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March 29, 2019

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2019 Cost of Service Study

BC Hydro writes to file its Fiscal 2019 Cost of Service Study (**F2019 COSS**) in compliance with its commitment made in the Negotiated Settlement Agreement Regarding BC Hydro's F2016 Cost of Service Study (**2016 NSA**) approved pursuant to Commission Order No. G-47-16.

BC Hydro filed the 2015 Rate Design Application (**RDA**) on September 24, 2015, pursuant to sections 58 to 61 of the *Utilities Commission Act*. A negotiated settlement process (**NSP**) for BC Hydro's cost of service study and rate class segmentation was held on March 7 and 8, 2016, and agreements were reached on issues raised during the NSP. On April 11, 2016, the Commission approved the 2016 NSA in which BC Hydro agreed to file the F2019 COSS and to further examine 14 topics raised in the NSP related to methodology used in the F2019 COSS. BC Hydro has examined the 14 identified topics and has attached its consideration of these topics in the attached filing.

Given the prohibition on rate rebalancing for F2020 and F2021 per Direction No. 8 to the British Columbia Utilities Commission (**Direction 8**) issued by the Government of B.C. on February 14, 2019, the F2019 COSS is being filed for information only and not in connection with a rate rebalancing application. BC Hydro is not recommending any changes to our cost of service methodology at this time.

For further information, please contact Anthea Jubb at 604-623-3545 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

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Enclosure

Cost of Service Study

Fiscal 2019

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1 Introduction and Purpose

BC Hydro writes to file its Fiscal 2019 Cost of Service Study (**F2019 COSS**) in compliance with its commitment made in the Negotiated Settlement Agreement Regarding BC Hydro's F2016 Cost of Service Study (**2016 NSA**) approved pursuant to Commission Order No. G-47-16. See Appendix A for the 2016 NSA.

On February 14, 2019, the Government of B.C. issued Direction No. 8 (**Direction 8**) to the British Columbia Utilities Commission (**BCUC** or **Commission**) which, among other things, specified that "in setting BC Hydro's rates for fiscal 2020 and fiscal 2021, the BCUC must not set rates for BC Hydro for the purpose of changing the Revenue to Cost (**R/C**) ratio for a class of customers."

A cost of service study may be prepared as evidence to support a utility's application for rate rebalancing. For example, if a cost of service study indicates that the R/C ratios for one or more rate classes is far from unity, rates may be changed by different amounts for different rate classes in order to move R/C ratios closer to unity. However, since Direction 8 prohibits this for fiscal 2020 and fiscal 2021, the F2019 COSS is not being filed in connection with a rate rebalancing application.

A cost of service study may also be prepared as evidence in support of a utility's rate design application. For example, the setting of basic charges, demand charge and energy charge for a given rate design may be informed by the analysis of the customer-related, demand-related and energy-related costs included in a cost of service study. The F2019 COSS is not being filed in connection with any specific rate design application. Should BC Hydro file a rate design application informed by a cost of service study, it will include the relevant study as evidence in the rate design application.

BC Hydro is not recommending any changes to our cost of service methodology at this time. As this COSS is not being filed in connection with a rate rebalancing or rate design application, it is being filed for information purposes only.

The F2019 COSS analysis is based on the F2017 Fully Allocated Cost of Service Study (**FACOS**) which was filed with the Commission on February 14, 2019. The F2017 FACOS used actual load and revenues to transparently allocate costs to BC Hydro's eight rate classes.[1] See Appendix B for the F2017 FACOS.

2 Context and Background

This section provides context for BC Hydro's filing by summarizing prior related Commission decisions and BC Hydro's current environment.

2.1 Context

In 2018, the Government of B.C. initiated a Comprehensive Review of BC Hydro. The terms of reference[2] included customer affordability and rates. As one outcome to this review, on February 14, 2019, the Government of B.C. issued Direction 8. Direction 8 directs that in setting BC Hydro's rates for fiscal 2020 and fiscal 2021, the BCUC must not set rates for BC Hydro for the purpose of changing the R/C ratio for a class of customers. The Comprehensive Review Report[3] also included the following statement:

> "The government intends to introduce legislation in spring 2019 to amend the Utilities Commission Act to permanently prevent

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1 The eight rate classes are as determined in the Negotiated Settlement Agreement Regarding the F2016 Cost of Service Study: Residential, GS < 35 kW, MGS, LGS, Irrigation, Street Lighting - BC Hydro Owned, Street Lighting – Customer Owned, and Transmission.

2 Downloaded February 2019 from: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/terms_of_reference_bc_hydro_review_public_final_may25_901am_2018_mmm_mcj_additions_lm.pdf.

3 Downloaded February 2019 from: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/final_report_desktop_bc_hydro_review_v04_feb12_237pm-r2.pdf.

> the BCUC from rebalancing rates unless otherwise requested to do so by a public utility".[4]

On April 11, 2016, Commission Order No. G-47-16 was issued, which included the 2016 NSA as Appendix A. The 2016 NSA examined 14 topics related to cost of service methodology. The 2016 NSA included a commitment by BC Hydro to file a new "Cost of Service Study and Rate Design Application" addressing rate rebalancing in fiscal 2019 that would be preceded by robust engagement. The understanding of the parties at the time that this commitment was made was that the prohibition on BC Hydro rebalancing rates would end in fiscal 2019.

However, since the prohibition on rate rebalancing has been extended under Direction 8, this application includes a Cost of Service Study only, and does not include an application requesting approval for rate rebalancing. Further, given that the Comprehensive Review was underway through 2018, with terms of reference that potentially encompassed rate rebalancing, BC Hydro has not undertaken recent engagement in preparing the F2019 COSS. BC Hydro relied on the record of engagement from the 2016 NSA to inform the scope of topics examined in this filing.

2.2 Background

On March 15, 2007 BC Hydro filed its 2007 Rate Design Application (**2007 RDA**).[5] This was BC Hydro's first general rate design application since 1991. This application included a FACOS Study that used the industry standard and widely accepted embedded cost methodology to allocate costs to rate classes using the following steps:

- The first step is Functionalization, and there are four Functions: Generation, Transmission, Distribution and Customer Care;

[4] This legislation has not been introduced as of the date of this filing.

[5] Available online at: https://www.bcuc.com/Documents/Proceedings/2007/DOC_15080_B-1_BCH_2007_Rate_Design_filing.pdf.

- The second step is Classification, and this step includes a review of the incurrence of costs in each Function and classifies the costs as customer, energy, or demand-related;
- The third step is the Allocation of costs to rate classes based on the various allocation factors; and
- The output is a table of the costs to serve each rate class. Six Rate Classes were defined for the 2007 RDA FACOS Study, these were: Residential, General Service < 35 KW, General Service > 35 KW, Irrigation, Street Lighting, and Transmission.

The use of the embedded cost methodology was approved by the BCUC in Order No. G-111-07[6] issued September 18, 2007. Since the filing of the 2007 RDA, BC Hydro has conducted and filed multiple FACOS Studies, all using the embedded cost methodology with various methodological refinements and updates over time, as approved by the Commission.

The following summarizes the timeline of BC Hydro's FACOS filings as well as any substantive updates to the FACOS methodology since BC Hydro's 2007 RDA:

- In Directive 2 of the Commission's Decision on the 2007 RDA attached to Order No. G-130-07 and dated October 26, 2007, including an erratum dated December 17, 2007[7] , BC Hydro was directed to "undertake FACOS studies on an annual basis within 90 days of its fiscal year end in order to calculate actual R/C ratios and determine the need for future rate rebalancing applications in regard to the 95 per cent to 105 per cent range of reasonableness and submit the findings to the Commission". With the exception of fiscal 2015, BC Hydro has completed FACOS studies covering each year from fiscal 2008 to

6 Available online at: https://www.bcuc.com/Documents/Proceedings/2007/DOC_16613_G-111-07_Interim-Order-FACOS-Rate-Schedules.pdf.

7 Available online at: https://www.bcuc.com/Documents/Proceedings/2007/DOC_17004_10-26_BCHydro-Rate-Design-Phase-1-Decision.pdf.

fiscal 2017. The F2015 FACOS was not completed due to BC Hydro's 2015 Rate Design Application (**2015 RDA**) being underway at that time;

- Commission Order No. G-111-07 (**Order G-111-07**)[6] issued September 18, 2007, directed BC Hydro to use the 4 Coincident Peak (**CP**) method to allocating demand-related generation and transmission costs to rate classes. The 4CP method allocates Generation demand-related and Transmission costs on the basis of the sum of each rate class' demand at each winter month's peak hour, divided by the sum of all rate classes' demand during those same hours. This method aligns with BC Hydro's system peak which occurs during winter. The 4CP has been used in all BC Hydro FACOS studies since the issuance of Order G-111-07;
- Order G-111-07 also directed BC Hydro to classify hydro plant as 55 per cent demand and 45 per cent energy. Although BC Hydro has considered and consulted on alternate classifications, no change has been adopted. BC Hydro used the Commission-ordered classification of hydro plant in our FACOS studies since the issuance of Order G-111-07;
- On October 16, 2009, BC Hydro submitted its Large General Service Rate filing, which was approved in Commission Order No. G-110-10. BC Hydro then transitioned its Medium General Service (**MGS**) and Large General Service (**LGS**) customers to new rate structures. This transition was sufficiently advanced by fiscal 2012 that the two classes could be identified separately in the FACOS analysis. Consequently, for FACOS studies from fiscal 2012 on, the number of rate classes increased from the six used in the 2007 RDA to seven as follows: Residential, Small General Service (**SGS**), MGS, LGS, Irrigation, Street Lighting, Transmission;
- On September 24, 2015, BC Hydro filed its 2015 RDA. This application included an F2016 Forecast FACOS based on forecast load and revenues. The

F2016 Forecast FACOS methodology was informed by a customer and stakeholder workshop, a cost of service methodology review, and a jurisdictional assessment. Based on this work, a number of changes to the cost of service methodology were proposed; and

- On April 11, 2016, Commission Order No. G-47-16 approved the 2016 NSA for BC Hydro pertaining to the F2016 Forecast FACOS Study that was included in the 2015 RDA. Two substantive changes arising from this process were:
  - Segmenting the Street Lighting Rate Class into two: Street Lighting – BC Hydro Owned, and Street Lighting – Customer Owned; and
  - Updating the number of years of customer load data used to allocate Generation, Demand and Transmission from an one-year to a five-year average.

Changes arising from the 2015 RDA and 2016 NSA were reflected in BC Hydro's F2016 FACOS, filed with the Commission March 15, 2018, and in BC Hydro's F2017 FACOS, filed with the Commission February 14, 2019.

3 Overview of Cost of Service Methodology

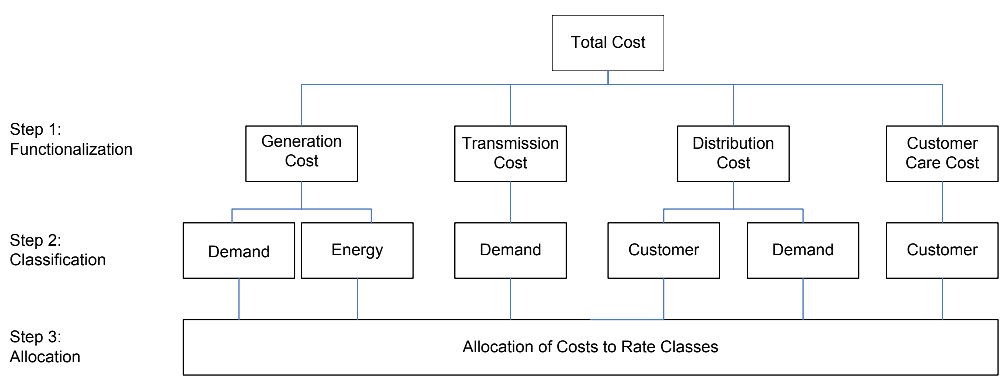
BC Hydro's cost of service study methodology adopts the industry standard, embedded cost method as directed in Order G-111-07[6]. The embedded cost methodology analyzes average system costs, assuming these costs are spread over all customers within each rate class based on standard allocators. BC Hydro's FACOS studies have typically used historic actual costs and customer data only, or on occasion, forecast costs from BC Hydro's revenue requirements filings.

BC Hydro adopts the traditional bundled approach to FACOS studies, which focuses on accounting costs. The main steps of this approach are summarized below, and are largely unchanged from as they were described by BC Hydro on page 3-4 of our 2015 RDA.[8]

BC Hydro's F2019 COSS uses the F2017 FACOS, filled with the BCUC on February 14, 2019, as the basis for analysis. The F2017 FACOS is also included as Appendix B. The F2017 FACOS takes the actual revenues, costs, energy sales from fiscal 2017 and the customer load profiles from fiscal 2013 through fiscal 2017, and transparently allocate those costs to the following eight rate classes: Residential; GS < 35 kW; MGS; LGS; Irrigation; Street Lighting – BC Hydro Owned; Street Lighting – Customer Owned, and Transmission.

This analysis provides a determination of the level of cost responsibility of each rate class and the revenue adjustments required to meet the cost of service. Where possible, costs are assigned directly to rate classes. Costs not directly assigned are allocated to rate classes in the widely-adopted three-step process summarized in Figure 1.

Figure 1 Cost Allocation Methodology



- Costs are functionalized into the following operating function categories: Generation, Transmission, Distribution and Customer Care;

[8] Available online: https://www.bcuc.com/Documents/Proceedings/2015/DOC_44664_B-1-BCH-2015-Rate-Design-Appl.pdf.

- Costs by function are classified into three categories: energy (variable costs that vary with kWh provided), demand (fixed costs that vary with kW demand) or customer-related (costs that are sensitive to connecting customers to BC Hydro's network irrespective of the customer's load, such as metering services and billing costs); and
- The energy, demand and customer categories are allocated to the eight rate classes on the basis of their respective energy use, demands or customer number (or other established allocator factor).

4 2016 Negotiated Settlement Agreement Items

The 2016 NSA was based on meetings held on March 7 and 8, 2016, attended by eight interveners in addition to BC Hydro and BCUC Staff. The NSA covered 14 topic items. The main issues arising from the NSA can be broadly summarized as follows:

- While most interveners supported the use of embedded cost methodology, one intervener suggested BC Hydro further examine the use of marginal cost methodology;
- Several interveners had suggestions regarding functionalization. In particular, suggestions were raised regarding the functionalization of IT costs, several regulatory accounts, distribution costs, and demand side management costs;
- Several interveners had suggestions regarding classification and allocation. In particular, suggestions were raised about the classification of Heritage Hydro, Heritage Thermal, IPP, the Heritage and Non-Heritage Deferral Account, Distribution, Demand Side Management, Generation-Related Transmission Assets, Smart Metering Infrastructure, and classification and allocation of Customer Care Costs; and
- Several interveners requested further examination of the 4CP allocator.

Below is BC Hydro's assessment of each of the topics raised in the NSA, organized by topic area and numbering as shown in the 2016 NSA, which can be found in Appendix A to this application.

4.1 NSA Item 1. Marginal Cost Study

One intervener, MoveUp, suggested BC Hydro identify if there are specific areas where there might be value in using marginal cost information. BC Hydro has historically used marginal cost information to inform investment decisions in demand side management, energy purchases from independent power producers, and for the purpose of rate design. A recent example of marginal cost analysis for rate design purposes can be found in BC Hydro's Freshet Rate Pilot Final Evaluation Report, filed with the BCUC on December 17, 2018. In this evaluation BC Hydro analyzed the marginal cost of energy to supply incremental load under the optional Transmission Service Rate Schedule 1892 – Freshet Energy. This marginal cost analysis was critical to BC Hydro's evaluation of the benefits that Rate Schedule 1892 provides to non-participants ratepayers.

BC Hydro continues to see value in the use of marginal cost information for the purposes described above, and acknowledges that there are likely also other suitable applications of marginal cost information. BC Hydro is not recommending the adoption of a marginal cost of service method as a substitute for embedded cost FACOS studies traditionally used by BC Hydro for the following reasons:

- **Transparency:** BC Hydro prepares embedded cost-related information as part of our revenue requirements applications (**RRA**). This information is publicly available and tested through a regulatory review process. No comparable process exists for marginal cost information. As a result, adopting a marginal cost of service approach to the FACOS Study would reduce transparency as the inputs would no longer be based on publicly available RRA estimates; and

- **Cost and complexity:** As a large, vertically integrated hydroelectric utility, producing reliable and timely estimates of marginal costs across all functions, and applying these costs to the FACOS would be costly and complex. Marginal costs may vary by location, time of year, and load characteristics. Multiple marginal cost of service studies would be required to be conducted on a regular basis in order to collect and maintain quality marginal cost information. Applying and reconciling these estimates with the FACOS information would introduce complexity, which may make the FACOS less readily understandable.
  BC Hydro would be required to incur additional costs to conduct the marginal cost studies and analyze their results.

While BC Hydro proposes to continue to use an embedded cost methodology for the purpose of its FACOS studies, we do not see this approach as restricting in any way the potential use of marginal cost information for a range of purposes, as appropriate. BC Hydro proposes not applying marginal cost of service analysis for the purpose of its FACOS studies.

4.2 NSA Item 2. Heritage Hydro Classification

As noted in section 2.2, Commission Order No. G-111-07 issued September 19, 2007, directed BC Hydro to classify hydro plant as 55 per cent demand and 45 per cent energy. BC Hydro has used this classification since.

Parties to the 2016 NSA indicated that classifying heritage hydro based on the capacity factor by plant weighted by book value would be consistent with the BCUC direction made in the 2007 RDA. Parties considered this to be the most appropriate classification mechanism for these generation costs given that capacity needs drive the design and costs of Heritage Hydro resources. The primary concern regarding using the capacity factor adjusted by book value approach was that the classification split between energy and demand may be unstable from year to year given that capacity factors varied with water flows and new investments made in individual generation stations.

To the assess the stability and validity of the long standing approach to classify hydro plant as 55 per cent demand and 45 per cent energy, BC Hydro analyzed actual fiscal 2017 energy production, capacity, capacity factor and book value for heritage hydro generating facilities. Results are presented below in Table 1.

Table 1 Analysis of Heritage Hydro Energy Production, Capacity, Capacity Factor and Book Value in Fiscal 2017

Facility (F2017 Year End Data)	Energy Production (GWh)	Capacity (MW)	Capacity Factor (%)	Book Value ($million)	Capacity Factor Weighted by Book Value (%)
Column	A	B	C = A*1000/(8760*B)	D	E =C x [D/sum of D]
GM Shrum	15,909.95	2,730	67	833.81	9
Revelstoke	8,264.38	2,480	38	1,438.65	8
Mica	7,396.96	2,720	31	1,069.99	5
Peace Canyon	3,887.37	590	75	305.13	4
Kootenay Canal	3,330.14	700	54	119.28	1
Seven Mile	3,326.14	810	47	273.27	2
Other	6,039.32	1,830	38	2,405.71	14
Total	48,154.25	11,860		6,445.85	43

As shown above, based on the analysis of fiscal 2017 data, the overall fiscal 2017 classification based on capacity factor adjusted by book value is 43 per cent energy and 57 per cent demand, which is very close to 45 per cent energy/ 55 per cent demand classification split that BC Hydro has applied since 2007. This result indicates that capacity factor adjusted by book value is relatively stable.

BC Hydro conducted sensitivity analysis on the fiscal 2017 R/C ratios using the fiscal 2017 classification based on capacity factor adjusted by book value (43 per cent energy/57 per cent demand) and the historical assumption of 45 per cent energy/55 per cent demand. The results are shown in Table 2 below.

Table 2 Impact on Fiscal 2017 R/C Ratios of Using Actual vs Historical Classification of Heritage Hydro

Rate Class (%)	R/C with Historical Heritage Hydro Classification	R/C Ratio with Updated F2017 Actual Heritage Hydro Classification	Change in R/C Ratio
Residential	93.2	93.2	0.0
GS Under 35 kW	123.6	123.7	0.1
MGS < 150 kW	115.1	115.1	0.0
LGS > 150 kW	103.9	103.9	0.0
Irrigation	89.5	89.9	0.4
Street Lighting BC Hydro	198.4	198.2	-0.2
Street Lighting Customer	95.1	95.0	-0.1
Transmission	95.4	95.5	0.1

As shown above, updating the classification based on the capacity factor adjusted by book value causes negligible changes in the R/C ratios. Therefore, BC Hydro concludes that the 45 per cent energy/55 per cent demand heritage hydro classification as approved in the 2007 RDA remains appropriate. BC Hydro proposes no changes to Heritage Hydro Classification.

4.3 NSA Item 3. Heritage Thermal Classification

In the 2016 NSA, the parties agreed that the Burrard Thermal plant's capital and operating cost should be classified as 100 per cent demand-related cost, and fuel cost should be classified as 100 per cent energy-related. Parties also agreed that the impact of the classification of the Fort Nelson Generating plant and Prince Rupert Generating plant thermal plants were low and consequently accepted BC Hydro's proposal of 74 per cent energy/26 per cent demand classification for the Fort Nelson Generating Plant, and 60 per cent energy/40 per cent demand classification for the Prince Rupert Generating Plant. Therefore, BC Hydro proposes no changes to the Classification of heritage thermal plants.

4.4 NSA Item 4. Classification of IPP Costs

In the 2016 NSA, BC Hydro presented its preferred option for classifying IPPs using the 'value of capacity' option, which results in a 93 per cent energy and 7 per cent demand classification that is generally consistent with characteristics of the electricity supplied by IPP contracts. BC Hydro was requested and committed to providing the policy context underpinning the procurement of fixed-price take-and-pay IPP contracts, and a discussion of the standard IPP contract structure. BC Hydro includes a discussion with respect to the IPP policy context below; and provides references to the previous standard IPP contract structure. In light of recent policy changes in respect of BC Hydro's acquisition of energy from IPPs, BC Hydro has not provided a detailed discussion with respect to our previous standard IPP contract structure.

The policy context underpinning the procurement of many BC Hydro's existing IPP contracts was informed by the Province's 2002 Energy Plan, the 2007 Energy Plan and the *Clean Energy Act*. The 2007 Energy Plan indicated that at least 90 per cent of all electricity generated in the province must continue to come from clean or renewable sources. The *Clean Energy Act* was issued in 2010 and set out, among other things, British Columbia's energy objectives and an obligation on BC Hydro to become electricity self-sufficient by 2016. These policies and the *Clean Energy Act* provided the policy context in which BC Hydro entered into contracts with IPPs.

IPP purchases were in the scope of the Comprehensive Review of BC Hydro that occurred during 2018. The Report on the Comprehensive Review of BC Hydro issued by Government on February 14, 2019 calls for a number of policy changes related to IPP procurement, including indefinitely suspending the Standing Offer

Program, BC Hydro's last open call for power.[9] The Report also indicates that Phase 2 of the Comprehensive Review, planned for 2019, is expected to:

> …look at changing energy markets, new utility models, emerging technologies and strategies to deliver on CleanBC's longer-term electrification goals.

Examples of BC Hydro's standard previous IPP contract structures are available publicly at bchydro.com[10].

BC Hydro proposes no changes at this time to the 93 per cent energy/7 per cent demand classification for IPP costs.

4.5 NSA Item 5. Functionalization of IT Costs

In the 2016 RDA, BC Hydro committed to repeating the high-level, bottom-up IT cost analysis that was undertaking for the 2015 RDA. BC Hydro has completed this work with fiscal 2017 costs, and presents the results below, where:

- The first step is "bottom up functionalization". In this step, IT costs are functionalized at the cost centre level to Generation, Transmission, Distribution, Customer, Corporate and General. This functionalization is based on cost centre level analysis with professional judgement. BC Hydro notes that this step defines IT costs based on six functional areas, two of which (Corporate and General) are functions that are not defined in the cost of service methodology (see Figure 1);
- The second step was to complete the "bottom up functionalization" based on cost of service functions. In this step, IT costs are functionalized to the four functions defined in the cost of service methodology, by adding the pro-rata

[9] The Comprehensive Review Report contemplated the launch of the Biomass Energy Program, but this program is a closed program for the benefit of a limited number of parties with expiring electricity purchase agreements.

