associated depreciation for Holyrood Unit 3 be assigned to generation. We also recommend that TL-247 and TL-243 be functionalized as transmission rather than generation. We agree with Hydro's policy regarding transmission assets currently assigned to customers and contributions for customers from new network additions policy.

    We recommend a general review of Hydro's assets, which provide interconnection into the transmission system for possible refunctionalization as transmission. It appears that Hydro uses whether the asset can be associated with loop flow on the transmission network as its criterion for transmission functionalization. In light of the U.S. Federal Energy Regulatory Commission's open access transmission policy, that is no longer deemed the sole basis for determining if an asset should be treated as a component of the transmission system and, thus, have a transmission tariff.

3. ***Classification***: Our recommendation on classification for the functionalized assets are as follows:

    a. We recommend the use of the system load factor to classify the Muskrat Falls generation purchase power costs. If the equivalent peaker method is to be used, we recommend removing the costs of the LIL and LTA in the calculation of the equivalent peaker calculation;

    b. Concerning the LIL and LTA, we recommend classifying these assets as demand related;

c. Concerning existing hydraulic assets and power purchase agreements not including the wind agreements, we recommend classifying these using the system load factor;

d. We recommend that when the Holyrood Unit 3 converts to use solely as a synchronous condenser that it be classified as energy;

e. Concerning the wind power purchase agreement, we believe Hydro's approach to classifying 22% of the costs as demand and the remaining 78% as energy is reasonable;

f. We recommend LIS and IIS diesel and gas turbine units be classified as demand with variable fuel costs as energy.

4. ***Allocation***: We recommend the continued use of the 1-CP allocator for the allocation of demand-related production and transmission classified costs. We agree with Hydro's use of an energy allocator for the allocation of energy-related production costs.

5. ***Other issues:***

a. *Use of marginal costs*: We are not recommending at this time the use of marginal costs to either directly set rates based upon study results (with a reconciliation to ensure that rates are sufficient to recover embedded costs) or to use as a component within the embedded COS study;

b. *Rural deficit*: We recommend the use of the revenue requirement approach for allocation of the Rural Deficit between Newfoundland Power and the Hydro rural customers;

c. *Conservation and demand management*: We agree with Hydro continuing the current approach in recovering CDM costs among its classes and classifying them as energy-related. In future GRA proceedings, depending on the success of programs emanating from the CDM Potential Study, it may be appropriate to classify some CDM costs to demand;

d. *Specifically assigned charges*: We recommend that Hydro continue tracking actual O&M expenses associated with each customer's dedicated assets and billing the customer directly. To the extent that it will take time to implement, we agree with the use of the methodology accepted in the Supplemental Settlement Agreement[8];

e. *Newfoundland power generation credit*: We agree with Hydro's continuation of the existing approach of providing the generation credit for both the hydraulic and thermal generation.

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[8] See Supplemental Settlement Agreement, July 16, 2018. Available at: http://www.pub.nl.ca/applications/NLH2017GRA/additionalfillings/Consent3%20-%202018-07-16.pdf.

f. *CBPP generation demand credit*: We are in agreement with Hydro on this issue.

g. *Allocation of net export revenues*: We recommend that the export credit be classified and allocated in the same manner as the Muskrat Falls generation, namely classified using the system load factor and allocated using the 1-CP allocator for demand-related costs and an energy allocator for energy-related costs. We also recommend the use of a rider to facilitate true-ups in between rate cases, with no less than annual frequency.

Regarding Hydro's Marginal Cost of Service Study, we have reviewed the overall methodology of the approach Hydro has taken concerning marginal generation capacity and energy costs and marginal transmission capacity and energy costs. Our main analysis has revolved around the marginal generation capacity costs as we have identified some methodological issues and approaches that we believe Hydro and its consultants should address. A detailed summary of our observations and opinions on Hydro's marginal cost study is included in Appendix: Marginal Cost of Service Study.

II. Embedded Cost of Service Study

A. Background on Embedded COS Studies

Embedded COS studies begin with the approved revenue requirement for the monopoly services offered by a utility. The goal of the embedded COS studies is to identify, summarize and attribute the costs that make up the revenue requirement to different categories of customers based on how those customers cause costs to be incurred. COS studies can also include the rate design process, which determines how costs are to be recovered from customers within each customer class, although in this report we generally do not discuss rate design issues.

By beginning with the approved revenue requirement, embedded COS studies primarily utilize the historical accounting data of the company to determine how much of the revenue requirement each customer class should be responsible for recovering.[9] Embedded COS is a methodology used in electricity ratemaking in the vast majority of the jurisdictions in North America. By contrast, as we discuss in the Appendix, a marginal COS study determines not the historical accounting costs of serving customers, but the forward-looking costs of serving customers. The starting point for the data in a marginal COS study tends to be system planning investment studies or, in the case of generation marginal costs, the starting point may be to utilize existing prices and forecasts of prices in organized wholesale markets.

Hydro's embedded COS study generally includes the following steps. The first is a systematization of the revenue requirement. Systemization is a step because historically there have been separate COS study areas. The second step is to functionalize the systematized revenue requirement, which consists of separating the revenue requirement into the different functions of the utility, such as generation, transmission, distribution, and customer. The next step is the classification of the functionalized revenue requirement, which is identifying the functionalized costs by the primary driver of costs, such as demand-related costs (also known as capacity costs), energy-related costs and customer-related costs. Finally, the last step prior to determining the appropriate rate design is the allocation of the classified costs, which is the process of assigning the functionalized and classified revenue requirement to the different customer rate classes based on a measure of the

[9] In some jurisdictions, embedded COS is based on forecasted accounting data for a future test year.

class' relative usage, such as its proportion of demand imposed on the system, energy consumed or customers served.

B. Systematization

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. Hydro also indicates that its proposal is consistent with the Government direction that exempts customers on the LIS from paying costs related to the Muskrat Falls Project (Embedded Cost Methodology Review at 7). CAEC recommends (at 9) that Hydro:

> …retain its practice of separate treatment in COS of the two interconnected regions. Costs shared by the two regions can continue to be separated prior to computation of costs by region, as performed by the current model.

In justifying its recommendation, CAEC (at 6) points out that interconnection of these two systems would be unconventional by North American standards because this event would connect two service territories made "contiguous" using a pair of high voltage direct current ("HVDC") circuits.

Both Hydro and CAEC identify two policy constraints as justification for why it is preferable to continue to keep the two areas separate from a COS perspective. The first is the policy requirement that Island Interconnected customers must pay for the Muskrat Falls project. The second is the policy requirement that the generation component for the Labrador Industrial rates, which serves two large customers, is determined outside of Hydro's COS study.

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). 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.

Our recommendation is for Hydro to plan for and prepare a single integrated system for COS purposes *in future* GRA proceedings and that it is not necessary to do so for this upcoming GRA. The current approach in effect implicitly "jurisdictionalizes" costs between the LIS and the IIS something that would be done more formally and explicitly in a single integrated system for COS purposes. From a practical perspective, we do not believe the results of a single integrated system for COS purposes will be different from the current approach that has separate LIS and IIS COS studies. That is one reason why we believe a single integrated system for COS purposes does not need to be developed for this GRA proceeding. Another reason is that, while we believe that developing and operationalizing a single integrated system for COS purposes will not have a material impact on the results, it will require work to develop the methodology and modify the models and may raise challenging issues that Hydro and stakeholders should carefully address.

C. Functionalization

Following systematization, functionalization is the next high-level task and objective in a cost of service study. Functionalization is the process of separating the total revenue requirement into components or assets assignable as production (generation), transmission, distribution and customer. In the U.S., the National Association of Regulatory Utility Commissioners ("NARUC") published a seminal manual on embedded and marginal cost of service. [10] Regarding functionalization, the NARUC manual (at 70) defines functionalization as:

> …the process of grouping costs associated with a facility that performs a certain function with the costs of other facilities that perform similar functions.

Functionalization is a key step of a cost of service study because the cost characteristics and the cost drivers can differ significantly among the different functionalized components/assets in an electric utility—production, transmission, distribution and general plant. Specifically, cost

[10] NARUC, Electric Utility Cost Allocation Manual, January 1992, ("NARUC Manual"), p. 70. Available at: https://pubs.naruc.org/pub.cfm?id=53A3986F-2354-D714-51BD-23412BCFEDFD.

classification for electric assets can be demand-related (costs that vary with the kW demand imposed by the customer), energy-related (costs that vary with the energy or kWh that the utility provides) or customer-related (costs that are directly related to the number of customers served). It is important, therefore, that electric utility assets be functionalized as accurately as possible so that the corresponding cost classification categories (demand, energy and customer) are associated with the corresponding functionalized assets.

Most functionalization decisions are relatively straightforward. Functionalization generally follows the associated accounting treatment of the asset. For example, assets that are generation from an accounting standpoint are generally functionalized as generation, and transmission assets from an accounting standpoint are generally functionalized as transmission. There are exceptions, however. As we discuss below, there could be some instances where even though the asset is clearly a generation asset from an accounting perspective; from a cost of service perspective, some part of generation should be functionalized as transmission.

1. Muskrat Falls Project

Hydro recommends that the power purchase costs resulting from the Muskrat Falls project, including the LIL and the LTA, be functionalized as generation. CAEC also recommends that the LTA and the LIL (including the converter facilities located at Muskrat Falls and Soldiers Pond) be functionalized as generation (CAEC Embedded Cost Report at 36-37).

We agree that the generation facilities at Muskrat Falls should be functionalized as generation. Concerning the LIL and the LTA, however, we believe that it is more appropriate to functionalize them as transmission.

The U.S. FERC defines a transmission system to include:[11]

> (1) All land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station, or point of receipt in case of purchased power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission;
>
> (2) All land, structures, high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and
>
> (3) All lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply.

For purposes of functionalization of the transmission system, the NARUC manual identifies two high-level approaches to functionalization, the "Rolled-in Transmission Plant Method" and the "Subfunctionalization Method.[12] Under the rolled-in method of functionalization, all the components of the transmission system are viewed as a fully integrated transmission system that are designed and operated jointly to deliver point-to-point bulk power on the system. Under this approach, all transmission assets are functionalized to transmission. By contrast, the subfunctionalization method views the transmission system as composing several sub-categories—

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[11] See FERC Uniform System of Accounts prescribed for public utilities and licensees subject to the provisions of the Federal Power Act. Available at: https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18.

[12] NARUC Manual, p. 71.

such as backbone and intertie facilities, generation step-up facilities, subtransmission plant, and radial facilities. These categories are similar to the categories that CAEC identified in their report—generation interconnection facilities (also known as generation leads), general-purpose transport facilities, terminal stations, and special facilities (CAEC Embedded Report at 32).

There are two practical reasons for utilizing the subfunctionalization approach. The first is from a customer cost causation perspective. Some customers may not utilize certain aspects of the transmission facilities. From a cost of service perspective, the subfunctionalization approach helps identify the different subcomponents of the systems and assists in the allocation process and in implementing the general costing principle that customers ought not to be charged for assets (services) they do not utilize. The second is that in some instances portions of a transmission network should be functionalized as something other than transmission. In this particular case, we need to decide whether the LIL and LTA, which are by definition transmission accounting assets, should be functionalized as generation. Thus, the subfunctionalization approach is required to identify which components of the transmission network could be functionalized to something other than transmission.

The process of subfunctionalization is specific to each utility and depends upon characteristics of the utility's transmission system. The NARUC Manual (at 72) observes that under subfunctionalization:

> The main distinction is usually between those facilities that connect all the major power sources with each other — the backbone transmission facilities — and everything else. Utilities have identified subsystems such as generation step-up facilities, system interconnection and subtransmission, among others. These

> transmission system components and other non-backbone facilities may often be considered as a separate network of facilities that are either not used to support the backbone system, or represent facilities that require special recognition in the ratemaking process.

In general, generator leads are taken to be the portion of the electrical facilities beginning at the point of interconnection to the generator and ending at, and including, the low voltage side of the step-up transformer that connects to the transmission system. The high side of the step-up transformer is taken to be the beginning of the transmission system. Although a high voltage radial line interconnecting a generation station is usually termed a 'generator lead," the Federal Energy Regulatory Commission has consistently required that high voltage circuits that connect solely to a single generator, or group or generators in the case of wind farms, are deemed required to have an Open Access Transmission Tariff (OATT).[13] It appears that the Newfoundland-Labrador System Operator (NLSO) has anticipated this and has preliminarily included these lines in its OATT.[14] Further, The North American Electric Reliability Corporation (NERC) requires that generators with significant transmission lines register as transmission owner/operators and that such high

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[13] See, for example, the discussion at https://www.windpowerengineering.com/electrical/grid/ferc-requires-filing-oatt-for-generator-lead-line/.

[14] See Newfoundland and Labrador Board System Operator Methodology for the Development of Rates for Transmission Service, February 5, 2018 p. 12 lines 9 – 14: "For LIL and the Labrador Transmission Assets (LTA), it is anticipated there will be a decision in the upcoming Cost of Service Methodology Hearing on the portion that should be functionalized as transmission and what portion should be functionalized as generation. For the purpose of developing the interim rates to be in place in advance of full commissioning of the Muskrat Falls Project, the NLSO has treated the LIL and LTA as transmission assets. Therefore 100% of the cost incurred for the use of the LIL and LTA are included in the interim transmission rates." Available at: https://www.oasis.oati.com/woa/docs/NLSO/NLSOdocs/Methodology_for_the_Development_of_Rates_for_Transmission_Service_FINAL_02052018.pdf.

voltage lines conform to its reliability standards for transmission systems.[15] Given the voltage level and the significant length of the LIL and LTA, it seems reasonable to conform to this approach.

In either case, if the Board decides to accept the LIL and LTA as functionalized to generation, we recommend that they both be classified as demand related and, as we describe below, the costs removed from the calculation of the equivalent peaker method.

2. TL-234 and TL-263

Hydro recommends no changes in the functionalization of existing generation and transmission assets except Hydro's TL-234 and TL-263 transmission lines. Hydro recommends that the functionalization of these assets change from generation to transmission.[16] We sent Hydro an interrogatory request to better understand why they were recommending changes to these two lines. Their response[17] was as follows:

> The addition of TL-269 from Granite Canal to Bottom Brook to support the import and export of energy over the Maritime Link creates a 230 kV transmission loop including TL-234 and TL-263. Therefore, Hydro has proposed Tl-234 and TL-263 change from functionalization as generation to transmission.

We agree with Hydro's recommendation to modify the functionalization of TL-234 and TL-263. Further, the transmission lines connecting Cat Arms (TL-247) and Hinds Lake (TL-243) should similarly be treated as transmission.

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[15] See the FERC's affirmation of the appropriateness of such a policy at 139 FERC ¶ 61,214. The NERC has deemed that such lines need only conform to a subset of its reliability requirements.

[16] Embedded Cost Methodology Review, p. 8.

[17] PUB-NLH-006.

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.

3. Holyrood Unit 3

Hydro recommends the functionalization of Holyrood Unit 3 as transmission after Hydro permanently converts the unit into a synchronous condenser.[18] A synchronous condenser is a synchronous motor generally running without load that can generate or absorb reactive volt-ampere (VAr) whose general purpose is to adjust conditions on the transmission grid. We recommend 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. Further, going forward, if other generating units operate solely as synchronous condensers, we recommend a similar treatment.

[18] Embedded Cost Methodology Review, p. 8.

4. Transmission Assets Currently Assigned to Customers

Hydro recommends that the transmission assets currently specifically assigned to customers continue to be specifically assigned. We understand that these are facilities that Hydro specifically assigns to customers due to the fact that the assets are dedicated and only utilized by the customer so assigned. Such an approach is common practice in COS studies and we agree with Hydro's recommendation.

5. Contributions for Customers from New Network Additions Policy

Hydro recommends that any contributions from customers as a result of a new network additions policy be deducted from rate base consistent with the current approach used in treating customer contributions in determining rate base for use in the cost of service study. We agree with this approach, as this is generally common practice in utility ratemaking.

D. Classification

The NARUC manual defines classification as a refinement of the revenue requirement. Specifically, it defines cost classification as the process of identifying the utility operation—demand, energy, customer—for which functionalized dollars are spent.[19] In other words, classification is the process of separating the functionalized costs by the primary driver for that cost.

[19] NARUC Manual, p. 34.

Demand-related costs are those costs that vary with the kW of instantaneous demand (and therefore peak capacity and reliability needs). Energy-related costs are those costs that vary with kWh of energy generated and consumed. Customer-related costs are those costs that vary with the number of customers on the system. Generation and transmission revenue requirements are either demand or energy related, or a combination of the two. Very much related to the concept of demand or energy-related costs is whether production costs are fixed and only vary with the additions to capacity or variable that vary with the energy produced from a given plant capacity. The fixed costs of production and transmission plant are those costs that are associated with the generation and transmission plant and facilities owned by the utility. They consist of the cost of capital, depreciation, taxes and fixed operation and maintenance expenses ("O&M"). The variable costs of generation production are the fuel costs, purchased power costs and some types of O&M (those O&M costs that vary with the amount of energy produced). The variable costs of transmission are the energy losses that arise from transmitting energy over the transmission lines.

