newfoundland labrador hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

March 31, 2016

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

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Cost of Service Methodology Review Report

Further to the Settlement Agreements to the 2013 GRA, enclosed please find the original and 12 copies of Newfoundland and Labrador Hydro's Cost of Service Methodology Review Report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Young
Legal Counsel

TLP/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy - Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. - Cox & Palmer
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
Thomas Johnson, Q.C. - Consumer Advocate
Yvonne Jones, MP Labrador
Senwung Luk – Olthuis, Kleer, Townshend LLP
Genevieve M. Dawson – Benson Buffett

NEWFOUNDLAND AND LABRADOR HYDRO

COST OF SERVICE METHODOLOGY REVIEW REPORT

March 31, 2016

Table of Contents

1.0 BACKGROUND

The completion of the Muskrat Falls Project and the ensuing interconnection of the Island Interconnected System with Labrador will result in a major change in the source of supply of electricity to the Island. For many years, load growth on the Island Interconnected System has been supplied by the Holyrood Thermal Generating Station (Holyrood).[1] Upon the commissioning of the Muskrat Falls Project, supply cost payments will commence under the Transmission Funding Agreement (TFA) and Muskrat Falls Power Purchase Agreement (PPA), and the role of Holyrood as a generating station will be phased-out.

The replacement of fuel costs with supply cost payments to cover the cost of transmission and generation assets has created the need to review the appropriate functionalization, classification and allocation of supply costs among customer classes. At present, fuel costs from Holyrood comprise the largest single portion of the supply costs incurred by Newfoundland and Labrador Hydro (Hydro). Over the past three GRAs, approximately 85%-90% of the revenue requirement related to Holyrood was classified as energy-related costs.[2]

Because of the material change in the forecast supply cost mix with the commissioning of the Muskrat Falls Project, Hydro proposed in its Amended 2013 General Rate Application (GRA) to conduct a Cost of Service Methodology review prior to its next GRA. The Settlement Agreements to the 2013 GRA requires Hydro to file a Cost of Service Methodology Review Report with the Board of Commissioners of Public Utilities (the Board) by March 31, 2016.

The scope of the Cost of Service Methodology Review, as stated in the Supplemental Settlement Agreement to the Amended 2013 GRA dated September 28, 2015, is as follows:

---

[1] Holyrood will function as a fully capable standby facility during the early years of operation of the Muskrat Falls Generating Plant and the Labrador-Island Link between Labrador and Newfoundland. Thereafter, Holyrood will be used as a synchronous condenser.

[2] For the 2007 and 2004 Test Years, respectively, 90% and 88% of the Holyrood revenue requirement was classified as energy-related. For the 2015 Test Year adjusted to reflect No. 6 fuel cost at $64.41 per barrel, approximately 85% of overall Holyrood costs would be classified as energy-related.

> *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 recovery.*

The Parties also agreed that the generation credit agreement between Hydro and Corner Brook Pulp and Paper Limited (CBPP), which was approved on a pilot basis by the Board in Order No. P.U. 4(2012), will be reviewed in the cost of service generic hearing.

Hydro has engaged Christensen Associates Energy Consulting (CA Energy Consulting) to conduct the methodology review. The CA Energy Consulting report is provided as Appendix A to this report.

2.0 LEGISLATIVE IMPACTS

Legislation and Provincial Government directives on customer rates have a material impact on rates matters in Newfoundland and Labrador. The legislative requirements also have implications for the cost of service methodology to be used to determine the revenue requirement to be recovered from each customer class.

Legislative impacts include: (i) the establishment of rates for rural customers that result in an annual deficit in recovery of the cost of serving those customers (the Rural Deficit); (ii) the recovery of the Rural Deficit from customers of Newfoundland Power and Hydro Rural customers on the Labrador Interconnected System (and the exclusion of Industrial Customers from the funding of the deficit); (iii) the establishment of a Labrador Industrial Rates Policy to promote the development of industrial activity in Labrador; (iv) the requirement for the cost of supply from Muskrat Falls[3] including the Labrador Island Link (LIL)[4] and the Labrador Transmission Assets (LTA)[5] to be recovered in full through Island Interconnected rates with no explicit provision requiring the value of export sales related to Muskrat Falls generation to be credited back to ratepayers to offset the cost of supply from Muskrat Falls. However, the current Government has indicated that export sales will be used to mitigate potential increases in electricity rates.[6]

Following the commissioning of the Muskrat Falls Project, Newfoundland and Labrador will have an inter-provincial transmission system fully interconnected with Quebec, Nova Scotia, and the broader North American electric grid. This development gives rise to the obligation for Hydro and its affiliated transmission owners to provide open, non-discriminatory access to transmission service on transmission lines used for inter-provincial trade by third parties. This requirement is established by the Federal Energy Regulatory Commission, or FERC, which is an independent agency that regulates the transmission of electricity in the United States. In order to meet the FERC requirement of reciprocity, Hydro must provide comparable open access to transmission service over the interprovincial transmission system within Newfoundland and Labrador.

From a cost of service perspective, FERC requires that Hydro record its transmission costs in a manner that can be used in the determination of open access transmission tariffs. The required process for the approval of transmission tariffs is not yet established.

The cost of service implication of each item is discussed further in the following sections.

---

[3] Muskrat Falls refers to the hydroelectric facilities of the Muskrat Falls Project.
[4] LIL refers to the transmission line and all related components to be constructed between the Muskrat Falls hydroelectric plant on the Churchill River and Soldier's Pond including converter stations, synchronous condensers, and terminal, telecommunications, and switchyard equipment.
[5] LTA refers to the transmission facilities of the Muskrat Falls Project to be constructed between the Muskrat Falls hydroelectric plant on the Churchill River and the generating plant located at Churchill Falls.
[6] See letter from the Premier to the Minister of Natural Resources dated December 14, 2015.

2.1 Rural Deficit

The *Electrical Power Control Act* (the EPCA) permits the Provincial Government to provide direction to the Board and Hydro with respect to the setting and subsidization of rural rates.[7] OC2003-347 provides direction to the Board with respect to the establishment of Hydro's Rural Rates.[8]

The EPCA also provides an exemption for Industrial Customers from being required "*to subsidize the cost of power provided to rural customers in the province*".[9]

2.2 Labrador Industrial Rates Policy

In December 2012, the Provincial Government introduced a series of legislative amendments to establish a new electricity rate policy for Industrial Customers on the Labrador Interconnected System. The purpose of the Labrador Industrial Rates Policy is to promote the development of industrial activity in Labrador.[10]

Under the Labrador Industrial Rates Policy, the generation costs in the Labrador Industrial Rates are established outside the purview of the Board. The transmission costs reflected in the Labrador Industrial Rates are approved by the Board; this approval is expected to occur through a general rate proceeding.[11]

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

---

[7] See Section 5.1(1) of the *EPCA*.
[8] See response to request for information PUB-NLH-077 provided in Hydro's 2013 General Rate Application.
[9] See Section 3.0(iv) and 5.1(1) of the *EPCA*.
[10] See Section 3.0(v) and 5.1(1) of the *EPCA*.
[11] See Section 5.8(2) of the *EPCA*.

2.3 Recovery of Muskrat Falls Costs

In OC2013-343, Government provided a directive setting forth the requirement for the cost of supply from the Muskrat Falls Project (including the Labrador Island Link and the Labrador Transmission Assets) to be recovered in full through Island Interconnected rates charged to the appropriate classes of ratepayers.[12] This Government direction exempts customers on the Labrador Interconnected System from paying costs related to the Muskrat Falls Project.

OC2013-343 also requires that any expenditures, payments or compensation paid directly or indirectly by Hydro under an agreement or arrangement to which the Muskrat Falls Exemption Order applies, shall be included as costs in Hydro's cost of service, without disallowance, to be recovered through Island Interconnected System customer rates. To enable Hydro to fully recover annual costs resulting from charges related to the Muskrat Falls Project will require Hydro to establish a supply cost recovery mechanism to deal such cost variances. This matter will be reflected in the Supply Cost Mechanism review to be filed with the Board in June, 2016.

2.4 Export Sales

Given the policy of the current Government is to use revenue from surplus power sales to mitigate potential increases in electricity rates, Hydro considers it appropriate to recommend an approach to deal with the value to customers of export sales in the Cost of Service Methodology Review.

3.0 COST OF SERVICE RECOMMENDATIONS

3.1 Transition to Muskrat Falls Project Commissioning

Hydro is required to file its next GRA at the end of the first quarter in 2017 based on a 2018 Test Year. To ensure that rates provide reasonable cost recovery beyond one year, Hydro may need to include two test years in its next GRA application.

[12] Section 5.1(2) of the *EPCA* sets forth the authority of the Government to direct the Board to implement policies, procedures and directives with respect to the Muskrat Falls Project.

For the purposes of the Cost of Service Methodology Review, Hydro has assumed that supply costs from the Muskrat Falls Project will be reflected in the 2019 costs for the full year. However, Hydro is not required to pay the costs of the Muskrat Falls Project until the entire project is commissioned (i.e., generation and transmission assets are fully commissioned). In the event that the new transmission assets are providing service from off the Island in advance of project commissioning, Hydro may have the opportunity to purchase energy to reduce generation at Holyrood.

To reflect this possibility in 2018, Hydro proposes that the existing cost of service methodology be used for the 2018 Test Year with the following two modifications:

(i) All forecast power purchase costs incurred to reduce Holyrood fuel costs should be classified as energy. These may include: Recall power from the Upper Churchill; pre-commissioning power from Muskrat Falls resulting from the availability of the LIL; or imports over the Maritime Link.

(ii) The Holyrood capacity factor used in classification of fixed assets for 2018 should be based on the forecast capacity factor for 2018 rather than the historical 5-year average currently approved in the existing Cost of Service methodology.

3.2 Post Muskrat Falls Project Commissioning

Based on the report of CA Energy Consulting, Hydro makes the following recommendations.

3.2.1 Systemization

Hydro proposes to maintain separate cost of service studies for the Labrador interconnected System and the Island Interconnected System.

3.2.2 Functionalization

(i) Hydro recommends no changes in the functionalization of existing generation and transmission assets with the exception of transmission line TL-248 from Deer Lake to Massey Drive. Hydro recommends the functionalization of this asset change from generation to transmission.

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

(iii) Hydro recommends that the frequency converter serving CBPP continue as a specifically assigned asset; and

(iv) Hydro recommends that the transmission assets currently specifically assigned to customers continue to be specifically assigned.

3.2.3 Classification of Functionalized Production/Generation Costs

Hydro's current Cost of Service methodology first classifies generation costs on the basis of demand and energy cost causation, and then allocates to each customer class using a coincident peak allocator in the case of demand costs and an annual energy allocator in the case of energy costs. Cost causation is established based on planners' views as to whether specific costs were incurred to meet peak demands or to supply total energy. There are many methods available to the industry to perform classification and the method chosen can result in material differences in the costs to be recovered from a customer class. For example, classification of a high proportion of costs as energy-related would result in a higher proportion of the costs being allocated to customers who use large amounts of energy relative to their peak demand requirements (i.e., high load factor customers like Hydro's Industrial Customers). Alternatively, classifying a higher proportion of total costs to demand cost would result in a higher allocation of costs to customers who have higher peak demands relative to their energy requirements (i.e., lower load factor customers like Newfoundland Power).

An alternative approach to the various traditional classification methods is to make use of the concept of marginal cost. Marginal generation costs, upon interconnection of the system to the North American grid, will be represented in most hours by wholesale prices of eastern regions of that grid. The use of marginal generation costs in cost allocation would permit Hydro to reflect resource market value in determining how to allocate the financial costs of generation to each class.

Hydro recently completed its Marginal Cost Study based on 2019 forecast costs. The use of this marginal generation cost data allows Hydro to estimate the cost to serve Island Interconnected System classes of customers by applying hourly marginal generation cost profiles to the hourly load profiles for each class served at transmission voltage. Cost shares for each customer class are then derived based on the proportion of the annual total marginal costs that result for each class. This approach gives consideration to the cost of serving each customer class 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 peak hours.

The use of marginal cost allocation in the cost of service also aligns with reflecting marginal costs in rate design to promote efficient use of resources by customers. Therefore, Hydro believes it is reasonable for the Board to consider the use of marginal generation costs for allocation of generation costs in the Cost of Service Study.

Classification Alternatives

Hydro presents two alternatives for the Board to consider in the classification and allocation of power purchase costs resulting from the Muskrat Falls Project:

(i) The equivalent peaker methodology be used for classification between demand and energy and a coincident peak approach (3 CP) be used for cost allocation among customer classes; or

(ii) The use of forecast marginal generation capacity and marginal generation energy costs to determine the proportion of power purchase costs to be classified and allocated to each customer class.

If the equivalent peaker methodology is selected for classification of Muskrat Falls Project costs, Hydro proposes few changes in the classification approach for the other functionalized generation assets. The only exception is that Hydro proposes to use a capacity factor for Holyrood based on the Test Year forecast rather than the current approved 5-year historical average. This approach would permit cost allocation to more immediately reflect the role of the plant.

Table 1 below summarizes the proposed generation/production classifications under this option.

Table 1 – Classification of Functionalized Generation Costs – Island Interconnected System

Generation Costs	**Existing**	**Proposed**
Hydraulic Assets	System Load Factor	System Load Factor
Holyrood Assets[13]	5-year average capacity factor	Forecast capacity factor
Gas Turbines/Diesel Assets	100% Demand Related	100% Demand Related
Power Purchases – MF	Not Applicable	Equivalent Peaker (25% D/75% E)
Other Power Purchases	System Load Factor	System Load Factor
Holyrood Fuel	100% Energy	100% Energy
Gas Turbine/ Diesel Fuel	100% Demand	100% Demand
Wind Purchases	100% Energy	100% Energy

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

If the forecast marginal cost approach is selected, Hydro proposes that all generation costs on the Island interconnected System be classified and allocated based on marginal generation costs. Table 2 below compares the existing and proposed generation cost classifications under this option.

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

Generation Costs	**Existing**	**Proposed**
Hydraulic Assets	System Load Factor	Marginal Generation Costs
Holyrood Assets[14]	5-year average capacity factor	Marginal Generation Costs
Gas Turbines/Diesel Assets	100% Demand Related	Marginal Generation Costs
Power Purchases – MF	Not Applicable	Marginal Generation Costs
Other Power Purchases	System Load Factor	Marginal Generation Costs
Holyrood Fuel	100% Energy	Marginal Generation Costs
Gas Turbine/ Diesel Fuel	100% Demand	Marginal Generation Costs
Wind Purchases	100% Energy	Marginal Generation Costs

3.2.4 Classification of Functionalized Transmission Costs

Hydro recommends that all functionalized transmission costs be classified as 100% demand-related. This is consistent with the approach currently used in the Cost of Service Study.

Hydro also proposes to update its annual transmission losses to 5.1% for energy and 7.3% for peak demand for use in the Cost of Service Study.[15] The transmission loss assumption does not vary by customer class as Hydro does not forecast locational losses on the Island Interconnected System.

[14] Ibid.
[15] The loss percentages are expressed as a percentage of customer class load requirements. Hydro will reflect these loss factor updates in its next GRA filing.

3.2.5 Allocation Method

Marginal Cost Approach

In the scenario in which marginal generation costs are used in the classification of generation costs, the allocation calculations are computed in partnership with cost classification. The sharing of generation costs by customer class is determined in the following manner.

Hydro has forecast hourly loads for each of Newfoundland Power, the Island Industrial class and the Hydro Rural bulk load on the Island Interconnected System. The forecast marginal generation cost by hour is applied to the hourly load forecast for each customer group to determine the marginal cost to serve each customer class for each hour. By totaling the marginal generation cost to serve each customer class across all the hours of the year, the total forecast marginal generation cost to serve each customer class is determined for the Test Year. The proportion of the total marginal costs attributable to each customer class in the Test Year is then applied to the total Test Year generation revenue requirement to determine the portion to be allocated to each customer class.

To apply the marginal cost classification and allocation to generation costs of Labrador Interconnected Customers would require class load shapes for each retail class. Hydro plans to continue to apply equal rate changes per class on a go forward basis for the classes on the Labrador Interconnected System until Hydro has reasonable estimates of class load shapes. In its 2013 Amended GRA, Hydro stated it plans to conduct a load research study for the Labrador Interconnected classes.

Traditional Approach

Hydro currently uses a single coincident peak approach to allocate demand costs among customer classes. Hydro has applied the FERC test in evaluating its allocation approach and as a result is recommending 3 CP for allocation of both generation and transmission demand costs.

Hydro considers the application of the FERC test consistent with generally accepted utility practice in the allocation of demand costs.

CA Energy Consulting has recommended that the peak periods for use in applying the CP methodology be based on system peak including the loads for exports. Hydro has concerns with the potential implications of this approach.

On the interconnection with the North American grid in combination with the commissioning of the Muskrat Falls Project, there is material excess capacity available for exports. However, this excess capacity will decrease over time. Including the amount of export load in determining the peak period for cost of service purposes could broaden the system peak period beyond the historical winter peak period. The value for export sales is high in summer periods so it makes sense to maximize export sales in high value periods. Using export sales to determine the cost of service peak period could possibly result in Hydro eventually allocating system demand costs based on a twelve-month average of coincident peak loads instead of just the three winter months.

As native load increases over time, the system may need expansion to meet native peak load requirements. These peak load requirements will continue to be in the coldest days of the winter. Hydro considers the use of export sales in the determination of the peak period to pose possible challenges to the accurate representation of cost causality from a system planning perspective. A material reduction in exports sales capability during a summer period will not cause Hydro to acquire additional capacity. However, a shortage in winter capacity to meet native peak load would cause Hydro to explore least cost approaches to supply the expected increases in native load. Therefore, Hydro believes it is appropriate to determine the times of system peak for the purpose of cost allocation based on native peak load requirements.