[10] For past standard IPP contracts please see: https://www.bchydro.com/work-with-us/selling-clean-energy/closed-offerings.html

share of Corporate and General IT costs to the Generation, Transmission, Distribution and Customer functions as applicable, and

- The third step was to also complete IT functionalization using the method applied by BC Hydro historically, which functionalizes IT based on corporate O&M allocators.

The results of these three steps are shown in Table 3 below.

Table 3 Fiscal 2017 IT Cost Functionalization

$ million	Generation (G), Transmission T), Distribution (D), Corporate (Co), Customer (Cu), and General (Ge)					
	G (%)	T (%)	D (%)	Cu (%)	Co (%)	Ge (%)
Bottom up functionalization	3	3	6	3	3	82
Bottom up functionalization based on COS functions	18.5	22.1	39.3	20.1	N/A	N/A
Status Quo Functionalized by Corporate O&M	25.9	33.3	27.6	13.2	N/A	N/A

As shown in Table 3, bottom up functionalization results in approximately 82 per cent of IT costs that cannot be further functionalized because these costs are general costs that overlap across all functions.

The fiscal 2017 R/C ratios were compared for the two options – IT costs functionalized bottom up based on the cost of service functions, and IT costs functionalized using the historical, status quo approach based on corporate O&M allocators.

Table 4 Impact on Fiscal 2017 R/C Ratios of the IT Functionalization Approach

Rate Class (%)	F2017 R/C with Status Quo Functionalization	F2017 R/C with New Bottom Up Functionalization based on COS function	Change to R/C Ratio
Residential	93.2	92.9	-0.3
GS Under 35 kW	123.6	123.4	-0.2
MGS < 150 kW	115.1	115.1	0.0
LGS > 150 kW	103.9	104.1	0.2
Irrigation	89.5	88.6	-0.9
Street Lighting BC Hydro	198.4	196.1	-2.3
Street Lighting Customer	95.1	94.9	-0.2
Transmission	95.4	96.0	0.6

Because IT costs are small relative to other costs, the choice of functionalization method has modest impact on the R/C ratios. Given the limitation and uncertainty of the high-level bottom-up approach, BC Hydro believes that the high-level Corporate O&M allocator approach is more transparent and appropriate to functionalize IT cost.

BC Hydro is proposing no change to the methodology for functionalizing IT costs.

4.6 NSA Item 6. Functionalization of Regulatory Accounts and Classification of Deferral Accounts

As part of the 2015 RDA, BC Hydro made a substantial improvement to the functionalization of regulatory accounts by moving from the functionalizing for total additions and recoveries of all regulatory accounts to functionalizing individual regulatory accounts. BC Hydro also reviewed and refined the functionalization and classification of the regulatory accounts, including the First Nation Costs Account, Remediation Regulatory Account, and the interest on regulatory and deferral accounts, to ensure their recovery aligns with the functionalization and classification of the underlying asset.

However, due to practical limitations BC Hydro was unable to further functionalize the largest regulatory account at that time, which was the Rate Smoothing Regulatory Account, which had a balance of $122.4 million at the time of the 2015 RDA.

Regulatory accounts were the subject of two reviews undertaken in 2018 – the Government of B.C.'s Comprehensive Review of BC Hydro, and the Auditor General's Review of Rate-Regulated Accounting at BC Hydro.[11] Given this work was underway while this cost of service study was being prepared, BC Hydro did not undertake further functionalization of regulatory accounts and classification of deferral accounts.

In February 2019, as an outcome of the Comprehensive Review of BC Hydro, BC Hydro ceased using the Rate Smoothing Regulatory Account and its entire balance was written off in 2019. This reduced the overall forecast Regulatory Account balance by 24 per cent.

With the write off of the Rate Smoothing Regulatory Account, BC Hydro is now of the view that the improvements to the functionalization method made in advance of the 2015 RDA are adequate and sufficient for the purpose of FACOS studies. BC Hydro is proposing no further changes to the methodology for functionalization of Regulatory Accounts and classification of Deferral Accounts.

[11] Downloaded February 2019: http://www.bcauditor.com/sites/default/files/publications/reports/OAGBC_RRA_RPT.pdf.

4.7 NSA Item 7. Sub-Functionalization and Classification of Distribution Costs

In the 2016 NSA, the parties agreed to sub-functionalize the distribution system into primary system, transformers, secondary and services,[12] and meters, and to then classify each of the sub-functionalized components separately.

Table 5 below shows how BC Hydro classifies sub-functionalized distribution costs into demand-related and customer-related costs.

Table 5 Classification of Distribution Sub-Functions

Distribution Sub-Function (%)	Demand-related	Customer-related
Substation	100	0
Meters	0	100
Primary	100	0
Transformers	50	50
Secondary and Services	50	50
Street lighting	N/A Direct Assigned	

As part of the 2015 RDA,[13] BCOAPO agreed that it was reasonable to classify substation costs as 100 per cent demand-related and meters as 100 per cent customer-related. Some parties argued that further work to refine classification of the distribution sub-functions should be undertaken.

To test the validity of the distribution classification of transformers, BC Hydro examined the classification of transformers using the "Zero Intercept" approach to review recent distribution transformer replacement cost data. Two regression models were fitted separately for 175,272 overhead transformers and 59,860 underground

[12] Secondary wires on the BC Hydro distribution system operate at voltages of less than 750 volts. The secondary wires are the backbone part of the secondary distribution system beginning at the point of transformation (from a higher distribution voltage) running all of the way to the last service connection for a customer. Service wires function at the same voltages as secondary wires. The service wire is that part of the system running between the secondary wires and the point of delivery of an individual customer.

[13] BC Hydro's 2015 Rate Design filing, Exhibit B-1, App. C 2A, pp. 289 of 439.

transformers for which replacement costs data were available. These transformers account for about 85 per cent of total distribution transformers that BC Hydro owned as of the end of fiscal 2017.

Table 6 and Table 7 are the outputs of regression models for overhead and underground transformers respectively. Regression models of overhead and underground transformers have adjusted explained variation (**R^2**) of around 88 per cent and 83 per cent accordingly, which means the models are reasonably well fitted. In both cases the probability value (**P Value**) of the parameter estimates are less than 0.001, indicating that the parameter estimates are highly statistically significant. The intercept parameter estimates are interpreted as the fixed cost of a transformer, independent of the transformer size, which should be classified as customer-related. The ratio of the intercept over the average replacement cost of transformers provides the proportion of cost to be classified as customer-related. The remaining transformer costs are classified as demand-related.

Table 6 Overhead Transformers Zero Intercept Analysis Results

Variable	Parameter Estimate	P Value
Intercept, Fixed costs ($)	2,391	<.0001
Transformer Size (Volts)	53	<.0001

Table 7 Underground Transformers Zero Intercept Analysis Results

Variable	Parameter Estimate	P Value
Intercept, Fixed costs ($)	5,363	<.0001
Transformer Size (Volts)	41.61	<.0001

The average replacing cost of overhead and underground transformers was $5,097.70 and $10,608 respectively. Therefore, using the estimation of intercept and average replacing cost, the results of the zero intercept analysis indicate that the classification of Overhead Transformers is 47 per cent ($2,391/$5,097.70) customer-related, and 53 per cent demand-related; whereas the classification of

Underground Transformers is 51 per cent ($5,363/$10,608) customer-related and 49 per cent demand-related. About 78 per cent transformers captured in this analysis were overhead transformers, and the rest (22 per cent) are underground transformers. Although these results are of limited value because they are based on replacement costs rather than embedded costs, this zero intercept analysis does produce results that are very close to, and support BC Hydro's current classification estimate of 50 per cent customer and 50 per cent demand. Therefore, BC Hydro believes that the sub function classifications presented above are still appropriate. BC Hydro proposes no changes to the classifications the distribution sub-functions.

In the 2016 NSA, BC Hydro committed to analysing the impact of using gross book value rather than net book value in sub-functionalization to better align with the operations, maintenance and administration, as well as depreciation cost of the underlying assets. Shown below is the distribution sub-function classification comparing net book value (**NBV**) to gross book value for fiscal 2017.

Table 8 Distribution Sub-Function Classification Based on Fiscal 2017 Net Book Value

Sub-Function	F2017 Year-End Assets (NBV) ($ million)	% of Assets (excluding Substation)	% of Assets without Street Lighting	Demand % of Total Costs	Customer % of Total Costs
Primary	2,909.9	58.5	58.8	58.8	0.0
Secondary and Services	926.2	18.6	18.7	9.4	9.4
Meters	74.5	1.5	1.5	0.0	1.5
Transformers	1,035.3	20.8	20.9	10.5	10.5
Substation	418.5				
Street lighting	24.3	0.5			
Total	**5,388.7**	**100**	**100**	**78.7**	**21.3**

Note - Percentage may not total 100 due to rounding.

Table 9 Distribution Sub-Function Classification Based on Fiscal 2017 Gross Book Value

Sub-Function	Assets (Gross Value) ($ million)	% of Assets (excluding Substation)	% of Assets without Street lighting	Demand % of Total Costs	Customer % of Total Costs
Primary	3,542.0	60.8	61.2	61.2	0.0
Secondary and Services	866.2	14.9	15.0	7.5	7.5
Meters	96.7	1.7	1.7	0.0	1.7
Transformers	1,287.3	22.1	22.2	11.1	11.1
Substation	504.3				
Street Lighting	30.7	0.5			
Total	**6,327.3**	**100**	**100**	**79.7**	**20.3**

Note - Percentage may not total 100 due to rounding.

Overall the classification of distribution sub-functions changes from 78.7 per cent demand/21.3 per cent customer to 79.7 per cent demand/20.3 per cent customer when the net book gross value approach is replaced by gross book value.

A sensitivity analysis was conducted to assess the impact on the fiscal 2017 R/C ratios of adopting the net book value versus gross book value approach to distribution sub-function classification.

Table 10 Impact on Fiscal 2017 R/C Ratios of Using Net Vs Gross Book Value for Distribution Sub Function Classification

Rate Class (%)	R/C with Net Book Value of Assets	R/C with Gross Book Value of Assets	Change to R/C Ratio
Residential	93.2	93.5	0.3
GS Under 35 kW	123.6	123.5	-0.1
MGS < 150 kW	115.1	114.6	-0.5
LGS > 150 kW	103.9	103.5	-0.4
Irrigation	89.5	89.1	-0.4
Street Lighting BC Hydro	198.4	192.7	-5.7
Street Lighting Customer	95.1	95.0	-0.1
Transmission	95.4	95.4	0.0

As shown above, with the exception of the Street Lighting BC Hydro Owned rate class, the influence of this methodological change on the R/C ratios is not material. Therefore, BC Hydro supports continuing using previous net book value approach to sub-functionalize and classify distribution cost. BC Hydro proposes no changes to distribution sub-function classification.

4.8 NSA Item 8. Functionalization of DSM Costs

In the 2016 NSA, the parties supported BC Hydro proposal to functionalize DSM as 90 per cent generation, 5 per cent transmission and 5 per cent distribution, subject to BC Hydro revisiting the functionalization between generation, transmission and distribution in the F2019 COSS.

In response to this, BC Hydro analyzed the F2017 Net Present Value (**NPV**) of avoided Generation energy and demand costs, as well as avoided Transmission and Distribution wires cost attributable to DSM as shown in Table 11.[14]

Table 11 Fiscal 2017 NPV of DSM Avoided Costs by Function

	NPV of Avoided Cost ($000)	% of Total Benefits
Generation (Energy)	505,965	78.4
Generation (Capacity)	120,423	18.6
Transmission (Wires)	17,579	2.7
Distribution (Wires)	1,953	0.3
TOTAL	645,920	100.0

The total avoided Generation costs, including energy and demand, accounted for 97 per cent of the total avoided cost of DSM. Transmission and Distribution avoided wire cost accounted for 2.7 per cent and 0.3 per cent respectively out of the total avoided cost attributable to DSM. To summarize, based on the fiscal 2017 NPV of

[14] The avoided cost assumptions used to estimate the benefits from the F2017 DSM activities in Table 11 are consistent with those used in the cost-effectiveness analyses shown in BC Hydro's Report on Demand-Side Management Activities for Fiscal 2017 (filed with the BCUC in July 2017).

Avoided Costs, DSM functionalization is 97 per cent generation, 2.7 per cent transmission and 0.3 per cent distribution.

BC Hydro conducted a sensitivity analysis of the impact on fiscal 2017 R/C ratios of updating DSM functionalization. As shown in Table 12 below, the impact of this change on fiscal 2017 R/C ratios is negligible.

Table 12 Impact on Fiscal 2017 R/C Ratio of Changes to DSM Cost Functionalization

Rate Class (%)	R/C with Previous DSM Functionalization (90% G, 5% T, 5% D)	R/C with F2017 Avoided Cost Based Functionalization (97% G, 2.7% T, 0.3% D)	Change to R/C Ratio
Residential	93.2	93.3	0.1
GS Under 35 kW	123.6	123.7	0.1
MGS < 150 kW	115.1	115.1	0.0
LGS > 150 kW	103.9	103.8	-0.1
Irrigation	89.5	89.6	0.1
Street Lighting BC Hydro	198.4	198.9	0.5
Street Lighting Customer	95.1	95.1	0.0
Transmission	95.4	95.3	-0.1

While the results above are representative of the functionalization of DSM costs for fiscal 2017, they may not be applicable to future periods. This is because BC Hydro’s DSM Plan continues to evolve, for example with the launch of electrification initiatives in 2018. Given the negligible impact of changes to DSM plan costs functionalization on the R/C ratio, and the continued evolution of the DSM plan, BC Hydro proposes no changes to DSM functionalization.

4.9 NSA Item 9. Classification of DSM Costs

In the 2016 NSA, some participants questioned if classifying the generation and distribution-related cost of DSM in the same way as overall generation and distribution-related costs is appropriate.

In the F2017 FACOS, $4.5 million of DSM costs were functionalized as distribution-related cost, as per BC Hydro's approach to functionalize DSM costs as 90 per cent generation, 5 per cent transmission and 5 per cent distribution. Because the distribution-related costs are low, relative to all costs, modifications to its classification will have negligible impact on the R/C ratios. BC Hydro therefore proposes no changes to the classification of distribution-related DSM costs.

An alternative approach to classifying DSM generation-related costs was examined. This approach classifies DSM generation-related costs based on avoided energy and demand cost resulting from DSM expenditures. The results are shown in Table 13. As shown, about 80.8 per cent generation cost is energy-related and and19.2 per cent is demand-related. Therefore, based on this alternative approach, generation-related DSM cost can be classified as 80.8 per cent energy and 19.2 per cent demand. The sensitivity analysis showing the impact of this change on fiscal 2017 R/C ratios is shown below.

Table 13 Impact on Fiscal 2017 R/C Ratio of Changes to DSM Costs Classification

Rate Class (%)	R/C with Previous Functionalization (90% G, 5% T, 5% D)	R/C with Updated Functionalization Only (97% G, 2.7% T, 0.3% D)	R/C with Updated Functionalization and Classification of G-related Cost	Change to R/C Ratio (C-B)	Change to R/C Ratio (C-A)
Column	**A**	**B**	**C**	**D**	**E**
Residential	93.2	93.3	93.3	0.0	0.1
GS Under 35 kW	123.6	123.7	123.7	0.0	0.1
MGS < 150 kW	115.1	115.1	115.1	0.0	0.0
LGS > 150 kW	103.9	103.8	103.8	0.0	-0.1
Irrigation	89.5	89.6	89.5	-0.1	0.0
Street Lighting BC Hydro	198.4	198.9	198.9	0.0	0.5
Street Lighting Customer	95.1	95.1	95.1	0.0	0.0
Transmission	95.4	95.3	95.2	-0.1	-0.2

BC Hydro concludes that changes to the classification of DSM costs have negligible impact on R/C ratios. Given this, BC Hydro's view is that for consistency and comparability, it is preferable to maintain the same classification method used in previous FACOS studies. BC Hydro therefore proposes no changes to the classification of DSM costs.

4.10 NSA Item 10. Classification of Generation-Related Transmission Assets

As part of the 2016 NSA, the parties accepted BC Hydro's approach of applying the classification of generation-related transmission assets consistent with the approach applied to Heritage Hydro. BC Hydro proposes no changes to this approach.

4.11 NSA Item 11. Classification of Smart Meter Infrastructure Costs

While it is common utility practice to classify metering-related costs as customer costs for FACOS studies, in the 2016 NSA parties suggested an alternative approach of classifying Smart Metering Infrastructure (**SMI**) costs by its underlying benefit areas and cost items. Shown in Table 14 below is the SMI Program Budget and Cost at Completion[15] as per BC Hydro's Smart Metering and Infrastructure Program Completion and Evaluation report which filed to BCUC in December 2016.

[15] Source: For more information on benefits see BC Hydro's Smart Metering & Infrastructure (SMI) Program – Program Completion and Evaluation Report filed with the BCUC on December 21, 2016

Table 14 SMI Program Budget and Cost at Completion

SMI Program Budget and Cost at Completion		
Program Expenditures ($ million)	**Cost at Completion**	**% of Total Cost**
Initiation Phase (Completed Fiscal 2007)	1.4	0
Identification Phase (Completed Fiscal 2008)	8.9	1
Definition Phase (Completed Fiscal 2011)	37.8	5
Implementation Phase (Fiscal 2011 to Fiscal 2016):		0
Smart Meter System	398.5	51
Solution Integration (Information Technology)	87.5	11
Theft Detection	86.5	11
Conservation Feedback Tools	19.2	2
Grid Modernization Infrastructure Upgrades	76.7	10
Program Delivery Activities	50.9	7
Total: Program Costs before IDC and Contingency	767.4	
Interest During Construction	11.8	2
Contingency	0	0
Reserve Subject to Board Control	0	0
Total: Program Authorized Amount	779.2	100

Except for Theft Detection, Conservation Feedback Tools and Grid Modernization infrastructure upgrades, all other SMI functions and their related costs are clearly identified as being customer-related. However, costs related to theft detection could arguably be considered to be generation-related and classified the same as heritage hydro. Similarly, costs associated to Conservation Feedback Tools could be considered DSM-related and classified the same as DSM costs. And finally, because Grid Modernization Infrastructure Upgrades enable faster power outage restoration, these costs could be considered to be distribution-related and be classified the same as distribution-related costs. Using this approach, overall SMI-related costs may be classified as 8.1 per cent energy, 15.3 per cent demand, and 76.6 per cent customer care.

Table 15 shows that the impact on R/C ratios of updated functionalization and its associated classification of SMI costs based on the underlying benefit areas and cost items is negligible.

Table 15 Impact on Fiscal 2017 R/C Ratios of SMI Classification

Rate Class (%)	R/C with Status Quo Classification	R/C with New Functionalization & Classification	Change to R/C Ratio
Residential	93.2	93.4	0.2
GS Under 35 kW	123.6	123.6	0.0
MGS < 150 kW	115.1	114.9	-0.2
LGS > 150 kW	103.9	103.7	-0.2
Irrigation	89.5	89.3	-0.2
Street Lighting BC Hydro	198.4	198.6	0.2
Street Lighting Customer	95.1	95.1	0.0
Transmission	95.4	95.3	-0.1

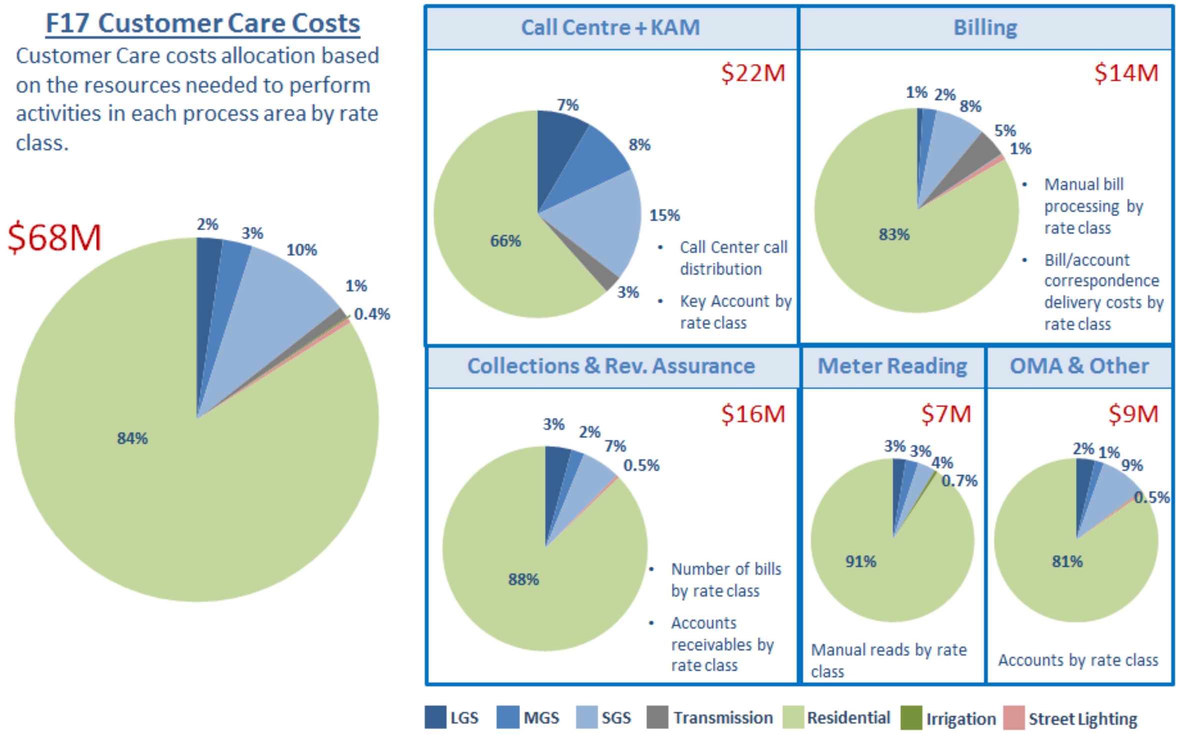
Considering that it is common practice of functionalize and classify metering-related cost as customer, and that changes to reflect underlying benefits results in negligible changes of the R/C ratios, BC Hydro proposes no change to the functionalization and classification of SMI-related costs.

4.12 NSA Item 12. Classification and Allocation of Customer Care Costs

Parties to the 2016 NSA agreed with BC Hydro's approach to classify all customer care-related costs as being customer-related. BC Hydro proposes no changes to this approach.

As part of the 2016 NSA, BC Hydro did commit to repeat the bottom up allocation of customer care-related costs in order to inform cost allocation to rate classes. The results of the detailed analysis are shown in Figure 2.

1 **Figure 2 Customer Care Costs Allocation**



2 Table 16 compares the 90 per cent number of bills and 10 per cent revenue
3 weighted allocator that BC Hydro has used with the more detailed “bottom up”
4 allocator.

Table 16 Comparison of Alternate Approaches to the Allocation of Customer Costs to Rate Classes

Rate Class (%)	F2017 FACOS Status Quo Weighted Customer Care Allocator (90%/10%)	Bottom up Analysis by Customer Care Category
Residential	83.02	83.98
GS Under 35 kW	9.20	9.47
MGS < 150 kW	2.26	2.62
LGS > 150 kW	2.65	2.33
Irrigation	0.06	0.15
Street Lighting BC Hydro*	0.47	0.43
Street Lighting Customer*	0.52	0.43
Transmission	1.81	1.02
Total	**100**	**100**

*: Customer care cost was not split between BC Hydro owned and customer owned street lightings.

BC Hydro notes there had been some major changes in the Customer Service area in and around fiscal 2017. In October 2016, BC Hydro repatriated the manual meter reading service. This resulted in a partial year of meter reading cost savings in fiscal 2017. A full year meter reading savings may be noticeable in later years. In fiscal 2019, significant changes were made to customer service delivery with the repatriation to BC Hydro of services previously outsourced to Accenture Business Services. The repatriation impact to the call centre and billing services is expected to result in costs savings to BC Hydro. Given these major changes to customer care-related service delivery and costs since fiscal 2018, the results of bottom up analysis of customer service cost allocation in fiscal 2017 may not be applicable to future years.

The sensitivity test of the impact of customer care cost allocation on the fiscal 2017 R/C ratios is shown in Table 17.