The NARUC Manual identifies two general approaches to cost classification, the cost accounting approach and the cost causation approach.[20] Under the cost accounting approach, all of the fixed production plant costs (cost of capital, depreciation, taxes and fixed O&M) are classified as demand because all of the plant capacity is fixed to meet the current level required of demand. Increases in the demand result in increases in the fixed production plant costs because facilities are typically sized to meet peak demand. Demand costs are then allocated to customers based upon the customer (or customer class) share of its demand of capacity either during the system peak or combinations

[20] NARUC Manual, p. 38.

of monthly peaks throughout the year. Under the cost accounting approach, the costs of production that are variable (fuel and purchased power costs and variable O&M) and losses are classified as energy-related and are assigned to customers based on their energy purchases.

In general, a peak demand approach implements the cost accounting approach to classification in that it classifies all production plant as demand-related. As we discuss in the section on allocation, these production costs are allocated among the customer classes on some element that measures the classes contribution to system peak, whether this is the single coincident peak method (1-CP), summer and winter peak method (SWP), sum of the twelve monthly coincident peaks (12-CP), multiple coincident peak method, or other peak-related measures. Setting rates based on each classes' relative peak demand reflects the costs that each class imposes on the utility and provides appropriate economic signals for customers to make purchases at the peak that is commensurate with the value of the service.[21]

Under the cost causation approach to classification and allocation, the general focus is on the utility planner's investment decisions to add capacity to meet reliability criteria such as loss of load probability, reserve margin, loss of load hours or other measures. The utility's load duration curve helps the utility planner determine what type of production plant is required to meet the reliability criteria and thus determines the cost of the additional capacity. The implication is that not all of the fixed production costs (*i.e.*, the cost of capital, depreciation, taxes and fixed O&M) are

[21] As we discuss in the Appendix, setting demand (capacity) rates on the basis of marginal costs ensures efficient consumption decisions on the part of customers. Nevertheless, demand (capacity) rates that are based upon embedded costs can also serve as a useful price signal to consumers regarding consumption during peak periods.

necessarily classified as demand-related. Instead, some portion of the fixed production costs may be classified as energy-related and allocated to customers on the basis of energy consumption. This is known as the energy-weighting method of classification and allocation. This approach recognizes that a major determinant that gives rise to production plant costs is energy loads. Some of the approaches that fall into the energy-weighting category include the average and excess method, the equivalent peaker method, system load factor or judgmental methods. Under the cost causation approach to classification, the variable costs of production generally remain classified as energy-related and allocated on the basis of energy consumption.

1. Hydro's General Approach

Hydro's general approach to classification (and by extension allocation) is to examine each generation facility (or to examine a common set of generation facilities by technology type) to determine which classification methodology to apply—either a peak-related approach or an energy-weighted approach. As CAEC states (at 9), Hydro classifies and allocates its generation costs in a manner that attempts to recognize *each* facility's role in generation dispatch with units identified as peaking units being entirely demand-related while other units are recognized as having both an energy component and a demand component. Table 2 below summarizes Hydro's existing and proposed classification methodology of functionalized generation costs in the Island Interconnected System.

Table 2: Classification of Functionalized Generation Costs – Island Interconnected System

Generation Costs	Existing	Proposed
Hydraulic Assets	System Load Factor	System Load Factor
Holyrood Assets[22]	5-Year Average Capacity Factor	Forecast Capacity Factor
Gas Turbines/Diesel Assets	100% Demand	100% Demand
Power Purchase Muskrat Falls	Not Applicable	Equivalent Peaker (20% Demand/80% Energy)
Other Power Purchase	System Load Factor	System Load Factor
Holyrood Fuel	100% Energy	100% Energy
Gas Turbine/Diesel Fuel	100% Demand	100% Demand
Wind Purchases	100% Energy	22% Demand/78% Energy

Source: Embedded Cost Methodology Review, Table 3.

Hydro also has diesel and gas turbine generation in the Labrador Interconnected system, as well as in the isolated systems. Table 3 summarizes Hydro's existing classification methodology of its functionalized diesel and gas turbines generation.

[22] When Holyrood is converted to a synchronous condenser, it will be converted to a transmission asset and classified as 100% demand.

Table 3: Hydro Classification of Diesel and Gas Turbine Generation

System	Assets	Fuel Costs
Island Interconnected and Labrador Interconnected	100% Demand	100% Demand
Isolated Diesel Systems[23] (excluding L'Anse-au-Loup)	System Load Factor	100% Energy
L'Anse-au-Loup[24]	100% Demand	100% Energy
Power Purchases	Not Applicable	100% Energy

Source: Embedded Cost Methodology Review, Table 2.

With respect to Hydro's approach, CAEC (at 10) states:

> The NARUC COS Manual reveals many different ways to classify generation plant. Some are demand-only in nature and others are a combination of demand and energy, but are termed "energy weighting methods". Since none of the conventional approaches can claim unchallenged superiority, the current Hydro approach of classifying on the basis of generator type, and using both demand-only and energy weight methods, appears to be within the norms of industry practice.

We are in general agreement with this statement. Hydro's approach—*i.e.*, examining and analyzing the reasons that gave rise to the investment in each generation facility rather than classifying all fixed production costs as demand-related—is, by definition, akin to the cost causation approach discussed above. By contrast, the cost accounting approach would be to classify all production fixed costs as demand-related and all production variable-costs as energy-related,

[23] Includes Labrador and Island Isolated diesel excluding L'Anse-au-Loup.

[24] Because a high percentage of the energy system supplied to L'Anse-au-Loup comes from secondary energy purchases from Hydro-Quebec, Hydro classifies its diesel assets as 100% demand-related as these assets are required primarily to supply peak periods.

irrespective of the reason why the investment was made—*i.e.*, irrespective of underlying cost causation considerations. Under Hydro's approach, Hydro examines each generation facility and attempts to explain the role of the plant in dispatch and the underlying reason for the plant investment decision. From a practical perspective, given the relatively small number of generation facilities that Hydro has compared to other much larger utilities in North America, examining each generation facility in this manner is practical, feasible and is generally consistent with the theory of COS as well as industry practice.

2. Production/Generations Costs

a. Muskrat Falls

As shown in Table 2 above, Hydro is recommending the use of the equivalent peaker method for classifying the Muskrat Falls Project Power Purchases, which would result in assigning approximately 20% of the Muskrat Falls Project Power Purchases revenue requirement to demand and the remaining 80% to energy.[25] Since the Muskrat Falls Project Power Purchases is a new element in Hydro's revenue requirement, Hydro's recommendation is not a change to an existing COS approach; rather, it is a case of first impression. We do note, however, that Hydro currently has other Hydraulic Purchase Power agreements such as Exploits generation as well as Hydro's purchases of Recapture Energy from CF(L)Co and these purchase power agreements are classified based upon system load factor, which results in approximately 55% energy and 45% demand classification.[26] Thus, changing the classification methodology used for either the Muskrat Falls

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[25] Embedded Cost Methodology Review, Exhibit 1.

[26] Embedded Cost Methodology Review, footnote 35.

Project Power Purchases or the existing Hydraulic Power Purchase agreements will have a material impact on the two rate classes (Newfoundland Power and Industrial customers) depending on the load factor of each class. It is generally the case that the revenue requirement responsibility of high (low) load factor customers and customer classes is greater (lower) as the proportion of fixed production plant classified to energy increases.

As discussed above, the equivalent peaker methodology is a type of energy-weighted classification methodology. Energy-weighted classification methodologies acknowledge that energy loads are a significant cost driver of production plant costs. The NARUC Manual (at 52) states the equivalent peaker method as being:

> …[b]ased upon generation expansion planning practices that consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added.

And (at 53):

> The premise of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of the peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.

To implement the equivalent peaker approach, one needs to estimate the levelized annual unit cost of a new peaking unit as well as the unit cost of a new baseload generation unit. Hydro selected a gas turbine as the peaking unit technology and the Muskrat Falls project (including the levelized costs of the LIL or the LTA) as the new baseload generation unit. Hydro calculated the levelized annual unit cost of the gas turbine to be $249 per kW and the levelized annual unit cost of the baseload plant (with the LIL and LTA) to be $1,267 per kW.[27]

The costing concept behind the equivalent peaker approach is that part of the unit cost of the baseload plant is incurred to meet peak demand and that amount can be estimated by taking the ratio of the levelized annual per unit cost of a peaking unit and the levelized annual per unit cost of a baseload plant. Specifically, in this case, the amount of the baseload plant classified as demand is $249/$1,267 = 20%. The remaining 80% is then classified as energy-related. Conceptually, this approach is guided by the belief that for a baseload plant the per unit costs can be separated into two components, a component that represents the demand-related reason the investment was made and a component that represents the energy-related reasons the investment was made. Compared to peaking units, non-peaking units, such as baseload and intermediate units, are more expensive and one can justify that extra expense as being energy-driven (that is, as a means to reduce per unit energy costs) not demand driven (that is, reliability-driven). From a cost causation and a least cost production perspective, it is appropriate to view that those higher expenses are incurred in part to reduce fuel costs that are typically higher for peaking units—thus the classification as energy.

As shown in Table 2 and Table 3 above, Hydro's current classification methodology for existing hydraulic assets and power purchase agreements on the IIS, as well as the isolated diesel system

27 Embedded Cost Methodology Review, Table 1 and Exhibit 1.

(excluding L'Anse-au-Loup) is the system load factor. The system load factor approach to classification is another example of energy-weighted classification that recognizes that a significant percent of production plant investment is caused by energy loads. The annual system load factor is the ratio of average annual demand to peak hour demand on the system. Conceptually, the system load factor approach to classification is similar to the equivalent peaker method in that the system load factor approach also has as its objective distinguishing the production plant investment cost of a generation unit between the investment in that unit incurred to meet average load and the investment in that unit to meet peak demand.

The system load factor approach to classification is straightforward and relatively free of controversy or subjectivity objections and is therefore more robust and less sensitive to assumptions. It requires the calculation of Hydro's annual system load factor, which is 54.6%, and uses this percentage to determine the amount of production plant investment to classify as energy-related.[28] The remaining amount, 45.4%, is classified as demand-related. Table 4 below summarizes the difference in the demand and energy-related cost split under the equivalent peaker method and the system load factor method.

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[28] Embedded Cost Methodology Review, footnote 35. We confirmed these numbers in our analysis; see Table 5.

Table 4: Demand and Energy Percent Classification under EPM and SLF

Classification Methodology	Demand-Related (%)	Energy-Related (%)
Equivalent Peaker	19.7	80.3
System Load Factor	45.4	54.6

Source: Embedded Cost Methodology Review footnote 35 and Exhibit 1.

As can be seen in the table above, the selection of the classification method for Muskrat Falls—that is selecting either the equivalent peaker method or the system load factor—has a material impact on the percent of costs that are classified as demand and the percent of costs that are classified as energy. This will also impact the revenue requirement responsibility of each class because the load factor of a class determines, in part, the impact on differing demand and energy classification. For example, industrial class customers tend to have higher load factors compared to residential and smaller commercial classes, two classes of customers that Newfoundland Power disproportionally serves. In general, high load factor customers tend to have less revenue assigned to them under those methods that classify a higher share of the fixed production (and transmission as well) costs as demand-related and less as energy-related. Lower load factor customers, on the other hand, such as residential and small commercial customer classes, have more revenue assigned to them under those methods that classify a higher share of the costs as demand-related and less as energy-related. In Table 5 below, we show the overall load factor for the IIS and for Newfoundland Power and the Industrial Customers and observe that IIS Industrial class have much higher load factor than IIS NP. This means that a higher demand split, all else equals, results in lower rates for the IIS Industrial class *vis-à-vis* IIS NP.

Table 5: Test Year Annual Load Factor for the IIS and by Customer Type

	Annual Load Factor
IIS	**54%**
IIS NP	50%
IIS Industrial	88%

Source: Calculation based on PUB-NLH-002.

Both the equivalent peaker and the system load factor approach to classification are energy-weighted approaches that recognize that energy loads are an important driver of production plant costs. Both approaches are reasonable ways to implement an energy-weighted approach to classification and we do not believe that one way is unequivocally superior to the other. In general, the decision should be case and utility-specific, taking into consideration current methodologies that are used and for how long, system-planning characteristics, and regulatory issues. These factors play an important role in determining which approach is preferred.

For the following reasons, we recommend extending Hydro's current system load factor approach to classification—that is, the approach Hydro is currently using for its hydraulic assets and purchase power agreements—to the Muskrat Falls purchase power agreement.

First, Hydro uses the system load factor as its prevailing classification methodology for its existing hydraulic generation as well as its other power purchases (excluding wind), with the largest being Exploits generation as well as Recapture Energy from CF(L)Co. Hydro has been using this classification methodology for its hydraulic plant costs since 1993 when it first undertook a cost of service review in a report to the Minister of Mines and Energy.[29] In the absence of evidence that the equivalent peaker approach is unequivocally superior for Muskrat Falls, we believe there is a benefit to treating all of Hydro's hydraulic assets similarly for classification purposes and in maintaining and extending the system load factor approach to the Muskrat Falls. Our experience is that the equivalent peaker method has more commonly found use in thermal generation-dominated systems.

Second, compared to the equivalent peaker methodology, the system load factor approach 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. The equivalent peaker approach requires the selection of the appropriate technology to use for the peaker and baseload plant, associated cap-ex (direct facility investment) and calculation of levelized costs taking into account appropriate values for the cost of capital, inflation and productivity trends over time. By contrast, the system load factor is the simple ratio of the average system demand and the system peak demand, a ratio that is easily calculated from the existing load data in a cost of service study.

One example of the type of input assumptions that would need to be carefully scrutinized when utilizing the equivalent peaker approach is the Direct Facility Investment of the peaker unit. In its analysis, Hydro assumes that the new peaking unit is a gas turbine with a capital cost of $182.2

[29] See Report of the Board of Commissioners of Public Utilities to The Honorable Minister of Mines and Energy, Government of Newfoundland and Labrador, February 1993, report entitled, "A Proposed Method for Adjusting its Rate Stabilization Plan to Take into Account the Variation in Hydro's Rural Revenues Resulting from Variations in the Rates set by the Board to be Charged by Newfoundland Light and Power Co. Limited to its Customer."

million (2019 dollars) financed at Hydro's long-term WACC of 5.9% with a capacity of 58.5 MW. This is the equivalent of a Direct Facility Investment of approximately $3,114 per kW. At first glance, this number seems to be materially different from publicly-available figures for gas turbines and the reasons for the differences would need to be thoroughly investigated, see Table 6 below.

Table 6: Direct Facility Investment Cost of Gas Turbines

Technology	Size (MW)	Cost ($/kW)	Study Year	Cost Type	Source
Combustion turbine	100	$1,126	2019	Overnight capital costs	EIA Annual Energy Outlook
Internal combustion engine	85	$1,371	2019	Overnight capital costs	EIA Annual Energy Outlook
Gas CT, Aeroderivative	93	$1,394	2018	Overnight capital costs	AESO CONE Study
Gas CT, Frame	243	$632	2018	Overnight capital costs	AESO CONE Study
Gas Simple Cycle	120	$1,039	2018	Total capital requirement	CERI Generation Options Study
Gas CT, Aeroderivative		$1,299	2014	Capital cost	WECC Capital Cost Review
Gas CT, Frame		$893	2014	Capital cost	WECC Capital Cost Review

Sources and Notes: All costs are converted to 2018 dollars, assuming 2% inflation rate. 2019 EIA Annual Energy Outlook, Table 2, available here: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf. AESO CONE Study, Table 8, available here: https://www.aeso.ca/assets/Uploads/CONE-Study-2018-09-04.pdf. CERI Generation Options Study, Table 3.9, available here: https://ceri.ca/assets/files/Study_168_Full_Report.pdf. WECC Capital Cost Review, Tables 6 and 7, available here: https://www.wecc.org/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf.

We requested support from Hydro for the Direct Facility Investment cost of $3,114.60 per kW.[30] Hydro referred us to its Reliability and Resource Adequacy Study Volume III: Long-Term Resource Plan, p. 45 (Table 9), which provided a reference to Attachment 14 of Volume III. The information in Attachment 14 of the Study (at 5) indicates that the capital budget estimates used for the direct facility investment cost is a Class 5 capital cost estimate and that "the estimated cost can be classified as Class 5 with an expected accuracy range of -20% to +40%." This level of cost uncertainty for the peaker unit means that, in this instance, the equivalent peaker methodology is less precise than the system load factor approach.

[30] PUB-NLH-017.