Under the current 1 CP approach, Hydro Cost of Service Study reflects that the Island Industrial Customers peak load has an 88% coincidence with system peak factor and the Newfoundland Power peak load has a 99.4% coincidence with system peak. Based on a preliminary analysis, Hydro has not seen any reason to change these coincidence factors under the 3 CP approach. However, Hydro will be conducting further analysis on this matter prior to filing its 2017 GRA.

Hydro currently allocates energy costs based on annual energy use by customer class. If marginal costs are not used for classification and allocation of generation costs, Hydro proposes to continue the current annual energy allocation approach.

3.2.6 Rural Deficit Allocation

Hydro also requested CA Energy Consulting to review the Rural Deficit allocation in the Cost of Service Methodology Review. CA Energy Consulting agreed that Hydro's proposed approach is preferable to the existing method.

Hydro recommends the use of the revenue requirement method for allocation of the Rural Deficit between Newfoundland Power and the Hydro Rural customers on the Labrador interconnected System. This recommendation is consistent with Hydro's proposal in the Amended 2013 GRA.

3.2.7 Conservation and Demand Management

Hydro will discuss with stakeholders the CA Energy Consulting recommendation to allocate CDM costs by customer class on a marginal cost basis. If not acceptable to the stakeholders, Hydro recommends the use of an energy allocation approach as recommended in its 2013 Amended GRA.

Hydro also recommends that, for the Island Interconnected System, Hydro's CDM costs and the CDM costs of Newfoundland Power should be pooled and allocated for recovery among customer classes on the Island Interconnected System.

3.2.8 Specifically Assigned Charges

Hydro recommends that the use of original asset costs as a basis for the allocation of operating and maintenance costs to specifically assigned assets be discontinued. Hydro proposes to engage in discussions with Industrial Customers to enter into an agreement to charge annual operating and maintenance costs to the Industrial Customers based on an as required maintenance approach for specifically assigned assets (including a markup to reflect administrative and general costs).

If this approach is not acceptable to all parties, Hydro recommends using indexed asset costs in operating and maintenance cost allocations in the determination of specifically assigned charges to eliminate the fairness concerns due to asset vintage differences.

3.2.9 Newfoundland Power Generation Credit

Hydro recommends continuation of the portion of Newfoundland Power's generation credit reflecting the operation of its hydraulic generation, as Newfoundland Power normally operates its hydraulic generation during peak periods.

Hydro also recommends that the thermal generation credit for use in the allocation of embedded demand costs not be renewed at the time of reflecting the costs of the Muskrat Falls Project in customer rates. However, Hydro has requested CA Energy Consulting to evaluate the implementation of an alternative credit for capacity availability which is more reflective of the market value of the capacity made available by Newfoundland Power's thermal generation. This issue will be further dealt with in the upcoming rate design review.

3.2.10 CBPP Generation Demand Credit

Similar to the Newfoundland Power generation credit, Hydro recommends the CBPP demand credit approach should be dealt with in the rates review to be filed in June 2016.

3.2.11 Allocation of Export Sales Credit

Due to the uncertainty with respect to the amount of an export sales credit that may be available annually, Hydro recommends that disposition of any export sales credit should be handled through a deferral mechanism outside the Cost of Service Study. Hydro will be filing its proposal for a supply cost deferral account to deal with future annual supply cost variances in June 2016. Hydro will include a detailed proposal on the approach to deal with export sales credits in that report.

4.0 CHANGES IN COST ALLOCATIONS

Hydro has prepared cost of service exhibits showing illustrative forecast 2019 revenue requirement projections for use in methodology evaluation (2019 Illustrative). The 2019 Illustrative revenue requirement allocations are compared to the Proposed 2015 Test Year revenue requirement adjusted to reflect a $64.41 per barrel cost of No. 6 fuel (2015 Proposed).[16]

The cost of service exhibits are provided for the Island Interconnected system as the material cost changes impact that system.[17] Hydro is recommending the cost of service and rates for the Labrador Interconnected System continue to be separate from the Island Interconnected System.

[16] The forecast 2015 Test Year revenue requirement for the Island interconnected System reflecting No. 6 fuel at $64.41 per barrel $CDN is approximately $540 million. See letter to Board dated October 28, 2015. The adjustment to reflect reduce fuel costs reflected $75.9 million reduction in No. 6 fuel and a $1.9 million reduction resulting from the lower forecast cost of No. 2 fuel.

[17] Approval of the recommendation to change from a 1 CP demand allocation to a 3 CP demand allocation would result in a minor reduction in the demand cost allocation to Hydro Rural customers and a minor increase in the demand cost allocation to Labrador Industrial customers.

Hydro has excluded rural deficit allocation in the presentation of results as this is not a relevant issue in evaluating the cost of service methodology for generation and transmission costs. The transmission costs on the Great Northern Peninsula are specifically assigned to Hydro Rural and therefore will not impact classification or allocation of common transmission assets.

The key financial forecast assumptions included in the 2019 Illustrative revenue requirement are:

(i) Muskrat Falls Project, including the Labrador Island Link and Labrador Transmission Assets will be in operation for all of 2019;
(ii) The TFA and PPA payments are consistent with a Nalcor long-term financial plan prepared in the fall of 2015;
(iii) Customer class demand and energy requirements for 2019 are based on Hydro's Spring, 2015 Load Forecast;
(iv) Hydro will continue its five year asset management plan which includes the addition of a 230 kV transmission line from Bay d'Espoir to Western Avalon;
(v) Material reductions in fuel consumption occur on the Island interconnected system;
(vi) Hydro's underlying operating and maintenance expenses are assumed to escalate at a rate of 2.5% per annum; and
(vii) Hydro's allowed return on equity remains at 8.8%.

Attachment 1 to this report provides a comparison of the allocations of the 2015 Proposed and the 2019 Illustrative revenue requirements under Option 1 which uses the equivalent peaker methodology for the classification of the costs of the power purchases related to the Muskrat Falls Project.

Attachment 2 to this report provides a comparison of the allocations of the 2015 Proposed and the 2019 Illustrative revenue requirements under Option 2 which uses a marginal cost approach in the classification and allocation of generation costs.

The differential between the average unit cost to serve Newfoundland Power and the Island Industrial Customers is approximately 1.2¢ per kWh in the 2015 Proposed, with the average cost to serve Island Industrial Customers being lower than the average cost to serve Newfoundland Power.[18] This reflects Island Industrial Customers having a higher load factor and a lower coincidence with system peak than Newfoundland Power.

Under the marginal cost scenario, the average cost differential in 2019 Illustrative relative to the 2015 Proposed is slightly higher by approximately 0.25¢ per kWh. However, under the equivalent peaker scenario, the average cost differential in 2019 Illustrative relative to 2015 Proposed widens by approximately 1¢ per kWh.

The increased average cost differential under the equivalent peaker classification approach primarily results from two factors: (i) the demand-related revenue requirement portion of the Muskrat Falls Project has a higher demand cost classification (25%) than the overall demand-related proportion of Holyrood costs in 2015 Proposed (14%); and (ii) the amount of demand-related revenue requirement in 2019 Illustrative is materially higher than the amount of demand-related revenue requirement in 2015 Proposed. The combination of these two factors increases the cost allocation to Newfoundland Power relative to the Island Industrial Customers when comparing the average unit costs for the 2015 Proposed and the 2019 Illustrative results.

[18] Excludes impact of the Rural Deficit.

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Illustrative Cost of Service
Summary Schedule - Island Interconnected

Attachment 1
Equivalent Peaker

Line No.	1	2	3	4	5	6	7	8	9	10	11
				Revenue Requirement [i]						Average Unit Cost	Differential NP vs Industrial [iii]
		Sales		Demand [ii]		Energy		Total			
		(MWh)	%	($ Millions)	%	($ Millions)	%	($ Millions)	%	($/kWh)	($/kWh)
	2019 Illustrative:										
1	Newfoundland Power	6,169,300	82.7%	298.2	80.3%	402.9	82.2%	701.9	81.5%	0.1138	0.0219
2	Industrial	894,300	12.0%	23.7	6.4%	58.4	11.9%	82.1	9.5%	0.0918	
3	Rural	396,202	5.3%	49.5	13.3%	28.9	5.9%	78.5	9.1%	0.1982	
4	Total	7,459,802		371.4		490.1		861.5			
	2015 Test Year Proposed:										
5	Newfoundland Power	5,924,100	85.0%	153.9	75.3%	241.3	84.4%	395.9	80.8%	0.0668	0.0117
6	Industrial	621,400	8.9%	8.9	4.4%	25.3	8.8%	34.2	7.0%	0.0551	
7	Rural	425,409	6.1%	41.7	20.4%	19.2	6.7%	61.1	12.5%	0.1437	
8	Total	6,970,909		204.5		285.8		490.3			

[i] Customer component of revenue requirement not presented for purposes of this study.
[ii] Includes both production and transmission demand costs.
[iii] Price differential excludes the impacts of the Rural Deficit that is included in the Newfoundland Power wholesale rate.

Assumptions:
1. Equivalent Peaker method deployed to classify Muskrat Falls purchased power only. Allocation is based on the existing 2015 methodology
2. System load factor continues to classify heritage hydraulic generation. Allocation is based on the existing 2015 methodology
3. 2015 CoS methodology for thermal costs is maintained.
4. Combustion Turbine costs are classified as 100% demand and alloacted on a CP methodology.
5. A 3 CP method is used to allocate demand costs.
6. Exploits assets are included as a purchased power at $0.04.
7. Completion of the TWINCo asset transfer has not been included in Rate Base.
8. 2015 Test Year Proposed No 6 fuel priced at $64.41 per barrel.

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Illustrative Cost of Service
Summary Schedule - Island Interconnected

Attachment 2
Marginal Cost

Line No.	1	2	3	4	5	6	7	8	9	10	11
				Revenue Requirement [i]						Average Unit Cost	Differential NP vs Industrial [iii]
		Sales		Demand [ii]		Energy		Total			
		(MWh)	%	($ Millions)	%	($ Millions)	%	($ Millions)	%	($/kWh)	($/kWh)
	2019 Illustrative:										
1	Newfoundland Power	6,169,300	82.7%	159.9	74.9%	534.4	82.5%	695.0	80.7%	0.1127	0.0143
2	Industrial	894,300	12.0%	12.7	5.9%	75.2	11.6%	87.9	10.2%	0.0983	
3	Rural	396,202	5.3%	40.9	19.2%	38.2	5.9%	79.3	9.2%	0.2002	
4	Total	7,459,802		213.5		647.7		861.3			
	2015 Test Year Proposed:										
5	Newfoundland Power	5,924,100	85.0%	153.9	75.3%	241.3	84.4%	395.9	80.8%	0.0668	0.0117
6	Industrial	621,400	8.9%	8.9	4.4%	25.3	8.8%	34.2	7.0%	0.0551	
7	Rural	425,409	6.1%	41.7	20.4%	19.2	6.7%	61.1	12.5%	0.1437	
8	Total	6,970,909		204.5		285.8		490.3			

[i] Customer component of revenue requirement not presented for purposes of this study.
[ii] Includes both production and transmission demand costs.
[iii] Price differential excluded the impacts of the Rural Deficit that is included in the Newfoundland Power wholesale rate.

Assumptions:
1. Marginal Cost ratios are used to classify and allocate all generation costs.
2. Marginal Cost ratios are used to classify and allocate all thermal generating costs.
3. Marginal Cost ratios are used to classify and allocate all Combustion Turbine costs.
4. A 3 CP method is used to allocate demand costs.
5. Exploits assets are included as a purchased power at $0.04.
6. Completion of the TWINCo asset transfer has not been included in Rate Base.

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

Cost-of-Service Methodology Review

for

Newfoundland and Labrador Hydro

by

Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, WI 53705-2299
Voice 608.231.2266 Fax 608.231.2108

March 31, 2016

Table of Contents

Cost-of-Service Methodology Review

for

Newfoundland and Labrador Hydro

by

CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

March 31, 2016

1. INTRODUCTION

Newfoundland and Labrador Hydro (NLH) requested Christensen Associates Energy Consulting to conduct a review of the utility's cost-of-service (COS) methodology, focusing on the system that is likely to emerge following its transition to integration with the electricity grid of eastern North America. This transition will occur upon completion of several major construction projects and the development work associated with them. The targeted in-service date is the latter half of 2018. The key projects involving NLH are: 1) the new 824 MW Muskrat Falls (MF) hydro dam on the Churchill River in Labrador; 2) the Labrador Transmission Assets (LTA) that will assist in coordinating generation at Muskrat Falls and Churchill Falls; and 3) the Labrador-Island Link (LIL), a direct current (DC) line that connects Muskrat Falls to Soldiers Pond near St. John's. In addition, Nalcor, NLH's parent company, has partnered with Emera to develop the Maritime Link (ML) that will connect Nalcor with Emera's grid in Nova Scotia and points beyond.

The cost of these investments is significant, and MF, LIL, and LTA costs will, by government direction, be borne by customers paying Island Interconnected rates (beginning with the

Muskrat Falls in-service date) as these facilities are being constructed for them. Additionally, as a result of the arrival of new supply on the Island, NLH will wind down the Holyrood generation facility, replacing its thermal generation with Muskrat Falls' hydro power.

This COS methodology review is part of a general review process leading up to the in-service date for Muskrat Falls and its associated transmission facilities. The review is occurring at the conclusion of the 2013 General Rate Application (GRA) process, during which many COS methodology issues were reviewed. This report makes reference to several of these issues and the related discussions, and follows recent issuance of a Settlement Agreement and Supplemental Settlement Agreement.[1]

The COS process is a direct consequence of the dominating presence of common and joint costs in the revenue requirements of electricity services. Large shares of the total costs associated with the provision of service are both common and joint: many consumers are served at the same time—in common; similarly, multiple services such as operating reserves are provided jointly by a single facility—all at the same time. Methodology review is periodically required to resolve issues of how best to attribute the total of common and joint costs to the various classes of consumers when costs cannot be assigned to individual consumers?

[1] The *Settlement Agreement* and *Supplemental Settlement Agreement* are untitled documents dated August 14, 2015 and September 28, 2015, respectively.

The focus of COS review in the 2013 proceeding was the methodology to support currently proposed rates. In contrast, this COS methodology review concentrates on the methodology issues that surround the completion of the new generation and transmission facilities. This review evaluates NLH's current cost allocation methods in light of the above changes and recommends changes to this methodology where needed. The Supplemental Settlement Agreement mentions the current review specifically, and states that it 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 recovery."[2] This report will discuss each of these issues.

The review begins with a "jurisdiction" question, investigating the potential for combining the two previously separate interconnected systems in the Island and Labrador. Sections on the core functions of generation and transmission then follow. (The distribution function is not part of this review.) A final section covers a set of topics outside the main functions: the treatment of: 1) the rural deficit; 2) conservation and demand management (CDM) costs; 3) specifically assigned costs; and 4) the frequency converter at Corner Brook Pulp and Paper. An appendix with a separate list of recommendations follows.

[2] *Supplemental Settlement Agreement*, paragraph 13, p. 3.

2. SYSTEM DEFINITION

Issue. NLH will have physically connected its two historically separate integrated systems on the Island and in Labrador. Should NLH now consider these systems to be a single integrated system for COS purposes?

Background. There are technical and institutional considerations to bear in mind in evaluating this issue. From a technical perspective, the interconnection of these two systems is unconventional by North American standards. Unlike circumstances in which a corporate merger brings together two hitherto separate but contiguous service territories in a market with multiple AC transmission lines and points of connection, this event connects two service territories made "contiguous" by means of a pair of high voltage direct current (HVDC) circuits.

Furthermore, the power flow pattern anticipated for NLH's physically interconnected system is not conventional when compared with the rest of the Eastern Interconnection.[3] NLH expects that in virtually all hours, barring an outage at Muskrat Falls or on the LIL, power will flow in one direction, south to the Island and points beyond. This is unconventional for AC-dominated meshed networks, but consistent with conditions in which DC transmission technology is utilized, especially in transporting power over long distances.

[3] The Eastern Interconnection is the largest AC-circuit grid in North America. It covers all of the United States east of the Rocky Mountains, approximately, except for the ERCOT region of Texas, as well as Manitoba, Ontario, and the Maritime Provinces of Canada. Quebec is not part of the Eastern Interconnection.

From an institutional perspective, one can find cases in the Eastern Interconnection in which utilities merge but contiguous service territories are not combined. For example, Emera Maine possesses two contiguous service territories due to a recent merger and, for the moment, maintains separate COS studies. Ameren's subsidiary, Ameren Illinois, preserves three rate zones derived from the boundaries of service territories previously owned by separate utilities.[4] This is partly an artifact of utility regulation, which has preserved a requirement that Ameren submit three separate COS studies. In contrast, Georgia Power acquired Savannah Electric & Power and simply merged their service territory into Georgia Power's, both in terms of cost of service and rate design.

Thus, the technical experience does not strongly suggest that the two regions be combined, and the institutional experience in North America is mixed.

NLH has a number of external institutional influences that suggest continuation of separate treatment. The Muskrat Falls Exemption Order requires that the costs "shall be recovered in full by Newfoundland and Labrador Hydro in Island Interconnected rates charged to the appropriate classes of ratepayers."[5] This obligation enshrines in law the cost causation underlying the decision to invest: least cost planning of new generation capability to serve the island.[6]

[4] Ameren Illinois' web site states: "Service territories formerly known as AmerenCIPS, AmerenCILCO and AmerenIP are now referred to as Rate Zone I, II and III, respectively." These service territories cover the southern two-thirds of Illinois.
[5] Order in Council 2013-343.
[6] The objective of least cost planning is articulated in *Nalcor's Submission to the Board of Commissioners of Public Utilities with Respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project*, Nov. 10, 2011, p. 4.