Table 17 Impact on Fiscal 2017 R/C Ratios of Changes to Customer Care Cost Allocation

Rate Class (%)	R/C with Status Quo (90%/10% Weighted Allocator)	R/C with Bottom Up Allocator	Change on R/C Ratio
Residential	93.2	93.2	0.0
GS Under 35 kW	123.6	123.5	-0.1
MGS < 150 kW	115.1	114.9	-0.2
LGS > 150 kW	103.9	103.9	0.0
Irrigation	89.5	88.2	-1.3
Street Lighting BC Hydro	198.4	199.3	0.9
Street Lighting Customer	95.1	95.6	0.5
Transmission	95.4	95.5	0.1

The results above indicate that changes to the customer care cost allocation have minor impact on the R/C ratios. Given this minor impact, and the changes noted above regarding BC Hydro customer service functions, BC Hydro proposes no change to the customer care related cost allocation at this time.

4.13 NSA Item 13. Generation Demand and Transmission Allocation and Derivation of 4CP and one NCP Allocators

In the 2015 RDA BC Hydro applied to change from a one-year to a five-year average of 4CP and NCP allocators in order to allocate generation and transmission-related costs, and distribution demand-related costs respectively. The request was approved and a five-year average has been applied to FACOS studies since that time.

Questions regarding 4CP allocator were raised by parties in the 2016 NSA. The questions raised and the results of BC Hydro's further examination are presented below.

Question 1: Is 4CP or 1CP or 12CP an appropriate demand allocator?

The selection of an appropriate CP (for example 4CP vs 1CP, vs 12CP) allocator is determined by the number of monthly peaks to be considered when BC Hydro plans adequate capacity to meet system need. A specific monthly peak should also be considered in capacity planning, only if this monthly peak has a comparable scale to the system annual peak.

The Ontario Energy Board proposed two tests to determine an appropriate CP to allocate CP basis demand cost[16].

CP Test No. 1 Result = Average of 12 Monthly Peaks ÷ Annual Peak

CP Test No. 1 examines if the 12-month average peak is comparable to the annual peak. If it is, a 12CP allocator should be used to allocate demand-related costs that are to be allocated on a CP basis. The Ontario Energy Board suggested that a test result of 81 per cent or greater indicated that monthly peaks in all 12 months are considerably high and a 12CP method should be adopted in CP basis demand cost allocation. When test result is less than 81 per cent, 12CP is not appropriate allocator and the following CP Test No. 2 should be conducted to test 4CP vs. 1CP method.

CP Test No. 2 Result = Average of Four Highest Monthly Peaks ÷ Annual Peak

The Ontario Energy Board suggests that a test result of 86 per cent or less indicates that the average peak in the four highest peak months is substantially lower than the annual peak and 1CP is an appropriate allocator to be adopted in CP basis cost allocation. Otherwise, the 4CP allocator should be applied in CP basis demand-related cost allocation.

[16] Accessed February 2019 from: https://www.oeb.ca/documents/cases/EB-2005-0317/proposedtests_111105.pdf.

BC Hydro conducted the CP tests using system hourly load data for fiscal 2017, which confirmed that the 4CP is the appropriate demand allocator, as follows.

- BC Hydro's CP Test 1 result was 79 per cent, which is below the threshold of 81 per cent set by the Ontario Energy Board as an indicator that 12CP may be appropriate; and
- BC Hydro's CP Test 2 results was 97 per cent, which is well above the 86 per cent threshold set by the Ontario Energy Board as an indicator that one CP may be appropriate.

BC Hydro therefore proposes no changes to the use of the 4CP demand allocator.

Question 2: Is it appropriate to use a one-year or five-year average for the 4CP/NCP calculations?

In the 2015 RDA, BC Hydro moved from a one-year approach to five-year average calculation of 4CP. The intent of this proposed change was to produce results that were closer to a normalized, long-term average result, given that one of the main uses of the FACOS studies is to inform rate designs, and rate designs are revised infrequently.

Participants in the 2016 NSA questioned whether it was appropriate to move from a one-year to a five-year average approach for 4CP and NCP estimations. BC Hydro conducted a sensitivity test in 2016 based on the F2014 FACOS Study and showed there was little difference of R/C ratios between using the one-year 4CP and non-coincident peak (**NCP**) versus the calculation using a five-year average approach.

To further examine the impact of using a five-year average 4CP/NCP in ongoing FACOS Studies, year fiscal 2017 is used as a test year. Shown below is the impact on the fiscal 2017 R/C ratios of moving form a five-year average to a one-year estimate for allocation of demand-related costs.

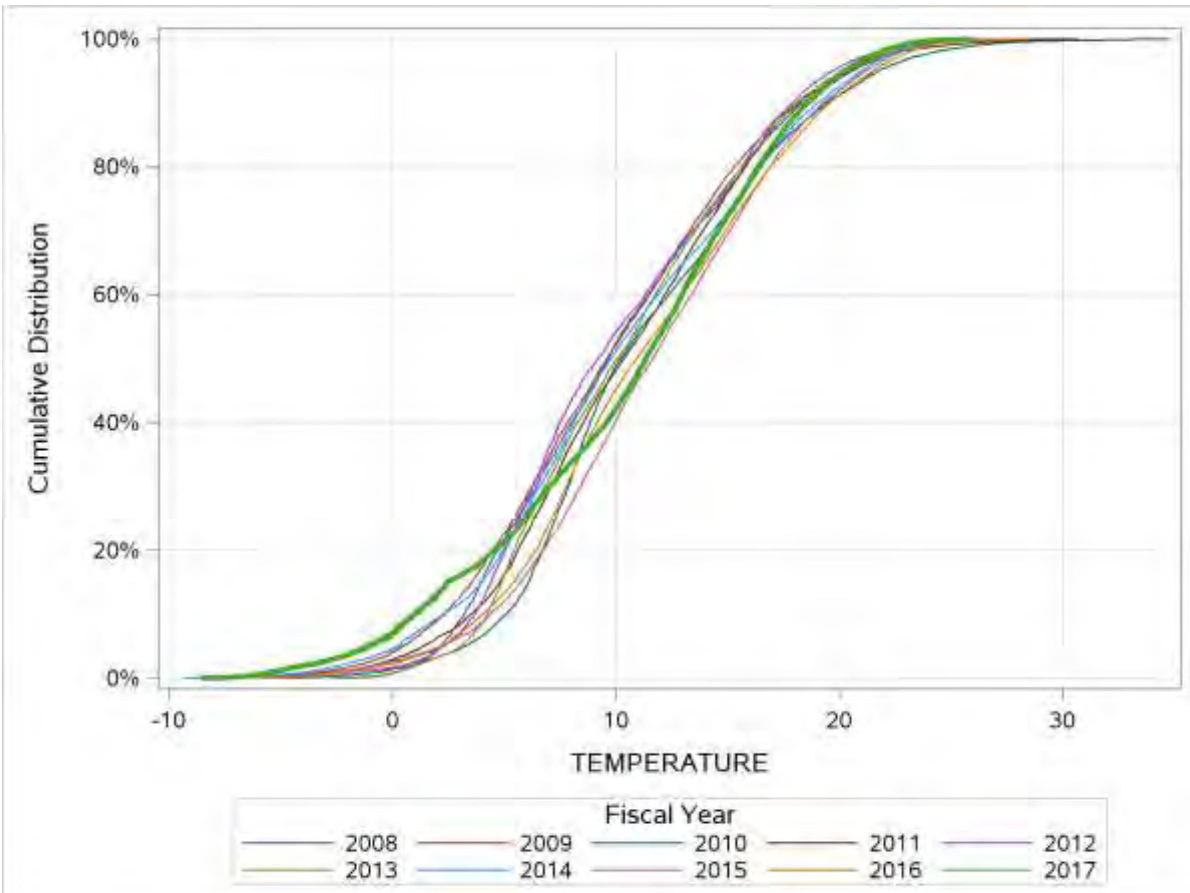
Table 18 Impact on Fiscal 2017 R/C Ratio of Five- Year Average, Vs One-Year Allocator of Demand-Related Costs

Rate Class (%)	R/C with 5-Year Average 4CP & NCP	R/C with 1-Year 4CP & NCP	Change to R/C Ratio
Residential	93.2	91.6	-1.6
GS Under 35 kW	123.6	123.5	-0.1
MGS < 150 kW	115.1	116.8	1.7
LGS > 150 kW	103.9	104.2	0.3
Irrigation	89.5	89.1	-0.4
Street Lighting BC Hydro	198.4	208.3	9.9
Street Lighting Customer	95.1	93.6	-1.5
Transmission	95.4	98.1	2.7

As shown above, fiscal 2017 R/C results were sensitive to the choice of one year versus five year for the allocation of demand-related costs. The impact occurred because fiscal 2017 was an exceptionally cold year. Because BC Hydro is a winter peaking utility, and use of a five-year average has the effect of weather normalizing demand-related costs, the use of the method will understate demand-related costs for weather sensitive rate classes in abnormally cold years, and overstate them in unusually warm years. Below is further examination of the weather effect in fiscal 2017.

Figure 3 shows the Cumulative Distribution Function (**CDF**) of hourly temperatures in the Lower Mainland in the 10-year period ending at fiscal 2017. The graph shows the duration curve over the entire year depicting the probability that the temperature was less than or equal to a given value. The CDF of fiscal 2017 is highlighted in the thicker green curve and it shows that fiscal 2017 was a significantly colder year compared to all other years. For example, in fiscal 2017, 7 per cent of days were below zero degrees Celsius, compared to 1 per cent to 4 per cent in the other nine years. Therefore, fiscal 2017 was not a normal but an unusually cold winter year. The one-year 4CP in fiscal 2017 particularly represents the demand cost allocation of a cold winter year, and it is remarkably different from the normalized 4CP calculated by five-year average approach.

Figure 3 Annual Cumulative Distribution of Hourly Temperature in BC Hydro's Lower Mainland Service Region during Fiscal 2008 to Fiscal 2017



BC Hydro recognizes the potential risk of overestimating and underestimating R/C ratios of some classes by using a one-year approach in an extreme weather year. As such, BC Hydro supports continuing to use the five-year average approach to calculate the demand allocator of 4CP and NCP because this will better represent more normal weather conditions.

4.14 NSA Item 14. Customer Segmentation and Street Lighting

In the 2015 RDA BC Hydro proposed and received approval to update the rate class segmentation to split the Street Lighting rate class into two segments – customer owned, and BC Hydro owned. No parties in the 2016 NSA objected to BC Hydro's proposed segmentation. Since that time, BC Hydro has introduced no new rate schedules that may indicate the need for further customer segmentation. Therefore, BC Hydro proposes no change to segmentation.

4.15 Conclusion

Based on the results of investigation on fourteen topics raised in the 2016 NSA, BC Hydro has not made any changes to the FACOS methodology at this time.

Cost of Service Study - Fiscal 2019

Appendix A

2016 Cost of Service Study
Negotiated Settlement Agreement

British Columbia Utilities Commission

Laurel Ross
Acting Commission Secretary

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FAX: (604) 660-1102

Log No. 51126

VIA EMAIL

April 11, 2016

To: British Columbia Hydro and Power Authority
Registered Interveners

Re: British Columbia Hydro and Power Authority
Project No. 3698781/G-156-15
2015 Rate Design Application Module 1
Cost of Service Study and Rate Class Segmentation Negotiated Settlement Agreement

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Further to the negotiated settlement process that took place on March 7 and 8, 2016, enclosed please find Commission Order G-47-16 approving the Cost of Service Study and Rate Class Segmentation Negotiated Settlement Agreement.

The Commission Panel notes that BC Hydro and the Movement of United Professionals will engage in discussions prior to the F2019 Cost of Service and Rate Design Application to identify if there are specific areas where there might be value to pursing marginal cost information. The Panel is concerned about the potential cost of a marginal cost study and urges BC Hydro to proceed only if there is an expectation that the benefits may outweigh the costs.

The Commission Panel also recognizes that the Heritage Hydro Classification is one of the larger impact issue items discussed and therefore recommends that BC Hydro provide robust information and analysis in the next cost of service study.

Yours truly,

Original signed by
Laura Sharpe for:

Laurel Ross

YD/cms
Enclosure

PF/BCH 2015RDA/GC/04-11-2016_COS-Negotiated-Settlement-Agreement (L)

British Columbia Utilities Commission

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BC Toll Free: 1-800-663-1385
FAX: (604) 660-1102

ORDER NUMBER
G-47-16

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
2015 Rate Design Application

BEFORE:
D. M. Morton, Commissioner/Panel Chair
D. A. Cote, Commissioner
K. A. Keilty, Commissioner

on April 11, 2016

ORDER

WHEREAS:

A. On September 24, 2015, British Columbia Hydro and Power Authority (BC Hydro) filed its 2015 Rate Design Application (Application);

B. A procedural conference was held on January 19, 2016, by the British Columbia Utilities Commission (Commission) to hear procedural matters on the Application;

C. By Order G-12-16 dated February 1, 2016, the Commission established the regulatory timetable for the review of the Application, which included a negotiated settlement process (NSP) for its cost of service study and rate class segmentation, to take place on March 7 and 8, 2016;

D. On February 24, 2016, the Commission issued a letter to all parties (Exhibit A-21) appointing Ms. Liisa O'Hara as the facilitator for the NSP along with the establishment of roles for several Commission staff;

E. The NSP was held in Vancouver, BC on March 7 and 8, 2016, and an agreement was reached on issues raised on the second day. The final negotiated settlement agreement (NSA) was circulated to participants on March 24, 2016;

F. The following registered interveners, along with Commission staff, participated in the NSP:

- BC Hydro;
- Association of Major Power Customers;
- British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, BC Poverty Reduction Coalition, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Together Against Poverty Society, and Tenant Resource & Advisory Centre;
- BC Sustainable Energy Association (BCSEA) and the Sierra Club of BC;

.../2

- Commercial Energy Consumers Association of BC;
- FortisBC Energy Inc. and FortisBC Inc.;
- Movement of United Professionals (MoveUP); formerly the Canadian Office and Professional Employees' Union, Local 378 (COPE378);
- Non-Integrated Areas Ratepayers Group; and
- Zone II Ratepayers Group;

G. Letters of support for the NSA have been received from all participants of the NSP;

H. On March 31, 2016, the NSP Facilitator filed the NSA and supporting documents with the Commission; and

I. The Commission has reviewed the NSA package and considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, the British Columbia Utilities Commission approves the Negotiated Settlement Agreement for British Columbia Hydro and Power Authority pertaining to its F2016 cost of service study and rate class segmentation as issued on March 31, 2016, and attached as Appendix A to this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 11th day of April 2016.

BY ORDER

Original signed by:

D. M. Morton
Commissioner/Panel Chair

Attachment

LIISA A. O'HARA
Consultant
c/o BC Utilities Commission
900 Howe Street, Vancouver, BC
V6Z 2N3

VIA E-MAIL

March 31, 2016

British Columbia Utilities Commission
6th Floor - 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Laurel Ross
Acting Commission Secretary

Dear Ms. Ross:

Re: British Columbia Hydro and Power Authority (BC Hydro)
2015 Rate Design Application
Negotiated Settlement Agreement
Re: F2016 Cost of Service Study

Enclosed with this letter is the proposed Negotiated Settlement Agreement (Agreement) for BC Hydro's F2016 Cost of Service Study. Also enclosed are Letters of Acceptance or Support received from the participants in the Negotiated Settlement Process (NSP).

On February 24, 2016, the Chair of the Commission appointed me to act as the facilitator of the NSP (Exhibit A-21). Participants in the NSP met on March 7 and 8, 2016 and reached an agreement at the end of the second day. During the following two weeks the Agreement was drafted and refined. The final Agreement was circulated to the participants on March 24, 2016 with a request for Letters of Acceptance or dissent due on March 30, 2016.

Since the Agreement was circulated on March 24, it has been brought to my attention that on page 3 of the Settlement Agreement, the Order issuing the Decision on BC Hydro's 2007 RDA is identified incorrectly as Order G-103-07. The proper Order is G-130-07. This reference was for context only and has no bearing on the substance of the Agreement. Rather than change the Agreement, I note the error and the proper reference here as an erratum.

The Agreement is now public and is being submitted to the non-participating registered Interveners and the Commission Panel for review. If non-participating registered Interveners have any comments, these should be received by the Commission within five business days.

In conclusion, I wish to thank all participants and BC Hydro for their willingness to co-operate and make every effort to find a path towards reaching this Agreement.

Yours truly,

Phillip Kohlmann

Liisa A. O'Hara
fn NSP Facilitator

Attachments

British Columbia Hydro and Power Authority (BC HYDRO)

2015 Rate Design Application
British Columbia Utilities Commission (Commission) Project No. 3698781

NEGOTIATED SETTLEMENT AGREEMENT
REGARDING THE
F2016 COST OF SERVICE STUDY

Introduction

Participants (listed below) in the negotiated settlement process (NSP) met on March 7 and 8, 2016 for the purpose of negotiating a settlement of the F2016 Cost of Service Study (COSS) proposed in BC Hydro's 2015 Rate Design Application (2015 RDA) in accordance with Commission Order G-12-16. The NSP discussions were facilitated by a third party, Ms. Liisa O'Hara, appointed by the Commission (Facilitator).

Commission Staff participated separately in the roles of:

1. Active Participant - providing representation to ratepayer groups not actively participating in the review of the COSS;
2. Advisor - providing technical and factual support to the discussions; and
3. Observers - monitoring the NSP to ensure that it is fair and open, and providing procedural information and technical assistance to the Commission Panel.

The Commission Panel did not participate in the NSP.

Participants in the NSP for the F2016 COSS were representatives for:

- Commission staff (Commission Staff),
- BC Hydro
- Association of Major Power Customers (AMPC)
- British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, BC Poverty Reduction Coalition, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Together Against Poverty Society, and Tenant Resource & Advisory Centre, (BCOAPO)
- BC Sustainable Energy Association (BCSEA) and the Sierra Club of BC (SCBC)
- Commercial Energy Consumers Association of BC
- FortisBC Energy Inc. and Fortis BC Inc. (collectively FortisBC)
- Movement of United Professionals (MoveUP); formerly the Canadian Office and Professional Employees' Union, Local 378 (COPE378)
- Non-Integrated Areas Ratepayers Group (NIARG)
- Zone II Ratepayers Group (ZoneIIRPG)

The British Columbia Ministry of Energy and Mines (MEM) attended the NSP as an observer and did not actively participate. All of those in attendance at the NSP, including participants, observers, the Advisor and the Facilitator, signed a copy of the Confidentiality Agreement appended to the February 2012 *Commission's Negotiated Settlement Process - Policy, Procedures and Guidelines*.

After completion of the negotiations, BC Hydro prepared a document for this Negotiated Settlement Agreement (NSA) titled "Cost of Service (COS) Model Changes as part of 2015 RDA. The document identified changes to the COSS resulting both from changes to the COSS as agreed to in the NSP and corrections for errors that were discovered during the revision to the COSS. That document is attached as Appendix B. In addition, the updated COSS is attached as Appendix C.

Issues for Negotiation

On February 11, 2016, prior to the NSP discussions, the Commission Panel issued a letter (Ex. A-18) that requested comments from interveners on the specific issues regarding the F2016 COSS that they wished to address. After receiving the intervener comments, Commission Staff acting in the role of Advisor circulated an Issues Summary on March 2, 2016 containing a list of issues to be addressed in the negotiations, including a summary of each issue as identified by each intervener.

At the beginning of the NSP, the Facilitator asked for, and received, agreement from the NSP participants that parts of the F2016 COSS that no one raised as an issue before or during the NSP would be presumed to be accepted by the NSP participants for the purposes of achieving a settlement.

Also at the beginning of the NSP the Facilitator asked the participants for suggestions on the most efficient order in which to address the issues. Those suggestions led to the issues being addressed in a different order than the Issues Summary, and the issues are presented here in the order in which they were addressed.

In the responses to the Commission Panel letter (Ex. A-18) there were four potential issues that one or more participants put forward that were either general in nature or applied to the Zone 1B and Zone II/Non-Integrated Areas. These were:

- The F2016 COSS changes relative to the 2007 RDA Decision
- Rate design and COSS principles
- The appropriateness of cost allocations as they apply to the Non-Integrated Areas (NIAs)
- COSS energy supply costs, specifically line loss and NIA diesel costs

These were identified during the NSP as either issues that would be better covered in one or more of the specific issues that follow, or as requests for clarification from BC Hydro rather than a dispute requiring resolution. BC Hydro's clarifications appeared to satisfy the parties, and these topics were not pursued further during the NSP. Consequently, they are not included in this NSA.

In the end, all the issues set out in the Issues Summary, and all other F2016 COSS issues raised in the course of the NSP, were addressed and resolved by agreement of the participants as described below.

Context

The last time BC Hydro filed a COSS for Commission approval was in 2007. This led to the Commission's Decision and Order G-103-07 (2007 RDA Decision).

On July 14, 2015 the Province issued Order in Council (OIC) 405, which directed that in setting BC Hydro's rates for F2017 through F2019, the BCUC must not set rates for BC Hydro for the purpose of changing the revenue-cost (R/C) ratio for a class of customer. The OIC removed much of the contention from the COSS, a key output of which is R/C ratios; parties noted that consequently the COSS would result in no rebalancing of rates between rate classes over that time period, although it could have an intra-class rate impact.

BC Hydro has committed to filing a new COSS and Rate Design Application in F2019. BC Hydro will use F2018 actuals as a basis for its F2019 RDA, and will precede it with a robust engagement process starting around the summer of 2017, using F2017 data as the initial basis of its analysis and consultation until F2018 data becomes available. Parties agreed at the outset of the negotiations that, regardless of positions taken in this NSP or the resolution of issues in this NSP, all cost of service issues would be open for discussion in the F2019 COSS and RDA, and the resolution of issues in this NSP would not establish a precedent or be used to justify approaches taken in the F2019 COSS and RDA (or to devalue alternative approaches).

A summary table of all Cost of Service (COS) issues addressed in the 2015 RDA, whether included for discussion in the NSP or not, is attached as Appendix A. The table compares the 2007 RDA Decision COS methodology to BC Hydro's 2015 RDA COS proposed methodology and to the 2016 NSA accepted methodology. With the exception of the classification of Heritage Hydro generation costs, the COS NSA resulted in no changes to BC Hydro's 2015 RDA COS methodology as proposed in Exhibit B-1.

Except where otherwise indicated, this document uses the COSS specialized terminology used by BC Hydro in the Application. Examples include: functionalization, sub-functionalization, classification, allocation, generation, transmission, distribution, customer costs, energy, demand, capacity, load factor, and capacity factor.

1.0 Marginal Cost Study

References:

Ex. B-1, pp. 3-6 and 3-7;
Ex. B-1, App. C-2A, p. 170 of 439 and pages 269 to 276 of 439
Ex. B-1, App. C-2B, Attachment 4 (pages 179 to 186 of 205)
Ex. C4-6
Ex. C12-5

Issue:

BC Hydro proposes an embedded cost COS approach to allocating its revenue requirement. BC Hydro does not support the use of a marginal COSS for allocating its revenue requirement, (Ex. B-1, pp. 3-5 to 3-7). MoveUP (formerly Cope 378) noted in response to Ex. A-18 that it "…intends to pursue an agreement that BC Hydro present modelling based on the Marginal Cost of Service in the next RDA even if it intends to continue with an application based on the current embedded COS." (Ex. C4-6)

Discussion:

BC Hydro states in its Application that most utilities use an embedded COS approach. It also notes that marginal COSS results in a revenue requirement that is different from the utility's approved revenue requirement, requiring adjustments to ensure that rates recover no more than the approved revenue requirement, thus varying from and diluting any price signals that would reflect "true" marginal costs. Prior to the NSP, AMPC indicated that it supported BC Hydro's proposal to continue to use an embedded cost of service for revenue requirement allocation purposes, and, consistent with the 2007 RDA Decision, believed it to be appropriate to continue to use this approach because marginal cost should not be relevant to rate design. (Ex. C12-5)

Several parties to the negotiations were concerned that the development of a marginal COSS is expensive, requires considerable judgment that would be open to debate, and would provide limited value. BC Hydro also noted that although almost all Canadian and Pacific Northwest utilities use embedded cost approaches, these jurisdictions use marginal costs to inform rate design rather than as a basis for their cost of service studies. It was also noted that BC Hydro uses Long–Run Marginal Cost (LRMC) to set Tier 2 rates and provide a price signal. In response it was argued that there might be value in using marginal cost information in specific areas and that there should be an attempt to identify any such areas.