Related to the point above regarding the equivalent peaker being less robust than the system load factor approach in part due to assumptions that must be made, is the fact that the costs of the transmission investments of the LIL and the LTA are included in the equivalent peaker calculation. Specifically, Hydro calculated the levelized annual unit cost of the gas turbine to be $249 per kW and the levelized annual unit cost of the baseload plant (with the LIL and LTA) to be $1,267 per kW. The $1,267 includes the costs of the LIL and the LTA, and given the length of the LIL and the LTA, these transmission investments are significant and account for approximately 40% of the net present value of the Muskrat Falls project.[31] We do not believe it is correct to include these large transmission investments in the calculation of the equivalent peaker method. We believe including the LIL and the LTA transmission investments in the equivalent peaker calculation distort the calculation and goes against the underlying logic behind using energy weighting to classify generation assets. Removal of the LIL and LTA from the equivalent peaker calculation results in a demand classification of approximately 33% (compared to the original 20%) and an energy classification of approximately 67% (compared to the original 80%).[32]

Third, and related to the previous point regarding potential sensitivity and robustness of the equivalent peaker methodology is the fact that the energy-component in the equivalent peaker approach is, in essence, a residual. That is, the demand component under the equivalent peaker

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31 See Embedded Cost Methodology Review Exhibit 1, p. 3.

32 See Embedded Cost Methodology Review, Exhibit 1, p. 2-3. The 20% demand classification under equivalent peaker methodology is calculated by dividing the levelized annual cost of the gas turbine by the levelized annual unit cost of the Muskrat Falls project *including* the LIL and LTA (= $249/kW / $1,267/kW). The levelized annual cost of Muskrat Falls generation *excluding* the LIL and LTA is $764/kW, yielding a 33% demand classification (= $249/kW / $764/kW).

approach is the ratio of the per-unit cost of the peaker plant and the per unit cost of the baseload plant—with the energy component being what is left over, *i.e.*, the residual. Unusually high or low baseload investment may distort the energy portion of classification. For example, an important consideration to take into account is the fact that if there are significant cost overruns compared to original estimates in the construction of baseload generation, as we understand to be the case with the Muskrat Falls generation station, those cost overruns are entirely reflected as energy-related and none would be classified as demand-related.

Fourth, an additional consideration in the decision is the impact on the price signals embodied in the rate design. The equivalent peaker approach would assign less of the Muskrat Falls costs to demand, compared to the system load factor approach, and this would dilute peak-reducing price signals. That is, demand charges under the equivalent peaker approach would be lower than under the system load factor approach and this would provide less of a disincentive to consume during peak demand periods. All else equal, curtailing consumption during peak demand is an economically appropriate goal of electricity rate making as it results in improvement in overall system load factor, and thus, results in lower unit costs.

Fifth, a useful piece of evidence to consider when evaluating the classification split between demand and energy in a power purchase agreement is the agreement itself. Importantly, under the agreement the payments that Hydro makes to the Muskrat Fall Corporation are not related to the amount of energy Hydro purchases. The Muskrat Falls power purchase agreement calls for a 50-year Base Block Capital Cost Recovery payment schedule. Each month Hydro pays the Muskrat Falls Corporation a pre-determined amount that recovers the original investment cost of the

Muskrat Falls generation and LTA assets. The schedule of monthly payments reflects an internal rate of return approach to derive a payment schedule that escalates annually at a rate of 2% per year.[33] There is an additional component that recovers the Operating and Maintenance (O&M) costs, as well as for sustaining capital for the assets over the 50-year supply period, which also does not vary in relation to the amount of energy that Hydro purchases.

b. Existing Hydraulic Assets

Hydro proposes to continue using the system load factor approach for classification of its existing hydraulic assets. These consist of units at Bay d'Espoir, Cat Arm, Hinds Lake, Granite Canal, Paradise River, Upper Salmon and Mini Hydro.[34] For the reasons discussed in the section above, we are in agreement that the classification methodology for these units should remain the system load factor.

c. Holyrood

The Holyrood units are currently classified based on the capacity factor of the plant. This approach is somewhat different to, but related to, the system load factor in that it is another example of an energy-weighted method of classification. The approach postulates that the utilization of the plant (*i.e.*, the capacity factor) represents the energy-related proportion of plant costs, with generation plants with high capacity factor implying higher energy-related costs compared to generators with lower capacity factors. Hydro states that Holyrood's role will change and the plant will cease to perform as a generating unit following the completion of the Muskrat Falls Project commissioning.

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33 PUB-NLH-004.

34 See Reliability and Resource Adequacy Study, Volume III, Tables 1 and 3.

The capacity factor of the plant is forecasted to change significantly following the Muskrat Falls Project commissioning because, while the plant may be required to be available for generation for a period of time after Muskrat Falls Project commissioning, it will be much less than historically. In this circumstance where Holyrood is still being used but producing much less than historically, Hydro proposes that Holyrood asset costs be functionalized as generation and classified using a forecast capacity factor, rather than the historical capacity factor. The Holyrood fuel cost is proposed to continue to be classified as an energy cost.

We agree with Hydro's recommendation to use the forecasted capacity factor for classification purposes for the Holyrood units that post commissioning will continue to meet both energy and demand needs.

d. Holyrood Unit 3

As mentioned above in the section on functionalization, Hydro recommends the functionalization of Holyrood Unit 3 as transmission after Hydro permanently converts the unit into a synchronous condenser. For classification, we recommend that the portion of rate base and depreciation associated with Holyrood 3's plant's prior use to provide generation be classified as demand. We recommend, however, that the capital additions and operations and maintenance costs associated with Holyrood 3's use as a synchronous generator be classified as energy, since those costs are largely dependent on kWh production. Further, going forward, as other generating units convert from their current use to meet energy and demand requirements to solely finding use as synchronous condensers, we recommend a similar treatment as Holyrood Unit 3.

e. Power Purchases (Excluding Wind)

In addition to the Muskrat Falls PPA and excluding wind PPAs, Hydro has some additional PPAs, including the Exploits (Grand Falls and Bishop's Falls and Star Lake) and CF(L)Co (Recapture Energy and TwinCo Block).[35] Hydro has used and proposes to continue to use the system load factor for classification for these hydro PPAs. With respect to the Exploits generation, Hydro states that from an operational perspective, it operates Exploits assets very similar to and no differently than if it owned the hydraulic production assets. Moreover, the Government has informed Hydro that the long-term plan is to transfer ownership of the Exploits assets to Hydro. This classification would also apply to Hydro's purchases of Recapture Energy from CF(L)Co. For these reasons and the reasons discussed above, we agree that these hydro PPAs should continue to be classified using the system load factor.

f. Power Purchases Wind

Hydro has two 20-year Power Purchase Agreements totaling 54 MW of wind generation on the island of Newfoundland. One wind farm is a 27 MW project located in St. Lawrence. The other wind farm is also a 27 MW project located in Fermeuse. Hydro recommends that the cost of wind purchases be classified 22% demand and 78% energy. This is a change from the previous approach where the cost of wind purchases was classified 100% energy. In its Reliability and Resource Adequacy Study, Hydro stated that:

> Given the interconnection to the North American grid, as part of its Reliability Model, Hydro re-evaluated the contribution of wind generation to system capacity. Utilities across North America use a variety of methods to determine the capacity contribution of

[35] See Reliability and Resource Adequacy Study, Volume III, Tables 1 and 3.

> intermittent sources. A common approach is to use the concept of effective load carrying capability ("ELCC"). The ELCC of a unit is a measure of the additional load that the system can supply with the particular generator of interest, with no net change in reliability.[36]

Hydro provides a full description of its ELCC Study in its Reliability and Resource Adequacy Study.[37] Hydro utilized the PLEXOS® model to calculate the ELCC using a probability distribution for wind generation based upon the historical hourly wind generation data from January 2010 to June 2018 for both the Fermeuse and St. Lawrence wind farms. Hydro runs PLEXOS® with both wind farms included in the model and adjusts the loads until the system loss of load hours ("LOLH") reaches 2.8 hours per year, Hydro calls this the baseline. Hydro then removes both wind farms from the system to determine the impact on LOLH. Hydro then adds what it calls an "ideal" generator to the system with a capacity close to the expected ELCC value (presumably of the wind farms) and reruns the model and adjusts the capacity of the ideal unit up or down (rerunning each time) until the system LOLH returns to 2.8. Hydro states that the capacity of the ideal generator, which produces a system LOLH of 2.8, determines the ELCC of the wind units, which it found to be 12 MW, which is approximately 22% of the installed wind generating capacity. Because of its ELCC study and analysis in its Reliability and Resource Adequacy Study, Hydro relies upon 12 MW from these wind farms as a reliable contribution to the islands firm capacity.

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[36] See Reliability and Resource Adequacy Study, Volume I, Attachment 6, p. 2.

[37] See Reliability and Resource Adequacy Study Volume I, Attachment 6, p. 5.

Hydro's methodology is consistent with other approaches to calculating the ELCC of wind units,[38] although we note that implementation of ELCC methodologies can be case specific and dependent upon the type of data and system models that are available. As a robust check, we have examined the historical output of these two wind farms to ascertain their production during the periods of peak demand and hours of highest reliability concerns. The purpose of this analysis was to determine how much output was produced during these periods and compare the historical results to the results predicted using Hydro's methodology and the PLEXOS® model.

Table 7 contains historical Fermeuse and St. Lawrence output data and capacity factor during the top 25 hours of system load 2013 through 2017. The average capacity factor for the top 25 hours of the year was significantly higher than 22% for each year, with average capacity factors being significantly higher for the St. Lawrence farm compared to the Fermeuse farm. Specifically, the St. Lawrence capacity factor was between 20 and 70 percent higher than the Fermeuse farm. While the average capacity factor at each farm was significantly higher than 22%, the standard deviation was quite high in each plant. For each farm and for each year, there were hours in which the capacity factor was less than 22%. For the Fermeuse farm for 2017, this occurred in seven instances, while for the St. Lawrence farm this occurred in five instances.

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[38] We should note that the original calculation of ELCC proposed by L.L. Garver (L. L. Garver. Effective load carrying capability of generating units. *IEEE Transactions on Power Apparatus and Systems*, PAS-85(8):910–919, Aug 1966.) used an approach, cumulants, that requires stochastic independence of units from one another and from load. Since wind and load are correlated, as demonstrated in our regression calculation below, that assumption may be violated. See *Capacity value assessments of wind power* by M. Milligan, et al. (WIREs Energy Environ 2016. doi: 10.1002/wene.226).

Table 7: Historical Fermeuse and St. Lawrence Capacity Factor during System Peak Hours, 2013-2017

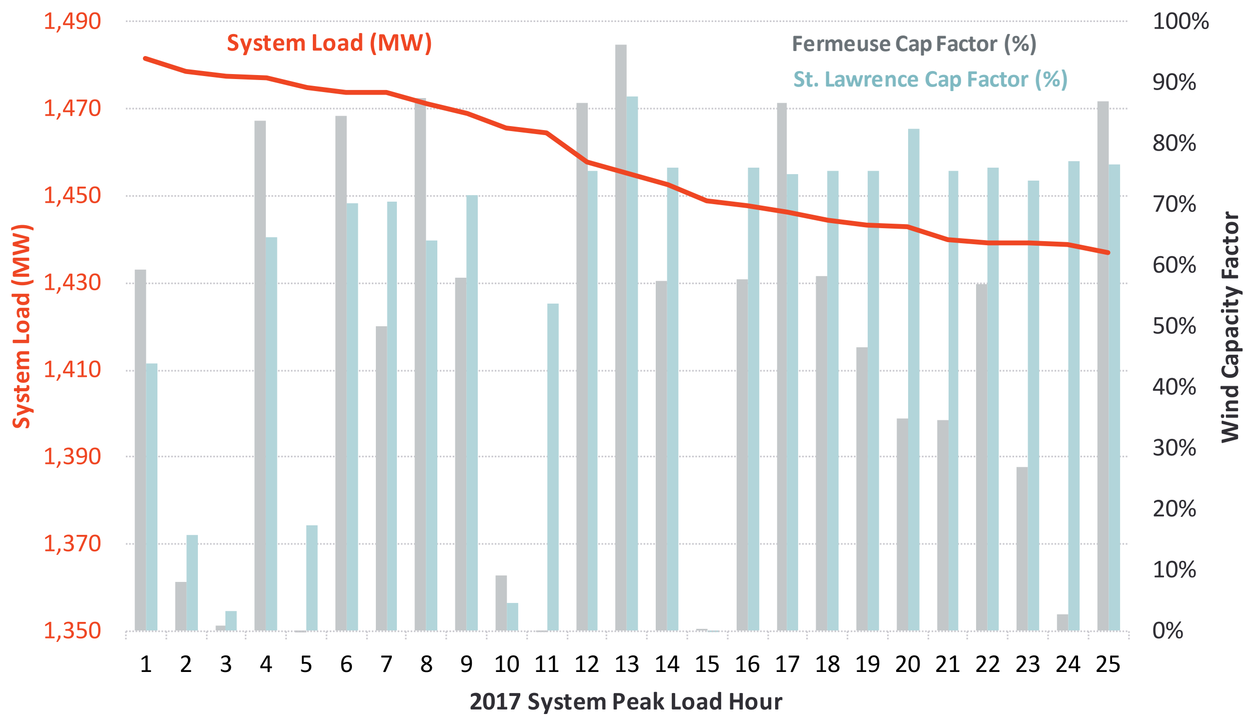
	System Load (MW)					Fermeuse Capacity Factor					St. Lawrence Capacity Factor				
Peak Hour	2017	2016	2015	2014	2013	2017	2016	2015	2014	2013	2017	2016	2015	2014	2013
1	1,482	1,448	1,470	1,424	1,410	59%	68%	44%	31%	96%	44%	87%	66%	85%	86%
2	1,479	1,426	1,458	1,412	1,399	8%	36%	68%	15%	90%	16%	76%	98%	86%	64%
3	1,478	1,424	1,457	1,404	1,393	1%	28%	57%	10%	98%	3%	3%	99%	14%	86%
4	1,477	1,408	1,455	1,404	1,388	84%	35%	24%	84%	97%	65%	82%	95%	97%	86%
5	1,475	1,400	1,453	1,403	1,383	-1%	16%	83%	94%	0%	17%	1%	98%	95%	14%
6	1,474	1,399	1,452	1,400	1,377	85%	32%	55%	94%	17%	70%	88%	98%	95%	55%
7	1,474	1,390	1,449	1,400	1,369	50%	1%	67%	86%	97%	71%	0%	98%	86%	54%
8	1,471	1,389	1,447	1,397	1,368	87%	55%	72%	31%	96%	64%	73%	98%	64%	86%
9	1,469	1,388	1,447	1,395	1,367	58%	19%	72%	82%	60%	71%	11%	98%	88%	97%
10	1,466	1,387	1,444	1,395	1,366	9%	76%	43%	94%	18%	5%	87%	98%	96%	85%
11	1,464	1,381	1,443	1,394	1,365	0%	74%	22%	53%	0%	54%	76%	94%	95%	8%
12	1,458	1,381	1,434	1,389	1,364	87%	-1%	4%	8%	10%	76%	0%	5%	9%	20%
13	1,455	1,381	1,431	1,388	1,361	96%	87%	85%	4%	0%	88%	98%	94%	0%	12%
14	1,453	1,373	1,431	1,387	1,361	57%	40%	77%	41%	15%	76%	15%	87%	85%	8%
15	1,449	1,373	1,426	1,387	1,351	0%	86%	25%	23%	5%	0%	98%	98%	85%	15%
16	1,448	1,372	1,425	1,385	1,347	58%	41%	13%	56%	25%	76%	8%	55%	83%	74%
17	1,446	1,372	1,424	1,385	1,346	87%	49%	0%	97%	0%	75%	83%	5%	97%	21%
18	1,444	1,366	1,419	1,384	1,344	58%	11%	5%	26%	43%	75%	1%	13%	41%	97%
19	1,443	1,366	1,419	1,379	1,342	47%	60%	53%	87%	87%	76%	76%	97%	95%	86%
20	1,443	1,365	1,413	1,378	1,335	35%	7%	5%	18%	3%	83%	2%	18%	45%	0%
21	1,440	1,365	1,411	1,377	1,332	35%	87%	13%	23%	0%	76%	76%	87%	3%	41%
22	1,439	1,365	1,407	1,377	1,330	57%	70%	8%	43%	4%	76%	75%	11%	64%	27%
23	1,439	1,365	1,407	1,376	1,330	27%	13%	43%	17%	92%	74%	35%	97%	78%	66%
24	1,439	1,362	1,406	1,375	1,330	3%	55%	75%	32%	98%	77%	96%	98%	17%	86%
25	1,437	1,360	1,403	1,374	1,329	87%	0%	54%	7%	66%	77%	0%	86%	87%	75%
Average						**47%**	**42%**	**43%**	**46%**	**45%**	**59%**	**50%**	**76%**	**68%**	**54%**
Std. Dev.						**33%**	**29%**	**28%**	**33%**	**42%**	**28%**	**40%**	**35%**	**34%**	**34%**

Source: Calculation based on hourly historical load and wind generation data provided by Hydro (PUB-NLH-003). Capacity factor calculation assumes 27 MW nameplate capacity for both Fermeuse and St. Lawrence.