As well, Labrador industrial rates, which serve two large customers, have two components arising from separate sources.[7] The cost of generation services is subject to direction by the Provincial Government and is outside the COS study of NLH. Transmission costs are within NLH's COS. This bifurcation would complicate cost allocation for industrial customers in a combined jurisdiction. Creating a single industrial class would require unbundling of pricing.[8] Retaining two separate classes would likely be more sensible, significantly negating the benefits of creating a combined service territory. Another factor suggesting separate treatment would be that the marginal cost to serve the two industrial groups could be quite different at times, given the possibility of transmission constraints separating the two regions temporarily and unexpectedly.

Additionally, Labrador's cost of service and, hence, retail pricing is very low compared to Island rates. In the 2015 COS study, Labrador rural interconnected average cost to serve is just 2.8¢/kWh, while Island average cost to serve is 8.4¢/kWh. The source of the difference is the dominant role in serving Labrador of Churchill Falls power, which currently costs just 0.2¢/kWh. Unifying service territories would likely have significant rate impacts. Such impacts might appear to be cost justified, but the contractual elements providing low-cost Churchill Falls power to the Labrador interconnected System will not be negated by the completion of the LIL.

Discussion/Analysis. It appears that NLH can resolve this issue in two ways that potentially lead to similar outcomes. First, the COS methodology could retain separate treatment of

[7] One of the two, Wabush Mines, is closed and in receivership, with resulting loads at a very low level.
[8] See Newfoundland and Labrador Hydro, *2016 Labrador Industrial Rate Submission*, December 22, 2015.

the two interconnected systems, based on the belief that all new and future assets and expenses will be readily separable by service territory. This would be computationally simple in the short run and would conform to cost assignment requirements. Second, the COS methodology could unify the two areas but retain separate rate classes based on geography, thus retaining the ability to allocate costs in the mandated fashion. This alternative might more readily accept future cost allocation in cases of assets or expenses that both regions must share. If this unification is not performed, then a "jurisdictional" assignment of costs must continue.

The combination of institutional and technical considerations appears to indicate that combining regions would be challenging, although possible. Costing theory and power flows do not necessarily line up with contractual mandates that assign the resource cost of power from specific locations to specific groups of customers. However, the power flows here appear to reasonably approximate the contractual mandates. It is difficult to see how a combination of regions could improve or simplify the allocation of costs after commissioning of the Muskrat Falls project.

Regarding combination of existing assets, this could not happen for generation, due to the contractual arrangement in Labrador whereby Churchill Falls recall power serves Labrador customers at a price determined outside the COS and GRA process. Even combining transmission assets would be difficult due to statutory requirements. The LIL and LTA are not cost obligations of Labrador customers, but of Island Interconnected customers only.

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

3. GENERATION

Issues. NLH's generation mix and regional configuration will change substantially at the time that Muskrat Falls and its associated transmission links, which is anticipated to be put in service in the second half of 2018, with 2019 being the projected first full calendar year of service of these facilities. How should this reconfiguration affect the allocation of generation costs?

Background. At present, NLH classifies and allocates its generation costs in a manner that attempts to recognize each facility's role in generation dispatch. Peaking units are classified as all-demand and other units are recognized as each having an energy and demand component. System load factor is the leading basis for classification. The method of classification varies with the type of generator and region. The table below provides a summary.

Current Classification and Allocation
Of Generation Assets of NLH

System	Generator Type	Classification	Allocation
Interconnected			
Island	Hydraulic	System Load Factor	D: 1 CP; E: annual Energy
	Holyrood	Capacity Factor (5-yr)	D: 1 CP; E: annual Energy
	Gas Turbines	Demand	1 CP
	Diesel	Demand	1 CP
Labrador	Gas Turbines	Demand	1 CP
	Diesel	Demand	1 CP
Isolated			
Island	Diesel	System Load Factor	D: 1 CP; E: annual Energy
	Other	System Load Factor	D: 1 CP; E: annual Energy
Labrador	Diesel	System Load Factor	D: 1 CP; E: annual Energy
L'Anse au Loup	Diesel	Demand	1 CP

The system load factor approach to cost classification attributes a share of generation investment cost to energy causation, based on the assumption that generation investment to meet average load should be distinguished from generation investment designed to meet peak demand. NLH uses system load factor to identify the share of production assumed to be base and intermediate generation-related. The generation cost not accounted for by energy classification is attributed to peak demand.

NLH classifies the Holyrood thermal generation facility separately, based on its average historical and forecasted capacity factor. The 2015 Test Year historical average five-year net capacity factor of 24% indicates the generator’s use primarily to meet demand needs as opposed to energy supply. Isolated systems use versions similar to the interconnected system methods.

NLH also engages in power purchases currently. The Island Interconnected system obtains the majority of its purchases from non-utility generation consisting primarily of hydro resources, along with some wind purchases. The hydro purchases are classified in the same manner as utility hydro resources (system load factor) and the wind purchases are classified as energy-only.

Labrador Interconnected purchases are entirely from Churchill Falls, and are classified on the basis of Labrador system load factor. Isolated system purchases occur mostly at L'Anse au Loup. Purchases are classified as energy-only due to their non-firm nature. Due to these purchases, that system's diesel unit is classified as demand-related.

Allocation of energy-related costs occurs on the basis of annual energy, while demand-related cost allocation is based on the 1 CP method, *i.e.* usage by each class in the single highest coincident peak hour of the year. These practices are conventional by industry standards, although utilities use a variety of CP definitions to reflect the seasonality of their peak usage.

The table above displays the classification and allocation of the generation cost elements of rate base. It does not display the dominant element of generation cost in COS: fuel costs. At present, these costs are the most significant element in revenue requirements, and the dominant component of fuel cost is no. 6 fuel for the Holyrood generating station. No. 6 fuel is classified as entirely energy-related while other fuels are classified in the same manner as the generator that they supply. The effect of this large fuel cost is that Holyrood revenue requirement is classified between 85-90% as energy.

The composition of NLH's generation assets and expenses will change significantly after 2018, with the introduction of Muskrat Falls' 824 MW of new hydraulic capacity, linked to the Island and to the Eastern Interconnection by undersea DC lines. The addition of Muskrat Falls to the NLH system facilitates the eventual retirement of the Holyrood thermal generation unit. The introduction of new DC interties to the mainland also raises the possibility of additional wind generation.

NLH will pay for the new generation services of Muskrat Falls via a stream of power purchases scheduled to recover the full costs of the new generation source over a fifty-year period. Payments will be predominantly monthly lump sum charges covering capital cost and operations and maintenance (O&M) expenses. The contractual agreements between NLH and MF also include periodic true-up payments covering the difference between actual and forecasted O&M costs and the cost of sustaining capital.

Classification and Allocation

Discussion/Analysis. Muskrat Falls and the associated transmission links have arisen because they have been deemed the least cost means to satisfy projections of energy and reliability needs of the Island. The expected export of wholesale power through Nova Scotia to the competitive wholesale markets of the Northeast increases the utilization of Muskrat Falls capacity, thus improving the viability of the NLH's overall resource package. The practical operation of these facilities is expected to fulfill this strategy, with power flows south forecasted to approach the limit of transmission capacity in many hours.

The NARUC COS Manual reveals many different ways to classify generation plant, some demand-only in nature and others, a combination of demand and energy, are termed "energy weighting methods."[9] Since none of the conventional approaches can claim unchallenged superiority, the NLH approach, which is a variant of the energy weighting methods, appears to be within the norms of industry practice.

This approach might, at first look, be feasible with the introduction of Muskrat Falls. NLH would treat the new facility in the same manner as other hydro facilities, by classifying on the basis of SLF. At current SLF levels of about 55%, a sizable portion of the facility would be treated as energy-related. However, one implication of the substitution of Muskrat Falls for Holyrood generation under the assumption of SLF classification is that the demand composition of generation revenue requirements may rise substantially. As mentioned, Holyrood's revenue requirement has historically been approximately 90% energy-related while that of Muskrat Falls under SLF would be approximately 55% energy-related.

A significant change in the makeup of generation capability can be expected to change system operations such that existing classification methods may be rendered out of date. While applying the SLF method to a new hydro unit may appear sensible, the shift in demand and energy components may misrepresent system operations as a whole.

An alternative approach to SLF of classifying the costs of Muskrat Falls might be to use the *equivalent peaker* methodology. This approach postulates that any cost per unit of capacity

[9] The NARUC Electric Utility Cost Allocation Manual, January 1992. Generation cost classification and allocation methods are discussed beginning on p. 39.

that exceeds that of a peaking unit should be classified as energy-related, while the peaking unit cost component is classified as demand-related. Baseload and intermediate units are typically more expensive to build than peaking units, and that extra expense is viewed as being energy-driven. That extra cost is incurred in order to save fuel cost relative to peaking unit production, with generation investment occurring to attain least cost production.

The equivalent peaker method is viewed by some as giving formal recognition to the generation planner's selection of a range of plants to serve the system. (The argument is that generation must meet peak demand, but that generation planning is caused by a need to meet varying load durations.) Muskrat Falls is a baseload unit with costs imposed as a lump sum on Island Interconnected customers. This approach recognizes that fact by treating much of its cost as being energy-related.

To implement this approach, the utility develops an estimate of the current cost per kW of a peaking unit, and compares that with the cost per kW of the new generation unit, being careful to use the same vintage as the plant under study. The actual computations can be complex, since they allow for plant vintage and financial cost details. However, it is possible to illustrate this approach in simplified form here. Suppose that the discounted revenue requirements for Muskrat Falls and its associated transmission investments of LIL and LTA approximate \$870 per kW, while the charges for CT capacity are \$219 per kW, stated in \$CAD.[10] The demand share of Muskrat Falls would be \$219 /\$870, or about 25%. The energy share would be the residual 75%, which is below the 90% share of Holyrood revenue

[10] These calculations are provisional, based on NLH's informal estimates.

requirement. Based on this estimate, it may be that the final shares developed by the equivalent peaker approach will better account for the main reason underlying the resource choice favoring Muskrat Falls—very large fuel costs savings over future decades. NLH's longstanding SLF approach, would likely obtain an approximate 45/55 split between demand and energy, a result which seems out of step with Muskrat Falls' envisioned purpose of serving base load and, in so doing, producing substantial fuel cost savings.

The equivalent peaker methodology received serious consideration by the Board in the 1992 COS methodology review. The approach was ultimately rejected for reasons of computational challenge, and plant vintage and valuation issues. However, those issues apply with less force in this case, since the peaking unit computations pertain to a plant of current vintage. As a result, this approach may deserve renewed consideration for its application to the classification approach for Muskrat Falls.

Following the introduction of Muskrat Falls power to the Island, Holyrood's role will change and the plant will eventually cease to perform as a generating unit. In the interim, the plant's net book value and fuel purchases will be reduced sharply in significance. Under the current methodology, the plant's capacity factor will fall gradually as its usage rate declines. The cost allocation implications will involve a reduction in fuel cost (classified as energy, of course) and a resulting shift in the direction of demand-related costs. With the plant coming to be used more for peaking purposes, serving in a standby role in its last years, this shift will be sensible. Another variant of this approach would be to shift the five-year average capacity factor to a forecast-only approach, causing cost allocation to reflect immediately the plant's changed role.

Holyrood's change in usage eventually will amount to NLH using the unit as a synchronous condenser, available for system stability but not supplying energy. At that point, it would begin to be treated as transmission rather than a generation facility. NLH could subfunctionalize it as such and then classify it in the same manner as general purpose transport services. (Please see the next section for a discussion of the classification and allocation of this type of transmission facilities.)

NLH's current generation cost allocation methods, as mentioned, utilize a 1 CP approach for demand-related costs and annual energy for energy-related costs. Both approaches are long-established and well recognized in the industry. In the transmission section, below, the report discusses several approaches to demand cost allocation. One of these arises from a U.S. Federal Energy Regulatory Commission (FERC) review of transmission cost allocation practice. It raises the issue of whether the 1 CP measure is preferable for cost allocation. Certainly, this measure is appealing in theory: it identifies class shares at the single hour of highest usage in the year, when the level that system planners recognize as the level of service to attain is recorded. Its weakness is the risk of anomalous behavior that might create variability over time. The issue is reviewed in the transmission section. The recommendation there—consideration of a 3 CP approach—may also be applicable here.

Marginal Cost-Based Cost Allocation

The upcoming transformation of the system and the advance of costing capabilities in North America and at NLH offer an opportunity to expand the range of costing methodologies relative to traditional demand-energy classification. The demand-energy approach, applied according to a variety of methods, attempts to compartmentalize costs in some sensible manner between costs incurred to meet peak demands and costs incurred to supply total energy. Its virtue is the effective use of limited available data to impute cost causation. Its weaknesses are that the information utilized is limited and there is no single preferred method of classification.

Marginal cost is defined as the change in total costs associated with a small change in the level of service provided. The concept is important because the price in a competitive market, where demand equals supply, is the marginal cost of providing the good or service. Marginal costs serve as highly desirable benchmarks of resource value because they communicate to all parties the economic worth of electricity services provided in particular timeframes, where services include energy, reserves or capacity. For regulated industries that in the past have not been viewed as workably competitive, marginal cost of service is a vital costing and pricing guideline for regulators.

Marginal costs have not been widely used for cost allocation in the past due to their computational challenges and the fact that total marginal costs do not necessarily equal the embedded costs that are the object of revenue recovery, subject to regulatory approval.

However, marginal costs can serve to develop an allocator that can be applied to embedded costs.

Marginal cost-based methods of cost allocation are particularly attractive for two institutional reasons. First, regulators seek methods, as a matter of public policy, that yield prices for public services that obtain improvements in resource efficiency. Thus, regulated prices should reflect the economic resource costs associated with regulated utility services, subject to the need to ensure revenue recovery. Second, with the development of wholesale markets, marginal costs are directly observable in wholesale prices. Thus, marginal costing offers the opportunity to link cost allocation, which guides regulated retail pricing, to wholesale market prices. As a result, marginal cost is playing an increasingly important role in wholesale and retail pricing, including cost allocation. The integration of marginal costs into cost allocation provides the basis to obtain improved efficiency. As a consequence, the allocation result has the potential to more closely adhere to the efficient outcomes that would result from competitive markets.

Marginal cost-based methods take advantage of the emergence of sophisticated techniques for measuring or estimating cost over hourly (and even finer) time intervals. The development of wholesale markets for energy, reserves services, and capacity, along with advances in internal cost computation advances, provide the means to project marginal costs over forward periods. This means that estimating the cost to serve a class of customers can be calculated by developing hourly marginal costs and applying them to hourly load profiles. The result is an annual total marginal costs for each class (and then a sum across classes representing the utility as a whole). By calculating each class's share of the utility total, one can derive a cost allocator applicable to generation services.

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.

In summary, the incorporation of marginal cost analytics within cost allocation captures the economic worth of the resources used in the provision of service. This result is both fair and efficient, and holds for both the internal cost and market-based marginal cost framework. Marginal cost-based COS provides cost foundation and detail by timeframe that is not available through conventional methods.

Thus, the marginal cost perspective provides the means to capture explicitly the components of generation services (including energy, reserves, and capacity) attributable to each class. Classes that tend to have high but variable usage at times of high capacity cost have their costs for the full year recorded. A utility that opts for marginal cost-based allocation of embedded costs can thus avoid classification debates (energy and demand shares of costs) and debates as to which measure of peak demand is most appropriate (*e.g.* 1 CP vs. 3 CP vs. 12 CP) but then must meet the challenge of modeling marginal cost.

Applying the marginal cost method requires hourly marginal cost and class load profile data sufficient to represent the range of likely market conditions that may apply in the service territory. NLH already has transmission-level hourly profiles for its NP and industrial customers, and for its aggregate rural customers on the Island and in Labrador. The utility has been developing forecasted hourly wholesale price/marginal cost scenarios for the forecasted early years of Muskrat Falls service, and is thus well on the way to operationalizing this approach.

Marginal cost-based allocation of embedded costs may seem to be novel, but variants of this approach have been in use for many years in a number of regulatory jurisdictions. West coast U.S. utilities have used this approach for twenty years.[11] In Canada, Manitoba Hydro applies a marginal cost-based allocation to generation services and utilizes a variant of the process in allocating transmission costs.[12]

Marginal cost-based allocation has sometimes been criticized for producing greater variability in allocator shares over time than embedded cost-based methods. Analysis of historical marginal costs can shed light on this issue. Concerns with respect to variation can generally can be resolved by the use of multiple scenarios for the development of marginal cost estimates over forward periods. As forecasts change, expected marginal cost levels and patterns change, and these changes can be incorporated within cost shares for consumer

[11] Example utilities include Pacific Gas & Electric, Southern California Edison, and Portland General Electric.
[12] The Manitoba Hydro method makes use of hourly marginal costs and loads in all hours of the year, by class for generation cost allocation. The utility additionally uses loads in many hours, the 50 highest-demand hours each in summer and winter, for transmission cost allocation.

classes. Such changes reflect in a timely manner expected changes in cost to serve. For example, a strongly peak-coincident class might see an increase in cost share if peak marginal costs/wholesale prices rise relative to off-peak. Conversely, a relative smoothing of price patterns would reduce the cost share of the class.

Under marginal cost-based cost allocation, NLH would first assemble its generation cost financial data and then assign costs to the five service regions. The three isolated regions would then have costs classified and allocated in the same manner as is currently applied, due to current data availability. To allocate each of the two interconnected regions' costs, NLH would develop hourly load profiles for its customers under various marginal cost scenarios and, summing across hours and scenarios, develop total marginal costs for each class in each region. Allocation would then be based on the shares of the total marginal cost to serve.[13] Allocator values would then be applied to aggregated generation assets and to generation-related expenses of each region.