Settlement:

MoveUp and BC Hydro will engage prior to the F2019 COSS and RDA to identify if there are specific areas where there might be value using marginal cost information.

2.0 Heritage Hydro Classification

References:

Ex. B-1, pp. 3-23 to 3-25
Ex. B-1, COS Methodology Review (App. C-2A, pp. 40 and 85 of 439);
Ex. B-1, Workshop 2 Discussion Paper (App. C-2A), pp 245-248 of 439;
Ex. B-1, Workshop 4 Discussion Guide (App. C-2B), pp. 62 and 65-67 of 205;
Ex. B-1 Workshop 4 Consideration Memo (App. C-2B), pp. 89-92 of 205;
Ex. B-5, BCUC IR 1.25.3 to 1.25.7; AMPC IR 1.3.1 -1.3.11
BCOAPO IR 1.37.2 - In its response, BC Hydro provides tables that show the energy, demand-related costs and total generation costs allocated to each rate class under the three hydroelectric classification options, which are described in section 4 of the Workshop 4 discussion guide (pages 65 to 67 of 205, Appendix C-2B, Exhibit B-1)

Issue:
BC Hydro is proposing a System Load Factor approach, adjusted for IPP energy and demand since it is classifying IPPs separately, to classify its Heritage Hydro generation. This results in a 55% energy/45% demand split. BC Hydro also put forward two alternative options:

- Capacity Factor approach weighted by book value (leading to a 45% energy/55% demand split)
- Use of BC Hydro's historic (pre-2007) classification of Heritage Hydro of a 50% energy/50% demand split.

It does not oppose adoption of any of the three classification methods. (Ex. B-1, pp. 3-23 to 3-25)

Discussion:

The 2007 RDA Direction 5 read as follows:

> *"For purposes of this Application the Commission Panel finds a 55 percent demand 45 percent energy split using the demand (head) approach is reasonable absent a detailed study and BC Hydro is directed to recalculate the FACOS [fully allocated cost of service] accordingly, as directed in Commission Order No. G-111-07.*
>
> *Further, BC Hydro is directed to include a detailed analysis of this issue as part of its next FACOS or rate design filing."*

Two participants raised the Heritage Hydro classification method as an issue for the NSP. Another party identified the Classification of Heritage Hydro as it applies to the NIA as an issue.

BC Hydro notes in its Workshop 4 Consideration Memo (App. C-2B, p. 89 of 205) that the classification of Heritage Hydro is one of the larger impact issues. The impact relative to some other COSS methodology changes is shown in the response to Fortis IR 1.2.1.

BC Hydro is proposing a System Load Factor approach, adjusted for IPP demand since it is classifying IPPs separately, to classify its Heritage Hydro generation. This results in a 55% energy/45% demand split. In the Application, BC Hydro provided a table outlining the three different options and the pros and cons of each (Ex. B-1, App. C-2A, p. 248 of 439). It notes that many utilities use a Load Factor approach, but acknowledges that such an approach doesn't account for how generation is being used for trade purposes. At the same time, BC Hydro acknowledges that a Load Factor approach doesn't account for recent expenditures on capacity, and recent additions to the Heritage Hydro system have been capacity additions.

Some parties support BC Hydro's proposed Load Factor approach; one noted that while there is no inter-class impact there would be an intra-class impact for some rate classes due to a change in the percentage of costs classified as energy-related versus demand-related. Other parties support a Capacity Factor approach weighted by book value that classifies Heritage Hydro costs 45% to energy and 55% to demand. These parties submit that such an approach is consistent with 2007 RDA Direction 5, and it continues to be the most appropriate classification mechanism for these generation costs given that capacity needs drive the design of Heritage Hydro resources making the approach more cost driven. However, the results of the Capacity

Factor approach may be unstable from year to year as capacity factors vary with water flows and new investments are made in individual generating stations.

Settlement:

As parties could not reach consensus on a methodology for classifying Heritage Hydro, parties agree to default to the energy and demand classification established in the 2007 RDA Decision (i.e. 45% energy and 55% demand) on the basis that this agreeement will not be used as a precedent or justification for a classification approach in the F2019 COSS and RDA.

3.0 Heritage Thermal Classification

References:

Ex. B-1, pp. 3-25 and 3=26
Ex. B-1, pages 87 to 90 of 439 (review of classification methods in other jurisdictions)
Ex. B-1, App. C-2A, p. 299 of 439, and 282 to 284 of 439
Ex. B-1, App C-2B, pp. 68-70 and 93 of 205
Ex. B-5, AMPC IR 1.5.1 to 1.5.3 (the latter describes how each of the three plants is used)
Ex. B-5, BCOAPO IRs 1.38.1 and 138.2.

Issue:

BC Hydro proposes different classification treatments, described below, for each of the Fort Nelson Generating plant (FNG), the Prince Rupert Generating plant (PRG) and Burrard Thermal plant (Burrard). One of the participants stated that Prince Rupert and Fort Nelson generating stations should be allocated as 45% energy /55% demand, and using a Capacity Factor approach instead of using a Load Factor approach.

Discussion:

BC Hydro proposes using a Load Factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generating costs, resulting in a 74% energy/26% demand split. For PRG, BC Hydro uses a System Load Factor approach with no adjustment for IPP supply to classify PRG's O&M and capital generation costs, resulting in a 60% energy/40% demand classification. For Burrard Thermal BC Hydro is proposing to classify O&M and capital costs as 100% demand. Fuel cost for all thermal generation will continue to be classified as 100 % energy related.

BC Hydro notes that the classification method selected for the three Heritage thermal plants does not change the COS R/C ratios when reported to one decimal place. (App. C-2B - Workshop 4 Consideration Memo, p. 13)

In the response to BCOAPO IR 1.38.1 BC Hydro confirms that all O&M, Depreciation, Tax and Finance charges associated with Thermal Generation were classified on the same basis as Heritage Hydro Generation. BC Hydro says the impact on the F2016 COSS results is negligible and it did not include the additional calculations in the F2016 COSS model in the interest of simplicity. In response to BCOAPO 1.38.2, BC Hydro provides a table showing the dollar impact resulting from its classification of Heritage Thermal costs.

Settlement:

Parties agree with the classification of Burrard Thermal's capital and operating costs as 100% demand related and fuel costs as 100% energy related. With regard to the Fort Nelson and Prince Rupert thermal plants, parties agree that the impact of the classification percentages is low and consequently accept the classification percentages proposed in the Application: that is, 74% energy/26% demand for FNG and 60% energy /40% demand for PRG. Participants did not reach consensus on a methodology for the classification of the Fort Nelson and Prince Rupert plants.

4.0 Classification of IPP costs

References:

Ex. B-1, section 3.7.3, p. 3-26
Ex. B-1, App. C-2A, Workshop 2 Consideration Memo, section 4 and Attachment 4
Ex. B-1, App.C-2B, pp. 83-84 of 205
Ex. B1-5, Responses to IRs: AMPC 1.4.1 to 1.4.7)
AMPC submission (Ex. C12-5, p. 3) and AMPC March 16 Comments (Ex, B-1, App. C-2C, p. 62 of 79)
BCOAPO submission (Ex. C2-6)

Issue:

BC Hydro's preferred option for classifying IPPs is the 'Value of Capacity' option, which results in a 93% energy and 7% demand classification. (Ex. B-1, p. 3-26) Some parties disputed BC Hydro's classification and felt much or all of it should be classified as demand.

Discussion:

Direction 6 of the 2007 RDA Decision directed BC Hydro to prepare a study for its next FACOS or rate design filing that examines and quantifies the capacity benefits associated with IPP contracts. In response to Direction 6, it undertook an 'EPA-by-EPA analysis' and developed five options (See section 4 of Workshop 2 Consideration Memo at App. C-2A).

Of the options developed, BC Hydro's preferred option for is the 'Value of Capacity' option, which results in a 93 % energy and 7 % demand classification. (Ex. B-1, p. 3-26) BC Hydro says in Section 5.2 of the Workshop 2 Consideration Memo that most participants favoured either a value of energy and capacity option or a value of capacity option (Ex. B-1, App. C-2A, pp. 284-285 of 439). BC Hydro's response to BCUC IR 1.27.1 shows the equations used to calculate the 'value of capacity' and, for various types of IPP contracts, the percentage of IPP costs classified as demand. BC Hydro provides details on the IPP contracts with fixed cost components in Attachment 4 to the Workshop 2 Consideration Memo (Ex. B-1, App. C-2A).

Discussion largely focused on the reasons why BC Hydro engages in IPP contracts and whether the chosen classification option properly reflected original cost causation. During this discussion, one participant suggested that while a principled approach based on the IPP contract structure could theoretically justify a 100% demand allocation, a more practical way to reflect what caused BC Hydro to enter into IPP contracts would be to use the same Heritage Hydro classification (45% energy and 55% demand) as a proxy for IPPs.

Settlement:

Parties accept the 93% energy/7% demand classification as proposed by BC Hydro, but not necessarily the principles behind the percentages.

In the information BC Hydro provides for the F2019 COSS, it will include high-level overviews of:
- the policy context underpinning the procurement of fixed-price take-and-pay IPP contracts (both with and without fixed cost components); and
- standard IPP contract structure(s) (e.g., why structured as take-and-pay on a MW/h basis instead of fixed monthly payments over the contract term, cancellation provisions, etc.).

BC Hydro will also discuss the energy and capacity attributable to the generation displaced by the IPP take-and-pay contracts.

5.0 Functionalization of Information Technology (IT) Costs

References:

Ex. B-1, p. 3-18 to 3-19
Ex. B-5, Responses to AMPC IRs 1.6.1 to 1.6.6; CEC IR 1.21.1
Ex. C-12-5

Issue:

BC Hydro proposes to treat IT costs as a corporate expense, functionalizing according to the “main beneficiary of the services”, based on Corporate OM&A, which is functionalized proportionate to the functionalization of O&M by business unit. BC Hydro doesn’t have a detailed “bottom-up” functionalization study, which some parties argued it should do in order to directly and more accurately assign IT costs to all significant users of IT services.

Discussion:

BC Hydro indicated that it would be difficult (“administratively complex and time-consuming”) to do a ‘bottom-up’ functionalization study of IT costs (Ex. B-1, p. 3-17 to 3-19, and Response to CEC IR 1.21.1).

One party argued that a study that directly and more accurately assigns IT costs to all significant users of IT services including and specifically identifying metering, billing, customer service, and distribution operations and planning is necessary and should be conducted to inform a F2019 COSS.

The issue is explored in BC Hydro’s responses to AMPC IRs 1.6.1 to 1.6.6, which generally address the functionalization of IT costs. The response to AMPC IR 1.6.2 shows what functionalized costs would be if based on total Corporate costs.

Settlement:

The parties agree to functionalize IT costs as proposed in the Application. BC Hydro agrees to repeat a high-level bottom-up cost analysis for its F2019 COSS and RDA, similar to that used for the F2016 COSS, although it does not agree that it will necessarily adopt the results of that subsequent study.

6.0 Functionalization of Regulatory Accounts and Classification of Deferral Accounts

References:

Ex. B-1, section 3.6.7, pp. 3-20 to 3-22
Ex. B-1, App. C-2B, Workshop 4 Discussion Guide, Section 3, pp. 64-65 of 205.
Ex. B-5, Response to BCOAPO IRs 1.36.1 and 1.36.2

Issue:

Annual Revenue Requirement amounts related to current amortization of deferral and regulatory account balances have previously been included in current OM&A amounts and not analyzed individually to determine the appropriate functionalization and classification. In the 2015 RDA, BC Hydro has broken these amounts out and applied a functionalization rationale to each regulatory account amount individually to follow the treatment of underlying assets. This has resulted in small adjustments to how these amounts are functionalized. The classification of deferral account amounts was similarly refined to reflect the classification associated with Cost of Energy instead of Heritage Hydro.

Discussion:

BC Hydro explained that the largest adjustment occurred as a result of changing the functionalization of the Rate Smoothing Account to align with total Revenue Requirement functionalization instead of current OM&A functionalization. No parties opposed the proposed treatment of Deferral and Regulatory Account amounts.

Settlement:

Parties accept the percentages for functionalization of Regulatory Accounts and for classification of Deferral Accounts as proposed in BC Hydro's application, but not necessarily the principles behind the percentages. As requested by the parties, BC Hydro agrees to re-examine this issue for the F2019 COSS and RDA.

BC Hydro also agreed to provide a table or tables showing the treatment of each of the Regulatory and Deferral Accounts whose functionalization or classification changed in the F2016 COSS, in order to provide more clarity. Regulatory and Deferral Accounts whose treatment did not change are not included. The table is provided below.

Account	Proposed Change to	Proposed
Heritage & Non-Heritage Deferral	Classification	Cost of Energy as per F2016 RRA: - 92% energy

Accounts		- 8% demand (previously Heritage Hydro classification)
PCB Remediation Regulatory Account	Functionalization	As per F2016 RRA: - 2% Generation - 55% Transmission - 43% Distribution (previously proportionate to functionalized Corporate O&M)
First Nations Regulatory Account	Functionalization	As per F2016 RRA: - 45% Generation - 55% Transmission (previously 100% Transmission)
Interest on Deferral & Regulatory Accounts	Functionalization	Functionalized as per associated Deferral or Regulatory Account. In F2016: - 72% Generation - 7% Transmission - 21% Distribution (previously proportionate to functionalized total annual finance charges in revenue requirement)
Rate Smoothing Regulatory Account	Functionalization	Functionalized proportionate to total revenue requirement functionalization. In F2016: - 60% Generation - 17% Transmission - 22% Distribution - 1% Customer Care (previously proportionate to functionalized Corporate O&M)

7.0 Sub-Functionalization and Classification of Distribution Costs

References:

Ex. B-1, section 3.6.3, p. 3-14
Ex. B-1, App. C-2A, pp. 256-257 of 439, and pp. 288-290 of 439
Ex. B-1, App. C-2B, pp. 72-74 of 205, and pp. 98-104 of 205
Ex. B-5, Responses to BCOAPO IRs 1.40.5; 1. 45.1; 1.47.1-2 and BCUC 1.29.1 and 1.29.2

Issue:

In the F016 COSS, BC Hydro sub-functionalized the distribution system into: primary system, transformers, secondary services, and meters, and then classified each of the sub-functionalized components separately. While parties generally were supportive of the sub-functionalization, some were opposed to the classification applied to some of the sub-functionalized assets.

Discussion:

In the F2016 COSS, BC Hydro has sub-functionalized the distribution system into: primary system, transformers, secondary services, and meters based on the advice of its COS consultants and in response to the Commission's comment in the 2007 RDA that BC Hydro should update its study of its distribution system. Customer care costs were treated separately and are included in this NSA as a separate issue.

BC Hydro's classification of the sub-functionalized distribution assets is as follows: (1) Meters: 100% customer; (2) Secondary and Services: 50% demand and 50% customer; (3) Direct Assignment of Transformers: 50% demand and 50% customer; (4) Substations and Primary: 100% demand. This results in overall Distribution classification before substations as 71% demand and 29% customer, and overall with substations (which are classified as 100% demand) as 73% demand and 27% customer.

One party took issue with the classification methodologies used by BC Hydro. Although it agreed with the sub-functionalization of distribution, it submitted that the classification methodologies do not provide a classification that is soundly grounded in the cost causation for the distribution sub-functions. In that party's view, the cost causation for the distribution system sub-functions of meters, secondary & services, transformers and primary is, at least in significant part, driven by the standards for electrical service to homes based on the quantity of amps provided for in the standard service. The BC Hydro distribution system standards then must deliver adequate capacity to enable the requirements of a standard service to be met. In its view, the standard service and the related distribution system costs caused by these design standards are largely independent of customer demand.

No other party offered an alternative proposal to BC Hydro's for the classification of distribution assets.

Settlement:

Parties agree with sub-functionalization of the distribution assets. Parties agree to accept the classification percentages used by BC Hydro in the F2016 COSS on the basis that the NSA will not be used as a precedent or justification for a classification approach in the F2019 COSS and RDA. Parties also agree that the classification of distribution assets will be comprehensively examined in the F2019 COSS and RDA.

For the F2019 COSS and RDA, BC Hydro will also review the related OM&A and Depreciation costs, by looking at the gross book value of the underlying assets to further sub-functionalize the OM&A and depreciation subject to the data being available.

8.0 Functionalization of Demand Side Management (DSM) Costs

References:

Ex. B-1, pp. 3-19 and 3-20;
Ex, B-1, Workshop 2 Consideration Memo (App C-2A), section 2.3 (pp. 10-13);
Workshop 4 Consideration Memo (App. C-2B), section 1.1 (pp. 5-70)
Ex. B-5, Responses to IRs: BCUC 1.23.2; CEC 1.23.1 to 1.23.5;

Issue:

Functionalization of DSM costs as 90% Generation, 5% Transmission and 5% Distribution

Discussion:

Direction 6 of the 2007 RDA Decision said:

> "…the Commission Panel finds that the functionalization of all revenue requirement related to demand-side management 90 percent to generation and 10 percent to transmission is appropriate. It also finds it appropriate that the portion functionalized to generation is allocated to the customer classes in the same proportions that the total generation revenue requirement is allocated to the customer classes…."

BC Hydro in the F2016 COSS proposes functionalizing DSM as 90% generation, 5% transmission and 5% distribution. BC Hydro looked at direct assignment of DSM costs but did not pursue it because it could not find a direct correlation between the benefits and costs of different DSM initiatives. (Ex. B-1, pp. 3-19 and 3-20). In its response to CEC IR 1.23.5, BC Hydro indicates that it arrived at a DSM functionalization of 90% Generation, 5% Transmission and 5% Distribution based on, among other things, an adjusted system load factor of 55%. BC Hydro further discusses direct assignment in Workshop 2 Consideration Memo section 2.3, and the rationale behind its functionalization proposal in Workshop 4 Consideration Memo section 1.1.

One party indicated that although BC Hydro's proposed functionalization of 90% generation/5%transmission and 5% distribution is an improvement over the prior split of 90% generation and 10% transmission, a higher weighting on generation would be appropriate because this better reflects the generation displacement focus and justification of utility funded DSM. (Ex. C12-5)

Settlement:

Parties support the BC Hydro proposal (90% generation/5% transmission/5% distribution), subject to BC Hydro revisiting the functionalization between generation, transmission, and distribution in the F2019 COSS and RDA.

9.0 Classification of DSM Costs

References:

Ex. B-1, Section 3.7.4, pp. 3-26 and 3-27
Ex. B-5, Responses to IRs: BCOAPO 1. 39.1 and 1.39.2.2

Issue:

BC Hydro proposes to continue classifying the part of DSM functionalized to generation (90%) in the same way as overall generation costs. Some participants questioned whether that was an appropriate classification. Parties also raised questions regarding the classification of the DSM costs functionalized to distribution.

Discussion:

BC Hydro proposes to continue classifying the part of DSM costs functionalized to generation (90%) in the same way as overall generation costs because DSM expenditures are primarily incurred to avoid generation costs. In its response to BCOAPO 1.39.1, BC Hydro notes that the proposed classification methodology for Generation-related DSM costs was not reflected in the

F2016-COS model, and BC Hydro has filed a revised series of COS Schedules as attachment 1 to the response.

In IR 1.39.2.2 (Ex. B-5), BCOAPO asks why it wouldn't be more appropriate to classify Generation-related DSM using the same percentages for demand and energy as proposed for IPPs. BC Hydro responds that this would underestimate the demand-related benefits of DSM and has revised its treatment to 76% energy and 24% demand the same as overall generation demand, and notes that it has filed revised COS schedules. (Overall generation demand and energy proportions change depending on the classification of all other generation-related costs including Heritage Hydro, therefore 76% energy/24% demand is not a fixed split for this portion of DSM costs.)

One participant indicated that it accepts the amount classified as generation, but thinks that the Distribution-related DSM, which is classified about 25% customer, should be classified as 100% demand related and pro-rated by other demand-related costs identified for distribution. BC Hydro confirmed that the order of magnitude on this issue is very small; the 25% represents about $1 million.

Settlement:

Parties agree to accept BC Hydro's classification of DSM costs, subject to revisiting the allocation of distribution-related costs in the F2019 COSS and RDA.

10.0 Classification of Generation-Related Transmission Assets

References:

Ex. B-1, p. 3-13
Ex. B-5, Responses to BCOAPO 1.31.1 and 1.31.2

Issue:

A participant raised the issue of how Generation-Related Transmission Assets (GRTAs) are classified.

Discussion:

BC Hydro has functionalized $43.3 million of transmission costs to generation as costs incurred to connect Heritage Generation assets to the transmission grid, and has classified them the same as Heritage Hydro.

A participant requested clarification on the classification of GRTAs and suggested that GRTAs should be classified based on the classification percentage using the same percentages as Heritage Hydro. BC Hydro confirmed that it classifies GRTAs in that manner.

Settlement:

Parties accept BC Hydro's classification of GRTAs on the same basis as Heritage Hydro.

11.0 Classification of Smart Meter Infrastructure (SMI) Costs

References:

Ex. B-1, section 3.7.8, pp. 3-29 to 30
Ex. B-1, App. C-2A, pp. 290-291 of 439 (Workshop 2 Consideration Memo)
Ex. B-1, App. C-2B, pp. 94-98 of 205 (Workshop 4 Consideration Memo)
Ex. B-5, Responses to IRs: BCUC 1.18.2; CEC 1.12.3, 1.12.4, 1.12.8.

Issue:

BC Hydro's proposed F2016 COSS classification of SMI costs is 100% customer-related.

Discussion:

BC Hydro proposes to classify those costs identified as SMI costs as 100% customer-related. It reviewed several other options but settled on 100% customer-related, and submits that that approach has "overwhelming jurisdictional support". BC Hydro also states that classification of SMI does not have a significant impact on R/C ratios and that it can revisit the issue in its F2019 COSS and RDA once the distribution system has feeder-by-feeder metering expected in 2016. (Ex. B-1, p. 3-30) BC Hydro evaluated 5 options; the description and impact of those options is shown in App. C-2B, Workshop 4 Consideration Memo, pp. 14-18.

The rationale for adopting a 100% customer classification was discussed with some parties putting forward the view that nothing much has changed between analogue and smart meters in terms of cost causation. Another party put forward the view that there are system-wide benefits to SMI (such as quick identification of outages and theft reduction) that should be considered, but indicated it was willing to accept BC Hydro's classification as long as the reasoning is not something that will be relied on in the F2019 COSS and RDA.

Settlement:

Parties accept the classification of SMI costs as 100% customer-related on the condition that BC Hydro agrees that the issue can be revisited in the F2019 COSS and RDA and it agrees to investigate other SMI benefits in advance of the F2019 COSS. Not all parties endorse the reasoning for the agreed-upon classification.

12.0 Classification and Allocation of Customer Care Costs

References:

Ex. B-1, pp 3-30 and 3-34
Ex. B-1, App. C-2A, p. 292 of 439
Ex. B-1, App. C-2B, pp. 74-76 of 205 and p. 109 of 205
Ex. B-5, BCUC 1.32.1

Issue:

Classification and allocation of Customer Care Costs

Discussion:

BC Hydro proposes to classify Customer Care costs as 100% customer-related. It says that customer care costs do not vary with demand and a 100% customer classification is consistent with how other utilities treat Customer Care costs.

BC Hydro currently allocates Customer Care costs to rate classes based 90% on number of customers, and 10% by revenue per rate class. The 10% allocated by revenue is an acknowledgement that the larger accounts require a different level of attention.

A 'bottom-up' approach to allocating customer care costs was discussed, BC Hydro acknowledges that a bottom-up approach would be possible, but that its analysis indicates the result would be largely the same. BC Hydro did a more detailed analysis and the results of its proposed weighted allocator method align closely with those based on a more detailed bottom-up approach (Ex. B-1, App. C-2B, pp. 74-76 of 205). It prefers the weighted allocator method because it yields a similar result to the bottom-up method but is easier to calculate.

Settlement:

Parties accept BC Hydro's approach to classifying and allocating Customer Care Costs for the 2015 RDA. BC Hydro will repeat its bottom-up study for comparison to the weighted allocator method in the F2019 COSS and RDA.