We also examined the relationship between the capacity factor at each farm and the system load. Specifically, we graphed the relationship between the system load in the top 25 hours and the capacity factor to see if there was any pattern in production as load in the top 25 hours changed. Figure 1 shows that there is no noticeable relationship between changes in system load in the top 25 hours and the capacity factor at each wind farm.[39]

[39] In addition, we estimated a simple linear regression of each farm's capacity factor on load for each hour of the year using 2017 data. For the St. Lawrence wind farm, we found a small positive relationship

Figure 1: System Load Top 25 Hours and Capacity Factors, 2017



Source: Calculation based on hourly historical load and wind generation data provided by Hydro (PUB-NLH-003), assuming 27 MW nameplate capacity for both Fermeuse and St. Lawrence.

We understand that Hydro's system planners see the interconnection to the continent's grid as materially affecting their perspective on wind capacity value[40] and the ELCC study performed by Hydro results in a 22% classification as capacity-driven. Our examination of the historical data on wind production at St. Lawrence and Fermeuse during the top 25 hours of the year for each year from 2013 to 2017 shows that a 22% classification as capacity-driven is not an unreasonable estimate.

where a 1 unit increase in load (in MW) is associated with a 0.029 percentage point increase in the capacity factor. For Fermeuse, a 1 unit increase in load (in MW) is associated with a 0.012 percentage point increase in the capacity factor. Both point estimates are statistically significant at the 1% level.

[40] See CAEC Embedded COS Report, footnote 27.

g. Diesel and Gas Turbine Generation

Besides Holyrood, Hydro's gas turbine units consist of Happy Valley, Hardwoods, and Stephenville, and Hydro's diesel turbine units consist of Hawkes Bay Diesel Plant and St. Anthony Diesel Plant. Hydro's classification of the gas and diesel units in the LIS and IIS are 100% demand; it does not use system load factor as these units are used primarily for peaking purposes. At the same time, Hydro classifies fuel costs also as 100% demand. Hydro recommends continuing this classification approach, a position with which we disagree. We believe 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.

Hydro's classification of its isolated diesel units (excluding L'Anse-au-Loup) by contrast is based upon the system load factor approach as these units are used much more intensively than the diesel units in the interconnected system. Concerning L'Anse-au-Loup, Hydro's classification is 100% demand-related with the fuel costs being 100% energy related.[41] Hydro is not recommending any changes to its classification methodology for these gas and diesel units. We agree with Hydro's classification methodology for these units.

3. Transmission Costs

a. LIL

As discussed above, we recommend that Hydro functionalize the LIL as transmission. This is different from Hydro's recommendation to functionalize the LIL as generation. For classification

[41] We understand that in L'Anse-au-Loup, some portion of energy and demand needs are being met by Hydro-Québec.

purposes, regardless of whether the LIL is functionalized as transmission or generation, we recommend that the LIL be classified as 100% demand related. The underlying cost characteristics of the LIL are such that the main cost driver of the LIL is demand, the transmission costs do not change with changes in production (other than potential losses). If the LIL were to be functionalized as generation, we believe it would be incorrect to use the system load (or the equivalent peaker) approach to classify the LIL. That would result in either approximately 55% (in the case of the system load) or 80% (in the case of equivalent peaker) of the transmission costs being classified as energy related. In our opinion, those amounts are too high and do not reflect the underlying cost drivers of the asset in question.

b. LTA

As discussed above, we recommend that Hydro functionalize the LTA as transmission and not generation as it is proposing. We recommend that Hydro classify the LTA as 100% demand related. For functionalized transmission costs, it is common COS practice to classify them as 100% demand-driven and to allocate to customer classes according to a coincident peak demand, usually the same allocation factor that is used for allocating generation demand-related costs. Hydro recommends that all functionalized transmission costs be classified as 100% demand related and proposes to use the same allocation factor as it uses for generation. We agree with this approach as it is reflects common COS practice.

E. Allocation

Allocation in a cost of service study is the process of assigning the functionalized and classified revenue requirement (cost of service) to the different jurisdictions and the different customer rate classes within a jurisdiction. In the present case, allocation is the process of assigning the functionalized and classified revenue requirement to Newfoundland Power and the Industrial Rate Classes. An allocation methodology is a specific approach used to assign the revenue requirement to the different customer classes. The following criteria are ones to consider when determining the appropriateness of a specific allocation methodology:

1. Reflect cost causation as much as possible; *i.e.*, based upon the actual activity that drives a particular cost and on rate classes' share of that activity;
2. Reflect the actual planning and operating characteristics of the utility's system;
3. Recognize customer class characteristics such as electric load demands, peak period consumption, number of customers and directly assignable costs;
4. Produce fairly stable results on a year-to-year basis;
5. Customers who benefit from the use of the system should also bear some responsibility for the costs of utilizing the system.

Cost allocation methods generally vary by the type of cost classification. For example, demand-related allocators include system peak responsibility allocators such as 1-CP, 4-CP and 12-CP, non-coincident demand allocators such as NCP or the average-excess demand allocator, which is a weighted average of the Average-Demand Allocator and the Excess Demand Allocator. Energy-related allocators are based upon kWh of energy sold—both at the customer meter and at generation—to the different customer classes.

Concerning the choice of a specific demand allocator, the NARUC Manual highlights the key role that the system planner's decision-making plays as well as the importance of taking into account reliability criteria.[42] The demand of each customer class in the peak hour can be an appropriate basis for allocating demand-related production costs if it is the case that the utility generally plans its generating capacity additions to serve demand in the peak hour. On the other hand, if reliability criteria are an important element in the utility's generation expansion planning and such reliability criteria have significant values in a number of hours, not just the peak hour, then the classes' demands in hours other than the single peak hour may provide an appropriate basis for allocating demand-related production costs.

Hydro utilizes the 1-CP allocator for assigning demand-related costs to the customer classes. We agree with this and discuss the approach below.

1. Demand-related Generation/Production Costs

For allocation of demand-related production and transmission costs, Hydro uses a single coincident peak allocator, the 1-CP allocator. For the reasons we discuss in this section, we agree with the use of the 1-CP allocator for demand-related generation/production costs.

Hydro has been utilizing the 1-CP since at least 2002.[43] The 1-CP allocator uses the system peak as being the highest single hour's system demand during the entire year. Each class's CP is that class's demand during that hour the system peak occurred. There are other coincident peak measures, such as the 3-CP, 4-CP or 12-CP allocators. These allocators start by identifying the highest single

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[42] NARUC Manual p. 39.

[43] See In the Matter of Application by Newfoundland & Labrador Hydro for a General Rate Review, Decision and Order of the Board, Order No. P.U. 7 (2002-2003), June 7, 2002, p. 108.

hour's system demand during each of the individual 12 months. The 3-CP is then an average of the 3 highest of these 12 monthly system demand (the three demands are from three different months' hours). The 4-CP is the average of the 4 highest of the 12 monthly systems while the 12-CP is the average of all 12 system demands.

As discussed previously, several factors help determine the appropriateness of the different allocators to any particular utility, including the system planner's approach to generation expansion planning and reliability criteria, seasonal and annual load curves, and overall system load factor. By definition, the 1-CP allocator best captures how much demand each class contributes to peak demand and provides strong signals to reduce consumption at peak demand. If, however, system engineers' expansion plans utilize loss of load probability or other reliability measures the 1-CP allocator may not entirely reflect cost causation, as other hours are also important in causing generation investment. Moreover, a 1-CP allocator may result in an allocation that is variable over time compared to one that is based upon averaging several monthly peak demands, such as the 3-CP, 4-CP and 12-CP allocators.

As stated by CAEC (at 13) while the NARUC Manual describes these coincident peak demand allocators, as well as other approaches such as the average-excess demand, it offers no general recommendation and points to developing an approach that is best given the specific characteristics and uniqueness of each utility. Hydro recommends continued use of the 1-CP approach. For example, Hydro states (at 14):

> Under the current 1 CP approach, the Island Industrial Customers peak load has an 88% coincidence with system peak and the Newfoundland Power peak load has a 99.3% coincidence with

> system peak. These coincidence factors were based on a review of historical coincidence. Based on a preliminary analysis, Hydro does not see a basis to change these coincidence factors for use in the cost of service study.

And (at 14):

> Hydro forecasts a single winter peak in its planning process. The system peak can happen in any of the four winter months (December to March). The timing of Hydro's system peak is highly coincident with the system peak of Newfoundland Power. Newfoundland Power's peak forecasting methodology also forecasts a single winter peak with no certainty on which month the system peak will occur. Hydro believes the continued use of 1 CP approach for generation demand classification is reasonable.

We have reviewed Hydro's historical hourly load data from 2013 through 2018 and found that the single winter peak occurred in December or January, depending on the year, see Table 8 below. The table also shows practically no growth in system peak load during 2013 and 2018 as the compound annual growth rate during this period was 0.432%.[44]

[44] 0.432% = (1,453 MW / 1,422 MW) ^ (1 / (2018-2013)) – 1.

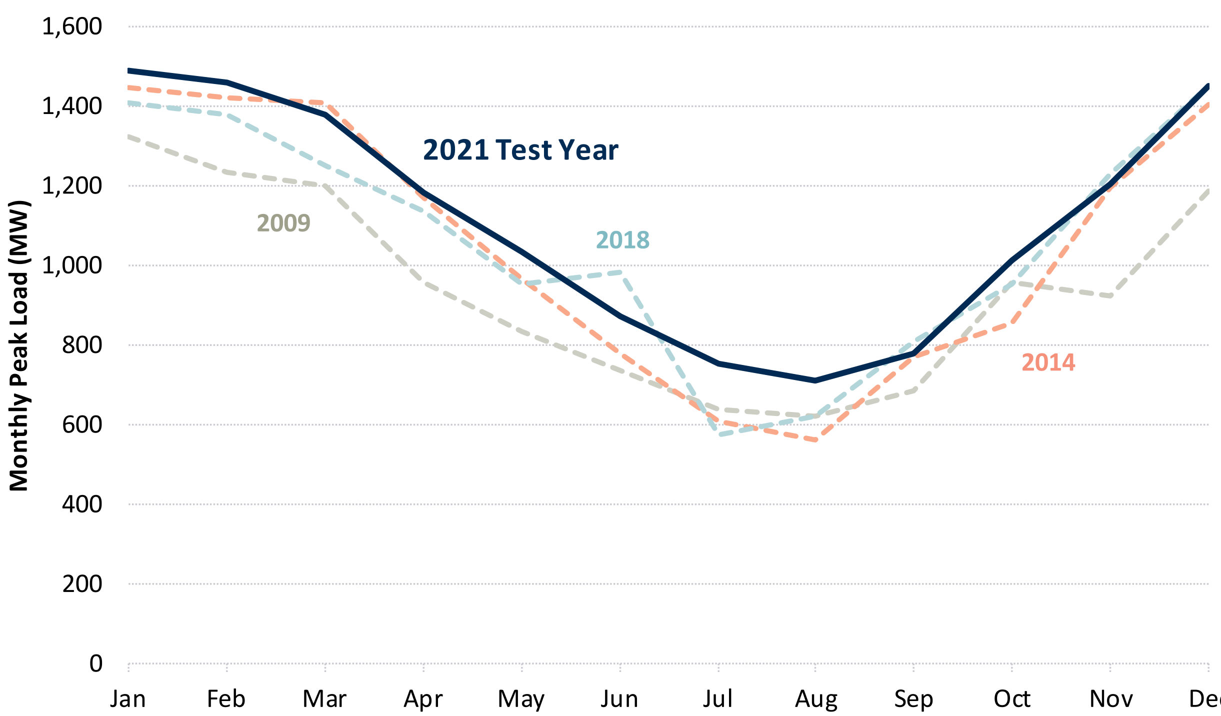
Table 8: Hydro System Peak Load (MW) and Date, 2013-2018

Year	Peak Month	System Peak (MW)
2013	Dec-13	1,422
2014	Jan-14	1,447
2015	Dec-15	1,474
2016	Dec-16	1,445
2017	Jan-17	1,452
2018	Dec-18	1,453

Source: Calculation based on historical monthly peak data provided by Hydro (PUB-NLH-012).

We have also graphed the system monthly peak load for different years between 2009 and 2018 as well as the 2021 test year (see Figure 2).

Figure 2: System Monthly Peak Load



Source: PUB-NLH-012.

We examined what the difference would be in using different allocators than the 1-CP. We computed the 1-CP and 3-CP allocation factors and did not find that they were significantly different, as shown in Table 9 below. Therefore, we would not expect the use of a 3-CP allocator to have a material impact on the allocations.[45] In the table, we also include allocation factors based on energy weighting for information purposes only. We are not recommending that energy-weighting factors be used for allocating demand costs.

Table 9: Historical and Test Year Allocation Factors. 1-CP, 3-CP and Energy

	1-CP		3-CP		Energy	
Customer Class	Historical	Test Year	Historical	Test Year	Historical	Test Year
IIS NP	90%	89%	90%	88%	86%	83%
IIS Industrial	4%	5%	4%	6%	7%	11%
IIS Hydro Rural	6%	6%	6%	6%	7%	6%

Sources and Notes: Calculation based on historical and test year load and energy data provided by Hydro (PUB-NLH-002 and PUB-NLH-012). Historical allocation factors reflect the 2009-2018 average annual factors; Test Year allocation factors reflect 2021 factors.

2. Demand-related Transmission Costs

Hydro proposes to allocate functionalized transmission demand costs following the same approach that it uses to allocate production/generation demand costs, namely the 1-CP allocator. For the reasons we discussed previously, we agree that the 1-CP is an appropriate allocator for production demand costs as well as for transmission-related demand costs.

3. Energy-related Costs

Hydro currently allocates energy costs based on annual energy use by customer class. Hydro proposes to continue the current energy allocation approach. We agree with this approach, as it is common practice in COS studies.

[45] We have compared the 1-CP to the 4-CP and found the results are quite similar as well.

F. Additional Issues

1. Rural Deficit

Hydro serves approximately 23,000 rural interconnected customers located in approximately 180 communities on the South Coast, Northeast Coast and along the Great Northern Peninsula. Hydro also serves approximately 4,000 customers, including L'Anse-au-Loup, in over 40 communities throughout coastal Newfoundland and Labrador, using 21 isolated diesel generating and distribution systems.[46] Fifteen of these systems are located in Labrador and six are on the island of Newfoundland.

Rate setting for customers in these isolated areas is different from rate setting for other customers in that the revenue to cost coverage for these parts of Hydro's system is materially different from other parts. The revenue to cost coverage is a ratio of the revenue to be collected from a specific customer category or class and the costs assigned to that class as a result of the overall cost of service. Specifically, while Newfoundland Power and the Rural Interconnected customers have a revenue to cost coverage of 1.08 for test year 2021, the revenue to cost coverage for those customers in the rural deficit areas ranges from 0.19 to 0.76.[47] Were these areas to pay a revenue to cost coverage closer to one, they would experience a significant increase in rates. One definition of the rural deficit is the difference between the rates these customers pay and what they would have

[46] See In the Matter of a General Rate Application for 2014 and 2015 Test Years, Decision and Order of the Board Order No. P.U. 49(2016) ("P.U. 49(2016)").

[47] CAEC Embedded COS Report, Schedule 1.2.

paid if their revenue to cost coverage were similar to the revenue to cost coverage of the other customer categories.

Pursuant to Government direction under the Electric Power Control Act, 1994, Newfoundland Power and Hydro's Labrador Rural Interconnected customers pay the rural deficit.[48] Industrial customers are exempt from contributing to the rural deficit. The Government directive does not, however, provide guidance as to how the Board should treat the rural deficit in a cost of service proceeding and the Board first considered the methodology to be used to allocate the rural deficit in its 1992 generic cost of service methodology hearing.[49] In that proceeding, the Board recommended that the methodology should be based on a mini cost of service analysis, which increased the unit costs equally in the two interconnected systems to fund the rural deficit. In general, this approach classified the rural deficit as energy, demand, and customer in proportion to the overall classification of total costs. Once classified as energy, demand and customer categories, the rural deficit was added to the unit costs for each classification for each of the two customer groups. In 2002, implementation of this methodology resulted in Newfoundland Power customers paying for approximately 87% of the rural deficit and Labrador Interconnected customers paying approximately 13%. In the general rate application for 2014 and 2015 test years, on a per-customer basis, however, the current approach resulted in \$216.64 for Newfoundland Power customers and \$653.15 for Labrador Interconnected customers.[50] Also, the revenue to cost

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48 See Executive Council Newfoundland and Labrador, OC2003-347, 2003/07/08.