One key issue will be determining how to treat the power purchases from Muskrat Falls. The payments are the form of lump sum capacity and O&M charges. Transmission lease payments that accompany Muskrat Falls charges for purchased power are also lump sum in nature, but are not broken down into capacity and O&M components. These charges will not vary with loads or peak demands, and resemble other generation fixed costs. Under a marginal cost-based approach, the lump sum of purchased power and transmission lease

[13] At present, NLH has hourly data for the combined set of interconnected rural customers in Labrador. Proxy hourly loads could be developed for the various rural classes based on billing data. Alternatively, the current method could be retained.

payments could be allocated on the basis of marginal cost-weighted usage, in the same manner as other generation-related costs.

On the periphery of the main cost allocation issues is the question of how to allocate the costs of wind generation. NLH has access to some wind at present, but independent wind generation might increase significantly in the future. Wind generation advocates sometimes argue that wind can have a capacity element and should not be classified as energy-only. NLH's system planners state wind is not available to meet system peak requirements. While originally conceived as substituting for Holyrood generation, that relationship no longer applies. This view underpins the utility's 2013 recommendation to treat wind generation as 100% energy-related.[14] This approach is common in the industry, although contribution to capacity has begun to be introduced. Additionally, after the commencement of Muskrat Falls service, new wind generation would most likely contribute to exports, as opposed to meeting peak demand of NLH customers. If marginal cost-based methods are introduced, wind generation purchases can be included in the allocation of the overall generation portfolio.

Recommendations. We recommend that NLH introduce marginal cost-based allocation of embedded generation costs for the Island Interconnected system beginning with the implementation of rates that recover revenue to cover payments by NLH for Muskrat Falls and its associated transmission facilities. This change will avoid the need to allocate each generation asset or cost on its own and relates cost to serve to an objective market-based

[14] See NLH, *2013 Amended General Rate Application*, Section 4.3.2.

value of generation services that recognizes cost to serve by each rate class in each hour. It appears that NLH can undertake this approach, as the utility already possesses the costing capabilities to generate the requisite marginal cost scenarios.

Marginal cost-based allocation can be used in the Labrador Interconnected system as well, following the Muskrat Falls in-service date. For Labrador, projections of marginal cost will be developed from the same process as used for the Island Interconnected system.

Until the Muskrat Falls project is included in the cost of service, we recommend that NLH continue its current generation cost allocation methodology, with modifications agreed upon in the 2013 Supplemental Settlement Agreement, specifically with regard to the treatment of Holyrood fuel and wind generation as 100% energy-related.

If marginal cost-based cost allocation of generation is not adopted for the period after the Muskrat Falls in-service date, the current system, with some modifications, could be retained after the transition, but with classification of Muskrat Falls costs based on the equivalent peaker methodology. It appears that this approach might prove more in line with generation planning practice, and might better reflect the base load role of Muskrat Falls than would an SLF allocation approach.

After Holyrood is converted into the role of synchronous condenser, then the plant should be subfunctionalized as transmission and its costs allocated in the same manner as general purpose transport facilities (described in the next section). The reduced fuel costs incurred at Holyrood prior to the conversion to transmission should continue to be allocated on the basis of energy.

If the plant does not immediately come to be used as a synchronous condenser, then it should be retained as generation and functionalized according to marginal cost-based cost allocation. In the event that marginal cost-based allocation is not adopted and the plant is still treated as generation, then the current capacity factor methodology, altered by the use of forecast-only capacity factors, would suffice.

We recommend that wind resources be allocated in the same manner as other generation facilities if marginal cost-based cost allocation is adopted. If not, then we recommend that NLH adopt a classification method based on NLH planners' forecasts. Current forecasts indicate that wind generation does not contribute to the ability to meet peak demand and should therefore be classified as 100% energy-related.

4. TRANSMISSION

Transmission costs, in their familiar form, consist of capacity costs recorded as fixed capital and operations and maintenance costs. Utility and regulatory practitioners are also familiar with transmission line losses, which are short-term variable and fixed transmission costs, and are recorded as variable energy costs. This section discusses each of these types of costs, focusing first on the treatment of capacity costs. Line losses are not always discussed as part of the process of reviewing a utility's COS methodology. However, in this case, projections of line losses associated with the new transmission investments help to highlight the nature of the changes that will take place in the system. The pattern of losses has implications for capacity cost allocation issues discussed below.

4.1 Capacity Costs

Transmission Facility Categories

Transmission facilities consist of conductors, poles, towers, transformers, substations, relays, meters, voltage support equipment, switchgear, monitoring gear to facilitate real time observability, and specialized equipment such as long distance direct current (DC) circuits and associated conversion equipment including rectifiers and inverters. This equipment, which together comprises transmission networks, can be categorized, for purposes of addressing cost allocation issues for the NLH power system, into four facility types:

- *Generator Interconnection Facilities:* sometimes referred to as generator leads, interconnection facilities consist of a dedicated equipment bundle associated with the interconnection of generators to the NLH transmission network. This equipment includes lines, substations, step-up transformers, switchgear, and monitoring equipment;
- *General Purpose Transport Facilities:* transport facilities include the equipment bundles which are most observable and recognizable as transmission: conductors, towers, poles, insulators, hangers; relays; reactors, capacitor banks and static var compensators to maintain/control voltage and provide stability; switches and protection gear;
- *Terminal Stations:* substations, transformers, switchgear, meters, and monitoring equipment; and,
- *Special Facilities:* an array of transmission facilities such as frequency converters and phase shifters. The relevant special purpose facilities for NLH include long direct current (DC) facilities such as NLH's Labrador Island Link (LIL) and associated rectifiers situated within the Muskrat Falls switchyard and the inverters situated at the Soldiers Pond substation, integrated within NLH's high voltage network on the Avalon Peninsula.

Additionally, some utilities, NLH included, assign transmission facilities that serve a single customer directly to that customer. This study reviews NLH's treatment of specific assignment in a separate section of the report.

Subfunctionalization

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

General Purpose Transport Facilities and Terminal Stations. These facilities inherently belong to the transmission function as a matter of definition and purpose. However, even among these quintessential transmission facilities, there is an exception: the converter facilities located at the Muskrat Falls and Soldiers Pond stations that serve as the terminal points of the LIL. These highly specialized facilities, including rectifiers, inverters and associated equipment, are a matter of some debate. As a component of the LIL, they are probably best functionalized in the same manner as the LIL, a special purpose facility discussed immediately below.

Special Purpose Transmission Facilities. Special purpose facilities are constructed for, or primarily because of, the provision and facilitation of least cost generation. Least cost generation plans reflect real-world constraints: generation cannot necessarily be sited near load centers. Large-scale generation, including hydraulic facilities, nuclear stations, and wind farms, often requires sizable properties, selected according to geographical features, available resources, and societal externalities and constraints.[15] These sites can be remote locations, thus requiring extended transmission leads in order to bring power supply into meshed transmission networks and load centers.

This is particularly the case with remotely sited hydraulic facilities where, because of the distances involved, DC facilities are the preferred technology choice. Under these conditions, the commitment of specific generation facilities is a resource choice involving joint generation and transmission—akin to a fixed proportions production function: generation provides no value in isolation of transmission; similarly, transmission provides little to no value in isolation of generation.

Also, transmission can substitute for local generation, in selected cases. For example, the recent expansion of transmission capability in Southwest Connecticut and along California's Path 15 rather dramatically improved flows, thus reducing the costs of generation by significantly lowering congestion costs, specifically costs related to out-of-merit generation

[15] *Geographical features* can include suitable sites within large river basins such as that of the Churchill River or remote locations with sufficient wind velocities for wind farms; *available resources* can refer to water sources to satisfy the cooling requirements of nuclear power stations (e.g., Georgia Power's Plant Vogtle Units 3 and 4, currently under development) or nearby rail and gas pipelines; *societal externalities* can refer to siting rules and regulations which delimit the available routes to site new transmission lines.

dispatch. Conversely, special purpose transmission facilities often accompany generation and special circumstances with respect to geography and opportunities to exploit and favorably employ natural resources.

The NLH system includes two major special purpose transmission facilities:

- *__Labrador Transmission Assets (LTA)__:* The LTA facilities are being put in place in order to enable least cost operation of the combined Churchill Falls and Muskrat Falls generation facilities. We can expect that the LTA facilities will improve network reliability while also facilitating energy transfers outside the Province.
- *__Labrador-Island Link (LIL)__:* The LIL is a 1,100 km DC transmission line, stretching from Muskrat Falls in Labrador across the Strait of Belle Isle, then southeast to Soldiers Pond on the Avalon Peninsula. LIL and MF constitute an integrated resource strategy where the net economic benefits of the strategy are jointly determined. The incremental economic value of LIL is compromised absent MF; and similarly for MF, absent LIL.

The transfer capability of the LIL is 900 MW. Because of capital indivisibility, the LIL can be utilized, especially in its early years, to serve out-of-province loads in addition to native loads. In combination, MF and LIL provide the capability for significant power exports through Maritime Link during the early years of the life of capital. However, capability for power exports is largely incidental: Nalcor's commitment to Muskrat Falls in combination with Labrador Island Link is for NLH electricity consumers—the Province as a whole.

The LIL can be subfunctionalized in two different ways. One approach is to treat the LIL as a "generation lead" that stretches from Muskrat Falls to Soldiers Pond, thereby functionalizing the facility as generation. Other Canadian utilities (BC Hydro, Manitoba Hydro, and Hydro-Quebec) make use of this approach for the DC connections from remote hydro generation sites to load centers.

The second approach is to assign the LIL facility to generation and transmission. Arguably, because the LIL creates a DC-dominated transmission loop on the fringe of the Eastern Interconnection, in which flows in both directions are at least theoretically possible, the LIL can be viewed as an example of joint-use facilities. In this case, the LIL could be assigned jointly to the generation and transmission functions, at least for the near term. Functionalization could occur based on some measure of native load and export shares of LIL transportation. The native load share would be classified as generation and the export share would be classified as transmission, since that is the share that will make use of the loop configuration.[16] (Note that this does not mean that a share of costs will be allocated to export load.)

[16] The shares of the revenue requirements associated with the LIL facility—which are in the form of monthly lease payments—can be determined in two ways, as follows:

- *Rated Path Method:* shares of LIL revenue requirements (RR) are assigned to generation and transmission according to the 12-month average of the expected flows over the LIL facility attributable to native loads and to export sales. The flows attributable to native loads are assigned to generation, where the remaining share of revenue requirements (for LIL facilities) is assigned to transmission. The rated path method is described in section *MOD-029* within the "White Paper on the MOD A Standards", *North American Electric Reliability Corporation*, July 3, 2013.
- *Native Peak Loads and Export Sales:* the share of the annual revenue requirement attributed to generation is the load ratio share of native loads within total system loads including export sales. The remaining share, attributed to transmission, is the load ratio share of export sales in total system sales.

However, this second approach creates conceptual difficulties for NLH given the structure of its agreements facilitating the LIL. The Order in Council that sets out the Muskrat Falls Exemption Order states that all costs are to be paid by NLH native load customers, since the LIL and MF are being constructed based on the supply needs of the Island without consideration of export opportunities.[17]

Subfunctionalization Recommendations.

NLH should continue to assign (functionalize) to generation the costs of generator interconnection facilities. General purpose transport facilities and terminal stations should be assigned to the transmission function. The converter facilities located at the Muskrat Falls and Soldiers Pond stations should be functionalized in the same manner as the LIL facility.

The special purpose facilities which comprise the Labrador Transmission Assets (LTA) should be assigned to the generation function for the reasons discussed above—facilitation of efficient use of hydro facilities along the Churchill River, including the Churchill Falls and Muskrat Falls stations. We recommend that the LIL facility, including its converter facilities, be functionalized as generation, in harmony with the formal cost designation of the facility as providing service to the Island.

[17] Reference the Order in Council 2013-343.

Classification and Allocation

Generator Interconnection Facilities. The previous section set out the alternatives for classification and allocation of generation facilities. NLH will presumably wish to classify and allocate the generator interconnection facilities in the same manner as other generation facilities. The options include retaining the current approach, in which classification and allocation by generator type occurs, or moving to the marginal cost-based approach, in which marginal cost-weighted shares of annual energy are the basis for both steps.

General Purpose Transport Facilities. Much of transmission cost classification and allocation is much more convoluted than generator interconnection; a cost allocation bright line is not easily discerned, since network operations are characterized by measurable externalities. Current industry practice is typically to classify general purpose transport facilities, terminal stations, and non-assignable special facilities as demand-related and then allocate costs to customer groups according to coincident peak demands. For this broadly defined facility pool (general purpose transport, substations, special equipment), such an approach is based on planners' longstanding assumptions that costs are more or less exclusively a function of peak demand.

The longstanding approach of NLH is compatible with this practice. The utility classifies much of its transmission costs as demand-driven and allocates transmission-related costs according to a 1 CP allocator. Some NLH generation-related transmission costs are classified in the same manner as their associated generation assets; in so doing, NLH resolves the issue of functionalization of generator interconnection costs: even if not assigned to generation, these costs are classified and allocated as extensions of their associated generators.

General Purpose Transmission Cost Classification Alternatives. The CP approach is reinforced by the policy of the FERC. In the case of broadly defined general use facilities, all-in total costs of transmission facilities are recovered as monthly $/kW access charges, determined according to load ratio shares based on coincident demands and, on occasion, non-coincident demands in the case of subtransmission.[18] In other words, in this consensus view, it is the expected level of peak demands which have, over decades, driven ongoing investment in transmission and, thus, cost allocation.

The use of demand-only allocation is broadly applied in contemporary systems in North America, a practice partly justified additionally by the mature state of the grid. To a large extent, power networks have been more or less fully developed, at least notwithstanding grid development to transport power produced by renewable resources situated in areas remote from load centers.[19] For developed systems, investment to increase capability is necessary largely to satisfy year-over-year growth in peak demands: accordingly, demand-based allocation is arguably appropriate for power systems that are substantially *built out*, either as meshed, loop, or radial systems.

[18] Generally, load ratio shares are based on observed loads and firm transmission reservations over a recent twelve-month period (12 observations of loads *pro rata*) or according to projected loads and reservations over a forward period. (This does not imply that NLH would need to use a 12 CP approach.)

[19] Not mentioned is the impact of restructured wholesale electricity markets, which have given rise to changes in flow patterns and thus revealing, in the process, the need for further grid expansion to better manage congested networks. A salient example is the expansion of Path 15 in California's wholesale market.

This view of transmission investment is open to challenge on causality grounds in that the factor of transport distances is clearly a cost driver for transmission.[20] (The longer the line, the greater the amount of equipment.) However, for electricity transactions, the dimension of distance is not easily measured or observable, notwithstanding the locational pricing inherent in unbundled wholesale markets, where the price differences reflect network congestion and marginal line losses. Even if the relationship between costs and transport distances is understood, the cost allocation process would need to attribute transport distances, and thus costs, to consumer groups with sufficient accuracy. In brief, billing consumer groups for electric transport distances, on an embedded cost basis would undoubtedly prove to be daunting and highly unwieldy. Such an approach would constitute a major departure from the demand-only classification convention and, if implemented, might lead to significant changes in assignable costs across consumer groups.

Is there any alternative to demand-only classification of general transmission facilities that bears consideration? One might explore this by categorizing transmission expenditures into major categories by type or purpose, such as replacement-, reliability-, extension-, and load-related activities, and then applying transmission planners' expertise to classify historical expenditures in each category. Some expenditures might be clearly peak demand-related, while others could be viewed as reliability reinforcement, or replacement and thus assigned to energy for purposes of cost allocation. While not explicitly accounting for transport

[20] At the most basic level, electric transmission is a transport service similar to air freight and long-haul rail services. For freight media, the costs of transport services are determined by both load (tons of freight) and distances (kilometers). Hence, freight of all types is typically billed according to ton-km/ton-mile metrics.

distances, such an approach would face clear challenges in the form of complexity, cost ambiguity, and uncertainty of stability over time.

Another alternative is to conceive of general transport facilities as no more than an extension of generation. If so, these facilities would then be viewed by utilities using a method of classification into demand- and energy-related cost as having a similar mixed demand-energy causation. However, this view of transmission is not common relative to the demand-only perspective.

At NLH, the plain fact of COS methodology continuity suggests retention of demand-only classification, in the absence of an alternative method that can improve on the established method.

General Purpose Transmission Cost Allocation. The cost share of real expenditures attributable to peak demands requires some means of measurement. Peak loads can be determined in one of three ways.

- *Conventional Coincident Peak Method.* NLH would determine the class shares of demand in peak hours using an appropriate measure of coincident peak. Hitherto NLH has utilized a 1 CP approach. Often utilities prefer some form of CP calculation that relies on more than the single hour peak hour of the year in order to avoid statistical anomalies from such a small sample. The U.S. FERC has been using a test in its cost allocation proceedings for some years. This test, applied to NLH peak demands, suggests that a 3 CP measure would be preferable to a 12 CP measure, even after 2019. Please see the note below for details.
- *Peak Load Frequency.* This method uses the frequency in which the hour and month where peak loads are expected to occur. Peak load frequency serves

as the basis to determine hourly weights which, by definition, sum to one over an annual period;[21] or,

- *Pro Rata Peak Load distribution.* Based on a max function algorithm, shares of an annual revenue requirement for transmission are assigned to system-level peak load hours *pro rata*. The max function algorithm is also used to estimate marginal capacity costs.[22]

The remaining costs shares[23] are then classified accordingly to energy. For general purpose transport facilities, the energy share basis of allocation can, potentially, weight hourly loads by marginal costs (both in hourly frequency).