13.0 Generation Demand and Transmission Allocation and Derivation of 4CP and 1NCP allocators

References:

Ex. B-1, Sections 3.8.3 an 3.8.4 pp. 3-32 to 3-34
Ex. B-1, App. C-2A, pp. 221-229 of 439 (COS Methodology Review Presentation, slides 55-63) and pp. 258-263 of 439 (Workshop 2 Discussion Guide, Sections 7 and 8)
Ex. B-1, App. C-2B, pp. 26- 31 of 205 (Workshop 4 slide deck, slides 26 to 31) and p. 85 of 205
Ex. B-5, Responses to IRs: BCOAPO 1.43.1-2, 1.52.1 to 1.53.1.2; Fortis 1.10.1

Issue:

Two issues were conjoined and discussed together in the NSP: (1) BC Hydro's proposal to use a 4 Coincident Peak (CP) method to allocate Generation Demand and Transmission, and (2) the actual derivation of the 4CP allocator. Although the 1CP allocator was included as a potential topic in the responses to Ex. A-18, parties to the NSP did not raise it as an issue and the discussion did not focus on it.

Discussion:

BC Hydro's F2016 COSS allocates Generation Demand and Transmission using a 4CP approach, which is consistent with the 2007 RDA Direction 3. BC Hydro submits that sensitivities provided at Workshop 4 (3CP, variations on 4CP) produced little difference in the results. (Ex. B-1, pp. 3-32 and 3-33).

BC Hydro's preferred option for calculating 4CP is to use a 5-year average of 4 monthly peaks for November through February (App. C-2B, workshop 4 Slide Deck Slide 29), using data from the five most recent preceding years. To clarify how it approaches the 4CP calculation, BC Hydro first calculates for each year the average of the 4 monthly peaks, and then it averages the peaks for the five years. To calculate a rate class's 4CP allocation, BC Hydro calculated the allocation for the rate class as the five year average of the sum of that rate class's demand at each winter month's peak divided by the sum of all rate classes' demand during those same hours (Ex. B-1, p. 3-32).

Regarding the 1NCP allocator, BC Hydro's proposed methodology for assigning Distribution demand-related costs is based on average rate class profiles for five years. For each year of data, each rate class is assigned a 1NCP percentage allocator based on its annual peak load as a proportion of the sum of all the rate classes' annual peak loads (Ex. B-1, p.3-33).

In the responses to Exhibit A-18 (Commission February 11, 2016 letter requesting submissions), one participant raised the issue of whether 4CP was an appropriate allocator to use. Another party said that it expects to raise the derivation of the 4CP and 1NCP allocators, although discussion largely focused on the derivation of 4CP. The two issues - Generation demand and transmission allocation and the derivation of 4CP and 1NCP allocators - were determined to have sufficient overlap that parties decided to discuss them together.

The participant raising the issue of whether 4CP is an appropriate allocator to use submitted that the cost causation for the generation and transmission demand is more closely aligned with the system design peak related to the coldest period in the preceding 10 years, and that BC Hydro must ensure that it has adequate capacity to meet this peak and therefore must invest in the cost of the facilities which enable BC Hydro to deliver the required demand.

Regarding the issue of the calculation of the 4CP allocator, one party stated that it understood that the 2007 RDA COSS used an average of the monthly coincident peaks of the 4 winter peak months from the preceding year and questioned whether it was appropriate to move to the five year average approach described above. BC Hydro provided a draft table showing the difference in the R/C ratios between using a single year to calculate the 4 CP for each year from F2010 to F2014, and a 5-year average based on the same five years. It showed that, for every rate class, the R/C ratios based on a 4CP calculated from a 5-year average fall within the range of R/C ratios based on the single-year 4CP calculated from each of the previous 5 years. The Table also established that there is little difference between using the one-year 4CP based on F2014 (consistent with the 2007 RDA Decision) versus that calculated using a 5-year average (F2010-F2014). BC Hydro also noted that F2014 was an unusual year and that the peaks were not representative of normal system demand.

Settlement:

While not all parties supported BC Hydro's proposal to use a 4CP allocator calculated on a 5-year average for the F2016 COSS, the parties accepted the approach on the understanding that the CP allocation issues including the manner in which each of the CP allocators are determined would be comprehensively examined in the F2019 COSS and RDA proceeding.

14.0 Customer Segmentation and Street Lighting

References:

Ex. B-1, pp. 4-2 to 4-27

Issue:

By Order G-12-16 and the attached Reasons for Decision, the Commission Panel ordered a negotiated settlement process (NSP) to be used to address issues related to the COSS, rate class segmentation and BC Hydro's proposal to split the Street Lighting Class into customer-owned Street Lighting and BC Hydro-owned Street Lighting. None of the parties raised either customer segmentation or BC Hydro's street lighting proposal as an issue in the responses to Ex. A-18.

Discussion:

Customer Segmentation: With the exception of the Street Lighting class, BC Hydro proposes to keep the current customer segmentation so that the customer classes remain the same. BC Hydro has committed to looking at the possibility of an Extra-Large General Service class in Module 2 of the 2015 RDA.

Street Lighting: BC Hydro is proposing to split the street lighting class into two classes – BC Hydro-owned street lighting and non-BC Hydro-owned street lighting.

Parties briefly discussed the customer segmentation and the street lighting proposal.

Settlement:

Parties accept the BC Hydro proposals to keep all customer classes except the street lighting class as they are currently, and to look at the possibility of an Extra-Large General Service class in Module 2.

Parties also accept the BC Hydro proposal to split the Street Lighting class into two classes, and note that the subject of the pole contact charge will be reviewed in Module 2.

Appendix A
Summary of Material COS Methodology Topics by 2007 RDA Decision, BC Hydro 2015 RDA COS Proposals, and March 2016 NSA

Cost	F2007 RDA Decision	2015 RDA – BCH proposed	2015 RDA – March 2016 NSA
Heritage Hydro: Classification	55% demand-related 45% energy-related	45% demand-related 55% energy-related	55% demand-related 45% energy-related
Heritage Thermal: Classification	Capital Generation costs & OMA 100% demand-related Fuel costs 100% energy	Treatment of capital generation costs & OMA varies by plant as described on page 3-25 of Exhibit B-1 Fuel costs 100% energy	
DSM: Functionalization	90% Generation 10% Transmission	90% generation 5% transmission 5% distribution	
DSM: Classification	Generation portion classified the same as all generation assets (57% demand-related, 43% energy-related)	Generation portion classified the same as overall generation	
IPP purchases: Classification	100% energy-related	7% demand-related 93% energy-related	
Distribution: Classification	35% customer-related 65% demand-related	Sub-functionalization method with the following classifications: • Substations – 100% demand-related; • Primary system – 100% demand-related; • Transformers – 50% customer-related / 50% demand-related; • Secondary system – 100% demand-related; • Services – 100% customer-related; • Meters – 100% customer-related Aggregate classification of about 73% demand-related, 27% customer-related	
Customer Care: Classification	35% customer-related 65% demand-related	100% customer-related	
IT costs: Functionalization	100% Generation	30% Generation 30% Transmission 30% Distribution 10% Customer Care Values based on F2016 RRA	
IPP capital lease	100% Customer Care	100% Generation	

costs: Functionalization		
ERP costs: Functionalization	100% Customer Care	100% Generation
Corporate Tax: Functionalization	61% Generation 0% Transmission (since BCTC was separate at the time) 39% Distribution	21% Generation 65% Transmission 30% Distribution Values based on F2016 RRA
Corporate Depreciation: Functionalization	60% Generation 0% Transmission (since BCTC was separate at the time) 40% Distribution	21% Generation 65% Transmission 14% Distribution Values based on F2016 RRA
Regulatory Accounts: Functionalization	100% Generation	See the Regulatory account section or BC Hydro's response to BCUC IR 1.24.3 for more detail
Deferral Accounts: Classification	As Heritage Hydro: 55% demand-related 45% energy-related	As Cost of Energy: 92% energy-related 8% demand-related Values based on F2016 RRA
SMI-related costs: Classification	Metering related distribution assets classified the same as other distribution (65% demand-related, 35% customer) Costs associated with regulatory account functionalized to generation and classified the same as generation assets (57% demand-related, 43% customer-related)	Both the metering related distribution assets and costs associated with the SMI regulatory account are 100% customer-related
Generation demand-related costs: Allocation	4 CP – single year	4 CP – 5 year average
Distribution demand costs: Allocation	NCP – single year	NCP – 5 year average
Metering costs: Allocation	# of customers	Weighted metering allocator

Appendix B

Cost of Service (COS) Model Changes as part of 2015 RDA

September 24, 2015

COS Model filed as Appendix E in 2015 RDA

November 17, 2015

COS Model re-filed as attachment to response to BCOAPO 1.39.1 with the following changes:

- Schedule 3.2: Correction to Distribution Sub-Functionalization
- Schedule 2.0: Correction to DSM Amortization Classification of Generation portion

March 24, 2016

COS Model re-filed as attachment to NSA with the following changes:

- Schedule 2.0: Revised Classification of Heritage Hydro
    - 2015 RDA proposed classification was 45% Demand-related and 55% Energy-related
    - NSP agreed-upon classification is 55% Demand-related and 45% Energy-related
    - Result is shift of $114.0M from Energy- to Demand-Related and $15.7M between rate classes
- Schedule 2.0: Inclusion of Thermal Generation classification by plant
    - Impact is negligible but not previously separately shown, now included for transparency
- Schedule 2.0: Correction to Classification of Deferral Account amounts
    - Proposed and accepted methodology is classification with total Cost of Energy
    - Previously classified mistakenly as Heritage Hydro
    - Result is shift of $37.1M from Energy- to Demand-related and $3.9M between rate classes
- Schedule 5.1: Correction to calculation of NCP allocators
    - 5-year average was weighted incorrectly
    - Result is shift of $0.2M between rate classes
    - Schedule is expanded to show the single-year inputs to the 5-year average calculation (see table below)

COS Model Schedule 4.0

Rate Class	Generation Costs	Transmission Costs	Distribution Costs	Customer Care Costs	Total Cost	Total Revenue	Revenue - Cost ($ million)	Revenue:Cost Ratios	R/C Ratios last filed (in response to BCOAPO IR 1.39.1)	R/C Ratio change from last filed
Residential	1,004.43	364.26	617.89	69.16	2,055.74	1,917.57	-138.2	93.3%	94.0%	-0.7%
GS Under 35 kW	184.62	57.35	118.43	7.55	367.95	411.82	43.9	111.9%	112.0%	-0.1%
MGS < 150 kW	168.79	51.19	85.68	2.06	307.72	360.50	52.8	117.2%	117.1%	0.0%
LGS > 150 kW	527.56	146.31	149.77	2.04	825.68	836.14	10.5	101.3%	100.8%	0.5%
Irrigation	2.79	0.00	4.05	0.06	6.90	6.04	-0.9	87.6%	84.8%	2.8%
Street Lighting BCH	3.19	1.56	6.71	0.41	11.88	20.61	8.7	173.6%	175.9%	-2.3%
Street Lighting Cust	9.36	3.15	4.05	0.40	16.96	17.77	0.8	104.8%	105.3%	-0.5%
Transmission	694.56	170.62	0.00	1.69	866.87	889.32	22.4	102.6%	101.3%	1.3%
Total	2,595.30	794.44	986.59	83.37	4,459.70	4,459.79	0.1	100.0%		

COS Model Schedule 5.1

Demand Allocators

Rate Class	4 CP	NCP w/o T	NCP w/o Prim
Residential	45.85%	56.57%	58.36%
GS Under 35 kW	7.22%	10.62%	10.95%
MGS < 150 kW	6.44%	8.56%	22.57%
LGS > 150 kW	18.42%	23.15%	6.98%
Irrigation	0.00%	0.43%	0.44%
Street Lighting BCH	0.20%	0.22%	0.23%
Street Lighting Cust	0.40%	0.45%	0.46%
Transmission	21.48%	0.00%	0.00%
Total	100.00%	100.00%	100.00%

Rate Class 4CP	F10	F11	F12	F13	F14	5-Yr Avg
Residential	45.61%	46.88%	47.59%	45.66%	43.51%	45.85%
GS Under 35 kW	7.00%	7.01%	6.66%	7.03%	8.39%	7.22%
MGS < 150 kW	6.15%	6.27%	6.61%	6.52%	6.67%	6.44%
LGS > 150 kW	19.13%	17.97%	17.00%	18.28%	19.70%	18.42%
Irrigation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Street Lighting BCH	0.19%	0.21%	0.21%	0.22%	0.14%	0.20%
Street Lighting Cust	0.38%	0.43%	0.43%	0.45%	0.29%	0.40%
Transmission	21.53%	21.24%	21.49%	21.83%	21.30%	21.48%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Rate Class NCP w/o T	F10	F11	F12	F13	F14	5-Yr Avg
Residential	57.58%	55.78%	57.70%	54.50%	57.30%	56.57%
GS Under 35 kW	10.45%	11.17%	10.92%	10.37%	10.17%	10.62%
MGS < 150 kW	7.98%	8.62%	9.02%	9.13%	8.06%	8.56%
LGS > 150 kW	22.82%	23.31%	21.35%	24.84%	23.42%	23.15%
Irrigation	0.52%	0.45%	0.36%	0.44%	0.39%	0.43%
Street Lighting BCH	0.21%	0.22%	0.21%	0.24%	0.22%	0.22%
Street Lighting Cust	0.43%	0.45%	0.43%	0.48%	0.45%	0.45%
Transmission	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Appendix C

Addendum to COS NSA: F2016 Cost of Service – Forecast Cost

See following pages

Addendum to COS NSA

F2016 Cost of Service - Forecast Cost

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Note: All costs are in $ X 1 million unless otherwise noted.

F2016 Cost of Service - Planned Cost

	F2016 Forecast Revenue Requirement	Generation	Transmission	Distribution	Customer Care
Cost of Energy					
IPPs and Long-term Purchases commitment	1,134.72	1,134.72	0.00	0.00	0.00
Domestic Transmission (Non-Heritage)	0.00	0.00	0.00	0.00	0.00
NIA Generation	34.30	34.30	0.00	0.00	0.00
Gas Transportation	12.10	12.10	0.00	0.00	0.00
Water Rentals	391.90	391.90	0.00	0.00	0.00
Market Purchases	56.60	56.60	0.00	0.00	0.00
Natural gas for thermal generation	26.90	26.90	0.00	0.00	0.00
Domestic Transmission (Heritage)	25.70	0.00	25.70	0.00	0.00
Non-treaty storage agreement	-19.80	-19.80	0.00	0.00	0.00
Other and Surplus Sales	-116.30	-116.30	0.00	0.00	0.00
Net purchases (sales) from Powerex	4.80	4.80	0.00	0.00	0.00
Heritage Deferral Account Recoveries	17.74	17.74	0.00	0.00	0.00
Non-Heritage Deferral Account Recoveries	104.82	104.82	0.00	0.00	0.00
Total	1,673.49	1,647.79	25.70	0.00	0.00
O M & A Expenses					
Generation	314.05	235.48	33.36	34.04	11.16
Transmission	237.96	19.31	218.64	0.00	0.00
Distribution	223.09	0.00	0.00	223.09	0.00
Customer Care	73.16	0.00	0.00	0.00	73.16
Corp Service	95.70	-7.19	43.64	39.47	19.78
Total	943.96	247.61	295.64	296.61	104.10
Depreciation & Amortization					
Generation	332.40	332.40	0.00	0.00	0.00
Transmission	182.97	0.00	182.97	0.00	0.00
Distribution	224.81	0.00	0.00	224.81	0.00
Customer Care	0.00	0.00	0.00	0.00	0.00
Corporate Services	30.06	13.50	7.43	9.13	0.00
Total	770.23	345.90	190.40	233.93	0.00
Taxes					
Generation	43.07	43.07	0.00	0.00	0.00
Transmission	131.96	0.00	131.96	0.00	0.00
Distribution	27.59	0.00	0.00	27.59	0.00
Customer Care	0.00	0.00	0.00	0.00	0.00
Corporate	15.76	3.35	10.26	2.15	0.00
Total	218.38	46.42	142.23	29.73	0.00
Finance Charges					
Generation	304.68	304.68	0.00	0.00	0.00
Transmission	231.13	0.00	231.13	0.00	0.00
Distribution	184.92	0.00	0.00	184.92	0.00
Customer Care	0.00	0.00	0.00	0.00	0.00
Interest on Regulatory Accounts	-61.74	-44.30	-4.32	-12.99	-0.13
Regulatory Account Recoveries	-26.24	-11.09	-8.42	-6.73	0.00
Total	632.75	249.29	218.39	165.20	-0.13
Allowed Net Income					
Generation	275.56	275.56	0.00	0.00	0.00
Transmission	207.27	0.00	207.27	0.00	0.00
Distribution	169.02	0.00	0.00	169.02	0.00
Customer Care	0.00	0.00	0.00	0.00	0.00
Total	651.85	275.56	207.27	169.02	0.00
Miscellaneous Revenues					
Non Tariff Revenue (Functionalized)	-112.08	-3.07	-39.19	-51.09	-18.73
Corporate Miscellaneous Revenue	-11.18	-0.31	-3.91	-5.10	-1.87
Total	-123.26	-3.38	-43.10	-56.19	-20.60
Deferral Accounts, Revenue Offsets & Other					
Subsidiary Net Income	-14.69	-14.69	0.00	0.00	0.00
Other Utility Revenue	-16.50	-16.50	0.00	0.00	0.00
Deferral Rider Revenue	-222.99	-222.99	0.00	0.00	0.00
Intersegment revenues	-53.51	-3.00	-50.51	0.00	0.00
Internal Allocations (GRTA, SDA)	0.00	43.30	-191.57	148.27	0.00
Total	-307.69	-213.88	-242.08	148.27	0.00
Total Revenue Requirement	**4,459.70**	**2,595.30**	**794.44**	**986.59**	**83.37**

Classification of Generation Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Energy Related	Demand Costs	Energy Costs	Comments
Cost of Energy						
IPPs and Long-term Purchases commitment	1,134.72	7.40%	92.60%	83.97	1,050.76	
Domestic Transmission (Non-Heritage)	-	0.00%	100.00%	-	-	
NIA Generation	34.30	0.00%	100.00%	-	34.30	
Gas Transportation	12.10	0.00%	100.00%	-	12.10	
Water Rentals	391.90	10.00%	90.00%	39.19	352.71	*Based on Water Rental Rate*
Market Purchases	56.60	0.00%	100.00%	-	56.60	
Natural gas for thermal generation	26.90	0.00%	100.00%	-	26.90	
Domestic Transmission (Heritage)	-	100.00%	0.00%	-	-	
Non-treaty storage agreement	(19.80)	0.00%	100.00%	0.0	(19.80)	
Other and Surplus Sales	(116.30)	0.00%	100.00%	-	(116.30)	
Net purchases (sales) from Powerex	4.80	0.00%	100.00%	-	4.80	
Heritage Deferral Account Recoveries	17.74	8.07%	91.93%	1.43	16.31	
Non-Heritage Deferral Account Recoveries	104.82	8.07%	91.93%	8.46	96.36	
Total	1,647.79	8.07%	91.93%	133.06	1,514.73	
O M & A Expenses						
Generation	215.05	55.00%	45.00%	118.28	96.77	
Burrard	6.24	26.00%	74.00%	1.62	4.62	
Fort Nelson	13.36	40.00%	60.00%	5.34	8.02	
Prince Rupert	0.83	100.00%	0.00%	0.83	-	
Thermal Generation	20.43	38.17%	61.83%	7.80	12.63	
Transmission	19.31	55.00%	45.00%	10.62	8.69	
Distribution	-	55.00%	45.00%	-	-	
Customer Care	-	55.00%	45.00%	-	-	
Corp Service	(7.19)	55.00%	45.00%	(3.95)	(3.23)	
Total	247.61			132.75	114.86	
					-	
Depreciation & Amortization					-	
Amort on March 2014 Assets	220.83	55.00%	45.00%	121.46	99.37	
Amortization on Additions	36.59	55.00%	45.00%	20.13	16.47	
DSM Amortization	74.98	28.93%	71.07%	21.69	53.29	
Generation	332.40	55.00%	45.00%	163.27	169.13	
Transmission	-	55.00%	45.00%	-	-	
Distribution	-	55.00%	45.00%	-	-	
Customer Care	-	55.00%	45.00%	-	-	
Corporate Services	13.50	55.00%	45.00%	7.42	6.07	
Total	345.90			170.70	175.20	
					-	
Taxes					-	
Generation	43.07	55.00%	45.00%	23.69	19.38	
Transmission	-	55.00%	45.00%	-	-	
Distribution	-	55.00%	45.00%	-	-	
Customer Care	-	55.00%	45.00%	-	-	
Corporate	3.35	55.00%	45.00%	1.84	1.51	
Total	46.42			25.53	20.89	
					-	
Finance Charges					-	
Generation	304.68	55.00%	45.00%	167.57	137.11	
Transmission	-	55.00%	45.00%	-	-	
Distribution	-	55.00%	45.00%	-	-	
Customer Care	-	55.00%	45.00%	-	-	
Interest on Deferral Accounts	(23.79)	8.07%	91.93%	(1.92)	(21.87)	
Interest on Regulatory Accounts	(20.50)	55.00%	45.00%	(11.28)	(9.23)	
Regulatory Account Recoveries	(11.09)	55.00%	45.00%	(6.10)	(4.99)	
Total	249.29			148.27	101.01	
					-	
Allowed Net Income					-	
Generation	275.56	55.00%	45.00%	151.56	124.00	
Transmission	-	55.00%	0.00%	-	-	
Distribution	-	55.00%	0.00%	-	-	
Customer Care	-	55.00%	0.00%	-	-	
Total	275.56			151.56	124.00	
					-	
Miscellaneous Revenues					-	
Non Tariff Revenue (Functionalized)	(3.07)	55.00%	45.00%	(1.69)	(1.38)	
Corporate Miscellaneous Revenue	(0.31)	55.00%	45.00%	(0.17)	(0.14)	
Total	(3.38)			(1.86)	(1.52)	
					-	
Deferral Accounts, Revenue Offsets & Other					-	
Subsidiary Net Income	(14.69)	28.93%	71.07%	(4.25)	(10.44)	*Total costs before subsidiary income*
Other Utility Revenue	(16.50)	55.00%	45.00%	(9.07)	(7.42)	
Deferral Rider Revenue	(222.99)	8.07%	91.93%	(18.01)	(204.99)	
Intersegment revenues	(3.00)	55.00%	45.00%	(1.65)	(1.35)	
Internal Allocations (GRTA, SDA)	43.30	55.00%	45.00%	23.82	19.49	
Total	(213.88)			(9.17)	(204.72)	
Total Generation Costs	**2,595.30**	**28.93%**	**71.07%**	**750.84**	**1844.46**	

Addendum to COS NSA

Classification of Transmission Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Demand Costs
Cost of Energy			
IPPs and Long-term Purchases commitment	-	100.00%	-
Domestic Transmission (Non-Heritage)	-	100.00%	-
NIA Generation	-	100.00%	-
Gas Transportation	-	100.00%	-
Water Rentals	-	100.00%	-
Market Purchases	-	100.00%	-
Natural gas for thermal generation	-	100.00%	-
Domestic Transmission (Heritage)	25.70	100.00%	25.70
Other and Surplus Sales	-		-
Total	25.70		25.70
O M & A Expenses			
Generation	33.36	100.00%	33.36
Transmission	218.64	100.00%	218.64
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Corp Service	43.64	100.00%	43.64
Total	295.64		295.64
Depreciation & Amortization			
Generation	-	100.00%	-
Transmission	182.97	100.00%	182.97
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Corporate Services	7.43	100.00%	7.43
Total	190.40		190.40
Taxes			
Generation	-	100.00%	-
Transmission	131.96	100.00%	131.96
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Corporate	10.26	100.00%	10.26
Total	142.23		142.23
Finance Charges			
Generation	-	100.00%	-
Transmission	231.13	100.00%	231.13
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Interest on Regulatory Accounts	(4.32)	100.00%	(4.32)
Regulatory Account Recoveries	(8.42)	100.00%	(8.42)
Total	218.39		218.39
Allowed Net Income			
Generation	-	100.00%	-
Transmission	207.27	100.00%	207.27
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Total	207.27		207.27
Miscellaneous Revenues			
Non Tariff Revenue (Functionalized)	(39.19)	100.00%	(39.19)
Corporate Miscellaneous Revenue	(3.91)	100.00%	(3.91)
Total	(43.10)		(43.10)
Deferral Accounts, Revenue Offsets & Other			
Subsidiary Net Income	-	100.00%	-
Other Utility Revenue	-	100.00%	-
Deferral Rider Revenue	-	100.00%	-
Intersegment revenues	(50.51)	100.00%	(50.51)
Internal Allocations (GRTA, SDA)	(191.57)	100.00%	(191.57)
Total	(242.08)		(242.08)
Total Transmission Costs	794.44		794.44