49 See P.U. 49(2016), p. 99.

50 See P.U. 49(2016), p. 105.

ratio under this approach for Newfoundland Power was 1.12 compared to 1.42 for Labrador Interconnected customers.

In the General Rate Application for 2014 and 2015, Hydro proposed, and the Board accepted, a new methodology called the revenue requirement approach.[51] The basic feature of the revenue requirement approach is to equate the revenue to cost ratio for Newfoundland Power and the Labrador Interconnected customers. In the General Rate Application for 2014 and 2015, this resulted in a cost-per-customer of $226.46 for Newfoundland Power customers and $207.60 for Labrador Interconnected customers.[52]

Cost of service theory does not provide good insights into how to deal with and recover a deficit emanating from a group of customers who from a policy perspective are given a subsidy in their rates. By definition under the embedded cost of service theory, no other customer group or class is responsible for the allocated costs assigned to the subsidized customers, and so cost of service theory provides almost no guidance in how best to recover the subsidies from customers.

Given the above, we believe there are several relevant principles to consider when determining how the rural deficit should be recovered; these include simplicity, transparency and overall impact on price distortions. In general, we prefer an approach that is simpler to calculate and more transparent, and in that sense, we believe the revenue requirement approach fares somewhat better

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[51] *Id.*

[52] See P.U. 49(2016), p. 104. Hydro states, "The difference in dollar value per customer reflects higher average cost to serve Newfoundland Power's customers and Hydro submitted that this is a fair overall result and is more reasonable than the outcome of the existing methodology."

than the mini cost of service approach developed in the 1992 Cost of Service Hearing. The revenue requirement approach we believe is more straightforward to apply as it takes the results of the embedded COS for Newfoundland Power and the Rural Labrador Interconnected classes and distributes the rural deficit in proportion to each class's cost of service. This has the effect of equalizing the revenue to cost ratio of Newfoundland Power and the Rural Labrador Interconnected classes. By contrast, we believe the mini cost of service approach is a bit more involved and less transparent.

Regarding the overall impact on rate distortions, a deficit means that the embedded cost of service study indicates that some customers pay less than their allocated share, while other customers pay more than their allocated share. In an embedded COS framework, a measure of price distortion is the degree to which revenues from a class deviate from their allocated costs, as measured by the revenue to cost ratio. Under this metric, the revenue requirement approach fares better than the mini cost of service given the fact that revenue to cost ratios are equalized for the rate classes under the revenue requirement approach, while not so for the mini cost of service approach. Also, as mentioned above, in the previous GRA the revenue requirement approach also led to similar yearly impact per customer for Newfoundland Power ($226.46) and for Rural Interconnected customers ($207.60).

For all these reasons, we support the continued use of the revenue requirement approach for allocating the rural deficit.

2. Conservation and Demand Management

Hydro is proposing to continue the current approach in recovery of Conservation and Demand Management ("CDM") costs among its customer classes.[53] Hydro's current CDM cost approach is to classify them as energy-related and not demand related. In the 2013 GRA, Hydro's justification of its CDM programs was system energy savings that benefit all customers on the IIS.[54] Specifically, Hydro and Newfoundland Power have jointly offered their customers a CDM program under the takeCHARGE brand since 2009. The focus of the takeCHARGE programs was on energy efficiency to save electrical energy based on an economic analysis driven by the cost of fuel consumption at Holyrood.[55] The fact that historically CDM programs were undertaken to save on fuel costs and for energy efficiency supports Hydro's classification of these programs as energy related.

We understand, however, that Hydro and Newfoundland Power are conducting and investigating a CDM Potential Study, the objectives of which are to:

> …identify the achievable, cost-effective electric energy and demand management measures to reduce or shift peak demand, outline general parameters for program development, and quantify achievable savings potential by sector and end use in the province.[56]

In future GRA proceedings, depending on the success of programs emanating from the CDM Potential Study, it may be appropriate to assign some CDM costs to demand.

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53 Embedded Cost Methodology Review, p. 15.

54 See Lummus Consultants International, Final Report Updated Exhibit 9 Addendum, October 29, 2014.

55 Reliability and Resource Adequacy Study, Volume III, p. 35-36.

56 Reliability and Resource Adequacy Study, Volume III, p. 35.

3. Specifically Assigned Charges

Four Island Industrial Customers in Hydro's territory utilize facilities that are dedicated to serving them only. Other Hydro customers do not use these facilities. It is customary cost of service practice to have these customers be fully responsible for paying for these facilities. The capital expenses associated with these facilities are usually paid for directly by the customer through a contribution charge. In addition, these customers also pay monthly operations and maintenance (O&M) costs as O&M costs are ongoing and recurring.

An issue arises in that Hydro does not recover in rates the actual O&M associated with each customer's dedicated facility. Instead, the dedicated facility is grouped into a capital category/asset type (similar in some sense to functionalization but much more detailed) and Hydro keeps track of the level of O&M expenses for the asset category as a whole. As of January 1, 2019, the four customers' share of O&M expenses is based upon the customer's share of the asset value, where the asset value is determined based on an index.

From a cost of service perspective, the relevant O&M costs for the four industrial customers are the actual O&M costs incurred to maintain and service the facilities that are dedicated to the customers. These O&M costs are costs that the four industrial customers caused to be incurred and it is appropriate that the industrial customers pay for these specific costs. It is preferable to have Hydro continue tracking actual O&M expenses associated with each customer's dedicated assets and to bill the customer directly. We understand that Hydro has commenced tracking actual costs.[57] In the interim, pending implementation of individual customer actual cost recovery, the 2017 proposed methodology should be used for determining the test year operating and maintenance costs to be recovered through specifically assigned charges to Industrial Customers, which is based upon the use of index costs as opposed to original costs.

4. Newfoundland Power Generation Credit

Hydro provides a generation credit to Newfoundland Power for its existing hydraulic and thermal generation assets because these assets provide firm capacity to Hydro to meet its system demand requirements. As explained by Hydro (at 16):

> The use of the generation credit provides Newfoundland Power with an estimated coincident peak demand requirement in the cost of service study that is effectively the same as if Newfoundland Power was operating its generation at peak times (with an adjustment for reserves). The provision of the generation credit removes the incentive for Newfoundland Power to operate its thermal generation to minimize its peak demand purchases from Hydro.

Specifically, Hydro's generation credit is in the form of a reduction in Newfoundland Power's native peak load in the cost of service study, thus reducing allocated demand costs to the Newfoundland Power class. The existing approach is described by Hydro (at 17) and consists of reducing Newfoundland Power's coincident peak demand at transmission and generation for the hydraulic generation credit. For the thermal generation credit, it consists of reducing Newfoundland Power's coincident peak demand at generation. Moreover, the coincident peak at

[57] CAEC Embedded Cost of Service Report, p. 66, footnote 85.

generation used in computing the system load factor does not reflect a reduction for the Newfoundland Power thermal generation.

Hydro is recommending the continuation of the existing approach of providing the generation credit for both the hydraulic and thermal generation. At the same time, however, Hydro is reviewing the approach and the reasonableness of the credit. Hydro indicates that it will file the results of the review in its next GRA filing. We agree with this general approach and agree that a fuller investigation can reveal whether this current arrangement between Hydro and Newfoundland Power accurately takes into account the full costs to the parties and the full value that both parties generate and receive. Ultimately, however, we believe that if both parties are in agreement with the current arrangement and absent any externalities not fully internalized in the arrangement, the current approach would seem to be economically appropriate.

5. CBPP Generation Demand Credit

According to Hydro (at 17), since 2009, CBPP has been operating under a piloted generation credit service contract that permits CBPP to maximize the efficiency of its 60 Hz Deer Lake Power generation. The general purpose of the agreement is that Hydro can make a capacity request to CBPP. Specifically, Hydro can call on CBPP to maximize its 60 Hz generation before Hydro increases generation at Holyrood for system reasons and before starting its standby units. CBPP receives savings for this additional capacity to the system in the form of Hydro permitting CBPP to exceed its firm power requirements and to avoid costs associated with thermal or standby energy rates.

Hydro (at 18) believes that the benefits to all customers arising from the fuel cost savings that supported the pilot project implementation are not expected to continue upon commissioning of the Muskrat Falls Project. Hydro proposes to discontinue the generation credit agreement between Hydro and CBPP upon full commissioning of the Muskrat Falls Project. However, Hydro believes CBPP should have the opportunity to manage its generation as efficiently as possible and, to that end, proposes to work with CBPP in the rate design review planned for 2019 to develop a proposal to achieve this objective.

Non-firm capacity assistance agreements and programs are common in utilities. The CBPP agreement is a form of non-firm, capacity assistance program but one where Hydro can call upon CBPP's own self-supply generation resources. To provide Hydro with capacity, CBPP must reduce its load requirement. Hydro treats the costs of capacity assistance program as being demand related, which we agree with as the programs are meant to lower consumption during peak demand periods.

6. Allocation of Net Export Revenues

The Muskrat Falls PPA agreement between Muskrat Falls and Hydro provides Muskrat Falls with the opportunity to sell any excess energy and capacity into external markets including markets in Quebec and New York and, because of the LIL and the ML, markets in Nova Scotia, New Brunswick and New England. As stated in the PPA agreement, the ability to sell excess energy and capacity on a firm or non-firm basis will depend upon Hydro's demand for energy and capacity and at times, there may not be energy or capacity available to export. Because of government policy, Island Interconnected customers are required to pay for the facilities of Muskrat Falls.[58] At the same time, all export sales associated with the Muskrat Falls PPA are to be credited to Island Interconnected customers, also resulting from government policy.[59]

Hydro is proposing that the export credit be included in the COS study, but with the implication being that test year export credits are uncertain and may not be a good indication of expected, annual export credits. We recommend the use of a rider to facilitate true-ups in between rate cases, with a frequency no less than annually.

Another relevant cost of service issue is the classification of the energy exports in the COS study. We recommend that the export credit be classified and allocated in the same manner as the Muskrat Falls generation, as discussed above, namely classified between demand and energy using the system load factor and allocated using the 1-CP for demand and the energy allocator for energy.

7. Marginal Cost-based Allocation Approach

Marginal cost is the change in the total cost of producing and transmitting electricity in response to a small change in customer usage, usually a kW or kWh. In the Appendix of our report, we discuss Hydro's marginal COS studies. In this section, we discuss the recommendation by CAEC to use marginal costs to assign the revenue requirement to the different rate classes.[60]

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[58] See OC2013-343.

[59] See letter from the Premier to the Minister of Natural Resources dated December 14, 2015 where the government indicated that export sales will be used to mitigate potential increases in electricity rates (PUB-NLH-018).

[60] CAEC Embedded COS Report, Section 3.3.

Marginal costs represent forward-looking economic costs to provide a good or service, in this case energy and capacity, as opposed to the embedded, historic cost of providing the service. A marginal COS study can be used instead of an embedded COS in assigning the approved revenue requirement to the different customer classes. The steps described above in an embedded COS study—functionalization, classification, allocation—are not explicit steps in a marginal COS study. Instead, a marginal COS study results in an implicit functionalization, classification, and allocation of the forward-looking economic resources required to provide energy and capacity. The marginal COS study also results in an implicit revenue requirement, one that may be quite different from the authorized revenue requirement. As a result, an important step in a marginal COS study is to reconcile the resulting rates and revenue requirement with the embedded COS study. There are different ways to reconcile the differences between the authorized revenue requirement and the implicit revenue requirement that results from marginal cost calculation. For example, the approach used in California is to increase or decrease the marginal cost rate by the same proportion for each class to reconcile the revenue requirements.

In addition to using a marginal COS study to determine a revenue requirement and rates based on forward-looking costs—rates that need to be reconciled with the authorized revenue requirement—a marginal COS can be used, in theory, as a component within an embedded COS study. CAEC supports the use of marginal costs in the classification and allocation of production/generation costs in the Cost of Service Study, subject to: "Hydro's mastery of the technical challenges of marginal cost development."[61]

[61] CAEC Embedded COS Report, p. 29.

At a high level, their approach is as follows:

1. Project marginal costs over forward periods;
2. Develop hourly marginal costs;
3. Apply customer class hourly forward load profiles.

This results in an annual total marginal cost for each customer class that is based upon the costs of their hourly forward load profile. Annual total costs for Hydro is the sum of each customer class. In this way, an allocator is created by calculating each class's share of Hydro's annual total costs. CAEC summarize the key to their approach:

> 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.

Hydro seems to agree in principle that a marginal COS study can be used to assist in the embedded COS when it states (at 8):

> Upon interconnection of the system to the North American grid, marginal generation energy and reserve costs will be represented in most hours by wholesale prices from eastern regions of that grid. For the Island Interconnected grid, marginal generation capacity costs will reflect the costs incurred on the island to serve additional capacity due to the potential for transmission constraints applying at times of peak demand. A marginal cost study produces an estimate of the marginal costs to supply energy for each hour of the period (day, month, and year) or forecasted period. In this way, the marginal cost approach gives consideration to the marginal cost of serving each customer class in all the hours of the year. By contrast, embedded cost of service does not generally provide an estimate of the hourly embedded costs to provide service and the use of the

> classification and allocation approach discussed previously makes use of a very limited number of peak hours in the allocation of demand-related costs.

Nevertheless, for several reasons, Hydro has decided not to recommend the use of marginal generation costs in the classification and allocation of production/generation in the Cost of Service Study. First, CAEC's review indicated that currently there are no utilities in Canada that apply this approach. Second, Hydro has concerns with the complexity and understandability of marginal cost derivation relative to the traditional cost of service approaches. Finally, Hydro also does not forecast the load requirements for each customer class on an hourly basis.

In principle, we agree that it is economically appropriate to use a marginal COS study to either directly set rates based upon study results (with a reconciliation to ensure that rates are sufficient to recover embedded costs) or to use as a component within the embedded COS study. Rates based upon marginal costs provide good economic price signals for consumers and producers and help ensure that scarce resources are being utilized efficiently.

We also believe, however, and as we discuss in more detail in Appendix: Marginal Cost of Service Study, that it is premature to pursue this methodology in the present proceeding given the lack of experience with marginal COS studies with Hydro in Newfoundland and Labrador and given some of the issues we have identified in the marginal COS study, as discussed in the Appendix.

Appendix: Marginal Cost of Service Study

I. Main Observations and Opinions

Marginal cost is the change in the total costs of providing a unit change in the output of a good or service. Marginal costs are a forward-looking concept, examining and estimating the economic resources that society will likely incur when producing an additional unit of a good or service. The marginal cost concept is different from the embedded cost concept and embedded COS studies discussed in the body of our report, the main objectives of which are to assign and allocate the historically incurred costs of electricity generation, transmission, and distribution.

Nevertheless, marginal costs play an important role in that they can be used for dynamic pricing and for time of use/time of day rates, for internal resource planning, company decision-making, wholesale transactions and for setting appropriate price floors to customers for economic development purposes. Marginal costs are used for rate setting and cost allocation purposes, as is being proposed by CAEC in this proceeding. For these reasons, even though we are not recommending that marginal costs be used as the basis for rate setting or cost allocation at this time, it is good policy to analyze, discuss and agree on an appropriate marginal cost methodology suitable for Hydro going forward.

We have reviewed Hydro's marginal cost of service study, which consists of marginal generation, and transmission capacity costs as well as marginal generation and transmission energy costs.[62] Concerning marginal generation costs, Hydro utilizes an internal cost approach for its marginal generation capacity costs, which uses Hydro's own marginal costs, and an external (opportunity cost approach) for its marginal generation energy costs which uses the marginal costs that arise in a competitive wholesale market. We have focused most of our analysis on Hydro's methodology and approach to its marginal generation capacity costs. We highlight our main insights in this section. Concerning Hydro's marginal generation energy costs and its marginal transmission capacity and energy costs, we have relatively minor comments and observations and are in general agreement with the high-level approach undertaken.

Regarding Hydro's marginal generation capacity costs, we have several concerns that we believe should be addressed by Hydro and its consultants. Demand growth plays a key role in the determination of marginal capacity costs as marginal capacity costs necessarily reflect the capacity costs needed to serve incremental load. If there is no load growth or load growth is *de minimis* during the planning period, marginal capacity costs may very well be close to zero. Moreover, if the anticipated need for new generation in a least cost planning scenario is driven primarily due to replacement of an existing or existing assets, with very little additional capacity to meet increases in demand that may eventually materialize, then those investments do not give rise to marginal capacity costs.

[62] See Hydro's Marginal Cost Study Update – 2018 Summary Report ("Marginal Cost Study Update Summary Report") and Marginal Cost Study Update Prepared by Christensen Associates Energy Consulting ("CAEC Marginal COS Report").