A Note on the FERC's CP Allocation Tests. FERC typically uses a coincident peak method to allocate demand costs, allocating based on each customer class's demand at the time of system peak demand. The coincident peak may be based, for example, on a single peak month (1 CP), the average of three peak months (3 CP), or the average of peaks in all twelve months (12 CP). The 1 CP method reflects traditional planners' views on the significance of the single highest peak of the year. In contrast, COS tends to seek a broader picture of peak demand. A utility that has a relatively flat demand requirement throughout the year would typically allocate demand costs on a 12 CP basis, recognizing the relatively constant peak demand requirements. A winter- or summer-peaking utility would more typically allocate

[21] For NLH, prior to the in-service date of Muskrat Falls, the determination of peak load frequency requires simulation analysis, where expected export sales are combined with observed historical peak loads, both measured in MW. Export sales can markedly alter the frequency distribution of peak loads from the observed historical pattern for native loads alone.

[22] The results of the max function algorithm, as a matter of practical application, prove to be unusually sensitive to the defined allocation parameter (referred to as simply α, and assumes a value within the interval $0 < \alpha < 1$) over certain parameter ranges.

[23] Note that a share of reinvestment to replace aging capital will be in the service of peak loads, insofar as the share of the historical investment in legacy assets is driven by the expected peak loads, at the time of investment.

demand costs on a 3 CP basis which assumes the system will peak during the three months with the highest peaks.

As mentioned, NLH currently applies a 1 CP method to transmission cost allocation. This approach has been widely used in the past, for the good reason that the single hour of highest use is the benchmark for system planning.[24] Other time periods, though, have been considered for a number of reasons. First, for many utilities (but not NLH), summer and winter peaks are not far apart and the class shares can differ significantly by season. Giving weight to peak hours in both seasons avoids possibly dramatic changes in cost shares over time. Second, measuring cost shares using a single hour of system peak can be statistically unreliable. As a result, utilities, even strongly seasonal utilities, have gravitated toward a 3 CP alternative to 1 CP.

In an effort to manage the seasonality issue, the FERC has developed three tests of seasonality of peak demands as guides to selection between 3 CP and 12 CP.[25] The three tests are:

- <u>The On- and Off-Peak test.</u> Compute two quotients: average system peaks during the peak season/annual peak demand and average system peaks during the non-peak season/annual peak demand. If the difference between these quotients is less than 19%, the conclusion on this test is that the utility is best represented by a 12 CP measure.
- <u>The Low to Annual Peak test.</u> Compute the quotient of the lowest monthly peak demand and annual peak demand. If that quotient is greater than 66%, the conclusion on this test is that the utility is best represented by a 12 CP measure.

---

[24] Reference the NARUC *Electric Utility Cost Allocation Manual*, January, 1992, p. 77.
[25] The tests are described in FERC opinion Golden Spread *et al* v. Southwestern Public Service Company, opinion no. 501, dockets EL05-19-002 and ER05-168-001, issued April 21, 2008, at paragraph 76*ff*.

- <u>The Average to Peak test.</u> Compute the quotient of the average of the 12 monthly peaks and the annual peak demand. If that quotient is greater than 81%, the conclusion on this test is that the utility is best represented by a 12 CP measure.

While some utilities are clearly quite seasonal, with all measures resulting in a 3 CP determination, and others are clearly less seasonal, with a 12 CP determination, still others provide mixed verdicts. The tests are used as guidelines, rather than rules, with an understanding that utility results can be close to the test boundaries.

NLH computed these tests, making use of forecasted peak demands for 2019 and 2020. They tested their system both including and excluding export sales. The results of the tests appear in the table below. Each cell presents the number of the above-mentioned tests that supported either the 3 CP or 12 CP construction. There are three test results for each of the two years, six in all. The tests are performed for two scenarios, one in which load totals are comprehensive, including export flows, the other in which exports are excluded from the computation.

The tests appear to support the conclusion that the utility, at least in the early stages following the Muskrat Falls in-service date, is best represented by a 3 CP representation. If exports are excluded, all six tests (three per year) support the 3 CP conclusion. If exports are included, two of three tests support the 3 CP conclusion in each year, for totals of four 3 CP outcomes and two 12 CP outcomes.

FERC Tests of NLH Seasonality
2019-2020

Seasonality	Including Exports	Excluding Exports
3 CP	4	6
12 CP	2	0

If these tests are to be accepted as guidelines, it is not strictly necessary to evaluate which column should serve as the reference point. However, given that the "including exports" results are less than fully conclusive, it is worth reviewing the issue of scenario selection. In our view, the shares allocated to NLH's customer classes ought to be measured with reference to the times when the system is at or near peak usage. This suggests that the full utilization of the system matters. Consider a hypothetical case in which a system's native load customers peak in the winter but that overall use of the system peaks in the summer. When should the shares of customer class usage be measured? If the system is built, either by design or due to project indivisibilities, such that the peak usage is in the summer, then contribution to the summer peak should be determinative.

Note that the preference for the inclusion of export loads in the determination of the peak season does not mean that export loads are included in cost allocation. It is assumed that regardless of the presence of exports, the transmission system is designed to serve native load. The approach recognizes the role of exports in determining the level and timing of system loading, but continues to allocate costs based on native load shares at the time(s) of coincident peak.

The FERC seasonality issue highlights the challenge of understanding and measuring transmission cost drivers. The other measures proposed take advantage of greater data availability and statistical sophistication to measure the probability with which peak demands occur in individual hours, and distribute the class responsibility for transmission cost based on hourly loads and probability of setting a peak. In spirit, these methods are close to the marginal cost-based computation recommended for generation cost allocation. These methods use more data than the traditional method but offer perhaps greater stability of measure given the use of information in more hours. These methods also may reduce the issue of determining utility seasonality in borderline cases (*e.g.* 3 vs. 12 CP) by objectively weighting the relative importance of each hour. Over time these weights may change, but significant changes in cost weights are unlikely.

Terminal Stations. Terminal stations provide interconnection among the various branches of meshed and radial transmission systems, and include equipment to transform voltage, provide voltage control, relays, switchgear, and various automated monitoring and control equipment, and phase shifters. Broadly speaking, investment in terminal stations is determined by peak loads and the amount of transformation, viewed at a system-wide level. Industry practice, as with general purpose transport facilities, is to classify costs related to these facilities as demand-related. NLH currently subscribes to this approach. Allocation typically takes place in the industry by means of a CP demand measure, although the use of annual noncoincident peak (1 NCP) is not uncommon. The CP measure selected can be the same as that used for general purpose transmission facilities.

Special Purpose Transmission Facilities. Classification and allocation of these facilities depends upon decisions regarding functionalization. For facilities classified as generation-related, which treats the DC lines of the LTA and LIL as generation leads, allocation compatible with the allocation of other generation assets is appropriate.

Classification and Allocation Recommendations

Generator Interconnection Facilities. We recommend that NLH classify and allocate the costs of Generator Interconnection Facilities in the same manner as their related generation facilities. If NLH adopts marginal cost-based allocation of embedded generation costs, then marginal costs would apply to the financial costs of generator interconnection as well. If NLH retains its existing allocation methods, we recommend that NLH assign interconnection facilities costs with each specific generator and allocate costs in the established manner.[26]

General Purpose Transport Facilities. We recommend that NLH retain the demand-only classification approach due in part to the absence of an analytically preferable or cost effective alternative, and partly to its acceptance by system planners of its ability to approximate their thought processes.

Demand-related costs should be allocated based on one of the three methods proposed. The Peak Load Frequency and *Pro Rata* Peak Load Distribution methods offer improved accuracy and stability over time, as well as an hourly analysis approach similar to that

[26] In theory, one could allocate generation costs, including those of generator interconnection, according to the marginal energy and capacity costs during the timeframes that the maximum level of output of each of the respective generation stations is approached. For some generation stations, high levels of production can occur in many hours; for others, only a few.

recommended for generation cost allocation. However, they require more analysis than the traditional CP method. If the traditional CP method is selected, we recommend that NLH adopt a 3 CP approach in preference to the traditional 1 CP approach, for reasons of statistical reliability. (Note that this does not suggest that planners deprecate the importance of the single annual peak for planning purposes but simply use more than one hour for cost allocation.)

Terminal Stations. The charges on capital and O&M costs (revenue requirements) associated with Terminal Stations should be classified as demand-related and allocated according to one of the methods described above.

Special Purpose Transmission Facilities. Assuming that the LTA is functionalized as generation, we recommend that its costs be classified and allocated in the same manner as other generation assets. (Our recommendation under this assumption would be that the LTA be allocated in the same manner as Muskrat Falls, based on marginal cost or, alternatively, equivalent peaker methods.)

If the LIL is functionalized as generation as well, it should be treated in the same fashion as the LTA. If, instead, the LIL is functionalized as jointly generation and transmission, the generation component can be classified and allocated in the same manner as Muskrat Falls. The transmission component would then be viewed as general purpose transmission facilities and classified and allocated in the approved manner.

4.2 Transmission Line Losses

NLH's grid is undergoing major restructuring including large-scale investment in generation and transmission facilities, and deep involvement in wholesale electricity markets. Key features of these changes are taking place in transmission, as follows:

1. Interconnection between the Labrador and Island power systems facilitated by the Labrador Island Link (LIL), a dual circuit DC facility (900 MW capability);
2. Coordination of energy management between Churchill Falls and Nalcor's new Muskrat Falls hydro facility (MF or Lower Churchill), facilitated by Labrador Transmission Assets (LTA), a dual circuit 315 kV AC facility (approximately 900 MW capability);
3. Interconnection of the Island system with the Eastern Interconnection, thus facilitating power transactions with the organized power markets of the Northeast through the Maritime Link, a dual circuit DC facility (approximately 500 MW capability); and,
4. Investment in the NLH's high voltage AC network (230 kV) in order to satisfy reliability standards associated with increased power flows across the NLH power system.

The NLH power system is currently comprised of high voltage (230 kV) and lower voltage (66 kV–138 kV) facilities configured within meshed and radial networks. NLH's transmission network spans fairly long distances in order to serve the sizable urban area residing on the Avalon Peninsula (St. John's) as well as rural communities and towns located throughout the Province. Restructuring includes major additions to the NLH network, as identified above. Coupled with the commercial operation of Muskrat Falls and significantly expanded export sales, the impacts on the NLH power system are twofold: flow patterns on key facilities will materially change, most likely; and the overall magnitude of average and marginal losses will likely rise.

Within transmission, system-wide average losses are often tabulated from observed power flows within networks, metered in hourly or monthly frequency. These data provide a historical record: determining total and average transmission losses involves adjusting observed historical quantities (MWh), for application within COS studies.[27] Beginning in 2019 however, major restructuring of the Newfoundland-Labrador Hydro (NLH) system will likely cause significant changes in both the profile and level of average and marginal losses. As a consequence, observed historical losses cannot be readily utilized within COS, following 2018. Thus, the issue: how should line losses be determined for purposes of cost allocation for 2019 forward, in view of the resource changes under way?[28]

It is perhaps useful to clarify key factors that determine transmission losses, which occur predominantly in the conductors that constitute transmission lines, as follows:

- Transmission losses are predominantly thermal losses, resulting from line resistances. Larger conductors will generally have lower losses.
- Transmission losses decline significantly with higher conductor voltages, as currents are lower by similar magnitudes.
- Line losses are approximately linear with respect to the length of circuits.
- Power system losses vary with respect to temperature: total and average losses decline under lower ambient temperatures, other factors constant.

Most importantly, thermal losses can change dramatically with respect to changes in load level and flow configuration on circuits. The Company has recently conducted a sizable set

[27] Average losses are non-linear with respect to load level.

[28] Energy costs for transmission are the physical loss of energy within transmission networks. Physical losses include charging losses and thermal losses, the latter often referred to as I^2R losses, where I describes electrical current flows within circuits, and R refers to resistance of the physical mass and related characteristics of conductors. Charging losses are associated with conductors and transformers and do not change with respect to load levels.

of load flow simulations covering selected seasons and load conditions including: *Winter: Peak, Moderate, and Off-Peak Loads*; *Spring-Fall: Peak and Off-Peak Loads; Cool-Summer: Peak and Off-Peak Loads*; *Warm-Summer: Peak and Off-Peak Loads*.[29] Load flow-based thermal and non-thermal losses resulting from these simulations are as follows:

Load Flow Estimates of Average Losses for the NLH Transmission Network, for Selected Season and Load Scenarios, for 2019
System-Wide Average Power Losses

Winter	
Peak	6.15%
Moderate	6.16%
Off-Peak	4.59%
Spring/Fall	
Peak	6.17%
Off-Peak	4.58%
Cool Summer	
Peak	8.19%
Off-Peak	5.95%
Warm Summer	
Peak	6.43%
Off-Peak	5.47%

The load flow studies[30] reveal some unusual patterns of loss levels across seasons. Specifically, percentage losses do not necessarily decline significantly during off-peak summer periods, although retail loads of the NLH power system vary significantly between the winter peak periods and the summer off-peak season. Sizable power flow withdrawals

[29] *Winter* season refers to the second half of November and December—March; *Spring/Fall* season refers to April, the first half of May, the second half of September, October, and the first half of November; *Cool-Summer* season refers to the second half of May, June, and the first half of September; Warm-Summer refers to July and August.
[30] The results shown above incorporate modifications to the load flow cases in to order to appropriately take account of expectations of differences in dispatch patterns to accommodate non-native loads. The result is improved estimates of energy losses with respect to changes in native loads—which is the relevant context for the immediate study.

at the Bottom Brook network location within the Island system alter the longstanding winter peak-summer off-peak load differences.

As shown above, energy losses within the Island AC 230 kV network can, under selected circumstances, rise during the off-peak summer season, reaching sizable levels. Although retail loads for summer decline, total loads may not be significantly lower in certain regions of the NLH network. Importantly, the power loading on lines within the Island AC high voltage system west of the West Avalon substation, because of the long distances—approaching 500 kilometers—can result in average losses above those of the winter season.

Recommendations

Following the in-service date for MF and its associated transmission links, NLH should estimate average losses with load flow analysis. Load flow study results can then be utilized to parameterize a losses algorithm based on the well-known I^2R approximation. The algorithm is directly applicable to the hourly loads utilized within COS studies, including energy and demand loss factors. For purposes of example, the table below presents estimates of average energy losses arising from recently conducted forecast hourly loss analytics. Shown as percentages of native loads, these average loss estimates are somewhat below—though close to—the losses obtained from the load flow cases. Specifically, average line losses for peak and off-peak hours are as follows:

Average Line Loss Percentage Estimates
NLH Power System for 2019

Month	Peak	Off-Peak	All-Hours	Maximum	Minimum
Jan	6.20%	5.49%	5.87%	7.18%	4.46%
Feb	6.34%	5.79%	6.06%	7.18%	4.82%
Mar	6.13%	6.10%	6.11%	7.31%	5.09%
Apr	6.12%	5.38%	5.77%	7.01%	4.64%
May	4.66%	4.18%	4.43%	5.64%	3.43%
Jun	4.66%	3.40%	4.06%	5.14%	2.88%
Jul	4.75%	3.27%	4.14%	5.12%	2.74%
Aug	4.53%	3.13%	3.93%	4.86%	2.46%
Sep	4.69%	3.41%	4.11%	5.47%	2.79%
Oct	5.05%	4.21%	4.66%	5.64%	3.38%
Nov	5.23%	4.78%	5.00%	6.30%	3.66%
Dec	5.93%	4.59%	5.31%	7.21%	3.10%
Annual	5.44%	4.70%	5.09%	7.31%	2.46%

The monthly average losses shown above were derived from an hourly losses algorithm, as parameterized according to a selection of load flow cases for 2019. As implied, the losses algorithm can be used to obtain estimates of peak and off-peak losses for monthly timeframes. Because of resource restructuring, it may be appropriate, for COS, to estimate and apply regional losses to selected areas of the NLH power system such as Labrador, Avalon Peninsula, and the Island AC network west of the Sunnyside substation.[31] Once sufficient historical experience under the restructured resources has accrued—say, two years—NLH can again utilize observed metered loads as the basis for estimating line losses (transmission energy costs).

[31] Loss measures of this sort are also compatible with the loss measure to be used in transactions with Emera via the Maritime Link. That measure utilizes a rolling 12-month average of measured losses which is likely to be quite close to the test year loss measure of total grid flows. See the Energy and Capacity Agreement, Schedule 3.

5. OTHER ISSUES

5.1 Rural Deficit

Issue. NLH charges its rural customers at rates based on those of Newfoundland Power, rates which fail to cover the cost of service, which tends to be high in isolated locations. NLH makes up the deficit with supplementary volumetric charges on Newfoundland Power and rural Labrador Interconnected system (RLIS) customers. The methodology of deficit allocation has been under review in the latest GRA, although stakeholders have not agreed on a change advocated by NLH. Does a superior approach recommend itself? Should NLH's proposed allocation based on revenue requirements be adopted in preference to the current approach, based on a representation of cost of service? Given the size of the deficit, should NLH customers continue to be the exclusive source of funds?

Background. Subsidizing rural customers has been a longstanding feature of service in the Province, and the practice of subsidizing small numbers of customers in remote locations is common in other provinces of Canada. In the Province of Newfoundland and Labrador, the subsidy was at one time covered by the Provincial Government but since 2002 the responsibility has been borne by some of NLH's non-rural customers. The customers benefiting from the subsidy are found in four groups: Island rural interconnected (about 23,700 customers) Island isolated (about 800) Labrador isolated (about 2,700) and L'Anse au Loup (about 1,000) totaling about 28,300 customers.[32]

[32] As recorded in NLH's COS model, 2015.

The cost burden of the rural deficit is allocated to NP and to Labrador Interconnected customers, Island industrial customers having been exempted from responsibility in 1999.[33] The Electric Power Control Act mandates that these two customer groups fund the subsidy, but does not prescribe how it is to be allocated.[34] Until recently, the allocation was based on an "equal unit cost" allocation mechanism developed in 1993 by the Board's witness, Mr. George C. Baker.[35] Under this mechanism, NLH classified the deficit total among demand, energy and customer categories based on the total costs in each classification for the NP and Labrador Interconnected rural customers combined. The classified amounts of the deficit were then applied to the combined groups' unit costs for each classification to determine the deficit share for each of the two groups of customers. Essentially, this approach has been viewed as allocating the deficit using a mini-COS study.