Classification of Distribution Function
(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Customer Related	SMI Energy Related	Streetlighting Costs (Direct Assigned)	Demand Costs	Customer Costs
Cost of Energy							
IPPs and Long-term Purchases commitment	-					-	-
Domestic Transmission (Non-Heritage)	-					-	-
NIA Generation	-					-	-
Gas Transportation	-					-	-
Water Rentals	-					-	-
Market Purchases	-					-	-
Natural gas for thermal generation	-					-	-
Domestic Transmission (Heritage)	-					-	-
Non-treaty storage agreement	-					-	-
Other and Surplus Sales	-					-	-
Net purchases (sales) from Powerex	-					-	-
Heritage Deferral Account Recoveries	-					-	-
Non-Heritage Deferral Account Recoveries	-					-	-
Total	-				-	-	-
O M & A Expenses							
Generation	34.04	71%	29%			24.17	9.87
Transmission	-	71%	29%			-	-
Distribution	191.77	71%	29%		1.23	135.28	55.25
Customer Care	-	71%	29%			-	-
Corp Service	39.47	71%	29%			28.03	11.45
Total	296.61				1.23	187.47	107.90
Depreciation & Amortization							
Generation	-	71%	29%			-	-
Transmission	-	71%	29%			-	-
Distribution	224.81	71%	29%		1.16	158.79	64.86
Customer Care	-	71%	29%			-	-
Corporate Services	9.13	71%	29%			6.48	2.65
Total	233.93				1.16	165.27	67.50
Taxes							
Generation	-	71%	29%			-	-
Transmission	-	71%	29%			-	-
Distribution	27.59	71%	29%		0.16	19.47	7.95
Customer Care	-	71%	29%			-	-
Corporate	2.15	71%	29%			1.52	0.62
Total	29.73				0.16	21.00	8.58
Finance Charges							
Generation	-	71%	29%			-	-
Transmission	-	71%	29%			-	-
Distribution	184.92	71%	29%		1.08	130.53	53.32
Customer Care	-	71%	29%			-	-
Interest on Regulatory Accounts	(12.99)	71%	29%			(9.22)	(3.77)
Regulatory Account Recoveries	(6.73)	71%	29%			(4.78)	(1.95)
Total	165.20				1.08	116.53	47.60
Allowed Net Income							
Generation	-	71%	29%			-	-
Transmission	-	71%	29%			-	-
Distribution	169.02	71%	29%		0.98	119.31	48.73
Customer Care	-	71%	29%			-	-
Total	169.02				0.98	119.31	48.73
Miscellaneous Revenues							
Non Tariff Revenue (Functionalized)	(51.09)	71%	29%			(36.27)	(14.82)
Corporate Miscellaneous Revenue	(5.10)	71%	29%			(3.62)	(1.48)
Total	(56.19)				-	(39.89)	(16.29)
Deferral Accounts, Revenue Offsets & Other							
Subsidiary Net Income	-	71%	29%			-	-
Other Utility Revenue	-	71%	29%			-	-
Deferral Rider Revenue	-	71%	29%			-	-
Intersegment revenues	-	71%	29%			-	-
Internal Allocations (GRTA, SDA)	148.27	100%	0%			148.27	-
Total	148.27				-	148.27	-
Total Distribution Costs	**986.59**	**72.8%**	**26.8%**		**4.61**	**717.96**	**264.01**

Classification of Customer Care Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Customer Related	Demand Costs	Customer Costs
Cost of Energy					
IPPs and Long-term Purchases commitment	-	0%	100%	-	-
Domestic Transmission (Non-Heritage)	-	0%	100%	-	-
NIA Generation	-	0%	100%	-	-
Gas Transportation	-	0%	100%	-	-
Water Rentals	-	0%	100%	-	-
Market Purchases	-	0%	100%	-	-
Natural gas for thermal generation	-	0%	100%	-	-
Domestic Transmission (Heritage)	-	0%	100%	-	-
Other and Surplus Sales	-	0%	100%	-	-
Total	-			-	-
O M & A Expenses					
Generation	11.16	0%	100%	-	11.16
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	73.16	0%	100%	-	73.16
Corp Service	19.78	0%	100%	-	19.78
Total	104.10			-	104.10
Depreciation & Amortization					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	-	0%	100%	-	-
Corporate Services	-	0%	100%	-	-
Total	-			-	-
Taxes					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	-	0%	100%	-	-
Corporate	-	0%	100%	-	-
Total	-			-	-
Finance Charges					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	(0.00)	0%	100%	-	(0.00)
Interest on Regulatory Accounts	(0.13)	0%	100%	-	(0.13)
Regulatory Account Recoveries	0.00	0%	100%	-	0.00
Total	(0.13)			-	(0.13)
Allowed Net Income					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	(0.00)	0%	100%	-	(0.00)
Total	(0.00)			-	(0.00)
Miscellaneous Revenues					
Non Tariff Revenue (Functionalized)	(18.73)	0%	100%	-	(18.73)
Corporate Miscellaneous Revenue	(1.87)	0%	100%	-	(1.87)
Total	(20.60)			-	(20.60)
Deferral Accounts, Revenue Offsets & Other					
Subsidiary Net Income	-	0%	100%	-	-
Other Utility Revenue	-	0%	100%	-	-
Deferral Rider Revenue	-	0%	100%	-	-
Intersegment revenues	-	0%	100%	-	-
Internal Allocations (GRTA, SDA)	-	0%	100%	-	-
Total	-			-	-
Total Customer Care Costs	83.37			-	83.37

Allocation of Generation Costs
(Classified Costs from Schedule 2.0)

Cost Classification	Generation Demand	Generation Demand-Related Costs	Generation Energy	Generation Energy Related Costs
Allocation Basis	4 CP Demand including losses (Sched 5.1)	750.84	Energy Including Loss (Sched 5.0)	1,844.46
Residential	45.85%	344.27	35.79%	660.16
GS Under 35 kW	7.22%	54.20	7.07%	130.41
MGS < 150 kW	6.44%	48.38	6.53%	120.42
LGS > 150 kW	18.42%	138.28	21.11%	389.28
Irrigation	0.00%	0.00	0.15%	2.79
Street Lighting BCH	0.20%	1.48	0.09%	1.71
Street Lighting Cust	0.40%	2.98	0.35%	6.38
Transmission	21.48%	161.26	28.91%	533.31
Total	100.0%	750.84	100.0%	1,844.46

Allocation of Transmission Costs
(Classified Costs from Schedule 2.1)

Cost Classification	Transmission Demand	Demand Related Costs (Sched 2.1)
Allocation Basis	4 CP demand including losses (Sched 5.1)	794.44
Residential	45.85%	364.26
GS Under 35 kW	7.22%	57.35
MGS < 150 kW	6.44%	51.19
LGS > 150 kW	18.42%	146.31
Irrigation	0.00%	0.00
Street Lighting BCH	0.20%	1.56
Street Lighting Cust	0.40%	3.15
Transmission	21.48%	170.62
Total	100.0%	794.44

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Allocation of Distribution Costs
(Classified Costs from Schedule 2.2)

Cost Classification	Distribution Demand Related	Distribution Demand-Related	Distribution Secondary Demand Related	Distribution Secondary Demand-Related	Distribution Transformer Related	Distribution Transformer Related	Distribution Customer Related	Distribution Customer Related	Distribution Metering Related	Distribution Metering Related	Street Light Customer	Street Light Customer Related
Allocation Basis	NCP (Sched 5.1)	585.70	NCP w/o Primary (Sched 5.1)	61.30	Transformer Allocator (Sched 5.4)	141.91	Customer Count (Sched 5.2)	75.60	Metering Allocator (Sched 5.2)	117.45	Street Light Direct Assignment	4.61
Residential	56.57%	331.34	58.36%	35.78	65.51%	92.97	88.87%	67.19	77.15%	90.62	0.00%	0.00
GS Under 35 kW	10.62%	62.18	10.95%	6.71	16.80%	23.85	9.19%	6.95	15.96%	18.74	0.00%	0.00
MGS < 150 kW	8.56%	50.15	22.57%	13.84	10.74%	15.25	0.94%	0.71	4.89%	5.74	0.00%	0.00
LGS > 150 kW	23.15%	135.58	6.98%	4.28	5.41%	7.67	0.33%	0.25	1.69%	1.99	0.00%	0.00
Irrigation	0.43%	2.52	0.44%	0.27	0.54%	0.76	0.18%	0.13	0.31%	0.36	0.00%	0.00
Street Lighting BCH	0.22%	1.30	0.23%	0.14	0.33%	0.47	0.25%	0.19	0.00%	0.00	100.00%	4.61
Street Lighting Cust	0.45%	2.62	0.46%	0.28	0.67%	0.95	0.25%	0.19	0.00%	0.00	100.00%	0.00
Transmission	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00
Total	100.0%	585.70	100.0%	61.30	100.0%	141.91	100.0%	75.60	100.0%	117.45	200.0%	4.61

Allocation of Customer Care Costs
(Classified Costs from Schedule 2.3)

Cost Classification	Customer Care Demand	Customer Care Demand Related Costs	Customer Care Customer	Customer Care Customer Related Costs
Allocation Basis	NCP Sched 5.1	0.00	Blended Customer Count & Revenue Sched 5.3	83.37
Residential	56.57%	0.00	82.96%	69.16
GS Under 35 kW	10.62%	0.00	9.06%	7.55
MGS < 150 kW	8.56%	0.00	2.47%	2.06
LGS > 150 kW	23.15%	0.00	2.45%	2.04
Irrigation	0.43%	0.00	0.07%	0.06
Street Lighting BCH	0.22%	0.00	0.49%	0.41
Street Lighting Cust	0.45%	0.00	0.49%	0.40
Transmission	0.00%	0.00	2.02%	1.69
Total	100.0%	0.00	100.0%	83.37

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Summary of Costs by Functions and Revenue to Cost Ratios

Rate Class	Generation Costs	Transmission Costs	Distribution Costs	Customer Care Costs	Total Cost	Total Revenue	Revenue - Cost ($ million)	Revenue:Cost Ratios
Residential	1,004.43	364.26	617.89	69.16	2,055.74	1,917.57	-138.2	93.3%
GS Under 35 kW	184.62	57.35	118.43	7.55	367.95	411.82	43.9	111.9%
MGS < 150 kW	168.79	51.19	85.68	2.06	307.72	360.50	52.8	117.2%
LGS > 150 kW	527.56	146.31	149.77	2.04	825.68	836.14	10.5	101.3%
Irrigation	2.79	0.00	4.05	0.06	6.90	6.04	-0.9	87.6%
Street Lighting BCH	3.19	1.56	6.71	0.41	11.88	20.61	8.7	173.6%
Street Lighting Cust	9.36	3.15	4.05	0.40	16.96	17.77	0.8	104.8%
Transmission	694.56	170.62	0.00	1.69	866.87	889.32	22.4	102.6%
Total	2,595.30	794.44	986.59	83.37	4,459.70	4,459.79	0.1	100.0%

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Summary of Costs by Classification

Rate Class	Energy Related Costs	Generation Demand Related Costs	Transmission Demand Related Costs	Distribution Demand Related Costs	Total Demand Related Costs	Customer Related Costs	Total
Residential	660.2	344.3	364.3	413.6	1,122.1	273.5	2,055.7
GS Under 35 kW	130.4	54.2	57.4	80.8	192.4	45.2	367.9
MGS < 150 kW	120.4	48.4	51.2	71.6	171.2	16.1	307.7
LGS > 150 kW	389.3	138.3	146.3	143.7	428.3	8.1	825.7
Irrigation	2.8	0.0	0.0	3.2	3.2	0.9	6.9
Street Lighting BCH	1.7	1.5	1.6	1.7	4.7	5.4	11.9
Street Lighting Cust	6.4	3.0	3.1	3.4	9.5	1.1	17.0
Transmission	533.3	161.3	170.6	0.0	331.9	1.7	866.9
Total	1,844.5	750.8	794.4	718.0	2,263.2	352.0	4,459.7

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Percent of Costs by Allocator

Rate Class	Generation Energy (kWh)	Generation & Transmission Demand (4CP)	Distribution Demand (NCP)	Customer (Various)
Residential	32%	34%	20%	13%
GS Under 35 kW	35%	30%	22%	12%
MGS < 150 kW	39%	32%	23%	5%
LGS > 150 kW	47%	34%	17%	1%
Irrigation	40%	0%	46%	14%
Street Lighting BCH	14%	26%	14%	46%
Street Lighting Cust	38%	36%	20%	6%
Transmission	62%	38%	0%	0%
Total	41%	35%	16%	8%

Energy Allocators

Rate Class	Energy @ Customer Meter	Distribution Loss Factor	Energy @ Transmission Interface	Transmission Loss Factor	Energy @ Generation Interface	Energy by Rate Class	Energy at Generator Allocation Factor
	(MWh)		(MWh)		(MWh)		
Residential	18,742,647	6.00%	19,867,206	6.00%	21,059,238	21,059,238	35.79%
GS Under 35 kW	3,702,548	6.00%	3,924,701	6.00%	4,160,183	4,160,183	7.07%
MGS < 150 kW Primary	87,191	3.44%	90,191	6.00%	95,602		
MGS < 150 kW Secondary	3,333,608	6.00%	3,533,624	6.00%	3,745,642		
MGS						3,841,244	6.53%
LGS > 150 kW Primary	7,118,064	3.44%	7,362,925	6.00%	7,804,701		
LGS > 150 kW Secondary	4,105,904	6.00%	4,352,258	6.00%	4,613,394		
LGS						12,418,095	21.11%
Irrigation	79,206	6.00%	83,958	6.00%	88,995	88,995	0.15%
Street Lighting BCH	48,676	6.00%	51,597	6.00%	54,692	54,692	0.09%
Street Lighting Cust	181,143	6.00%	192,011	6.00%	203,532	203,532	0.35%
Transmission	16,049,484	0.00%	16,049,484	6.00%	17,012,453	17,012,453	28.91%
Total	53,448,470		55,507,955		58,838,432	58,838,432	100.00%

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Demand Allocators

Rate Class	4 CP	NCP w/o T	NCP w/o Prim
Residential	45.85%	56.57%	58.36%
GS Under 35 kW	7.22%	10.62%	10.95%
MGS < 150 kW	6.44%	8.56%	22.57%
LGS > 150 kW	18.42%	23.15%	6.98%
Irrigation	0.00%	0.43%	0.44%
Street Lighting BCH	0.20%	0.22%	0.23%
Street Lighting Cust	0.40%	0.45%	0.46%
Transmission	21.48%	0.00%	0.00%
Total	100.00%	100.00%	100.00%

Rate Class 4CP	F10	F11	F12	F13	F14	5-Yr Avg
Residential	45.61%	46.88%	47.59%	45.66%	43.51%	45.85%
GS Under 35 kW	7.00%	7.01%	6.66%	7.03%	8.39%	7.22%
MGS < 150 kW	6.15%	6.27%	6.61%	6.52%	6.67%	6.44%
LGS > 150 kW	19.13%	17.97%	17.00%	18.28%	19.70%	18.42%
Irrigation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Street Lighting BCH	0.19%	0.21%	0.21%	0.22%	0.14%	0.20%
Street Lighting Cust	0.38%	0.43%	0.43%	0.45%	0.29%	0.40%
Transmission	21.53%	21.24%	21.49%	21.83%	21.30%	21.48%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Rate Class NCP w/o T	F10	F11	F12	F13	F14	5-Yr Avg
Residential	57.58%	55.78%	57.70%	54.50%	57.30%	56.57%
GS Under 35 kW	10.45%	11.17%	10.92%	10.37%	10.17%	10.62%
MGS < 150 kW	7.98%	8.62%	9.02%	9.13%	8.06%	8.56%
LGS > 150 kW	22.82%	23.31%	21.35%	24.84%	23.42%	23.15%
Irrigation	0.52%	0.45%	0.36%	0.44%	0.39%	0.43%
Street Lighting BCH	0.21%	0.22%	0.21%	0.24%	0.22%	0.22%
Street Lighting Cust	0.43%	0.45%	0.43%	0.48%	0.45%	0.45%
Transmission	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

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Distribution Customer Allocators

Rate Class	Distribution Customer Count	Distribution Customer Allocator	Distribution Meter Weighting	Distribution Metering Allocator
Residential	1,766,045	88.87%	1.00	77.15%
GS Under 35 kW	182,647	9.19%	2.00	15.96%
MGS < 150 kW	18,639	0.94%	6.00	4.89%
LGS > 150 kW	6,466	0.33%	6.00	1.69%
Irrigation	3,534	0.18%	2.00	0.31%
Street Lighting BCH	4,998	0.25%	0.00	0.00%
Street Lighting Cust	4,998	0.25%	0.00	0.00%
Transmission	304	0.00%	0.00	0.00%
Total	1,987,630	100.00%	1.15	100.00%

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Customer Care Allocators

Rate Class	Number of Accounts	Annual bills per account	Annual bills per rate class	# of Bills Allocator	Revenue ($millions)	Revenue Allocator	90% # of Bills Allocator	10% Revenue Allocator	Blended Customer Care Allocator
Residential	1,766,045	6	10,596,267	87.40%	$1,918	43.00%	78.7%	4.3%	82.96%
GS Under 35 kW	182,647	6	1,095,883	9.04%	$412	9.23%	8.1%	0.9%	9.06%
MGS < 150 kW	18,639	12	223,665	1.84%	$361	8.08%	1.7%	0.8%	2.47%
LGS > 150 kW	6,466	12	77,590	0.64%	$836	18.75%	0.6%	1.9%	2.45%
Irrigation	3,534	2	7,068	0.06%	$6	0.14%	0.1%	0.0%	0.07%
Street Lighting BCH	4,998	12	59,976	0.49%	$21	0.46%	0.4%	0.0%	0.49%
Street Lighting Cust	4,998	12	59,976	0.49%	$18	0.40%	0.4%	0.0%	0.49%
Transmission	304	12	3,648	0.03%	$889	19.94%	0.0%	2.0%	2.02%
Total	1,987,630		12,124,073	100.00%	4,459.8	100.00%			100.00%

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Distribution Transformer Allocators

Rate Class	OH Transformers	UG Transformers	Weighted Allocator
Residential	72.15%	55.79%	65.51%
GS Under 35 kW	17.03%	16.47%	16.80%
MGS < 150 kW	6.90%	16.37%	10.74%
LGS > 150 kW	1.66%	10.89%	5.41%
Irrigation	0.85%	0.07%	0.54%
Street Lighting BCH	0.47%	0.13%	0.33%
Street Lighting Cust	0.94%	0.27%	0.67%
Transmission	0.00%	0.00%	0.00%
Total	59.41%	40.59%	100.00%

* Based on replacement costs

Addendum to COS NSA

Distribution Classification by Sub-Functionalization

Sub-Function	F14 Year-End Assets	% of assets (excluding Substation)	% of assets without Streetlighting	Demand-related %	Customer-related %	Demand % of Total Costs	Customer % of Total Costs	% of total Demand costs	% of total Customer costs
Primary	2,176.2	55.2%	55.6%	100%	0%	55.6%	0.0%	77.8%	0.0%
Secondary/Services	576.1	14.6%	14.7%	50%	50%	7.4%	7.4%	10.3%	25.7%
Meters	498.0	12.6%	12.7%	0%	100%	0.0%	12.7%	0.0%	44.5%
Transformers	666.8	16.9%	17.0%	50%	50%	8.5%	8.5%	11.9%	29.8%
Substation	629.5								
Streetlighting	22.9	0.58%							
Total	4,569.5	100.0%	100.0%			71.4%	28.6%	100.0%	100.0%

Addendum to COS NSA

Rate Base
(re-calculated with DSM 90-5-5 alternative)

Function		SQ		Preferred	
Generation	Mid-Year Net Assets	6,500.2	42.3%	6,500.2	42.3%
	90% of DSM	851.0		851.0	
Transmission	Mid-Year Net Assets	5,482.1	32.1%	5,482.1	31.8%
	% DSM	94.6		47.3	
Distribution	Mid-Year Net Assets	4,461.8	25.7%	4,461.8	25.9%
	% DSM	-		47.3	
Corporate	Mid-Year Net Assets	776.3		776.3	

William J. Andrews
Barrister & Solicitor
1958 Parkside Lane, North Vancouver, BC, Canada, V7G 1X5
Phone: 604-924-0921, Fax: 604-924-0918, Email: wjandrews@shaw.ca

March 29, 2016

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC, V6Z 2N3
Attn: Ms. Liisa O'Hara, NSP Facilitator
By email: liisao@shaw.ca

Dear Madam:

Re: British Columbia Hydro and Power Authority 2015 Rate Design Application (RDA);
BCUC Project No.3698781;
Negotiated Settlement Agreement regarding the F2016 Cost of Service Study
BC Sustainable Energy Association and Sierra Club BC support letter

I am counsel for the interveners BC Sustainable Energy Association and Sierra Club BC. BCSEA-SCBC participated fully in the negotiated settlement process (NSP) regarding BC Hydro's F2016 Cost of Service Study pursuant to Order G-12-16 and in accordance with the Commission's February 2012 *Negotiated Settlement Process Policy, Procedures and Guidelines*[1]. In person meetings were held on March 7 and 8, 2016 and follow-up communications were conducted by email. A Negotiated Settlement Agreement was concluded. The final text was circulated to the parties on March 24, 2016. I confirm that BCSEA-SCBC support the Agreement. BCSEA-SCBC support a Commission order approving the Agreement.

Yours truly,

William J. Andrews

Barrister & Solicitor
cc. NSP Distribution List by email

[1] Appendix A to Order G-11-12.

British Columbia Utilities Commission

Eileen Cheng
Senior Economist, Rates

Eileen.cheng@bcuc.com
Website: www.bcuc.com

Sixth Floor, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
TEL: (604) 660-4700
BC Toll Free: 1-800-663-1385
FAX: (604) 660-1102

Log No. 51126

VIA EMAIL

March 29, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Attention: Mr. Jim Fraser, Consultant/BCUC Staff Advisor
Ms. Liisa O'Hara, BCUC Facilitator

Dear Mr. Fraser and Ms. O'Hara:

Re: British Columbia Hydro and Power Authority
Commission Order G-12-16/Project No. 3698781
2015 Rate Design Application/Cost of Service Study Negotiated Settlement Agreement

I am a British Columbia Utilities Commission (Commission) staff member who acted as an Active Participant to the Negotiated Settlement Proceeding (NSP) established by Commission Order G-12-16 to review the cost of service study and rate class segmentation that formed part of BC Hydro's 2015 Rate Design Application (RDA).

The role of an Active Participant is described in Section IV (iv) of the Commission's NSP Guidelines and further clarified in the Introduction section of the proposed Negotiated Settlement Agreement (NSA).

I am providing this letter to confirm my support of the terms of the proposed NSA and accept its use in informing the 2015 RDA proposals.

Sincerely,

Eileen Cheng
BCUC staff member – Active Participant

EC/cms
cc: parties of the NSP

PF/BCH 2015RDA/GC/03-29-2016_NSA Support Letter-Cheng

Linda Dong Associates
Energy Consulting

2491 Hyannis Drive
North Vancouver, BC
Canada V7H 2E7
604.417.8877
linda@dongassociates.com

VIA EMAIL

March 29, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street, Box 250
Vancouver, BC
V6Z 2N3

Attention: Ms. Liisa O'Hara, NSP Facilitator
Mr. Jim Fraser, NSP Advisor

Dear Ms. O'Hara and Mr. Fraser:

Re: BC Hydro 2015 Rate Design Application
Project No. 3698781
Negotiated Settlement Agreement regarding the F2016 Cost of Service Study

The Zone II Ratepayers Group confirms its acceptance of the terms of the Negotiated Settlement Agreement regarding the F2016 Cost of Service Study for the BC Hydro 2015 Rate Design Application accompanying your email to the parties to the NSP dated March 24, 2016.