For the reasons we discuss in this and the next several paragraphs, the level of demand growth is highly uncertain during the forecast period and may well result in little to no demand growth, meaning that Hydro's marginal capacity costs are likely low. Hydro forecasts its peak demand in 2028 to increase by 16 MW over 2018 levels—less than 1% cumulative growth.[63] Forecasted load growth is dependent on assumptions regarding customer rates post Muskrat Falls. The forecasted load growth is uncertain given that it is unknown what rate mitigation strategies, if any, may be implemented as well as how much export revenues will be earned from Muskrat Falls. The export revenues from Muskrat Falls will be used as a credit in the revenue requirement and lower customer rates.

Hydro's Reliability and Resource Adequacy Study contains four scenario cases (low, mid and high retail rates, respectively and high growth rates), which consider a range of potential retail electricity rates. For the period 2017-2023, all four scenarios result in negative MW demand growth. For the 2017 to 2029 period, two scenarios (mid-retail rate and high retail rate) result in negative MW demand growth. The Low retail rate and High growth scenarios result in positive MW demand growth.

Additional demand growth uncertainty during the period is driven by the level of demand-related CDM expenditure and associated impact on peak load reduction, changes in rate structure (such as the implementation of time-of-use rates) and the role that alternative technologies, such as battery storage, will have on peak load reductions.

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[63] Marginal Cost Study Update Summary Report, Chart 1.

Another reason why it is likely that Hydro's marginal capacity cost is low is that to the extent there is additional generation investment during the planning period, the additional capacity does not add much capacity, it mostly replaces existing capacity. An investment made to replace existing capacity without adding additional capacity is not considered a marginal capacity cost. Specifically, regarding planned capacity additions and retirements, in Hydro's Reliability and Resource Adequacy Study in addition to the retirements of Holyrood units 1 and 2, Hydro plans to retire the Hardwood GT (50 MW) and the Stephenville GT (50 MW) in 2021.[64] Hydro's marginal cost study utilizes the peaker deferral method (discussed below) and is based upon planned capacity additions of two 58.5 MW single-cycle combustion turbines, which combined, is roughly equal to the capacity that is being retired. These planned additions are effectively a replacement of the existing resources, and not for addressing load growth, indicating they, in general, should not be counted as marginal costs.

A closer look at the planned capacity additions further reveals that the likelihood of Hydro actually deploying these turbines is low. Specifically, in terms of capacity additions for years 2019-2029, Hydro modeled 24 scenarios. Of the 24 scenarios modeled, seven required additional resources inside the 10-year study period.[65] Four of the seven scenarios required one gas turbine and the remaining three required the two gas turbines. The seven scenarios were contained in the high growth case and the low retail rate case.

[64] PUB-NLH-011 and Reliability and Resource Adequacy Study, Volume III, Tables 4 and 5.

[65] Reliability and Resource Adequacy Study, Volume III, p. 64-67.

The high level of uncertainty surrounding Hydro's planned additions of the two 58.5 MW turbines is confirmed in its Reliability and Resource Adequacy Study.

> The results of the reserve margin-based analysis across all 24 scenarios indicate that the requirement for additional resources is capacity driven and most sensitive to the projections for load growth in Labrador and the use of the P90 weather variable as the base case condition for supply planning assessments. Of the 24 cases considered, 7 cases required additional resources inside the 10-year study period. A summary of the incremental resource additions for these cases are included in Table 16. The remaining 17 cases considered require no additional resources through the study period. The full results for all 24 cases considered are included in Volume III, Attachment 15. Currently, conventional GTs are being selected by the model as the least cost option in all scenarios requiring additional resources. However, as noted in Section 4 of this Study, Hydro is committed to better understanding the roles that CDM, rate structure, and alternative technologies, such as battery storage, can play in the NLIS. Additional information will then feed into Hydro's annual planning cycle, which will be used to determine if these alternatives can meet system requirements at a lower cost than the conventional generation output. As in most cases, incremental resources are not required until later in the study period, there is sufficient time to better understand these options before a final decision is required.[66]

And:

> The results for the above indicates that, on a planning reserve margin basis, incremental resources are unlikely to be required before the mid-to-late 2020s. Based on this timeline the most cost-effective and prudent approach at this time is to wait until more certainty around utility retail rates, more certainty around potential quantity and timing of industrial Labrador load growth and operational experience with the Lower Churchill Project assets is obtained. This analysis is planned to be revisited annually and will incorporate all evolutions of inputs described in this Study to ensure the system is built to provide reliable, least-cost service to

[66] Reliability and Resource Adequacy Study, Volume III, p. 65.

> customers. Hydro commits to working with stakeholders and the Board to inform analysis and decision-making around utility rates to help obtain certainty. Further, in the cases where additional resources are required and the need is resultant from a capacity deficiency, potential load growth will be carefully monitored and the role of alternative resources and technologies (e.g., batter storage technology and rate design) will continue to be investigated.[67]

In its 2016 marginal cost study, in addition to estimating marginal generation capacity costs based upon an internal costing approach, as it does in this case, Hydro used an opportunity cost approach as well and we believe there is merit to examining this issue more closely in this proceeding.[68] In the section below, we provide an alternative estimate for marginal generation capacity costs using the opportunity cost approach. We understand that a key constraint is the availability of firm transmission capacity during Hydro's winter period and that certainly will need to be explored closely. We believe, however, that there could be substantial benefits to both Hydro and the Northeast wholesale markets as Hydro is a winter peaking utility while the Northeast wholesale market is a summer peaking market. We note that in the Reliability and Resource Adequacy Study Volume III: Long-Term Resource Plan, in the section on Expansion Options under Consideration, Hydro has a sub-section entitled "Market Purchases" which states:

> For the study period, Nalcor Energy Marketing ("NEM") provided Hydro with information regarding the potential for capacity and energy purchases from various counterparties using the interties. This information was based on publicly available information (*e.g.*, fuel costs, transmission costs, excess available capacity, and capacity costs) for neighboring jurisdictions. In the event that Hydro is forecasting a capacity deficit at any time in the future, NEM will

[67] Reliability and Resource Adequacy Study Volume III, p. 67.

[68] Marginal Cost Report, Part II, Estimation: Marginal Costs of Generation and Transmission Services for 2019, February 26, 2019. Note that the date of the report should be 2016 not 2019.

conduct a detailed market sounding for capacity and/or energy as required.

We believe there is merit to having NEM conduct a detailed market sounding for capacity to examine the feasibility and economics of procuring capacity from counterparties using the interties. As such, we provide a high-level and preliminary economic analysis below.

II. Background of Marginal COS Studies

Marginal cost is the change in the total costs of providing a unit change in the output of a good or service. Marginal costs are a forward-looking concept, examining and estimating the economic resources that society will likely incur when producing an additional unit of a good or service. The marginal cost concept is different from the embedded cost concept and the embedded COS study discussed in the body of our report, the main objectives of which are to assign and allocate the historically incurred costs of electricity generation, transmission and distribution.

The precise definition of marginal costs, a useful economic concept that will assist in understanding the different approaches commonly used to estimate marginal costs in electricity, involves estimating the present value of the cash flows caused by a permanent increase in production.[69] Specifically, marginal cost is the difference between two incremental system costs where incremental system cost is the change in the cost of providing an increment of service and not just one additional unit. The first incremental system cost is the change in the present value of the flow

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[69] Ralph Turvey, "Marginal Costs," *The Economic Journal*, June 1969, for an academic article discussing how to implement and calculate marginal costs. See also W. S. Vickrey, "Some objections to Marginal-Cost Pricing," *Journal of Political Economy*, Vol. 56, No. 3 (Jun. 1948), pp. 218-238.

of costs caused by a permanent increase in production. The second incremental system cost reflects the same increase in production deferred by one year. The difference in the two incremental cost flows is the first-year marginal cost. This is known as the deferral approach to calculating first-year marginal costs and forms the basis of the peaker deferral method for marginal generation capacity costs that we describe below.

Marginal costs form the basis for efficient pricing in competitive markets and provide correct market signals to customers and to firms in their consumption and investment decisions, respectively. Marginal cost is a forward-looking concept and the use of forward-looking costs improves economic efficiency. From a business perspective, if the incremental revenues are insufficient to recover the incremental (marginal) costs of a project, the business (and society) is better off using its scarce economic resources for other potential projects. Conversely, if the incremental revenues are more than sufficient to recover the incremental costs, the signal being sent by consumers is that they place a high-enough value on the products that more should be produced.

In electricity markets, utilities utilize marginal costs for a variety of purposes. Marginal costs form the basis for dynamic pricing and for time of use/time of day rates. Dynamic pricing attempts to expose customers to the economic resources used to provide electricity services at different times throughout the day, month and year and results in economically efficient consumption decisions. Marginal costs are used for cost allocation purposes in an embedded COS study, as is being proposed by CAEC in this proceeding, although not many jurisdictions use marginal costs for this purpose. Marginal costs are commonly used by utilities for internal resource planning, company decision-making, and wholesale transactions. And, marginal costs are commonly used as a basis for setting appropriate price floors to customers for economic development purposes and for those customers who may have options to self-generate and/or relocate.

In electricity markets, marginal costs consist of marginal generation (production) costs, marginal transmission costs and marginal distribution costs. For our purposes the first two, marginal generation and marginal transmission costs, are relevant. Marginal generation costs consist of two components, a marginal energy component and a marginal reliability component. The former is commonly referred to as the marginal generation energy cost while the latter is referred to as marginal generation reliability costs or also as marginal generation capacity costs. Similarly, marginal transmission costs also consist of two components, a marginal transmission capacity cost and a marginal transmission energy cost, the latter consisting primarily of the losses within the transmission system. In this section, we define and discuss the main elements of marginal generation and transmission electricity costs.

A. Short-run and Long-run Considerations

In economics, short-run marginal costs refer to the change in a firm's total costs for a given unit change in output, holding all factors of production constant. The factor usually held constant is the capital used to produce the good or service. By contrast, long-run marginal cost refers to the least cost change in a firm's total costs for a given unit change in production when the firm can alter all factors of production, including its capital.

In electricity, short-run marginal costs refers to a change in the total cost of electricity production given a unit change output, holding constant the amount of capacity of the system, where the capacity can consist of generation, transmission or distribution assets. Depending on the relationship between current demand and the available fixed capacity of, say, the generation plant, a change in output may result in relatively small changes in costs or in a large change. For example, when capacity is more than sufficient to accommodate current and anticipated increases in demand, short-run marginal costs are the fuel and variable O&M costs of the most efficient generation unit that is dispatched to meet the increase in demand. These generation units tend to have the lowest fuel and O&M costs compared to units that come online only with greater levels of demand. As demand grows relative to capacity, however, generation units with higher fuel and O&M costs become the basis for the short-run marginal costs. As such, short-run marginal electricity costs tend to be lower during low periods of demand and much higher during higher periods of demand. At the limit, when current and anticipated changes in demand bump against fixed capacity, short-run marginal costs can be thought of as the cost to the consumer of doing without electricity, a concept known as the consumer shortage costs. Shortage costs include the value the consumer foregoes from not consuming electricity as well as any direct costs that the consumer incurs to mitigate and minimize the costs of being without electricity for a period.

In electricity, long-run marginal costs refer to the least-cost change in the total cost of electricity production due to a change in output when all factors of production of the electricity system can be adjusted. Whenever a utility adds or retires capacity (in the form of a new plant or capital equipment) to its existing plant that decision reflects a long-run one. Moreover, the decision to add capacity is a decision that is related to and influenced by short-run marginal cost considerations. Specifically, in a least-cost, optimal system generation capacity tends to be added up until the point where the cost of the additional unit of generation capacity is roughly equal to the consumer shortage cost related to that unit of capacity. At that point, consumers are indifferent to the additional capacity as the amount they are willing to pay for additional capacity is roughly equal to the costs they incur when doing without electricity. It is for this reason that a proposition that generally holds is that when a utility system is designed in a least-cost, optimal manner, long run, and short-run marginal costs tend to be equal.[70]

Demand and demand growth are key factors in determining long-run marginal costs for goods and services including electricity. Lack of demand growth may well imply that long-run marginal costs are relatively low or zero. The long-run marginal cost of capacity in a capital-intensive industry—such as electricity, telecommunications, natural gas, *etc.*—can be estimated using the capacity cost methodology. The capacity cost methodology justifies recovering the capital costs of a piece of equipment across the capacity of the plant, rather than across the units of output in service at a particular point in time, which may be very different than the equipment's capacity given the timing of investment and relationship between current demand and capacity. Indeed, the capacity cost methodology is the basis for the equivalent peaker approach commonly used in electricity to estimate the long run marginal costs of capacity, as we discuss further below.

70 This coincides with standard microeconomic theory in which the long run average cost curve is derived from the envelope of short run costs curves and at the optimal output, the long run cost is equal to the short run cost.

Two important conditions in utilizing the capacity cost methodology are that forecasted demand must exhaust the capacity before a planned replacement of the asset and changes in demand must be of sufficient duration to require future investments. In other words, whenever increased output demands affect the size or timing of new capital purchases, a capacity cost methodology is appropriate. Otherwise, long-run marginal costs may be relatively low.

Another relevant point regarding short run and long-run costs is that the short and long run do not refer to specific periods *per se*, rather they refer to decision making at specific points in time. A planning horizon that involves multi-year periods—*e.g.*, 5 to 10 years—may be consistent with a short run approach. For example, if it is the case that forecasted demand throughout the period implies that additions to capacity will not occur, or that such additions will be relatively minimal, then long-run marginal costs will be relatively low and short-run marginal costs are more relevant from a pricing perspective. At the same time, a relatively short planning horizon—*e.g.*, one or two years—may reveal that significant additions to capacity are required to meet current demand and increases in current demand and therefore is consistent with a long run decision.

B. Internal Marginal Costs and Opportunity Costs

In electricity markets, marginal generation costs are determined by using an *internal* approach, which estimates marginal costs based upon the utilities' own production of electricity, or by reference to market prices established in a relevant *external* market, such as a regional transmission organization (RTO) or a system run by an independent system operator (ISO). The latter approach determines marginal costs based on an external market and the opportunity costs the utility faces when deciding to produce electricity using its own production plant or purchasing from the external market. Unlike the internal market approach, which is used for generation, transmission, and distribution, the external market approach is confined primarily to generation costs.

The internal market approach relies on the utilities own costs as the basis for determining the marginal cost of generation (both energy and capacity), transmission and distribution. The primary tool of the internal market approach is the utilities' system planning production methodologies and production tools. Production tools, such as PLEXOS®, are computer models that simulate a utility's economic, least-cost dispatch and can be used to determine the marginal generation energy costs associated with a change in consumer usage. Production tools take into account the company's physical operating constraints of its generation and transmission assets, contractual obligations that may exist, the need for ancillary services and must run units, and other constraints. Production tools are also used to determine the marginal generation capacity costs associated with a change in consumer demand through a generation resource plan expansion approach. Under this approach, a base case is established for a planning horizon and the production model is run with an increase and decrease in demand to determine optimal expansion or retirement of generation units.

By contrast, the opportunity cost approach (the external approach) looks to a market price for determining the marginal generation energy cost and the marginal generation capacity costs. In competitive markets, prices reflect the opportunity costs of goods and services. The basic economic principle behind the opportunity cost approach is the "make" or "buy" decision. Specifically, if the utility can produce the electricity for a lower marginal cost than the external market, the utility is better off producing electricity to meets its internal demand and selling any excess to the market. The opportunity cost to the utility for the electricity that it generates and sells internally to its customers would be the foregone revenues that it could have earned if it had sold the electricity into the external market. The opportunity costs to the utility, therefore, are the prices prevailing in the external market. On the other hand, if the utility produces electricity at a higher marginal cost than in the external market, the utility is better off not producing electricity to meet its internal demand and instead purchasing from the market. The opportunity cost to the utility for the electricity that it generates and sells internally to its customers would be the foregone savings that it could have earned if it had purchased the electricity from the external market. The opportunity costs to the utility, therefore, are again established through the prices prevailing in the external market.

C. Marginal Generation Costs

We first discuss marginal generation capacity costs and then discuss marginal generation energy costs. Marginal generation capacity costs are the costs of the generation unit that would be added to accommodate increased peak-period demand, in an optimal, least cost generating system, where imbalances between demand and supply are not excessive or chronic.[71] Marginal generation capacity costs are determined using either an internal approach, as discussed above, or through an opportunity cost approach relying on capacity prices established in an RTO or ISO. The latter is

[71] As we mentioned above, in an optimal, least cost system the long run costs of generation capacity tend to equal shortage costs.

feasible only if the utility has access to an external, competitive markets and only if the utility can import capacity on a firm basis. We discuss these important points further below.