The difficulty with this approach is that it allocates relatively large amounts per customer to Labrador customers (who are significantly higher users of energy than Island customers, chiefly due to relatively colder weather and consequent heavy use of electric heating). This approach produced much higher revenue/cost (R/C) ratios for RLIS customers than for NP—1.42 vs. 1.12—as revealed by NLH's recent analysis.[36]

[33] Order-in-Council 2003-347 also specifies that NP customers and Labrador rural interconnected customers are to fund the rural deficit. See NLH, *2013 General Rate Application, Final Submission*, revision 1, p. 14. The 1999 date regarding the Island industrial customers is referenced on p. 15.
[34] See Dr. J. Feehan, *Report on the Allocation of the Rural Deficit*, prepared for Miller& Hearn, representing the towns of Labrador City, Wabush, Happy Valley-Goose Bay, and North West River, p. 1, footnote 1.
[35] Board of Commissioners of Public Utilities, *Report on … the Proposed Cost of Service Methodology…* February 1993, Appendix 1.
[36] NLH, *2013 Amended General Rate Application*, Section 4.3.1, reference Table 4.2 for the R/C ratios.

NLH analyzed the impact of this approach in response to customer concerns about the impact of the resulting charge, and concluded that it was sensible to modify the approach. After considering options, the utility selected a revenue requirements-based allocation whose purpose is to equalize R/C ratios, and whose effect is to shift the deficit burden in the direction of NP customers and away from Labrador Interconnected customers.

Discussion/Analysis. Extensive debate over the years since the 1993 COS methodology review has revealed general agreement that there is no solid basis for allocating the rural deficit burden. Since the deficit has no association with any of the costs of the subsidizing customers, there is no clear cost allocation method available to recommend from a perspective of costing theory. Additionally, industry practice does not have much to offer, since smaller subsidies are less noticeable and do not create debate as a result.

In the absence of cost-related guidance, NLH gravitated to a notion of fairness based on results, a departure from standard costing practice, and hampered by the difficulty in defining what constitutes fairness. That search for improved fairness caused the utility to explore two alternatives to the established method of allocating the rural deficit. They assessed an equal R/C ratio approach based on revenue requirements, as well as an approach that relies on number of customers. Arguably, achieving equal R/C ratios after imposition of the rural deficit charge is a desirable criterion for allocation. However, a case can be made for equal customer bill impact as well.

These methods lead to annual average costs per customer numbers that are very similar between the two groups of subsidizing customers, NP and Labrador Interconnected.[37] In contrast, the established method, based on equalized unit costs, imposes an annual bill increase of $653 on RLIS customers and just $217 on NP customers, due to differences in consumption levels. Even with impact equalization by means of the alternative approaches, subsidizing customers would have $207-$235 added to their annual bills.

The 2013 GRA process resulted in commentary on NLH's analysis and proposed change. Most intervenors, and the Board's consultant, Mr. John Wilson, supported a change. The exception, Mr. Larry Brockman, representing NP, felt that the change was unwarranted and that the min-COS methodology was sound.[38] Another intervenor, Dr. James Feehan, participating on behalf of several Labrador towns, suggested four alternative approaches to allocating the rural deficit, including one similar to NLH's customer-based alternative.[39]

In the absence of a cost-causative criterion for allocation of the rural deficit, or of a single best indicator of fairness, the choice of an allocator may be influenced by criteria such as simplicity and by acceptability of outcome to stakeholders. These criteria place the equal unit cost method at a disadvantage on both counts.

NLH's revenue requirements method has the virtue of simplicity of computation and comprehensibility of outcome, relative to its predecessor, the equal unit cost method. The

[37] NLH, *2013 Amended General Rate Application*, Section 4.3.1, p. 4.10. See Table 4.3 for results.
[38] These views are summarized in NLH's *2013 General Rate Application, Final Submission*, revision 1, p. 71*ff*.
[39] Dr. J. Feehan, *op. cit.*, pp. 7-10.

revenue requirements method also avoids the apparent problem of significant differences in R/C ratios that arises with the equal unit cost method, and the consequent price distortions away from unit cost that arise with R/C ratios of 1.42 for rural Labrador interconnected customers and 1.12 for NP customers.

Additionally, the revenue requirements approach may have an advantage over the customer approach. The customer approach is initially appealing: equal charges to all customers. However, customers vary significantly in size and average bill between NP and rural Labrador interconnected groups, and the approach imposes a small distortion in R/C ratios. A rate designer striving for parity would automatically move rates against the allocation and in the direction of the equal R/C ratios of the revenue requirements method. In that case, it may make sense not to affect R/C ratios in the first place, and undertake the slightly more complicated revenue requirements computation.

NLH's proposed approach appears well suited to manage the transition process that will occur beginning in 2018 and provide effective guidance in allocation of the rural deficit thereafter. The advantages of this approach are: 1) a perception of fairness based on a sensible and measurable benchmark; and 2) computational simplicity via the R/C ratio. Other suggestions, including the current method, all appear to have identifiable weaknesses in the form of differential price distortions or questionable benchmarks (such as the count of customer numbers) or computational complexity. While fairness itself does not necessarily produce a clear favorite, the combination of influences and the recognized problems of the current method suggest that a change in methods is both justified and timely.

Recommendations. We recommend that NLH adopt its proposed allocation method based on revenue requirements. The criterion of equalizing R/C ratio across regions and the concomitant avoidance of price distortion appear to be desirable features of this approach. The relative simplicity of the calculation method, when compared with the existing approach, is an additional advantage.

5.2 Conservation and Demand Management

Issues. Conservation and Demand Management (CDM) costs tend not to be driven by the specific decisions of individual customers but instead by the program scale decisions of the utility, subject to regulatory approval. Accordingly, there is debate about how CDM costs should be allocated.

Additionally, NLH plans its CDM activities in conjunction with Newfoundland Power (NP). NP customers pay NP CDM costs and are also charged for some NLH CDM costs. Thus, there is concern about double billing for CDM expenses for NP customers. How should costs be allocated to avoid double billing, if it is occurring?

Another consideration is whether the changes introduced to the NLH landscape by the completion of the MF and LIL investments should alter CDM activities and the way CDM costs are allocated.

Background. Like most utilities, NLH undertakes expenditures to induce its customers to undertake cost-effective measures that reduce total consumption and peak demand. Relative to other categories of utility expense, the amounts are not large, but the cost allocation process still produces controversy due the absence of agreement regarding allocation method. NLH's CDM costs are divided into two categories: 1) expenditures dedicated to particular programs, and 2) general CDM program administration costs. NLH treats the latter as conventional O&M costs and allocates them in the same manner as other O&M expenditures.

As proposed by NLH in the 2013 GRA, and as endorsed by parties to the recent Settlement Agreements, specific actual program costs for each year are to be aggregated for the year and are made subject to deferral in equal amounts over a seven-year period. Costs for the period 2009 to 2015 are proposed for recovery. Once deferred, each year's cost recovery is based on the previous year-end's balance of the resulting CDM Deferral Account, which consists of the deferred amounts that apply to that year and true-up amounts from the previous year.

Deferral appears to play two roles. It distributes revenue recovery over a period in which the conservation measures are most likely to be affecting consumption, and smooths the time pattern of cost recovery should expenditures vary significantly across years. The use of deferral accounting and the time period of deferral are not issues in this review.[40]

[40] Expert testimony in the 2013 GRA review noted that other Canadian provinces that use deferral accounting elect to use longer deferral periods. See P. Bowman and H. Najmidonov, *Updated Pre-filed Testimony*, June 4, 2015, p. 63, footnote 137.

Cost recovery will occur through an add factor or tracker called the CDM Cost Recovery Adjustment, charged against each customer's energy consumption.[41] The Adjustment value is to be differentiated by class as a result of cost allocation/assignment plans. Island Industrial customers will face a different rate from that facing NP and its customers. Conservation program costs associated with the Labrador interconnected system are excluded from this account and charged to NLH income.[42]

NLH does not have to specify formally how its CDM program costs are functionalized or classified, as they are removed from the COS study. However, some indication of the utility's attitude regarding the purpose of CDM programs can be gleaned from the documentation related to the 2013 GRA. NLH has promoted conservation programs whose focus appears to be overall energy conservation, as opposed to peak demand reduction.[43] Additionally, energy savings from CDM programs in the past have been seen as reducing the need for use of the Holyrood thermal generating station.[44]

The current CDM program cost allocation plan begins with segmentation of CDM costs among Island Interconnected, Rural Isolated and Labrador Interconnected categories. The Island Interconnected amount is allocated among NP, IC, and Rural Island Interconnected customers on the basis of the previous year's energy sales. Energy sales are defined as

[41]*NLH 2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46.
[42]*NLH 2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46; and Vol. I, Sec. 3, Finance Schedule V, p. 1.
[43] *NLH 2013 Amended General Rate Application*, Vol. II, Exhibit 9; Lummus Consultants, *Cost of Service Study/Utility and Industrial Rate Design Report,* July 7, 2013, p. 19.
[44] J.W. Wilson, *Updated Report to The Newfoundland and Labrador Board of Commissioners of Public Utilities on Cost Allocation and Rate Design Issues in the Newfoundland and Labrador Hydro ("Hydro") November 10, 2014 Amended General Rate Application*, June 1, 2015, p. 36.

utility firm and firmed-up secondary and industrial firm invoiced energy, plus rural bulk island interconnected transmission energy. Rural Island Interconnected and Rural Isolated CDM amounts are then re-allocated to NP and Labrador Interconnected customers according to the Rural Deficit allocation rule.[45] As mentioned above, Labrador Interconnected CDM costs are initially allocated to Labrador Interconnected customers, but are written off.

Additionally, NP has its own CDM expenditures, which it allocates to its customers on the basis of annual energy consumption. Thus NP customers pay these costs and are also allocated substantial CDM costs from NLH.[46]

Discussion/Analysis. Although CDM expenses are not caused by the traditional cost causative factors (customer numbers, energy consumption, or peak demand) they might be thought of in terms of the costs that they intend to avoid. One could, potentially, review each CDM program individually and determine whether its focus is overall energy reduction or peak demand reduction or some combination. Views reported by experts during the 2013 GRA suggest that NLH's focus has been exclusively on energy reduction. For example, Lummus Consulting, in its 2013 review of COS methodology stated that, "the justification of the Utilities' CDM programs has been on system energy savings that benefit all customers on the Island interconnected System."[47] Similarly, Bowman and Najmidinov, in expert

[45] *NLH 2013 Amended General Rate Application*, Vol. I, Rates Schedules, p. 18 of 46.
[46] J.W. Wilson, *op. cit.*, p. 36.
[47] *NLH 2013 Amended General Rate Application*, Vol. II, Exhibit 9; Lummus Consultants, *Cost of Service Study/Utility and Industrial Rate Design Report,* July 7, 2013, p. 19.

testimony on behalf of industrial customers, say that "Hydro's focus is on fuel savings through CDM. As a result, Hydro has developed programs targeting energy savings. There are no Hydro programs currently designed to reduce system peak."[48] If true, this objective helps to justify an energy-only cost classification scheme, and the use of an energy allocator in some form, at least for the present.

This perspective may not hold for the future, of course, and NLH should not feel constrained to engage in conservation practices that save energy but do not focus on peak demand. In particular, CDM programs have made efforts to reduce isolated system consumption. (Since these customers' costs exceed the rates charged, CDM programs that improve these customers' energy efficiency help to reduce the rural deficit.) At some point the marginal value of additional consumption spending for this class may fall relative to the value of incremental spending for other classes and other programs. Thus, a system of cost allocation that is flexible enough to deal with program variability is desirable.

Industry practice regarding cost allocation is variable. Some jurisdictions such as North Carolina attempt to distinguish between program objectives and then use demand and energy allocators to allocate separately classified costs.[49] Others are content to use energy-only allocation regardless of the purpose of CDM programs. A NARUC report from 1993, though somewhat dated, provides a useful summary of methodological issues and cost

[48] P. Bowman and H. Najmidonov, *Updated Pre-filed Testimony*, June 4, 2015, p. 62.
[49] North Carolina Utilities Commission, *The Results of Cost Allocations for Electric Utilities…, Part 2. Demand-Side Management and Energy Efficiency Costs.* P. 7*ff*.

allocation practices.[50] The report notes that some jurisdictions directly assign CDM costs to customer classes, and subsequently allocate them based on a variety of allocators, while others simply allocate CDM cost based on energy consumption regardless of cost classification. The policy of direct assignment of each program's costs to its target class stems partly from a principle that one ought not to burden a class with costs when its customers derive no direct benefit from them. The counter-argument, apparently shared by NLH, is that all classes benefit from energy conservation, regardless of the source, and thus should share the burden of paying those costs.

The report views CDM costs as being equivalent to the costs of new generation: both are aimed at meeting the supply needs of all customers. On the basis of cost causation, then, allocation based on some measure of class responsibility for demand and energy should occur, rather than on the basis of the alternative hypothesis of avoiding burdens on classes not eligible to participate in a specific program.

NLH's unusual circumstances may influence its approach. Instead of the conventional mix of residential, commercial, and industrial customers with roughly similar shares of consumption found at most utilities, NLH's usage is dominated by sales to NP, with residual sales to industrial and rural customers. NLH's CDM expenditures are focused on rural and isolated customers, with some expenditure on the Industrial class. These classes benefit from those expenditures but NP's customers also benefit from CDM-related consumption

[50] National Association of Regulatory Utility Commissioners, Committee on Energy Conservation, *Cost Allocation for Electric Utility Conservation and Load Management Programs*, February 1993. See the executive summary for a quick review of the conclusions.

reductions. NP's CDM expenditures likewise benefit NLH customers. NP's customers pay all their own CDM costs, allocated on the basis of annual energy. Presumably NLH's (interconnected) customers also benefit from the conservation efforts of NP customers since they are part of the same grid.

NLH and NP jointly plan their CDM activities and expenditures, and the customers of both utilities appear to benefit from the programs that result from this joint planning. The utilities already share costs for one initiative, the takeCharge program, which serves isolated diesel-served communities, along with some other costs.[51]

PUB expert John Wilson argues that NLH should modify its CDM allocation approach to avoid the apparent double-counting involved in NP's CDM allocation.[52] He proposes excusing NP from the initial allocation while retaining the rural deficit-based reallocation. By his computation, more than $300,000 of CDM costs would shift from NP to Island Industrial customers, while NLH would absorb a small increase in Labrador cost allocation.

It is useful to ask how costs would be allocated were the Province served by a single utility. Combined CDM costs would either be directly assigned by program to their target classes or perhaps classified to energy and allocated by means of annual energy. In fact, the latter approach is being considered at present by NLH and NP, with combined cost recovery occurring through a single rider. The approach differs from the Wilson suggestion in that the

[51] *NLH 2013 Amended General Rate Application*, Vol. I, p. 1.14. See also P. Bowman and H. Najmidonov, *Updated Pre-filed Testimony*, June 4, 2015, p. 62.
[52] J.W. Wilson, *op. cit.*, p. 37.

pooled costs allocated to NP before reallocation might not equal NP's current costs. The pooled cost method would simplify computation while still permitting the rural customer CDM cost reallocation to NP and Labrador interconnected customers, and would likely achieve an effect similar to that of the Wilson suggestion.

Another approach that eliminates NP sharing of NLH CDM costs would be to use the intra-class direct assignment method within each utility. NP customers would pay only their costs. This would terminate the rural customer reallocation of CDM costs. This plan would drive up the NLH rural subsidy, producing an offsetting increase in costs that would subsequently need to be reallocated to NP customers. Clarity regarding the size of the subsidy would be improved, though.

The NARUC report suggests an alternative to energy-based allocation. The report indicates that American states that use marginal costing for generation cost allocation appear to avoid the controversy of embedded cost-based jurisdictions. This approach involves allocation of CDM costs based on a marginal cost-based allocator for generation function costs. This is an attractive alternative for NLH following 2019, especially since, as we argue elsewhere in this report, the generation function's costs might best be allocated based on each class's share of load-weighted marginal costs. The approach would allow NLH to view CDM costs, which chiefly avoid generation costs, in the same light as generation.

Under this approach, total NLH CDM costs would be allocated based on NLH's computation of marginal cost. NP could adopt a similar approach, extending marginal cost-based allocation to its own customer classes, or it could retain energy consumption unweighted by marginal cost as its allocator internally if it did not wish to use marginal cost itself. The rural deficit would still reallocate the extra costs of serving rural customers to NP and Labrador customers.

An additional complication for the future is that conservation expenditures will serve not so much to reduce energy use and, hence, generation costs but, in the absence of transmission constraints on the Maritime Link and LIL, to enable increased exports. Ideally, NLH and NP will jointly plan CDM program scale to optimize use of system resources (and to minimize uneconomic use of fossil fuel generation) with an eye to profitable export sales. Thus, if prices in the ISO of New England (ISONE) are forecast to be high on average in coming years, indicating tight resources in the Eastern Interconnection, it would be cost effective to increase CDM expenditures, while low ISONE price expectations would reduce the value of CDM programs.

A marginal cost-based allocation of CDM costs would be a useful and compatible element of this environment. Additionally, the use of marginal cost-based allocation finesses the issue of whether a program is focused on energy or demand, since all CDM costs are allocated based on the generation-related cost shares of the various NLH classes.

Additionally, NLH is seeking to recover CDM costs incurred over the period 2009–2015, with cost recovery deferred over a seven-year period. The question may arise as to whether one cost allocation approach should be preferred over another, especially when the system itself will change significantly in the near future. The deferral does not appear to change the cost-causative relationships involved in that the stream of benefits from these programs takes place over a number of years. Those benefits appear to be best expressed in terms of weighted marginal costs in the current period. The energy-based allocation approach currently in use may not be notably inferior, however, depending on the marginal costs that are used in the future.