Yours truly,

Linda Dong

Linda Dong
Principal

cc: Parties to the NSP

BULL HOUSSER
CELEBRATING 125 YEARS

Bull, Housser & Tupper LLP
1800 – 510 West Georgia Street
Vancouver, BC V6B 0M3
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Reply Attention of:	Matthew D. Keen
Direct Phone:	604.641.4913
Direct Fax:	604.646.2551
E-Mail:	mdk@bht.com
Our File:	14-3364
Date:	March 30, 2016

VIA COMMISSION E-FILING

British Columbia Utilities Commission
6th Floor – 900 Howe Street
Vancouver, BC V6Z 2V3

Attention: Ms. Liisa O'Hara, NSP Facilitator

Dear Madam:

Re: British Columbia Hydro and Power Authority (BC Hydro) 2015 Rate Design Application (RDA); BCUC Project No. 3698781
Negotiated Settlement Agreement re F2016 Cost of Service Study
Association of Major Power Customers (AMPC) Support Letter

We are legal counsel to AMPC in this matter. AMPC actively participated in the negotiated settlement process regarding BC Hydro's F2016 Cost of Service Study. AMPC supports a Commission order approving the Negotiated Settlement Agreement in the form circulated to the parties on March 24, 2016.

Please contact the writer if you have any questions.

Yours truly,

Bull, Housser & Tupper LLP

Matthew D. Keen

BC Hydro
Power smart

Tom A. Loski
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

March 30, 2016

Mr. Jim Fraser
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Fraser:

RE: Project No. 3698781
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
F2016 Cost of Service Study (COS) Negotiated Settlement Agreement (NSA)

BC Hydro writes to confirm its acceptance of the NSA attached to Mr. Jim Fraser's email dated March 24, 2016, and to provide the following comments.

The Negotiated Settlement Process took place on March 7 and 8, with further communication between participants via email over the following weeks. In BC Hydro's view, the COS NSA represents a reasonable compromise of the issues regarding the F2016 COS Study, and BC Hydro respectfully submits that the Commission should approve it.

BC Hydro thanks all participants for their efforts during these negotiations.

For further information, please contact Gordon Doyle at 604-623-3815 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

(for) Tom Loski
Chief Regulatory Officer

dr/af

Copy to: BCUC (Jim Fraser) March 24, 2016 Email Distribution List.

BCPIAC
Public Interest Advocacy Centre

208-1090 W. Pender St, Vancouver BC V6E 2N7 Coast Salish Territory
604.687.3063 fax 604.682.7896 www.bcpiac.com

March 30, 2016

Our file: 7615

VIA EMAIL

Jim Fraser, Facilitator
Consultant to BCUC
BC Utilities Commission
6th Floor 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Fraser:

**Re: BC Hydro and Power Authority 2015 Rate Design Application
March 24, 2016 Negotiated Settlement Agreement regarding the F2016 Cost of Service Study**

BCOAPO confirms its acceptance of the terms of the Negotiated Settlement Agreement dated March 24, 2016 (NSA) regarding the F2016 Cost of Service Study.

The only point we wish to raise about the NSA is regarding the following excerpt on page 13:

> "A participant requested clarification on the classification of GRTAs and suggested that GRTAs should be classified based on the classification percentage using the same percentages as Heritage Hydro. BC Hydro confirmed that it classifies GRTAs in that manner."

BCOAPO was the participant that raised this point, and we wish to clarify that the issue we raised was whether GRTAs should be classified using the percentages for all costs of Heritage Hydro, including Heritage Energy. This was in contrast to BC Hydro's proposal which forms the basis for the NSA and classifies GRTAs based on Heritage Hydro, excluding the cost of Heritage Energy.

Please let me know if you have any questions.

Sincerely,

BC Public Interest Advocacy Centre

Sarah Khan and Erin Pritchard
Staff Lawyers

c. NSP Participants

OWEN • BIRD
LAW CORPORATION

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Direct Line: 604 691-7557
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E-mail: cweafer@owenbird.com
Our File: 23841/0131

March 30, 2016

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Jim Fraser, Facilitator Consultant to BCUC

Dear Sirs/Mesdames:

Re: British Columbia Hydro and Power Authority ("BC Hydro") 2015 Rate Design Application, Project No. 3698781
Negotiated Settlement Agreement Regarding F2016 Cost of Service Study

We are counsel for the Commercial Energy Consumers Association of British Columbia ("CEC") and write to advise that the CEC confirms its acceptance of the terms of the Negotiated Settlement Agreement dated March 24, 2016 for the BC Hydro F2016 Cost of Service Study.

Should you have any questions regarding the foregoing, please do not hesitate to contact the writer.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer
CPW/jlb
cc: CEC
cc: BC Hydro
cc: Parties to NSP

{00476999;1}

FORTIS BC

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
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Cell: (604) 908-2790
Fax: (604) 576-7074
Email: www.fortisbc.com

March 30, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Liisa O'Hara, BCUC Facilitator
Mr. Jim Fraser, Consultant/BCUC Staff Advisor

Dear Ms. O'Hara and Mr.Fraser:

Re: Project No. 3698781/ BCUC Order No. G-12-16

British Columbia Hydro and Power Authority (BC Hydro) 2015 Rate Design Application Cost of Service Study Negotiated Settlement Process (NSP)

FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC)

On behalf of FortisBC we, the undersigned, participated in the negotiated settlement process (NSP) established by BCUC Order G-12-16 regarding BC Hydro's F2016 Cost of Service Study and conducted in accordance with the Commission's 2012 *Negotiated Settlement Process Policy, Procedures and Guidelines*. We participated in the in-person meetings held on March 7 and 8, 2016 and in the follow-up communications conducted by email. A Negotiated Settlement Agreement (NSA) was reached in this process, the final text of which was circulated to the parties on March 24, 2016. We confirm that FortisBC supports the NSA and recommend that the Commission issue an order approving it.

If further information is required, please contact Dave Perttula at (604) 592-7470 or Corey Sinclair at (250) 469-8038.

Sincerely,

on behalf of FORTISBC

Original signed by: Dave Perttula & Corey Sinclair

cc (email only): BC Hydro
NSP Participants

ALLEVATO QUAIL & WORTH

BARRISTERS AND SOLICITORS

Allevato & Quail Law Corporation
Leigha L. Worth Law Corporation

March 30, 2016

our file 15-070
Leigha Worth
direct: 604-424-8634
lworth@aqwlaw.ca

via email

British Columbia Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Attention: Ms. Liisa O'Hara, BCUC Facilitator
Mr. Jim Fraser, Consultant/BCUC Staff Advisor

Dear Ms. O'Hara and Mr. Fraser:

RE: BC Hydro and Power Authority
Commission Order G-12-16 / Project No. 3698781
2015 BC Hydro Rate Design Application
Cost of Service Study Negotiated Settlement Agreement

Please be advised that I make the following submission on behalf of my client, the Movement of United Professionals, also known as the Canadian Office and Professional Employees Union, Local 378. MoveUP confirms its acceptance of the terms of the proposed Negotiated Settlement Agreement to inform the Utility's 2015 Rate Design Application.

Please do not hesitate to contact the undersigned should you have any questions.

Yours truly,

Leigha Worth
Barrister & Solicitor

cc: parties to the NSP

WEISBERG LAW
CORPORATION

2730 Ailsa Crescent
North Vancouver BC V7K 2B2
Reply to: Fred J. Weisberg
Telephone:(604) 980-4069
Email: fredweislaw@gmail.com

VIA EMAIL

March 29, 2016

British Columbia Utilities Commission
6th Floor 900 Howe Street
Vancouver, BC V6Z 2N3
Attention: Mr. Jim Fraser, Consultant/BCUC Staff Advisor
and Ms. Liisa O'Hara, BCUC Facilitator

Dear Mr. Fraser and Ms. O'Hara:

RE: BC Hydro and Power Authority
2015 Rate Design Application
Non-Integrated Areas Ratepayers Group
Negotiated Settlement Agreement for
F2016 Cost of Service Study

I am legal counsel to our clients, the Heiltsuk Tribal Council, Shearwater Marine Limited and the Gitga'at First Nation, collectively registered as the Non-Integrated Areas Ratepayers Group ("NIARG") in the above-captioned proceeding. NIARG actively participated in the March 7 and 8, 2016 Negotiated Settlement Process ("NSP") regarding BC Hydro's F2016 Cost of Service Study. The NSP negotiations were carried out pursuant to Commission Order G-12-16 and consistent with the Commission's Negotiated Settlement Process Policy, Procedures and Guidelines. Subsequent communications by email resulted in a consensus draft Negotiated Settlement Agreement ("NSA").

NIARG confirms its support for the proposed NSA regarding BC Hydro's 2016 Cost of Service Study and rate class segmentation. NIARG accepts the use of the NSA to inform BC Hydro 2015 Rate Design Application proposals.

Letter to BC Utilities Commission
Non-Integrated Areas Ratepayers Group
Confirmation of Support for COSS NSA
March 29, 2016

Yours truly,

Fred J. Weisberg
Barrister & Solicitor
Weisberg Law Corporation
Counsel to the Non-Integrated Areas Ratepayers Group

Addendum to Cost of Service Negotiated Settlement
Dated March 24, 2016

Spreadsheet

G-47-16_Addendum-
to-COS-NSA_March-2

Cost of Service Study - Fiscal 2019

Appendix B

Fiscal 2017 FACOS Study

BC Hydro
Power smart

Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

February 14, 2019

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

**RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
F2017 Fully Allocated Cost of Service (FACOS) Study**

BC Hydro writes to file our F2017 FACOS study reflecting fiscal 2017 actual results pursuant to Commission Directive No. 2 of the 2007 Rate Design Application (**2007 RDA**) Decision[1].

BC Hydro filed our last annual FACOS study on March 15, 2018, based on fiscal 2016 actual revenue and load data. BC Hydro is now filing our F2017 FACOS study based on actual fiscal 2017 revenue and load data. This filing is being made for information only.

BC Hydro's fully allocated cost of service study methodology was the subject of a Negotiated Settlement Process Regarding BC Hydro's F2016 Cost of Service Study, included as Appendix A to Commission Order No. G-47-16 (**NSA**). This compliance filing incorporates changes to methodology described in the settlement to the NSA, as did our prior FACOS filing of March 15, 2018.

BC Hydro has undertaken further examination of the topic areas raised in the NSA. BC Hydro will file a Cost of Service Study Application before March 31, 2019, presenting this further examination and proposing changes to the methodology as applicable, for use in future FACOS filings.

The table below shows Revenue-to-Cost (**R/C**) ratios for all rate classes as compared to prior results. The F2014 FACOS were based on actual revenue and customer load data. The F2015 FACOS was not completed due to BC Hydro's 2015 Rate Design Application being underway. BC Hydro's 2015 Rate Design Application relied on an F2016 Forecast FACOS, and therefore two results are presented for fiscal 2016. The F2016 Forecast

1 https://www.bcuc.com/Documents/Proceedings/2007/DOC_17004_10-26_BCHydro-Rate-Design-Phase-1-Decision.pdf

cost of service study was based on forecast revenue and load data and was the subject of the NSA. The F2016 FACOS was based on actual revenue and load data and incorporates the methodology changes agreed to in the NSA. The F2017 FACOS is also based on actual revenue and load data, and uses the same methodology as was used in the F2016 FACOS.

	Revenue to Cost Ratios				
Rate Class	**F2014 Actual (%)**	**F2016 Forecast (%)**	**F2016 Actual (%)**	**F2017 Actual (%)**	**Percentage Point Change (F2016 Actual to F2017 Actual) (%)**
Residential	92.9	93.3	90.8	93.2	2.4
GS < 35 kW	123.5	111.9	122.6	123.6	1.0
MGS	119.5	117.2	123.5	115.1	-8.4
LGS	101.5	101.3	103.9	103.9	0.0
Irrigation	90.3	87.6	95.1	89.5	-5.6
Street Lighting – BC Hydro Owned	129.4	173.6	183.6	198.4	14.8
Street Lighting – Customer Owned		104.8	101.8	95.1	-6.7
Transmission	97.3	102.6	98.8	95.4	-3.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

There are a number of factors giving rise to the variances between F2017 Actual results and results of prior years, including:

- Residential Rate Class revenues were higher in fiscal 2017 largely because the winter of fiscal 2017 was colder than the winters of the other years presented above. For example, in fiscal 2017, seven per cent of days were below zero degrees Celsius, compare to an average of three per cent for fiscal 2014 and fiscal 2016. All else being equal, higher revenues from a rate class will increase its Revenue to Cost Ratio. Increased revenues due to the colder winter were a contributing factor to the change in the Residential Rate Class R/C ratio in fiscal 2017 relative to fiscal 2016;
- Cost of energy was higher in fiscal 2017 than in fiscal 2016. The increase in cost of energy was due to an increase in load as well as reductions in offsets to energy related generation functionalized costs such as surplus sales and other utility revenue. All else being equal, an increase in cost of energy without a corresponding increase in revenue will lower the R/C ratio for an individual rate class. Increased cost of energy, combined with little change to revenues, were the main reasons for

the change in the Transmission Rate Class R/C ratio in fiscal 2017 relative to fiscal 2016;

- A slight decrease in revenue and moderate increase of cost allocated to the MGS Rate Class resulted in a lower R/C ratio in fiscal 2017 relative to fiscal 2016 and;
- Improvements to the quality of load data collection on the Street Lighting and Irrigation Rate Classes resulted in an increase in demand related costs being assigned to Street Lighting - Customer Owned and Irrigation Rate Classes, and a decrease in demand related cost allocated to Street Lighting - BC Hydro Owned Rate Class. Although these changes in demand related costs were small in absolute value, they resulted in meaningful changes to the R/C ratios for these three rate classes. Variability in the R/C ratios is to be expected for smaller rate classes.

For further information, please contact Anthea Jubb at 604-623-3545 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

aj/rh

Enclosure

Copy to: BCUC Project No. 3698781 (2015 RDA) Registered Intervener Distribution List.

F2017 Cost of Service - Actual Cost

Table of Contents

Note: All costs are in $ X 1 million unless otherwise noted.

F2017 Cost of Service - Actual Cost
Functionalization Details

Revenue Requirement Schedule (F2017 Actual) [1]

		F2017 Revenue Requirement	Generation	Transmission	Distribution	Customer Care
Cost of Energy						
Sched 4, L37 + L99	IPPs and Long-term Purchases commitment	1,286.0	1,286.0	0.0	0.0	0.0
Sched 4, L 41	Domestic Transmission (Non-Heritage)	0.0	0.0	0.0	0.0	0.0
Sched 4, L 39	NIA Generation	25.0	25.0	0.0	0.0	0.0
Sched 4, L 40	Gas Transportation	11.7	11.7	0.0	0.0	0.0
Sched 4, L 26 + L36	Water Rentals	387.0	387.0	0.0	0.0	0.0
Sched 4, L 28 + L35 + L27	Market Purchases	3.4	3.4	0.0	0.0	0.0
Sched 4, L 29	Natural gas for thermal generation	9.5	9.5	0.0	0.0	0.0
Sched 4, L 30	Domestic Transmission (Heritage)	50.8	0.0	50.8	0.0	0.0
Sched 4, L 31	Non-treaty storage agreement	-23.3	-23.3	0.0	0.0	0.0
Sched 4, L 32 +L 33	Other and Surplus Sales	-174.1	-174.1	0.0	0.0	0.0
Sched 4, L 42	Net purchases (sales) from Powerex	2.3	2.3	0.0	0.0	0.0
Sched 4, L 46	HDA Additions	31.0	31.0	0.0	0.0	0.0
Sched 4, L 47	NHDA Additions	17.2	17.2	0.0	0.0	0.0
Sched 4, L 52	Deferred Operating HDA	-0.1	-0.1	0.0	0.0	0.0
Sched 4, L 53	Deferred Operating NHDA	-8.9	-8.9	0.0	0.0	0.0
Sched 4, L 54	Deferred Amortization NHDA	-3.3	-3.3	0.0	0.0	0.0
Sched 4, L 55	Deferred Taxes NHDA	-0.4	-0.4	0.0	0.0	0.0
Sched 4, L 57	Heritage Deferral Account Recoveries	-4.7	-4.7	0.0	0.0	0.0
Sched 4, L 58	Non-Heritage Deferral Account Recoveries	179.4	179.4	0.0	0.0	0.0
Total		1,788.6	1,737.8	50.8	0.0	0.0
O M & A Expenses	(updated according to organization structure change in F2017)					
Sched 5.0, L132	Training, Development and Generation	163.5	140.0	10.1	11.6	1.8
Sched 5.0, L133 to 134	Transmission, Distribution and Customer Services	672.2	35.3	248.8	269.9	118.3
Sched 5.0, L136	Capital Infrastructure Project Delivery	90.7	64.4	50.1	-25.7	1.9
Sched 5.0, L137+ L139, - Sched 5.1, L22.	Operations Support	36.4	-49.8	39.4	28.4	18.4
Total		962.8	189.9	348.3	284.1	140.4
Depreciation & Amortization						
Sched 7, L 61	Generation	276.0	276.0	0.0	0.0	0.0
Sched 7, L 62	Transmission	211.3	0.0	211.3	0.0	0.0
Sched 7.0, L 63	Distribution	189.4	0.0	0.0	189.4	0.0
Sched 7.0, L 64 - L23	Customer Care	0.0	0.0	0.0	0.0	0.0
Sched 7, L57	Business Support	167.1	35.1	108.6	23.4	0.0
Total		843.8	311.1	319.9	212.8	0.0
Taxes						
Sched 6, L 32	Generation	40.5	40.5	0.0	0.0	0.0
Sched 6, L 33	Transmission	137.9	0.0	137.9	0.0	0.0
Sched 6, L34	Distribution	26.8	0.0	0.0	26.8	0.0
Sched 6, L 35 less L12	Customer Care	0.0	0.0	0.0	0.0	0.0
Sched 6, L 36	Business Support	15.7	3.1	10.5	2.0	0.0
Total		220.9	43.6	148.4	28.8	0.0
Finance Charges						
Sched 8,	Generation	300.2	300.2	0.0	0.0	0.0
Sched 8,	Transmission	256.1	0.0	256.1	0.0	0.0
Sched 8,	Distribution	165.8	0.0	0.0	165.8	0.0
Sched 8,	Customer Care	0.0	0.0	0.0	0.0	0.0
	Business Support	0.0		0.0	0.0	0.0
Sched 8.0, L 31	Interest on Regulatory Accounts	-75.3	-54.2	-5.3	-15.8	0.0
	Regulatory Account Recoveries	-167.9	-69.8	-59.5	-38.6	0.0
Total		478.9	176.2	191.2	111.5	0.0
Allowed Net Income						
Sched 9, L 65	Generation	284.2	284.2	0.0	0.0	0.0
Sched 9, L 66	Transmission	242.4	0.0	242.4	0.0	0.0
Sched 9, L 67	Distribution	157.0	0.0	0.0	157.0	0.0
Sched 9, L 68	Customer Care	0.0	0.0	0.0	0.0	0.0
Sched 9, L 69	Business Support	0.0	0.0	0.0	0.0	0.0
Total		683.5	284.2	242.4	157.0	0.0
Miscellaneous Revenues						
Sched 15, L 5, 13, 17, 25	Non Tariff Revenue (Functionalized)	-123.6	-2.3	-44.1	-52.7	-24.6
Sched 15, L 32	Corporate Miscellaneous Revenue	-19.5	-0.4	-6.9	-8.3	-3.9
Sched 15, L36	Regulatory Account Additions	-0.3	0.0	0.0	0.0	-0.3
Total		-143.4	-2.6	-51.0	-61.0	-28.7
Revenue Offsets & Other						
Sched 1, L17	Subsidiary Net Income	-68.4	-68.4	0.0	0.0	0.0
Sched 1.0, L24	Other Utility Revenue	-13.0	-13.0	0.0	0.0	0.0
Sched 3.0, L80	liquefied Natural Gas Revenue	-0.4	-0.4	0.0	0.0	0.0
Sched 1.0, L21	Deferral Rider Revenue	-223.7	-223.7	0.0	0.0	0.0
Sched 1.0, L8	Intersegment revenues	-56.9	-3.0	-53.9	0.0	0.0
Sched 3.4, L11 (L9, L10)	Internal Allocations (GRTA, SDA)	0.0	43.3	-168.9	125.6	0.0
Total		-362.4	-265.2	-222.8	125.6	0.0
Total Revenue Requirement		**4,472.6**	**2,474.9**	**1,027.3**	**858.7**	**111.7**

1. As included in Attachment 2 of Section 6 of BC Hydro's Annual Financial Report to Commission dated September 14, 2017.