Concerning the internal approach, there are two methodologies commonly used to measure generation capacity costs. The first is the generation resource plan expansion approach discussed above while the second approach is known as the peaker deferral method. The generation resource plan expansion approach uses production cost modeling to establish a base case of electricity resource additions over a relevant planning horizon—*e.g.*, 5, 10, 15 years—and then increments or decrements the load forecast that was the basis for the base case. The annual costs of the base case, as well as the annual costs of the revised scenario, are calculated and discounted to arrive at the present value of the base case and revised scenario. The difference between the two scenarios is the marginal capacity cost caused by the change in demand. These two scenarios are somewhat similar to the two incremental cost scenarios that we discussed above when providing the precise definition of marginal costs.

The peaker deferral method is a more specific implementation of the definition of marginal costs that we discussed above. The analysis begins by observing that peaking units, often referred to as "peakers", are typically added by a utility to meet capacity requirements since they have relatively low capital expenditures requirements and high running costs. This makes economic sense since peaking units are used for significantly fewer hours in the year than intermediate or baseload plant. The peaker method calculates the discounted stream of annual costs associated with purchasing a peaker in a given year. The next step in the methodology is to calculate the discounted stream of annual costs associated with purchasing the same peaking unit deferred by one year. The difference in the two flows of annual costs is the marginal capacity cost spread across the available capacity of the peaker plant. In essence, the peaker deferral method is one implementation of the capacity cost methodology discussed above.

The peaker deferral approach calculates long-run marginal capacity costs. It determines the marginal capacity cost of adding new facilities to meet an increase in load. Importantly, however, an important assumption of the peaker deferral is concerning the current operation of the utility system. Specifically, the peaker deferral method does not examine whether the current existing utility system is optimally designed and operating in a least cost manner.

The opportunity cost approach can also be used to estimate marginal generation capacity costs. The organized wholesale electricity markets, run and operated by an ISO or an RTO, provide market prices for a variety of unbundled electricity services such as energy, ancillary services and, depending on the wholesale market, also provides market-determined prices for generation capacity. In the case of Hydro, the New England ISO provides a relevant possibility as it runs a Forward Capacity Market (FCM) and the interconnection of Newfoundland with Nova Scotia provides for a feasible path and connection to the New England ISO markets.

Marginal generation energy costs are the generation costs that vary in proportion to additional production of energy at a given point in time. Marginal generation energy costs consist of the fuel and the variable operation and maintenance expenses (savings) associated with the increases (decreases) in energy production. Utilities have several generation units that are dispatched to meet demand throughout the day, month and year. At any given hour the marginal energy cost is the fuel and variable operation and maintenance expense associated with the marginal (*i.e.*, last) unit dispatched to meet demand.

The internal approach to estimating marginal generation energy costs also utilizes a production-costing model as discussed above. Specifically, production tools simulate a utility's economic, least-cost dispatch and take into account the company's physical operating constraints of its generation and transmission assets, contractual obligations that may exist, the need for ancillary services and must run units, and other constraints. Typically, production tools provide an output that shows hourly marginal energy costs by day, month and year.

The opportunity cost approach can also be used to estimate marginal energy costs. For utilities that operate within an ISO, the locational marginal prices (LMPs) are the marginal energy costs that the utilities face. LMPs are typically calculated on an hourly basis and form the basis for estimating marginal energy costs. Similar to the internal approach, the opportunity cost approach requires a forecast of LMPs going forward to derive the anticipated forward-looking marginal cost of energy. Typically, the utility will apply the expected load profile of its customer and its different customer classes to arrive at marginal energy costs per customer class or group.

D. Marginal Transmission Costs

Marginal transmission costs also include two marginal cost components, an energy component, and a capacity component. Marginal transmission capacity costs are costs of the transmission system that would be added to accommodate increased peak demand while marginal transmission energy costs are the energy losses that arise within the transmission network.

When calculating marginal transmission capacity costs, the focus is on examining changes in transmission investment due to changes in peak load-carrying capability, in MW. Transmission investment, however, occurs for reasons other than increases in peak load-carrying capability. It is important to distinguish among the reasons for the observed increased investment over time as well as when forecasting transmission investment. For example, transmission investment can occur for reasons related to maintaining or increasing reliability, replacing older equipment, tying remote generation to the central transmission system, and interconnecting with other utilities. There are several different approaches to estimating marginal transmission capacity costs, which start with obtaining a time series of historic and forecasted peak-related transmission investment, converting to inflation-adjusted dollars, and determining a transmission investment cost per unit of output, such as MW or kW. The specific approach used will depend on the data that are generally available.

Marginal transmission energy costs, that is, losses, arise because transmission systems lose some of the electricity received at the generation interconnection points when delivering it onto the distribution interconnection points in the form of heat. Normally, load flow and losses studies are required to ascertain the level of energy losses in any particular part of the network.

III. Review of the Newfoundland and Labrador Hydro MCOS Study

A. Summary of Hydro's Marginal Costs

Table A-1 below summarizes Hydro's 2021 marginal cost estimates by category. The All-in Marginal Costs in the last column in the table is the summation of the three main components and categories of Hydro's marginal cost, namely marginal energy (both generation and transmission) and operating reserve costs, marginal generation capacity costs and marginal transmission capacity costs. The table below shows that capacity costs (both generation and transmission) are much higher during the winter period when Hydro faces its highest demand compared to the non-winter period when there is much less demand. The ratio between winter and non-winter generation capacity costs is approximately 60 while for transmission capacity it is approximately 130, both figure using the All Hours estimate in the table below. By comparison, the ratio of marginal energy and reserve winter and non-winter costs is approximately 2.5, again using the All Hours estimate in the table below. While we performed a general review of Hydro's methodology and approach of all components of its marginal cost study, our main comments and analysis focus on Hydro's marginal generation capacity cost methodology and approach.

Table A-1: Newfoundland and Labrador Hydro Marginal Cost Estimates, 2021 ($/MWh)

Season/Peak	Hours Ending	Energy and Operating Reserves	Generation Capacity	Transmission Capacity	All-In Marginal Costs
Winter (Jan-Mar, Dec)					
2 Period Model					
All Hours		59.87	116.48	11.80	188.15
Peak Hours	HR 7-21	61.81	174.47	17.92	254.21
Off-Peak Hours	HR 1-6, HR 22-24	56.63	19.83	1.58	78.04
3 Period Model					
All Hours		59.87	116.48	11.80	188.15
Peak Hours	HR 7-10, HR 17-21	56.05	216.30	23.00	295.35
Shoulder Hours	HR 11-16	69.49	109.58	10.21	189.27
Off-Peak Hours	HR 1-6, HR 22-24	56.41	19.77	1.59	77.76
Non Winter (Apr-Nov)					
2 Period - Broad Peak Model					
All Hours		24.93	1.88	0.09	26.89
Peak Hours	HR 9-22	25.52	2.49	0.13	28.13
Off-Peak Hours	HR 1-8, HR 23-24	24.12	1.01	0.03	25.16
2 Period - Narrow Peak Model					
All Hours		24.93	1.88	0.09	26.89
Peak Hours	HR 14-20	29.14	3.44	0.19	32.76
Off-Peak Hours	HR 1-13, HR 21-24	23.21	1.19	0.05	24.44

Source: CAEC Marginal COS Report, Figure 14.

B. Generation

1. Energy

a. Hydro approach

Hydro's MCOS study uses an opportunity cost approach based on prices in the New England ISO (ISO-NE). That is, rather than basing its marginal energy costs on its own internal costs, Hydro relies on a market-based approach. The study includes two distinct periods 2019-2020 and 2022-2029. During the 2019-2021 period, the marginal generation energy costs are based on hourly estimates of the ISO-NE prices, as forecasted by Hydro. During the 2021-2029 period, prices are based on on-peak and off-peak prices as forecasted by CAEC on a monthly basis and the hourly price shape is based on historical data from the ISO-NE import node at Salisbury.[72] These prices reflect the ISO-NE[73] price plus the price for reserves and ancillary services less transmission wheeling costs and losses as estimated by Hydro or CAEC. Reserves and ancillary services are assumed to be a constant 4.5% percent of energy prices, and the energy prices are increased to reflect these costs.[74] Hydro notes that although past marginal cost studies have used an internal production cost approach,[75] the interconnection to the North American grid makes the opportunity cost more appropriate.[76] Figure A-1 below shows Hydro's estimate of marginal energy and operating reserves costs for January 2021.

[72] Marginal Cost Study Update Summary Report, p. 6.

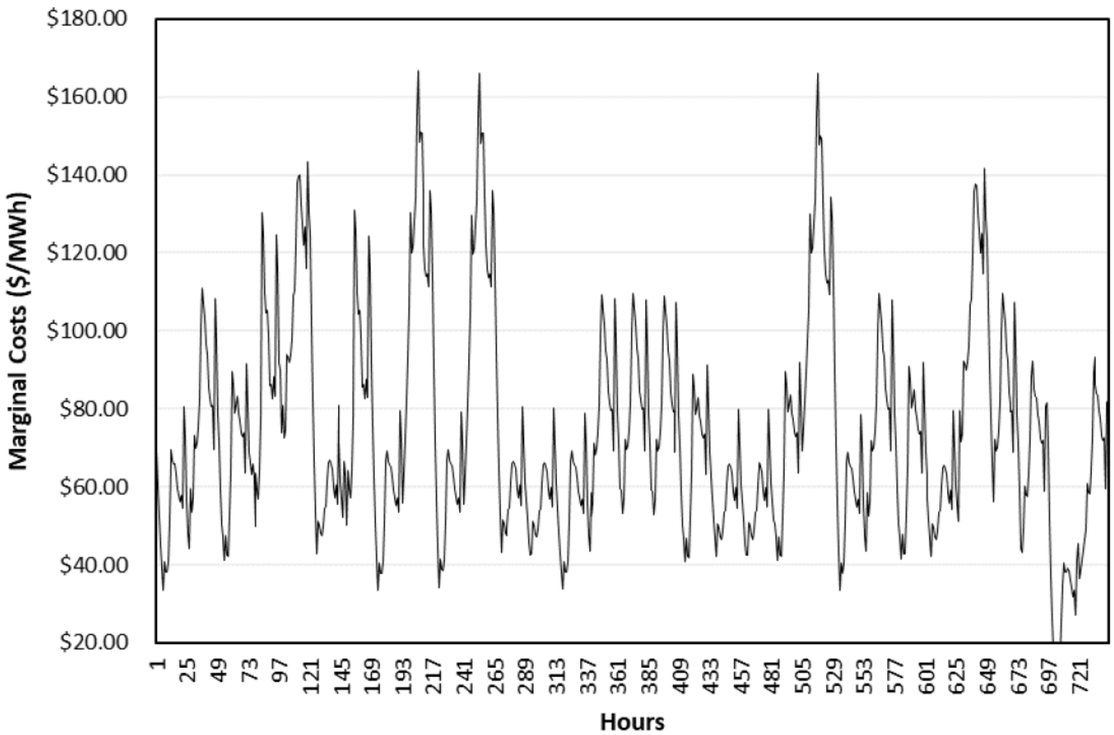
[73] CA Associates further estimated opportunity costs for NYISO Zone A. Those data were not used in the 2018 update. See CAEC Marginal COS Report, p. 15, footnote 26.

[74] Marginal Cost Study Update Summary Report, p. 16, footnote 28.

[75] Marginal Cost Study Update Summary Report, p. 5, lines 2-7.

[76] Hydro stated that its internal marginal generation cost of energy is zero for 2021-2019 [sic] in PUB-NLH-010.

Figure A-1: Estimates of Hourly Marginal Energy and Operating Reserve Costs, January 2021 ($/MWh)



Source: CAEC Marginal COS Report, p. 13.

b. Analysis

To assess Hydro's approach to marginal generation energy costs, we considered the applicability of the opportunity cost (external market purchase) approach. Based on our understanding of the Hydro system, the opportunity cost approach is reasonable and applicable for most operating conditions. When the internal marginal cost is set by Hydro (*i.e.*, when Hydro's internal marginal cost is lower than the market price), which is expected to occur most of the time, the opportunity cost is appropriate as the energy would otherwise be exported. Likewise, if thermal generation is on the margin and setting prices, Hydro's most economic decision is to sell into the market if Hydro's thermal marginal generation cost is less than market prices plus applicable transaction and transmission fees or buy from the market if Hydro's thermal marginal generation cost is greater than market price plus transaction and transmission fees. If the market price in ISO-NE is not sufficiently high enough, net of losses and transmission charges, then the appropriate marginal energy cost is equal to the internal marginal energy cost. Hydro has stated in PUB-NLH-031 that its internal marginal energy costs are zero since under the Muskrat Falls Purchase Power Agreement; Hydro is not required to pay either an increase or a decrease in purchase power charges as a result of an increase or decrease in customer load requirement.

2. Capacity

a. Hydro Approach

Hydro estimates the marginal cost of capacity using internal capacity costs that reflect the investment and ongoing expenditures for a simple cycle combustion turbine. Unlike with marginal energy costs, it does not utilize the opportunity cost, market-based approach. In explaining the use of the internal capacity cost approach, Hydro referred to its resource adequacy study, noting the study's determination that, "determined that if capacity additions are required to meet load growth, the capacity additions should be located on the Island."[77] In PUB-NLH-011, Hydro explained that it anticipates the retirement of 100 MW of gas turbines in 2021 and further anticipates the need for new generation in 2021.[78] The marginal cost study reflects Hydro's planned all-in expenditures for two 58.5 MW oil-fueled CT capacity and includes the operations and maintenance costs for one week (168 hours) of continuous run-time.[79]

77 Marginal Cost Study Update Summary Report, p. 5, lines 9-10.

78 PUB-NLH-002.

79 CAEC Marginal COS Report, p. 18-19.

Although Hydro considered purchasing capacity from external markets in its 2016 Marginal Cost Study, it declined to do so in the 2018 update. The 2018 study asserts that the external capacity market approach is not appropriate due to Hydro's system location (not contiguous to a regional wholesale market) and institutional constraints.[80] The 2018 study poses, but does not attempt to answer, the question of whether or not Hydro would have access to capacity along transmission paths between either the New York ISO or ISO-NE.[81] Hydro stated that any imports would need to be classified as "firm" to satisfy resource adequacy constraints. It also stated that it does not currently have firm contracts in place.[82]

b. Analysis

Marginal costs necessarily reflect the need to serve incremental load. As discussed above in Section A, in addition to the retirements of Holyrood units 1 and 2, Hydro plans to retire the Hardwood GT (50 MW) and the Stephenville GT (50 MW) in 2021.[83] Hydro's marginal cost study utilizes the peaker deferral method (discussed above) and is based upon planned capacity additions of two 58.5 MW single-cycle combustion turbines, which combined, is roughly equal to the capacity that is being retired. These planned additions are effectively a replacement of the existing resources, and not for addressing load growth, indicating they, in general, should not be counted as marginal costs.

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[80] CAEC Marginal COS Report, p. 9.

[81] CAEC Marginal COS Report, p. 8.

[82] PUB-NLH-002, p. 1, lines 16-23.

[83] PUB-NLH-011 and Reliability and Resource Adequacy Study, Volume III, Tables 4 and 5.

Putting aside the question of whether or not marginal capacity costs are positive, it is not apparent that Hydro's 2018 MCOS has selected the least cost method to procure capacity. As raised in the 2015-2016 MCOS, capacity may be procured from external markets. Below, we calculate an alternative marginal generation capacity cost amount based upon the assumption that it is feasible to import firm capacity from an external market, in this case the NE-ISO. We understand that the feasibility of importing firm capacity from a market like the NE-ISO will need to be examined in detail by Hydro and the Board. Nevertheless, we believe it is important to describe a potential methodology and approach for providing an estimate for marginal generation capacity costs and to highlight potential differences in the two approaches.

Second, the internal cost approach could be used but with the recognition that energy from the peaker unit under certain conditions may also be sold into external markets (as mirrored in the marginal generation energy discussion above). Hydro calculates marginal costs by dividing the total investment expenditures on the peaker unit by the capacity of the peaker unit. However, the peaker unit could also earn revenues by selling its energy in a different market. Therefore, if the internal capacity methodology is used to calculate capacity costs, the correct cost should reflect the investment costs of the peaker, net of energy revenues. This is known as the Net Cost of New Entry (Net CONE) approach, using capital costs net of energy revenues as an estimate of the marginal cost of capacity.

As summarized in Table A-2, based upon our analysis described below, the least cost option for procuring capacity may very well be purchasing from the ISO-NE capacity market followed by the Net Cone approach (internal capacity approach as adjusted for energy sales to an external market).

The difference between the Net Cone and CAEC internal capacity cost is approximately 4%, indicating that the potential sales to external market are not substantial relative to the cost of the peaker's capacity.

Table A-2: Marginal Cost of Generation Capacity Estimated Under Alternative Methodologies

	Generation Capacity MC ($/kW-year)	% Difference from 2018 MCOS
2018 MCOS (CA Associates)	**$283.60**	
Alternative Methodologies		
Capacity Price Methodology - Annual	$208.00	-27%
Capacity Price Methodology - Winter Only	$86.67	-69%
Net CONE Methodology	$272.91	-4%

Sources: 2018 MCOS Generation Capacity MC from CAEC Marginal COS Report, p. 20. Alternative Methodologies are calculated based on assumptions provided by Hydro. Details are described in each Methodology section.