Lastly, NLH's cost allocation issues for the future include the degree to which reallocation of costs occurs between classes. Currently, NLH reallocates some allocated CDM costs, based on the reallocation structure of the rural deficit. That allocation may change as a result of the establishment of DC transmission links between the two interconnected areas of Labrador and the Island. However, the changes that are expected in 2019 do not rule out the reallocations mandated at present, provided that Island and Labrador industrial customers are not combined into a single class. Other contractual features make such a combination unlikely.

Recommendations. NLH should continue its current CDM cost allocation approach for the near future. Industry practice admits of both direct assignment by program to class and allocation on the basis of cost causation of the need for supply, usually expressed as energy allocation, but sometimes including both demand and supply. In NLH's case, energy-only allocation seems to have been appropriate in the past, given the energy conservation focus of past programs, but this approach may not necessarily be appropriate in the future.

NLH should consider converting to a marginal cost-based allocation system following the in-service date of Muskrat Falls and its associated transmission assets. This approach avoids classification issues and improves upon an energy-only allocation by virtue of its use of cost weighting. Additionally, marginal cost-based cost allocation is compatible with our recommended future generation cost allocation approach and with the concept of CDM costs as avoiding generation costs primarily.

If acceptable to NP, NLH should adopt the pooled CDM cost computation immediately. This system will simplify computations and clarify NP’s share in advance of the reallocation of the rural CDM share. If this approach proves not to be workable, then an approach which allocates each utility’s costs within its own customer classes, prior to reallocation of rural costs, would be a feasible second-best.

Regardless of the cost allocation mechanism selected, NLH does not need to revise its revenue recovery scheme of deferred cost recovered through the CDM Cost Recovery Adjustment. The marginal cost-based approach would utilize rate-specific pricing in a manner similar to that currently proposed.

5.3 Specifically Assigned Charges

Issue. Four Island Industrial Customers are assigned a number of specific charges because each of the customers is served by assets that are deemed to serve them alone.[53] The central issue, identified in the most recent GRA, pertains to the allocation of Operating and Maintenance (O&M) costs. Currently O&M costs are allocated to these customers based on asset share, with asset value defined in terms of original cost. Periodic investment in new or

[53] Costs are also specifically assigned to Newfoundland Power for lines and terminal stations that connect them to the NLH grid. NLH’s definition of specifically assigned plant is “that equipment and those facilities which are owned by Hydro and used to serve the customer only.” NLH *2013 Amended General Rate Application*, Schedule A, Article 1.01(ee).

upgraded facilities results in variation in shares over time across customers due to variations in age of plant.

Background. The issues surrounding specific cost assignment have grown in the past decade as the value of the charges has increased. Charges for the 2007 Test Year were $0.7 million while those for the 2015 Test Year were $1.7 million, spread across four customers: Corner Brook Pulp and Paper (CBPP), North Atlantic Refining, Ltd. (NARL), Teck, and Vale Newfoundland and Labrador Limited (Vale).[54] O&M, depreciation expense, and return on debt and equity are the bulk of the charges, in declining order, with O&M constituting somewhat more than half in aggregate. Customers who paid for their assigned assets through contributions in aid of construction (CIAC) pay for O&M only.

The assets that generate the charges are solely transmission-related, consisting mostly of lines and terminal stations that connect the customers to the grid. The CBPP facility is different from the others in that the customer has some facilities that operate at 50 Hz instead of the 60 Hz common to the rest of the grid. Additionally, the customer has a small hydro plant that provides generation services to its site. Issues related to the frequency converter that transforms 50 Hz power into 60 Hz are discussed in the next section.

Assignment of a share of O&M expenses to the Island Industrial class and to its customers requires use of a sharing mechanism applied to total O&M. The basis for identifying O&M costs assigned to the customer group is the group's share of transmission plant in service,

[54] Vale was connected in 2012 and does not currently pay a specifically assigned charge.

with plant valued at original cost. Similarly, allocation of O&M assigned to these four customers is based on their shares of transmission assets, again valued at original cost.

Analysis. Some US jurisdictions deem virtually all transmission assets, including connections to large customers, as common property, to be allocated by the utility's transmission cost allocation rule. These utilities tend to be large, with the result that no single customer is a significant share of total sales and no assets that might be directly assigned are a significant share of the total. For example, Georgia Power Company has many large customers, but the utility does not engage in direct assignment of transmission costs because the system as a whole has a capacity of over 17,000 MW. Smaller utilities that serve one or more customers whose loads are an appreciable share of total sales are more likely than other utilities to engage in direct assignment of transmission costs in cases in which the transmission assets serve the individual customer only.

As a consequence, direct assignment of transmission assets is not widespread, but NLH may fit the pattern of having significant assignable assets. The Industrial customers with directly assigned transmission assets consume about 10% of Island sales at present and are assigned a little more that 10% of transmission assets in 2015.

Even among utilities that engage in direct assignment, the practice of directly assigning O&M costs is not uniform. Xcel Energy in Minnesota simply allocates all its transmission-related O&M costs on the basis of the CP allocator that it uses for transmission expenses generally. This approach is arguably less precise in allocating O&M costs to direct assignment customers but likely avoids swings in O&M charges to those customers in response to equipment upgrades. More generally, though, it appears that direct assignment of assets leads to direct assignment of expenses, and that assignment is based on original cost.

One customer, (Vale) responsible for roughly $500,000 of directly assigned costs for the 2015 Test Year, proposed an improvement to the determination of O&M charges. Their expert, Mr. Melvin Dean, advocated and set out the steps for development of allocation based on current cost.[55] This technique makes use of Handy-Whitman indexes, which are available for sufficiently detailed segments of the electric utility industry to produce reliable cost indexation over many years.

NLH investigated this approach and found it to be feasible.[56] The utility also found that the outcome of its calculations confirmed Mr. Dean's belief: the relatively newer transmission assets directly assigned to customers, when compared with other transmission assets, produced a reduced O&M cost allocation for the direct assignment customers.[57]

This approach has a parallel in distribution cost classification. Minimum system studies classify the minimum system needed by a utility as customer-related and the remainder as demand-related. Such computations resort to conversion of assets to test year value to avoid biased outcomes, due perhaps to smaller assets being of older vintage. Thus, it seems reasonable to consider test year dollar valuation in transmission as a reasonable approach.

---

[55] Melvin Dean, *Expert's Report on Newfoundland and Labrador Hydro's Amended General Rate Application*, June 4, 2015, p. 3*ff*.
[56] See V-NLH-083, rev. 1, for a description of the method.
[57] NLH, *2013 General Rate Application, Closing Submissions*, Dec. 23, 2015, p. 76.

Critics might object that even test year dollar valuation may not capture the full impact of age. Two identical transmission lines, one built in 2015 and another built in 2005 might have the same 2015 dollar value, but the ten-year-old line would likely be associated with higher O&M costs. Attaining this degree of accuracy in an index would require knowledge of the relationship of O&M cost to vintage, which would be very challenging.

An alternative might be to track actual expenses associated with each customer's dedicated transmission assets and bill the customer directly, while in addition charging them for their share of remaining transmission-related expenses on the basis of the standard transmission allocator. Under this system, a customer who is directly assigned high asset costs for new or upgraded transmission assets would also have the lower expenses associated with new equipment. NLH would need to investigate whether its accounting systems would find this approach to be cost effective. Directly assigned O&M costs would be removed from the COS, although customers would continue to be allocated their share of common transmission-related O&M costs. The outcome of this approach is fairly allocated cost for the share of the transmission system common to all customers plus charges for actual repair costs. Depreciation and return on investment on the dedicated assets would still be based on original cost, in conformance with charges for other assets.

An additional alternative is available. Instead of directly assigning O&M costs, NLH could allocate all transmission-related O&M costs, including those that would have been directly assigned, via the standard transmission-related cost allocator. That is, no O&M costs would be directly assigned. This method is used by Xcel Energy in the United States (whose directly assigned costs are not as significant a share of cost as at NLH). This approach would shield individual customers against large, unexpected repair costs by "socializing" the costs across the utility. However, this approach is a second-best method due to its failure to recognize differences in asset vintage among customers, and between direct assignment customers and other customer groups.

Lastly, direct assignment also affects the treatment of administrative and general expenses in that the allocation of the various categories of A&G expenses is typically prorated based on shares of underlying assets. Specifically assigned transmission-related A&G thus depends on gross transmission plant assets. NLH proposed in their 2013 GRA submission to modify A&G allocation to match proportionally the modification in direct assignment of O&M expenses. This methodology is applied to all categories of A&G expenses, with a proposed saving to direct assignment customers outside the direct impact of the change in O&M methodology. This appears to be a consistent extension of that methodology.

If NLH were to adopt the alternative approach of charging for actual O&M expenses, there is a question as to the treatment of A&G expenses. The customers with specifically assigned assets would still be allocated a share of A&G costs based on the allocation of common transmission costs. The issue would then be whether additional charges should be due based on actual O&M expenses which are separately billed. If 5% of all transmission O&M costs were related to specifically assigned facilities, for example, one would expect the charge to reflect not merely direct labor and materials costs but additional elements to cover A&G. NLH would then use company accounting data to develop such a rate so that the share of A&G in total transmission maintenance cost would carry over into charges for specifically assigned asset maintenance costs.

Recommendations. We recommend that the transmission assets directly assigned to industrial customers continue to be so assigned due to their use solely by the individual customers and their apparent importance within the Island's transmission assets.

The current method of allocation of O&M expenses is correctly viewed by customers and NLH as problematic, since direct assignment on the basis of original cost appears to be poorly correlated with actual expense patterns over time. There appears to be a feasible improvement, based on determination of test-year transmission asset value via Handy-Whitman indexes.

If NLH finds that keeping separate accounts for each industrial customer's transmission repair expenses is feasible, then the utility could adopt a simpler approach than that of indexing by charging each customer for their actual expenses and allocating remaining utility transmission O&M costs via the established allocator for such costs. This approach recognizes that assets of lesser vintage likely are associated with lower repair costs. Allocation of other costs arising from direct assignment of assets (depreciation and return on investment) can be derived from original cost.

We also recommend that NLH adopt the process of separate accounting of actual O&M expenses for each customer, if feasible in terms of internal accounting processes. The charges for services would include a markup for A&G services. If this approach is not feasible, using current-year (or "constant dollar") costs for direct allocation of O&M expenses would provide a partial remedy to perceived excessive charging for O&M expenses. If that approach still appears to NLH to allocate excessive costs relative to actual costs, then abandoning direct allocation of O&M expenses would be an acceptable strategy.

5.4 Frequency Converter

Issue. Corner Brook Pulp and Paper Limited's (CBPP) paper mill load is served partly through a frequency converter (FC) through the conversion of some of its 50 Hz generation to 60 Hz. The customer faces a number of cost allocation and pricing issues arising from the presence of the converter. As a specifically assigned asset, capital expenditure on the FC induces increases in O&M and other costs allocated to the customer through a specifically assigned charge which is updated each GRA. Underlying the issue of the cost allocation mechanism for specifically assigned charges is a question raised by the customer as to whether the unit should in fact be treated as common rather than directly assigned. The customer's relationship with NLH is affected as well by its piloted Generation Credit service contract and Capacity Assistance Arrangements. While rate design issues will be reviewed in the future, the core issue here is whether the FC is properly directly assigned to the customer. Rate design issues spill over into COS, though, since the customer's power requirements can be reduced by up to 90 MW under the Capacity Assistance Agreements during the winter months.

Background. The CBPP Mill is the last remaining facility on the Island with load served at the 50 Hz frequency. The customer owns and operates hydro plants with a combined installed capacity of approximately 135 MW. The hydro plants generate electricity at both 50 and 60 Hz and the mill site uses energy at both frequencies. Some of the 50 Hz generation produced at the customer's hydro facilities is converted to 60 Hz[58] at the NLH frequency converter to serve its mill load.

Originally, the frequency converter provided services not just to the host customer but to the system as a whole. However, the expansion of the Island interconnected system reduced their contribution to the provision of voltage control for the local mill system, and for conversion of 50 Hz power to 60 Hz for use on site. This change in function over time was the basis for the conversion to specific assignment of the assets in 2001.[59]

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 agreement allows Hydro to call on CBPP to maximize its 60 Hz generation (including the frequency converter) prior to increasing generation at Holyrood for system reasons and prior to starting its standby units (i.e., a "capacity request"). However, capacity is only made available to the grid in this manner if Mill loads are reduced and CBPP is able to generate in excess of what it requires for its own use. Otherwise, if the Mill is using its maximum power requirements, there is no excess generation made available to the grid under this provision[60]. Savings are provided to CBPP for providing this additional capacity to the

[58] Approximately 18 MW.
[59] See 2001 General Rate Application, IC-NLH-32 Revised.
[S] See RFI IC-NLH-186.

system by permitting CBPP to exceed its firm power requirements and to avoid costs associated with thermal or standby energy rates.[61,62].

Prior to the winter of 2014/2015, Hydro entered into Capacity Assistance and Supplementary Capacity Assistance agreements with CBPP[63]. Under these arrangements and on rare occasions the facility provides emergency capacity to the grid.[64] This is achieved through load interruption of up to 90 MW at the Corner Brook mill when system generation reserves are low[65]. NLH compensates CBPP for services under these arrangements through fixed winter fees and usage payments.

After the commission of the Muskrat Falls Project, NLH may find that the opportunities for the frequency converter to be used for system support such as capacity assistance may be reduced, since the NLH system will be long in generation with the arrival of Muskrat Falls power. Should an outage occur on the LIL, NLH feels that under certain circumstances such as temporary unavailability of sufficient 10-minute reserves, the capacity assistance may be a consideration. The amount of extra capacity required would be uncertain. If the Capacity Assistance Arrangements were in place, it would provide a platform for payment to CBPP. Considering that there are only transmission constraint issues, CBPP's value of services

[61] Reference NLH 2015 Amended Exhibit 4, Section 3.3.1 pg.'s 12-13 and Table 8 pg. 21.
[62] See IC-NLH-059 Rev 1.
[63] See IC-NLH-186.
[64] Bowman and Najmidinov, Updated Pre-Filed Testimony, NLH 2013 Amended General Rate Application, June 4, 2015, p. 58.
[65] Net to the system is approximately 80 MW as this level of load interruption at the mill would effectively shut down production from the CBPP cogeneration unit. There are two contractual arrangements for providing capacity: one for Capacity Assistance (up to 60 MW) and another for Supplemental Capacity Assistance (up to an additional 30 MW). There are fixed fees for the Capacity Assistance arrangements only.

provided may drop from its current level, which may be reflected in any future contract payments.

The frequency converter is relatively old, having been placed in service in 1967. It is owned and maintained by NLH. NLH has undertaken significant investment at the FC since Hydro's last GRA. Direct assignment of these costs to CBPP has significantly increased their cost, which is proposed to amount to $891 thousand in the 2015 Test Year. This cost is a combination of $329 thousand of O&M cost, $185 thousand of depreciation, with the residual being predominantly return on debt and equity. Due partly to a reduction in consumption of NLH power, CBPP expects its share of its bill due to directly assigned costs rise to 21%.[66]

NLH maintains, in the most recent GRA, that the "Corner Brook Frequency Converter remains of primary benefit to Corner Brook Pulp and Paper Limited ."[67] Capital expenditures at the FC are subject to the standard Public Utility Board Capital Budget Application process, and customers (including CBPP) are given an opportunity to review and question the Capital Budget Application on a project-by-project basis[68]. Thus, there appear to be questions of interpretation about the role of the frequency converter and associated cost responsibility that interact with the overall issue of specifically assigned charges.

[66] Bowman and Najmidinov, o*p. cit.*, p. 53.
[67] See IC-NLH-186.
[68] See IC-NLH-100 Rev 1.

Discussion/Analysis. Regarding the issue of how to treat the frequency converter, there are a variety of views in discussion in the most recent rate case. Some support the current arrangement. Mr. Patrick Bowman, representing industrial customers, argues for adjusted treatment of the CBPP FC unit on four grounds.[69] First, he believes that the technical limit of 18 MW ought to result in a reduction in the value of the rate base that should be allocated to the customer. Second, he joins others in arguing about improper O&M cost allocation due to the vintage issue.[70] (See the section on direct assignment for a discussion of this issue, including NLH's proposal to allocate on the basis of current rather than original cost.) He also feels that all increases in O&M responsibility since 2007 should be eliminated. Third, he questions the core issue of whether the unit delivers benefits to the NLH system, claiming that the FC unit permits improvements in system stability and the occasional delivery of energy during emergency situations. If benefits are conferred upon the system, then some costs should be allocated in common, arguably. Fourth, he states that the technical constraint on the FC unit forces peak consumption of CBPP (and thus industrial customers as a class) upward by about 4.5 MW. More generally, Mr. Bowman objects to the imposition of expenses to maintain the FC, arguing that these have not improved its operation as was expected.

For the longer term, Mr. Bowman would like to explore changes in ownership of the unit, presumably to alleviate its cost burden. Thus by reducing the asset share of the customer

[69] See Bowman and Najmidinov, op. cit., p. 59*ff*.

[70] In fact, in oral testimony, Mr. Bowman suggests that the direct assignment of O&M charges to specific customers might occur very rarely in the industry, and that a cursory investigation failed to turn up an example. Transcript of Hydro GRA, Sept. 5, 2015, p. 145.

and revising the O&M allocation methodology, Mr. Bowman believes that CBPP and industrial customer cost assignment should be significantly reduced.