Classification of Generation Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Energy Related	Demand Costs	Energy Costs
Cost of Energy					
IPPs and Long-term Purchases commitment	1,286.0	7.00%	93.00%	90.02	1,195.94
Domestic Transmission (Non-Heritage)	-	0.00%	100.00%	-	-
NIA Generation	25.0	0.00%	100.00%	-	24.97
Gas Transportation	11.7	0.00%	100.00%	-	11.68
Water Rentals	387.0	10.00%	90.00%	38.70	348.34
Market Purchases	3.4	0.00%	100.00%	-	3.39
Natural gas for thermal generation	9.5	0.00%	100.00%	-	9.51
Domestic Transmission (Heritage)	-	100.00%	0.00%	-	-
Non-treaty storage agreement	(23.3)	0.00%	100.00%	0.0	(23.32)
Other and Surplus Sales	(174.1)	0.00%	100.00%	-	(174.07)
Net purchases (sales) from Powerex	2.3	0.00%	100.00%	-	2.32
HDA Additions	31.0	8.43%	91.57%	2.62	28.43
NHDA Additions	17.2	8.43%	91.57%	1.45	15.71
Deferred Operating HDA	(0.1)	8.43%	91.57%	(0.01)	(0.09)
Deferred Operating NHDA	(8.9)	8.43%	91.57%	(0.75)	(8.16)
Deferred Operating NHDA	(3.3)	8.43%	91.57%	(0.27)	(2.99)
Deferred Amortization NHDA	(0.4)	8.43%	91.57%	(0.03)	(0.35)
Heritage Deferral Account Recoveries	(4.7)	8.43%	91.57%	(0.39)	(4.29)
Non-Heritage Deferral Account Recoveries	179.4	8.43%	91.57%	15.12	164.30
	1,737.8	8.43%	91.57%	146.44	1,591.34
O M & A Expenses					
Training, Development and Generation	126.6	55.00%	45.00%	69.63	56.97
Burrard	6.8	100.00%	0.00%	6.84	-
Fort Nelson	6.0	26.00%	74.00%	1.56	4.43
Prince Rupert	0.6	40.00%	60.00%	0.25	0.37
Thermal Generation	13.4	64.26%	35.74%	8.64	4.81
Transmission, Distribution and Customer Services	35.3	55.00%	45.00%	19.40	15.87
Capital Infrastructure Project Delivery	64.4	55.00%	45.00%	35.40	28.96
Operations Support	(49.8)	55.00%	45.00%	(27.37)	(22.40)
Total	189.9			105.69	84.21
					-
Depreciation & Amortization					-
Amort on March 2016 Assets	191.0	55.00%	45.00%	105.02	85.93
Amortization on Additions	4.9	55.00%	45.00%	2.70	2.21
DSM Amortization	80.2	26.99%	73.01%	21.64	58.54
Generation	276.0	46.86%	53.14%	129.36	146.68
Transmission	-	55.00%	45.00%	-	-
Distribution	-	55.00%	45.00%	-	-
Customer Care	-	55.00%	45.00%	-	-
Business Support	35.1	55.00%	45.00%	19.30	15.79
Total	311.1			148.65	162.46
Taxes					-
Generation	40.5	55.00%	45.00%	22.28	18.23
Transmission	-	55.00%	45.00%	-	-
Distribution	-	55.00%	45.00%	-	-
Customer Care	-	55.00%	45.00%	-	-
Business Support	3.1	55.00%	45.00%	1.70	1.39
Total	43.6			23.98	19.62
					-
Finance Charges					-
Generation	300.2	55.00%	45.00%	165.11	135.09
Transmission	-	55.00%	45.00%	-	-
Distribution	-	55.00%	45.00%	-	-
Customer Care	-	55.00%	45.00%	-	-
Interest on Deferral Accounts	(29.6)	8.43%	91.57%	(2.49)	(27.10)
Interest on Regulatory Accounts	(24.7)	55.00%	45.00%	(13.56)	(11.09)
Regulatory Account Recoveries	(69.8)	55.00%	45.00%	(38.39)	(31.41)
Total	176.2			110.67	65.49
					-
Allowed Net Income					-
Generation	284.2	55.00%	45.00%	156.28	127.87
Transmission	-	55.00%	45.00%	-	-
Distribution	-	55.00%	45%	-	-
Business Support	-	55.00%	45.00%	-	-
Total	284.2			156.28	127.87
					-
Miscellaneous Revenues					-
Non Tariff Revenue (Functionalized)	(2.3)	55.00%	45.00%	(1.25)	(1.02)
Corporate Miscellaneous Revenue	(0.36)	55.00%	45.00%	(0.20)	(0.16)
Regulatory Account Additions	-	55.00%	45.00%	-	-
Total	(2.6)			(1.45)	(1.18)
					-
Revenue Offsets & Other					-
Subsidiary Net Income	(68.4)	26.99%	73.01%	(18.46)	(49.93)
Other Utility Revenue	(13.0)	55.00%	45.00%	(7.18)	(5.87)
liquefied Natural Gas Revenue	(0.4)	0.00%	100.00%	-	(0.36)
Deferral Rider Revenue	(223.7)	8.43%	91.57%	(18.85)	(204.82)
Intersegment revenues	(3.0)	55.00%	45.00%	(1.65)	(1.35)
Internal Allocations (GRTA, SDA)	43.3	55.00%	45.00%	23.82	19.49
Total	(265.2)			(22.3)	(242.9)
Total Generation Costs	**2,474.9**	**26.99%**	**73.01%**	**667.95**	**1806.96**

Classification of Transmission Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Demand Costs
Cost of Energy			
IPPs and Long-term Purchases commitment	-	100.00%	-
Domestic Transmission (Non-Heritage)	-	100.00%	-
NIA Generation	-	100.00%	-
Gas Transportation	-	100.00%	-
Water Rentals	-	100.00%	-
Market Purchases	-	100.00%	-
Natural gas for thermal generation	-	100.00%	-
Domestic Transmission (Heritage)	50.8	100.00%	50.83
Other and Surplus Sales	-		-
Total	50.8		50.83
O M & A Expenses			
Training, Development and Generation	10.1	100.00%	10.07
Transmission, Distribution and Customer Service	248.8	100.00%	248.76
Capital Infrastructure Project Delivery	50.1	100.00%	50.10
Operations Support	39.4	100.00%	39.41
Total	348.3		348.34
Depreciation & Amortization			
Generation	-	100.00%	-
Transmission	211.3	100.00%	211.29
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Business Support	108.6	100.00%	108.59
Total	319.9		319.88
Taxes			
Generation	-	100.00%	-
Transmission	137.9	100.00%	137.90
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Business Support	10.5	100.00%	10.54
Total	148.4		148.44
Finance Charges			
Generation	-	100.00%	-
Transmission	256.1	100.00%	256.05
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Interest on Regulatory Accounts	(5.3)	100.00%	(5.27)
Regulatory Account Recoveries	(59.5)	100.00%	(59.54)
Total	191.2		191.25
			-
Allowed Net Income			-
Generation	-	100.00%	-
Transmission	242.4	100.00%	242.37
Distribution	-	100.00%	-
Customer Care	-	100.00%	-
Total	242.4		242.37
Miscellaneous Revenues			
Non Tariff Revenue (Functionalized)	(44.1)	100.00%	(44.06)
Corporate Miscellaneous Revenue	(6.9)	100.00%	(6.94)
Regulatory Account Additions	-	100.00%	-
Total	(51.0)		(51.00)
Revenue Offsets & Other			
Subsidiary Net Income	-	100.00%	-
Other Utility Revenue	-	100.00%	-
Deferral Rider Revenue	-	100.00%	-
Intersegment revenues	(53.9)	100.00%	(53.93)
Internal Allocations (GRTA, SDA)	(168.9)	100.00%	(168.88)
Total	(222.8)		(222.81)
Total Transmission Costs	**1,027.3**		**1,027.3**

Classification of Distribution Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Customer Related	SMI Energy Related	Streetlighting Costs (Direct Assigned)	Demand Costs	Customer Costs
Cost of Energy							
IPPs and Long-term Purchases commitment	-					-	-
Domestic Transmission (Non-Heritage)	-					-	-
NIA Generation	-					-	-
Gas Transportation	-					-	-
Water Rentals	-					-	-
Market Purchases	-					-	-
Natural gas for thermal generation	-					-	-
Domestic Transmission (Heritage)	-					-	-
Non-treaty storage agreement	-					-	-
Other and Surplus Sales	-					-	-
Net purchases (sales) from Powerex	-					-	-
Heritage Deferral Account Recoveries	-					-	-
Non-Heritage Deferral Account Recoveries	-					-	-
Total	-				-	-	-
O M & A Expenses							
Training, Development and Generation	11.6	79%	21%			9.13	2.43
Transmission, Distribution and Customer Services	269.9	79%	21%		1.32	212.16	56.40
Capital Infrastructure Project Delivery	(25.7)	79%	21%			(20.30)	(5.40)
Operations Support	28.4	79%	21%			22.41	5.96
Total	284.1				1.32	223.39	59.38
Depreciation & Amortization							
Generation	-	79%	21%			-	-
Transmission	-	79%	21%			-	-
Distribution	189.4	79%	21%		0.93	148.88	39.58
Customer Care	-	79%	21%			-	-
Business Support	23.4	79%	21%			18.48	4.91
Total	212.8				0.93	167.35	44.49
Taxes							
Generation	-	79%	21%			-	-
Transmission	-	79%	21%			-	-
Distribution	26.8	79%	21%		0.13	21.06	5.60
Customer Care	-	79%	21%			-	-
Business Support	2.0	79%	21%			1.62	0.43
Total	28.8				0.13	22.68	6.03
Finance Charges							
Generation	-	79%	21%			-	-
Transmission	-	79%	21%			-	-
Distribution	165.8	79%	21%		0.81	130.38	34.66
Customer Care	-	79%	21%			-	-
Interest on Regulatory Accounts	(15.8)	79%	21%			(12.50)	(3.32)
Regulatory Account Recoveries	(38.6)	79%	21%			(30.46)	(8.10)
Total	111.5				0.81	87.41	23.24
Allowed Net Income							
Generation	-	79%	21%			-	-
Transmission	-	79%	21%			-	-
Distribution	157.0	79%	21%		0.77	123.41	32.81
Business Support	-	79%	21%			-	-
Total	157.0				0.77	123.41	32.81
Miscellaneous Revenues							
Non Tariff Revenue (Functionalized)	(52.7)	79%	21%			(41.63)	(11.07)
Corporate Miscellaneous Revenue	(8.3)	79%	21%			(6.56)	(1.74)
Regulatory Account Additions	-	79%	21%			-	-
Total	(61.0)				-	(48.19)	(12.81)
Revenue Offsets & Other							
Subsidiary Net Income	-	79%	21%			-	-
Other Utility Revenue	-	79%	21%			-	-
Deferral Rider Revenue	-	79%	0.2			-	-
Intersegment revenues	-	79%	21%			-	-
Internal Allocations (GRTA, SDA)	125.6	100%	0%			125.58	-
Total	125.6				-	125.58	-
Total Distribution Costs	**858.7**	**81.7%**	**17.8%**		**3.95**	**701.63**	**153.13**

Classification of Customer Care Function

(Functionalized Costs from Schedule 1.0)

	Functionalized Costs	Demand Related	Customer Related	Demand Costs	Customer Costs
Cost of Energy					
IPPs and Long-term Purchases commitment	-	0%	100%	-	-
Domestic Transmission (Non-Heritage)	-	0%	100%	-	-
NIA Generation	-	0%	100%	-	-
Gas Transportation	-	0%	100%	-	-
Water Rentals	-	0%	100%	-	-
Market Purchases	-	0%	100%	-	-
Natural gas for thermal generation	-	0%	100%	-	-
Domestic Transmission (Heritage)	-	0%	100%	-	-
Other and Surplus Sales	-	0%	100%	-	-
Total	-			-	-
O M & A Expenses					
Training, Development and Generation	1.8	0%	100%	-	1.80
Transmission, Distribution and Customer Servic	118.3	0%	100%	-	118.35
Capital Infrastructure Project Delivery	1.9	0%	100%	-	1.91
Operations Support	18.4	0%	100%	-	18.37
Total	140.4			-	140.43
Depreciation & Amortization					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	-	0%	100%	-	-
Business Support	-	0%	100%	-	-
Total	-			-	-
Taxes					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Customer Care	-	0%	100%	-	-
Business Support	-	0%	100%	-	-
Total	-			-	-
Finance Charges					
Generation	-	0%	100%	-	-
Transmission	-	0%	0%	-	-
Distribution	-	0%	100%	-	-
Customer Care	-	0%	100%	-	-
Interest on Regulatory Accounts	-	0%	100%	-	-
Regulatory Account Recoveries	-	0%	100%	-	-
Total	-			-	-
Allowed Net Income					
Generation	-	0%	100%	-	-
Transmission	-	0%	100%	-	-
Distribution	-	0%	100%	-	-
Business Support	-	0%	100%	-	-
Total	-			-	-
Miscellaneous Revenues					
Non Tariff Revenue (Functionalized)	(24.6)	0%	100%	-	(24.57)
Corporate Miscellaneous Revenue	(3.9)	0%	100%	-	(3.87)
Regulatory Account Additions	(0.3)	0%	100%	-	(0.31)
Total	(28.7)			-	(28.75)
Revenue Offsets & Other					
Subsidiary Net Income	-	0%	100%	-	-
Other Utility Revenue	-	0%	100%	-	-
Deferral Rider Revenue	-	0%	100%	-	-
Intersegment revenues	-	0%	100%	-	-
Internal Allocations (GRTA, SDA)	-	0%	100%	-	-
Total	-			-	-
Total Customer Care Costs	**111.7**			**-**	**111.7**

Schedule 2.3

Allocation of Generation Costs

(Classified Costs from Schedule 2.0)

Cost Classification	Generation Demand	Generation Demand-Related Costs	Generation Energy	Generation Energy Related Costs
Allocation Basis	4 CP Demand including losses (Sched 5.1)	667.95	Energy Including Loss (Sched 5.0)	1,806.96
Residential	46.22%	308.71	35.72%	645.47
GS Under 35 kW	7.53%	50.28	8.10%	146.29
MGS < 150 kW	6.21%	41.49	6.83%	123.44
LGS > 150 kW	18.58%	124.07	22.19%	401.03
Irrigation	0.01%	0.05	0.16%	2.85
Street Lighting BCH	0.15%	1.00	0.10%	1.74
Street Lighting Cust	0.44%	2.96	0.36%	6.54
Transmission	20.87%	139.38	26.54%	479.60
Total	100.0%	667.95	100.0%	1,806.96

Allocation of Transmission Costs

(Classified Costs from Schedule 2.1)

Cost Classification	Transmission Demand	Demand Related Costs (Sched 2.1)
Allocation Basis	4 CP demand including losses (Sched 5.1)	1,027.30
Residential	46.22%	474.79
GS Under 35 kW	7.53%	77.34
MGS < 150 kW	6.21%	63.81
LGS > 150 kW	18.58%	190.82
Irrigation	0.01%	0.08
Street Lighting BCH	0.15%	1.54
Street Lighting Cust	0.44%	4.54
Transmission	20.87%	214.37
Total	100.0%	1,027.30

Allocation of Distribution Costs

(Classified Costs from Schedule 2.2)

Cost Classification	Distribution Demand Related	Distribution Demand-Related	Distribution Secondary Demand Related	Distribution Secondary Demand-Related	Distribution Transformer Related	Distribution Transformer Related	Distribution Customer Related	Distribution Customer Related	Distribution Metering Related	Distribution Metering Related	Street Light Customer	Street Light Customer Related
Allocation Basis	NCP (Sched 5.1)	557.04	NCP w/o Primary (Sched 5.1)	68.28	Transformer Allocator (Sched 5.4)	152.64	Customer Count (Sched 5.2)	66.00	Metering Allocator (Sched 5.2)	10.81	Street Light Direct Assignment	3.95
Residential	57.09%	318.03	70.67%	48.25	65.51%	99.99	88.92%	58.69	77.40%	8.37	0.00%	0.00
GS Under 35 kW	10.02%	55.79	12.40%	8.46	16.80%	25.65	9.20%	6.07	16.01%	1.73	0.00%	0.00
MGS < 150 kW	8.35%	46.49	8.14%	5.56	10.74%	16.40	0.84%	0.56	4.40%	0.48	0.00%	0.00
LGS > 150 kW	23.43%	130.49	7.41%	5.06	5.41%	8.25	0.36%	0.24	1.90%	0.21	0.00%	0.00
Irrigation	0.42%	2.32	0.52%	0.35	0.54%	0.82	0.17%	0.11	0.29%	0.03	0.00%	0.00
Street Lighting BCH	0.19%	1.04	0.23%	0.16	0.33%	0.51	0.24%	0.16	0.00%	0.00	100.00%	3.95
Street Lighting Cust	0.51%	2.87	0.64%	0.43	0.67%	1.02	0.27%	0.18	0.00%	0.00	0.00%	0.00
Transmission	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00
Total	100.0%	557.04	100.0%	68.28	100.0%	152.64	100.0%	66.00	100.0%	10.81	100.0%	3.95

Allocation of Customer Care Costs

(Classified Costs from Schedule 2.3)

Cost Classification	Customer Care Demand	Customer Care Demand Related Costs	Customer Care Customer	Customer Care Customer Related Costs
Allocation Basis	NCP Sched 5.1	0.00	Blended Customer Count & Revenue Sched 5.3	111.68
Residential	57.09%	0.00	83.02%	92.72
GS Under 35 kW	10.02%	0.00	9.20%	10.27
MGS < 150 kW	8.35%	0.00	2.26%	2.53
LGS > 150 kW	23.43%	0.00	2.65%	2.96
Irrigation	0.42%	0.00	0.06%	0.07
Street Lighting BCH	0.19%	0.00	0.47%	0.53
Street Lighting Cust	0.51%	0.00	0.52%	0.58
Transmission	0.00%	0.00	1.81%	2.02
Total	100.0%	0.00	100.0%	111.68

Summary of Costs by Function and Revenue to Cost Ratios

Rate Class	Generation Costs	Transmission Costs	Distribution Costs	Customer Care Costs	Total Cost	Total Revenue	Revenue - Cost ($ million)	Revenue:Cost Ratios	R/C Ratios last filed (F2016)	R/C Ratio change from last filed
Residential	954.18	474.79	533.33	92.72	2,055.02	1,916.21	-138.8	93.2%	90.8%	2.4%
GS Under 35 kW	196.58	77.34	97.71	10.27	381.89	472.14	90.2	123.6%	122.6%	1.0%
MGS < 150 kW	164.93	63.81	69.48	2.53	300.75	346.04	45.3	115.1%	123.5%	-8.4%
LGS > 150 kW	525.10	190.82	144.25	2.96	863.13	896.47	33.3	103.9%	103.9%	0.0%
Irrigation	2.90	0.08	3.63	0.07	6.69	5.99	-0.7	89.5%	95.1%	-5.6%
Street Lighting BCH	2.73	1.54	5.82	0.53	10.62	21.08	10.5	198.4%	183.6%	14.8%
Street Lighting Cust	9.49	4.54	4.50	0.58	19.12	18.17	-0.9	95.1%	101.8%	-6.7%
Transmission	618.99	214.37	0.00	2.02	835.38	796.87	-38.5	95.4%	98.8%	-3.4%
Total	2,474.91	1,027.30	858.72	111.68	4,472.61	4,472.97	0.4	100.0%		

Note:The 0.36 $M discrepancy between total revenues and total costs apparent in the table above arises from the treatment of revenues and costs associated with electricity sales to liquefied natural gas (LNG) customers. Costs associated with LNG customer load were omitted in compliance with The Direction Respecting Natural Gas Customers, B.C. Reg 150/2016 and the Domestic Long Term Sales Contracts Regulation, B.C. Reg 201/2014 which was in effect in F2017. Note that on October 2, 2018, Order in Council 512 was issued that repealed the above noted Regulations.

(https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/091%20ts-91.pdf)

Summary of Costs by Classification

Rate Class	Energy Related Costs	Generation Demand Related Costs	Transmission Demand Related Costs	Distribution Demand Related Costs	Total Demand Related Costs	Customer Related Costs	Total
Residential	645.5	308.7	474.8	416.3	1,199.8	209.8	2,055.0
GS Under 35 kW	146.3	50.3	77.3	77.1	204.7	30.9	381.9
MGS < 150 kW	123.4	41.5	63.8	60.3	165.6	11.8	300.8
LGS > 150 kW	401.0	124.1	190.8	139.7	454.6	7.5	863.1
Irrigation	2.9	0.1	0.1	3.1	3.2	0.6	6.7
Street Lighting BCH	1.7	1.0	1.5	1.5	4.0	4.9	10.6
Street Lighting Cust	6.5	3.0	4.5	3.8	11.3	1.3	19.1
Transmission	479.6	139.4	214.4	0.0	353.8	2.0	835.4
Total	1,807.0	668.0	1,027.3	701.6	2,396.9	268.8	4,472.6

Percent of Costs by Allocator

Rate Class	Generation Energy (kWh)	Generation & Transmission Demand (4CP)	Distribution Demand (NCP)	Customer (Various)
Residential	31%	38%	20%	10%
GS Under 35 kW	38%	33%	20%	8%
MGS < 150 kW	41%	35%	20%	4%
LGS > 150 kW	46%	36%	16%	1%
Irrigation	43%	2%	46%	9%
Street Lighting BCH	16%	24%	14%	46%
Street Lighting Cust	34%	39%	20%	7%
Transmission	57%	42%	0%	0%
Total	40%	38%	16%	6%

Energy Allocators

Rate Class	Energy @ Customer Meter	Distribution Loss Factor	Energy @ Transmission Interface	Transmission Loss Factor	Energy @ Generation Interface	Energy by Rate Class	Energy at Generator Allocation Factor
	(MWh)		(MWh)		(MWh)		
Residential	18,067,745	6.00%	19,151,810	6.00%	20,300,918	20,300,918	35.72%
GS Under 35 kW	4,094,959	6.00%	4,340,657	6.00%	4,601,096	4,601,096	8.10%
MGS < 150 kW Primary	87,981	3.44%	91,007	6.00%	96,468		
MGS < 150 kW Secondary	3,369,302	6.00%	3,571,460	6.00%	3,785,748		
MGS						3,882,216	6.83%
LGS > 150 kW Primary	7,863,645	3.44%	8,134,154	6.00%	8,622,204		
LGS > 150 kW Secondary	3,551,627	6.00%	3,764,724	6.00%	3,990,608		
LGS						12,612,811	22.19%
Irrigation	79,793	6.00%	84,581	6.00%	89,655	89,655	0.16%
Street Lighting BCH	48,569	6.00%	51,483	6.00%	54,572	54,572	0.10%
Street Lighting Cust	182,990	6.00%	193,970	6.00%	205,608	205,608	0.36%
Transmission	14,230,201	0.00%	14,230,201	6.00%	15,084,013	15,084,013	26.54%
Total	51,576,812		53,614,047		56,830,890	56,830,890	100.00%

Demand Allocators

Rate Class	4 CP	NCP w/o T	NCP w/o Prim
Residential	46.22%	57.09%	70.67%
GS Under 35 kW	7.53%	10.02%	12.40%
MGS < 150 kW	6.21%	8.35%	8.14%
LGS > 150 kW	18.58%	23.43%	7.41%
Irrigation	0.01%	0.42%	0.52%
Street Lighting BCH	0.15%	0.19%	0.23%
Street Lighting Cust	0.44%	0.51%	0.64%
Transmission	20.87%	0.00%	0.00%
Total	100.00%	100.00%	100.00%

F2017 Cost of Service - Actual Cost Allocator by Customer, Bill and Revenue

Total BC Hydro - F17

Rate Class	Actual Number of Accounts F17	Annual bills per account	Annual bills per rate class	# of Bills Allocator
Residential	1,776,503	6	10,659,018	87.49%
GS Under 35 kW	183,708	6	1,102,248	9.05%
MGS < 150 kW	16,818	12	201,816	1.66%
LGS > 150 kW	7,276	12	87,312	0.72%
Irrigation	3,356	2	6,712	0.06%
Street Lighting BCH	4,817	12	57,799	0.47%
Street Lighting Cust	5,390	12	64,685	0.53%
Transmission	301	12	3,612	0.03%
Total	1,998,169		12,183,202	100.00%

Rate Class	Actual Number of Accounts F17	Distribution Customer Count	Distribution Customer Allocator
Residential	1,776,503	1,776,503	88.92%
GS Under 35 kW	183,708	183,708	9.20%
MGS < 150 kW	16,818	16,818	0.84%
LGS > 150 kW	7,276	7,276	0.36%
Irrigation	3,356	3,356	0.17%
Street Lighting BCH	4,817	4,817	0.24%
Street Lighting Cust	5,390	5,390	0.27%
Transmission	301	301	0.00%
Total	1,998,169	1,998,169	100.00%

Rate Class	Actual Number of Accounts F17	Distribution Customer Count	Distribution Metering Allocator
Residential	1,776,503	1,776,503	77.40%
GS Under 35 kW	183,708	183,708	16.01%
MGS < 150 kW	16,818	16,818	4.40%
LGS > 150 kW	7,276	7,276	1.90%
Irrigation	3,356	3,356	0.29%
Street Lighting BCH	4,817	4,817	0.00%
Street Lighting Cust	5,390	5,390	0.00%
Transmission	301	301	0.00%
Total	1,998,169	1,998,169	100.00%

Rate Class	Revenue ($millions)	Revenue Allocator
Residential	$1,916	42.84%
GS Under 35 kW	$472	10.56%
MGS < 150 kW	$346	7.74%
LGS > 150 kW	$896	20.04%
Irrigation	$6	0.13%
Street Lighting BCH	$21	0.47%
Street Lighting Cust	$18	0.41%
Transmission	$797	17.82%
Total	$4,473	100.00%

Rate Class	90% # of Bills Allocator	10% Revenue Allocator	Blended Customer Care Allocator
Residential	78.74%	4.28%	83.02%
GS Under 35 kW	8.14%	1.06%	9.20%
MGS < 150 kW	1.49%	0.77%	2.26%
LGS > 150 kW	0.64%	2.00%	2.65%
Irrigation	0.05%	0.01%	0.06%
Street Lighting BCH	0.43%	0.05%	0.47%
Street Lighting Cust	0.48%	0.04%	0.52%
Transmission	0.03%	1.78%	1.81%
Total			100.00%

Distribution Classification by Sub-Functionalization

Sub-Function	F17 Year-End Assets (NBV)	% of assets (excluding Substation)	% of assets without Streetlighting	Demand-related %	Customer-related %	Demand % of Total Costs	Customer % of Total Costs	% of total Demand costs	% of total Customer costs
Primary	2,909.9	58.5%	58.8%	100%	0%	58.8%	0.0%	74.8%	0.0%
Secondary/Services	926.2	18.6%	18.7%	50%	50%	9.4%	9.4%	11.9%	43.9%
Meters	74.5	1.5%	1.5%	0%	100%	0.0%	1.5%	0.0%	7.1%
Transformers	1,035.3	20.8%	20.9%	50%	50%	10.5%	10.5%	13.3%	49.1%
Substation	418.5			100%	0%				
Streetlighting	24.3	0.49%							
Total	5,388.7	100%	100%			78.7%	21.3%	100.0%	100.0%