We discuss below the details of each approach used to determine the approximate figures in Table A-2.

Capacity Price Methodology

Assuming Hydro can obtain firm transmission capacity rights from ISO-NE, the ISO-NE capacity prices can serve as an estimate of the marginal cost of capacity on the Island. To import capacity from New England, Hydro must purchase firm capacity from ISO-NE, then import the capacity from New England to New Brunswick, from New Brunswick to Nova Scotia, and from Nova Scotia to Newfoundland via the Maritime Transmission Link.

We understand that for this to be feasible, Hydro would need to do a detailed market and technical analysis of its ability to obtain sufficient transmission capacity from ISO-NE to rely on that market for capacity. We have done a preliminary examination of the potential for firm transmission from

ISO-NE by examining the transfer capability from New England to New Brunswick, from New Brunswick to Nova Scotia, and from Nova Scotia to Newfoundland and Labrador. Regarding New England to New Brunswick, we examined select days (both weekdays and weekends) in December 2018 through February 2019 and found that Total Transfer Capability (TTC) was consistently 200 MW.[84] For New Brunswick to Nova Scotia, we again examined the months of December 2018 through February 2019 and found that Firm Actual Transfer Capability (FATC) was about 300 MW.[85] Concerning Nova Scotia to Newfoundland and Labrador, the Maritime Link provides 500 MW of capacity.

That leaves obtaining firm transmission within ISO-NE for a generating capacity purchase in that market, and/or for wheeling through. We first note that all market participants in ISO-NE can purchase firm and non-firm transmission services on a non-discriminatory basis and all transmission providers in the market have an OATT and a well-functioning OASIS. While there are transmission congestion and pockets of constraints throughout the network, those conditions are reflected and accounted for in the Locational Marginal Prices (LMPs) for buyers and seller. Moreover, ISO-NE has a well-developed Financial Transmission Rights (FTRs) market that makes it feasible for market participants to hedge against LMP risk between and among different nodes that may be the source and sink nodes in bilateral contracts providing longer-term firm capacity.

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[84] See, ISO New England, TTC Tables. Available at: https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/ttc-tables.

[85] See, Nova Scotia Power, Hourly New Brunswick Intertie TTC & ATC. Available at: http://oasis.nspower.ca/en/home/oasis/monthly-reports/hourly-new-brunswick-intertie-ttc-atc.aspx.

To investigate the potential magnitude and timing of transmission congestion in the geographic area most relevant to Hydro were it to purchase capacity from ISO-NE, we examined the LMP separation (price separation) between the Maine zone in IS0-NE and the Salisbury node in ISO-NE. The Salisbury node is the node connecting to the New Brunswick network while the Maine zone is the zone closest to the south of Salisbury. As the table below shows for 2017 and 2018, LMPs tend to be lower in Salisbury than in the Maine zones. This implies that there is congestion from north to south.

Table A-3: LMP Separation Between Salisbury-New Brunswick Interface and Maine Zone

	Average Price Difference		Hours with >3% Price Difference	
Month-Year	SALBRY - MAINE ($/MWh)	% Difference from MAINE Price	Number of Hours	% of Hours
Jan-17	-$1.79	-5%	701	94%
Feb-17	-$0.57	-2%	166	25%
Mar-17	-$0.36	-1%	0	0%
Apr-17	-$2.04	-7%	195	27%
May-17	-$2.26	-9%	341	46%
Jun-17	-$1.87	-8%	634	88%
Jul-17	-$1.17	-4%	624	84%
Aug-17	-$1.25	-5%	629	85%
Sep-17	-$0.89	-4%	564	78%
Oct-17	-$1.09	-4%	619	83%
Nov-17	-$2.92	-9%	519	72%
Dec-17	-$3.57	-5%	508	68%
Jan-18	-$7.17	-7%	622	84%
Feb-18	-$2.70	-7%	611	91%
Mar-18	-$2.00	-6%	659	89%
Apr-18	-$9.74	-24%	488	68%
May-18	-$5.89	-26%	471	63%
Jun-18	-$1.06	-4%	387	54%
Jul-18	-$1.07	-3%	419	56%
Aug-18	-$1.05	-3%	366	49%
Sep-18	-$1.85	-6%	486	68%
Oct-18	-$6.72	-18%	479	64%
Nov-18	-$7.17	-13%	353	49%
Dec-18	-$2.55	-5%	244	33%

Sources and Notes: Calculation based on data from Velocity Suite. Day-Ahead LMPs are pulled for the .Z.MAINE and .I.SALBRYNB345 1. nodes.

Assuming that obtaining firm transmission is feasible, then a combination of ISO-NE capacity prices at the New Brunswick interface and the costs of using the transmission paths can be used to estimate of the cost of firm capacity imports from New England to Hydro. In the past five years, prices for the New Brunswick interface have consistently been lower than capacity prices for the ISO-NE system and have ranged between $3.21/kW-mo to $5.41/kW-mo, as shown in Table A-4 below.

Table A-4: ISO-NE Forward Capacity Auction Clearing Prices (2018 CAD/kW-month)

Auction	Auction Year	Delivery Year	Capacity Clearing Price: ISO-NE System $/kW-mo	Capacity Clearing Price: New Brunswick Interface $/kW-mo
FCA 13	2019	2022	$4.55	$3.21
FCA 12	2018	2021	$5.66	$3.86
FCA 11	2017	2020	$6.88	$4.39
FCA 10	2016	2019	$9.50	$5.41
FCA 9	2015	2018	$12.69	$5.24

Sources and Notes: Capacity clearing prices reflect prices paid to existing units. Prices are converted to 2018 dollars assuming a 2% inflation rate, then converted to CAD using annual average exchange rates reported by the IRS. Capacity prices available here: https://www.iso-ne.com/static-assets/documents/2018/05/fca-results-report.pdf.

Hydro's implied cost of purchasing capacity from New England on a $/kW-year basis is then calculated by multiplying the New Brunswick capacity price by an assumption for a number of months in a year during which Hydro will purchase capacity from New England. The 2018 MCOS implies an almost negligible value of capacity in non-winter months (May – October) for Hydro, so it seems to be the case that it may make sense for Hydro to only purchase capacity from New England in the winter months. Therefore, the cost of purchasing capacity is calculated for two cases: the "Annual" case assumes Hydro will purchase capacity from New England for the entire year, while the "Winter Only" case assumes Hydro will only purchase capacity in the winter months (Dec-Apr). Table A-5 below summarizes these implied costs for the past five capacity auctions.

Table A-5: Hydro's Implied Cost of Purchasing Capacity from ISO-NE

Auction	Auction Year	Delivery Year	Annual	Winter Only
			$/kW-yr	*$/kW-yr*
FCA 13	2019	2022	$38.53	$16.06
FCA 12	2018	2021	$46.35	$19.31
FCA 11	2017	2020	$52.63	$21.93
FCA 10	2016	2019	$64.89	$27.04
FCA 9	2015	2018	$62.84	$26.18

Source: Brattle calculation based on capacity prices from ISO-NE.

Taking the FCA 13 implied cost as an example, Table A-6 below shows how the marginal cost of capacity could be estimated by adding the charge for firm point-to-point transmission service to the cost of purchasing capacity under both the "Annual" and "Winter Only" assumptions.

Table A-6: Marginal Cost of Capacity Based on Capacity Prices (2018 CAD/kW-year)

	Annual	Winter Only
ISO-NE FCA 13 Cost of Purchasing Capacity	$38.53	$16.06
Charge for Firm Point-to-Point Transmission Service		
New England	$143.23	$59.68
New Brunswick	$26.24	$10.93
Nova Scotia	$61.07	$25.45
Marginal Cost of Capacity	**$208.00**	**$86.67**

Sources: Transmission charges are pulled from Section II of the ISO-NE OATT and Schedule 7 of the New Brunswick and Nova Scotia OATTs.

The alternative MC of capacity is 27% lower and 69% lower than the MC calculated by CA Associates, under the "Annual" and "Winter Only" assumptions, respectively. This is summarized in Table A-2 above.

NET CONE APPROACH

As stated above, the 2018 MCOS uses the internal cost methodology to determine marginal capacity costs. These internal costs reflect the costs associated with a single cycle combustion turbine, which is recognized as the least-cost investment to provide generation reliability. Assumptions for the peaker that Hydro used in its marginal cost calculation are listed in Table A-7 below.

Table A-7: Peaker Assumptions

Max Dispatch (MW)	58.5
Heat Rate at Max Dispatch (BTU/kWh)	10,460
Fuel Price (CAD/mmBTU)	$14.85
Variable Costs	
Fuel Cost at Max Dispatch (CAD/MWh)	$155.31
VOM (CAD/MWh)	$0.00

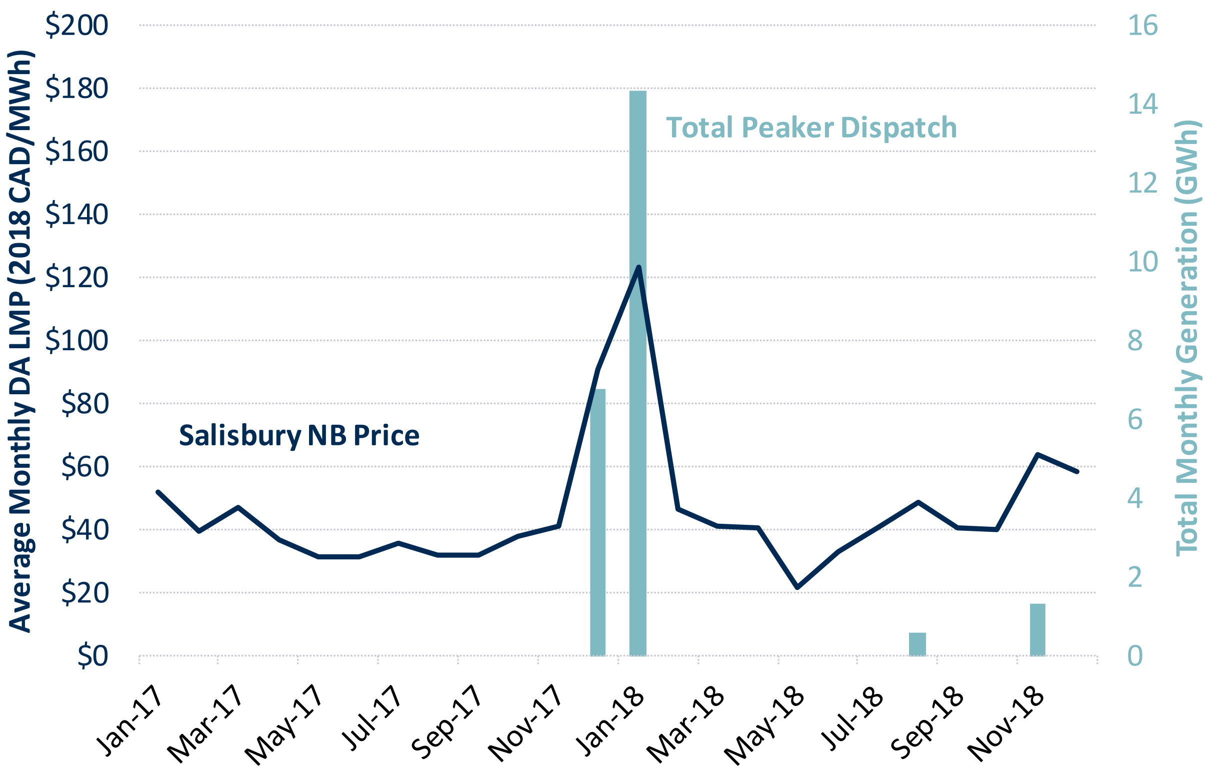
Source: PUB-NLH-001. Fuel Cost at Max Dispatch is calculated by Brattle using the assumptions provided by Hydro; VOM is a Brattle assumption. Costs are in 2018 CAD.

In theory, the peaker unit may earn revenues from the market that would offset the cost of capacity. While our estimate below shows that it is not likely that the peaker unit will earn a significant amount of energy revenues, it is important to consider it from a methodological perspective.

We estimate what the energy revenues received by the peaker could be, assuming the peaker sells energy into the ISO-NE market at a price equal to the LMP at the Salisbury NB 345 node. We assume the peaker will provide its maximum dispatch of 58.5 MW to the New England market in all hours such that the combined fuel and VOM costs (in $/MWh) are lower than the LMP at the

Salisbury NB 345 node. Figure A-2 below summarizes nodal LMPs and peaker dispatch at a monthly level—the peaker will generate more when LMPs are high.

Figure A-2: 2017-2018 Illustrative Peaker Dispatch Summary



Sources and Notes: Nodal LMPs are pulled from Velocity Suite, converted to 2018 dollars assuming a 2% inflation rate, then converted to CAD using annual average exchange rates reported by the IRS (available here: https://www.irs.gov/individuals/international-taxpayers/yearly-average-currency-exchange-rates). Peaker generation is calculated by Brattle, using peaker assumptions provided by Hydro.

Taking the average of 2017 and 2018 dispatch results, net energy revenues are estimated to be $10.69/kW-year. These net energy revenues can then be subtracted from the marginal cost of capacity as reported in the 2018 MCOS to yield an estimate of the marginal cost of capacity under the Net CONE approach. Table A-8 below summarizes dispatch results and marginal cost calculations assuming historical 2017 and 2018 nodal LMPs.

Table A-8: Marginal Cost of Capacity Adjusted for Net Energy Revenues (2018 CAD/kW-year)

Year	Peaker Dispatch					Capacity Marginal Cost	
	Generation	Capacity Factor	Energy Revenue	Variable Costs	Net Energy Revenue	IIS Marginal Cost from 2018 MCOS	Less Net Energy Revenue
	MWh	*%*	*$ thousands*	*$ thousands*	*$/kW-yr*	*$/kW-yr*	*$/kW-yr*
2017	6,786	1.32%	$1,422	$1,054	$6.30	$283.60	$277.30
2018	16,263	3.17%	$3,408	$2,526	$15.07	$283.60	$268.53
Average					**$10.69**		**$272.91**

Sources and Notes: Simple peaker dispatch is calculated using historical LMPs from Velocity Suite and peaker assumptions provided by Hydro. Capacity Marginal Costs from the 2018 MCOS are from the CAEC Marginal COS Report, Figure 7. All costs are in 2018 CAD.

C. Transmission

1. Energy

a. Hydro Approach

Hydro bases its marginal transmission energy costs on the marginal line losses based on load flow analysis. The load flow analysis reflects the system configuration as of 2019.[86]

b. Analysis

We reviewed the estimated losses for overall reasonableness. The seasonality aspect, with highest losses occurring during winter's peak demand season, match our expectations. The overall range of losses, as a percentage of load, varies from approximately 8% of the load to 11% of load, is in-line with general expectations.[87]

[86] 2018 MCOS Update, p. 12

[87] 2018 MCOS Update, p. 22

2. Capacity

a. Hydro's Approach

Hydro bases its marginal transmission capacity costs on peak load related expenditures for transmission. The costs are based on Hydro's list of planned projects and upgrades for 2018-2022. CAEC reviewed the complete list of upgrades to select those that it determined to be peak related, which included those that: upgrade transformer capacity or functionality, increased carrying capacity of transmission lines or power cables, and additions of new transmission or terminal station infrastructure.

b. Analysis

In principle, the general approach taken by Hydro/CAEC is reasonable. We requested the transmission investments provided by Hydro, and while we were unable to review each investment selected for inclusion, we noted that the majority of investments were not included.[88] Similarly, we were unable to confirm that the system required additional transmission capacity to serve peak load (*i.e.,* we could not confirm peak capacity provided by the investments included in the study were necessarily related to marginal cost as opposed to increases in capacity that would have occurred regardless of load growth.)

88 Out of 163 expected transmission projects in 2018-2022, only 12 projects were included as part of the marginal cost. See PUB-NLH-009.

D. Conclusions

For the reasons discussed in this Appendix, we believe that it is premature at this stage to base Hydro's rates on marginal costs or to use the marginal cost results as an element of the cost allocation process. In principle, we agree that it is economically appropriate to use a marginal COS study to either directly set rates based upon study results (with a reconciliation to ensure that rates are sufficient to recover embedded costs) or to use as a component within the embedded COS study. Rates based upon marginal costs provide good economic price signals for consumers and producers and help ensure that scarce resources are used efficiently. Nevertheless, given the lack of experience with marginal COS studies in Newfoundland and Labrador and the issues we have identified especially regarding generation capacity costs, we believe that the parties should continue to analyze and refine the marginal cost methodology and application for possible use in future proceedings or cases.

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