The unique 50 Hz situation and the ongoing requirement to convert 50 Hz generation to 60 Hz to supply mill load, suggests that the unit's purpose is predominantly, if not exclusively, to serve CBPP. This suggests that the unit fulfills the basic criterion of direct assignment: facilities that provide service exclusively to a particular customer (or customers).[71] This view is in line with that formed by the Board in its final ruling in the 2001 GRA, which supported the conversion to direct assignment. CBPP is compensated for its services in providing emergency capacity support to the grid under the Capacity Assistance Arrangements.

Regarding cost control, one can understand CBPP's concern for cost effective repairs to an aging unit. From NLH's perspective, ownership imposes the obligation to maintain the unit, and decisions on the scale and cost of the expenditures reside first with the utility. Modifications in the method by which O&M costs are allocated to specific assignment customers may offer some degree of relief to CBPP (as suggested in the section of this report on specific assignment). However, about $550 thousand of annual costs associated with depreciation and return are unavoidable without further action.

Two other issues raised by Mr. Bowman, and mentioned above, pertain to the technical limit of 18 MW on the operation of the FC. CBPP views the limit as having been imposed

[71] Reference NARUC's *Electric Utility Cost Allocation Manual*, p. 74. "For cost of service purposes, these [radial] facilities may be directly assigned to specific customers on the theory that these facilities are not used or useful in providing service to customers not directly connected to them."

upon it by NLH. However, a study by General Electric for Bowater Newfoundland, Ltd. (CBPP's predecessor) recommended the 18 MW limit.[72] This review offers no opinion on this technical topic. It has COS implications through the 4.5 MW impact on peak demand. Since the customer is the source of this limit, it appears that the customer would need to make a technical argument for its adjustment.

Recommendations. We recommend that the FC unit continue to be assigned directly to CBPP, due to its apparent use almost solely by the customer and the availability of compensation for service that is provided from time to time. The questions of demand credit fairness and the appropriateness of the structure of the Capacity Assistance Agreement are a matter for the upcoming rate review which will include an inquiry into the rate structure and pricing methodology. This study cannot pass an opinion on the technical issues surrounding benefit limitations pertaining to the 18 MW technical limit on capacity or on the question of cost effectiveness of repairs.

5.5 Newfoundland Power Generation Credit

Issue. Newfoundland Power owns both thermal and hydraulic generation facilities that contribute to the Island Interconnected supply. While many pricing issues surround this capability, one element concerns the cost of service: the size of the capacity that is credited by NLH to reduce the Newfoundland Power native peak in the current COS study. The COS issue relates to the value to NLH of the generation given as compared to the embedded cost allocation impact of simply reducing the Newfoundland Power native peak requirements to

[72] See IC-NLH 194, Rev. 1.

reflect the generation availability. Upon commissioning of the Muskrat Falls Project, marginal capacity costs on the system are forecast to decline to a low level, whereas the embedded demand costs reflected in the COS study can be materially higher (depending on the classification methodology). The issue thus becomes determining what credit value should be provided to Newfoundland Power for making its capacity available to meet system requirements.

Background. NLH's current COS methodology credits NP for making its generation available to reduce its contribution to system peak under the terms of NLH's Utility tariff. NP annually demonstrates its ability to run its generation to meet the capacity credit reflected in the cost of service study and in the Utility tariff. At the most recent GRA, the 2015 Test Year reflected a generation credit, adjusted for reserves, of 119.3 kW, of which 83 kW is for hydraulic capacity and 36 kW is for thermal generation. The picture is complicated by the presence of interruptible load deliverable by NP customers upon request. NLH also provides a curtailable credit in the tariff to cover provision of curtailment. The result is that NP's "minimum billing demand is computed as maximum native load less these two credited amounts (and a small downward adjustment to reflect an energy conservation incentive).

Discussion. A full discussion of how rates and credits might operate following the Muskrat Falls in-service date is properly set in the upcoming rate review. For the present, the issue of importance is whether NLH will value NP's generation at peak times to the same degree as it currently does (i.e., based on the value of embedded cost). For the first few years, NLH will be long in generation, with reduced need to request supply from NP, in all likelihood, with the exception of supply interruption on the LIL. This situation is analogous to wholesale markets in which increases in net supply are reflected in capacity and reserves market price reductions.

For the moment, it is sufficient to review the anticipated patterns of usage of the NP generation that NLH is likely to call. NLH expects that the increase in available generation supply from Muskrat Falls will reduce the need to call upon NP generation. NP currently operates its hydraulic supply to maximize its hydraulic generation on an annual basis and does so (as requested by Hydro) at daily peak times. Therefore, NP's system peak requirements already reflect the operation of its hydraulic generation. So it is appropriate for NP's native load during system peak times be reduced to reflect the operation of its Hydraulic generation.

The current generation credit for NP's thermal generation in the COS study and the Utility tariff remove the incentive for Newfoundland Power to run its thermal generation to reduce its billing demand. NP is reimbursed for its fuel costs when requested to operate its thermal generation which makes it more expensive for Hydro to call upon than NP's hydraulic services. NLH expects that the utility will not need to call upon NP's thermal generation support to meet native load requirements after Muskrat Falls begins providing energy. Given the reduced need for support, the expectation of need for thermal generation disappears, at least in the early years of Muskrat Falls operation.

For the years following the introduction of Muskrat Falls supply, NLH anticipates less need for NP's generation supply. Under these circumstances, one might anticipate that the thermal generation credit might not be renewed, at least for a period of time.

Recommendations. We recommend that NLH review expectations regarding likely demand for NP's two forms of supply. For testing purposes, eliminating the thermal capacity from the credit would provide a preliminary reflection of the possible outcome of the arrival of Muskrat Falls power.

For the longer term, though, it might be worth investigating a separate pricing arrangement in which the credits are eliminated altogether and a separate arrangement for delivery of supply by the NP generators developed. This would obviate the need to agree on a credit kW amount. Instead, the arrangement would offer a credit for availability, agreed upon each year based on expected net supply conditions and market-quoted capacity value. The agreement would also provide for payment based on some function of marginal costs for the actual delivery of supply upon request. This recommendation is preliminary, but suggests an alternative for future contracting and rate design that offers market-based compensation for both availability and response. This approach is subject to further review in upcoming rate design review.

5.6 Export Revenues/Credits

Issue. There are no requirements in the financing agreements to state that NLH will receive revenues from potential Muskrat Falls export sales power to customers outside the Province. Interconnected customers are, however, required to pay all the costs of the facility and all costs of the LIL and LTA. Instead, all revenues will redound to Nalcor and its shareholder, the Province of Newfoundland and Labrador. NLH customers will receive partial reimbursement under this system by way of reduced taxation relative to what it would otherwise be to sustain provincial government revenues. However, it is worth asking how export revenues could be credited to NLH Island Interconnected customers if the Province were to devise a crediting mechanism to offset the large increases in customer bills that will be necessary to cover the costs of the new facilities. What alternatives are available for allocation of credits in such an event?

Background. The apparent asymmetry between cost and revenues facing Island Interconnected customers (payment of all costs, receipt of no export revenues) is due to the investment decision made to develop these facilities: provide secure supply for Island customers. Under current policy, export revenues are accorded to the people of the Province for use in the manner judged most productive. It is not obvious that credits are automatically due to electricity consumers who will pay for the facilities, but instead is a policy decision of the government.

If the government chooses to provide export revenues partially to NLH customers, there is no cost basis that obviously serves to provide a rebate. An obvious rebate method, though, is a rebate in proportion to allocated costs. This simple approach proportionally reduces costs according to the same rules that allocate the new generation-related costs. Proportional reduction does not alter the shares of costs paid, with the shares being based on some cost-based method of cost allocation. For example, a marginal cost-based allocation of distribution costs would not be affected by this proportional credit mechanism.

Credits likely would take two forms, a base rate rebate for expected exports, and a credit adjustment taking the form of a class-specific energy credit/debit for export overages/shortfalls relative to expectations.

If the credit is large, there might be some issues regarding the relative level of prices and marginal costs. That issue concerns another Canadian utility, Manitoba Hydro. There, under some circumstances, export rebates can bring price close to or below marginal cost. However, the cost-price relationships likely will be different here. At any rate, the key point is that a credit system, if the credit is a sizable share of export revenues, will need to evaluate the likely impact on price.

Naturally, this approach might expect criticism. For example, some may object that NLH exports are likely to be the residual of all system supply that is made available. For example, some may ask why exports should provide credits to Island Interconnected customers only. The allocation rule relies on the assumption that all exports are derived from Muskrat Falls only. The credit could make room for Labrador customers who pay energy charges too.

Recommendation. It is somewhat speculative to inquire about how to allocate a currently hypothetical rebate. In addition, the timing of any export amount may require that it be handled through a deferral mechanism outside the COS study. However, a first review suggests that a rebate proportional to Muskrat Falls and related transmission investment cost allocation is simple and non-distortionary, but could be revised depending on what classes are viewed as entitled to a share of the rebate. Fairness rather than cost causation would figure in such a review.

APPENDIX: SUMMARY OF RECOMMENDATIONS

System Definition

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

Generation

- We recommend that NLH introduce marginal cost-based allocation of embedded generation costs for the Island Interconnected system beginning with the institution of rates that recover revenue to cover payments by NLH for Muskrat Falls and its associated transmission facilities. This change will avoid the need to allocate each generation asset or cost on its own and relates cost to serve to an objective market-based value of generation services that recognizes cost to serve by each rate class in each hour. It appears that NLH can undertake this approach, as the utility already possesses the costing capabilities to generate the requisite marginal cost scenarios.
- Marginal cost-based allocation can be used in the Labrador Interconnected system as well following the Muskrat Falls in-service date. Marginal cost forecasts will be produced by the same process as used for the Island Interconnected system.
- Until the Muskrat Falls project is included in the cost of service, we recommend that NLH continue its current generation cost allocation methodology, with modifications agreed upon in the 2013 Supplemental Settlement Agreement, specifically with

regard to the treatment of Holyrood fuel and wind generation as 100% energy-related.

- If marginal cost-based cost allocation of generation is not adopted for the period after the Muskrat Falls in-service date, the current system, as modified, could be retained after the transition, but with classification of Muskrat Falls costs via the equivalent peaker methodology. It appears that this approach might prove more in line with generation planning practice, and might better reflect the base load role of the unit than would an SLF approach.
- After Holyrood is converted into the role of synchronous condenser, then the plant should be subfunctionalized as transmission and its costs allocated in the same manner as general purpose transport facilities (described in the next section). The reduced fuel costs should continue to be allocated on the basis of energy.
  - If the plant does not immediately come to be used as a synchronous condenser, then it should be retained as generation and functionalized according to marginal cost-based cost allocation. In the event that marginal cost-based allocation is not adopted and the plant is still treated as generation, then the current capacity factor methodology, altered by the use of forecast-only capacity factors, would suffice.
- We recommend that wind resources be allocated in the same manner as other generation facilities if marginal cost-based cost allocation is adopted. If not, then we recommend that NLH adopt a classification method based on NLH planners'

forecasts. Current forecasts indicate that wind generation does not contribute to the ability to meet peak demand and should therefore be classified as 100% energy-related.

Transmission

Capacity Costs

Subfunctionalization

- **Generator Interconnection Facilities.** NLH should continue to assign (functionalize) to generation the costs of generator interconnection facilities.
- **General Purpose Transport Facilities and Terminal Stations.** General purpose transport facilities and terminal stations should be assigned to the transmission function.
  - The converter facilities located at the Muskrat Falls and Soldiers Pond stations should be functionalized in the same manner as the LIL facility.
- **Special Purpose Transmission Facilities.** The special purpose facilities which comprise the Labrador-Transmission Assets (LTA) should be assigned to the generation function due to their role in facilitation of efficient use of hydro facilities along the Churchill River, including the Churchill Falls and Muskrat Falls stations. We recommend that the LIL facility, including its converter facilities, be functionalized as generation, in harmony with the formal cost designation of the facility as providing service to the Island.

Classification and Allocation

- **Generator Interconnection Facilities.** We recommend that NLH classify and allocate the costs of Generator Interconnection Facilities in the same manner as their related generation facilities.
    - If NLH adopts marginal cost-based allocation of embedded generation costs, then marginal costs would apply to the financial costs of generator interconnection as well.
    - If NLH retains its existing allocation methods, we recommend that NLH assign interconnection facilities costs with each specific generator and allocate costs in the established manner.
- **General Purpose Transport Facilities.** We recommend that NLH retain the demand-only classification approach due in part to the absence of an analytically preferable or cost effective alternative, and partly to its acceptance by system planners of its ability to approximate their thought processes.
- Demand-related costs should be allocated based on one of the three methods proposed.
    - The Peak Load Frequency and *Pro Rata* Peak Load Distribution methods offer improved accuracy and stability over time, as well as an hourly analysis approach similar to that recommended for generation cost allocation. However, they require more analysis than the traditional CP method.

- If the traditional CP method is selected, we recommend that NLH adopt a 3 CP approach in preference to the traditional 1 CP approach, for reasons of statistical reliability. (Note that this does not suggest that planners deprecate the importance of the single annual peak for planning purposes but simply use more than one hour for cost allocation.)

- **Terminal Stations.** The charges on capital and O&M costs (revenue requirements) associated with Terminal Stations should be allocated to peak loads, determined according to one of the methods listed above.

- **Special Purpose Transmission Facilities.** Assuming that the LTA is functionalized as generation, we recommend that its costs be classified and allocated in the same manner as other generation assets.

  - If the Lil is functionalized as generation as well, it should be treated in the same fashion as the LTA.

  - If, instead, the LIL is functionalized as jointly generation and transmission, the generation component can be classified and allocated in the same manner as Muskrat Falls. The transmission component would then be viewed as general purpose transmission facilities and classified and allocated in the approved manner.

Line Losses (Transmission Energy Costs)

- Following the in-service date for MF and its associated transmission links, NLH should estimate average losses with load flow analysis. Load flow study results can then be utilized to parameterize a losses algorithm based on the well-known I^2R approximation. The algorithm is directly applicable to the hourly loads utilized within COS studies, including energy and demand loss factors.

- Once sufficient historical experience under the restructured resources has accrued—say, two years—NLH can again utilize observed metered loads as the basis for estimating line losses (transmission energy costs).

Other Issues

Rural Deficit

- We recommend that NLH adopt its proposed allocation method based on revenue requirements. The criterion of equalizing R/C ratio across regions and the concomitant avoidance of price distortion appear to be desirable features of this approach. The relative simplicity of the calculation method, when compared with the existing approach, is an additional advantage.

Conservation and Demand Management

- NLH should continue its current CDM cost allocation approach for the near future. Industry practice admits of both direct assignment by program to class and allocation on the basis of cost causation of the need for supply, usually expressed as energy allocation, but sometimes including both demand and supply. In NLH's case, energy-only allocation seems to have been appropriate in the past, given the energy conservation focus of past programs, but this approach may not necessarily be appropriate in the future.

- NLH should consider converting to a marginal cost-based allocation system following the in-service date of Muskrat Falls and its associated transmission assets. This approach avoids classification issues and improves upon an energy-only allocation by virtue of its use of cost weighting. Additionally, marginal cost-based cost allocation is compatible with our recommended future generation cost allocation approach and with the concept of CDM costs as avoiding generation costs primarily.
- If acceptable to NP, NLH should adopt the pooled CDM cost computation immediately. This system will simplify computations and clarify NP's share in advance of the reallocation of the rural CDM share.
    - If this approach proves not to be workable, then an approach which allocates each utility's costs within its own customer classes, prior to reallocation of rural costs, would be a feasible second-best.
- Regardless of the cost allocation mechanism selected, NLH does not need to revise its revenue recovery scheme of deferred cost recovered through the CDM Cost Recovery Adjustment. The marginal cost-based approach would utilize rate-specific pricing in a manner similar to that currently proposed.

Specifically Assigned Charges

- We recommend that the transmission assets directly assigned to industrial customers continue to be so assigned due to their use solely by the individual customers and their apparent importance within the Island's transmission assets.
- The current treatment of O&M expenses is correctly viewed by customers and NLH as problematic, since direct assignment on the basis of original cost appears to be poorly correlated with actual expense patterns over time. There appears to be a feasible improvement, based on determination of test-year transmission asset value via Handy-Whitman indexes.
- If NLH finds that keeping separate accounts for each industrial customer's transmission repair expenses is feasible, then the utility could adopt a simpler approach than that of indexing by charging each customer for their actual expenses and allocating remaining utility transmission O&M costs via the established allocator for such costs. This approach recognizes that assets of lesser vintage likely are associated with lower repair costs. Allocation of other costs arising from direct assignment of assets (depreciation and return on investment) can be derived from original cost.
- We also recommend that NLH adopt the process of separate accounting of actual O&M expenses for each customer, if feasible in terms of internal accounting processes.

   - If that approach still appears to allocate excessive costs relative to actual costs, then abandoning direct allocation of O&M expenses would be an acceptable strategy.

Frequency Converter

- We recommend that the FC unit continue to be assigned directly to CBPP, due to its apparent use almost solely by the customer and the availability of compensation for service that may be provided to NLH from time to time. The questions of demand credit fairness and the appropriateness of the structure of the Capacity Assistance Agreement are a matter for the upcoming rate review.

Newfoundland Power Generation Credits

- We recommend that NLH review expectations regarding likely demand for NP's two forms of supply. For testing purposes, eliminating the thermal capacity from the credit would provide a preliminary reflection of the possible outcome of the arrival of Muskrat Falls power.

- For the longer term, though, it might be worth investigating a separate pricing arrangement in which the credits are eliminated altogether and a separate arrangement for delivery of supply by the NP generators developed.

Export Revenues/Credits

- It is somewhat speculative to inquire about how to allocate a currently hypothetical rebate. However, a first review suggests that a rebate proportional to Muskrat Falls and related transmission investment cost allocation is simple and non-distortionary, but could be revised depending on what classes are viewed as entitled to a share of the rebate. Fairness rather than cost causation would figure in such a review.