2015 Rate Design Application
Cost of Service Methodology Assessment
Workshop - October 7, 2014

Discussion Guide

Strawman proposal #2 concerning
BC Hydro's Cost of Service (COS)

Table of Contents

List of Tables

List of Figures

1 Methodology - Preferred Options and Sensitivity Analysis

BC Hydro's Consideration Memo[1] concerning the Rate Design Application (**RDA**) June 19, 2014 workshop discusses stakeholder views on different COS methodology topics. The Consideration Memo explains why BC Hydro selected a particular methodology for the F2016 COS study for the following topics due to among other things a fair degree of stakeholder agreement:

- Continue with the British Columbia Utilities Commission’s (**BCUC**) 2007 RDA decision to use an embedded COS approach as opposed to a marginal COS approach;
- Continue with the 2007 RDA Direction 7 classification of Powerex Corp. Net Income following overall Generation classification;
- Continue with the 2007 RDA decision classification of Transmission as 100% demand;
- Change the 2007 RDA Direction 5 classification of Customer Care from 65% demand/35% customer to 100% customer; and
- Include Dual Fuel Interruptible Service in the 4 Coincident Peak (**CP**) calculation.

For the other COS topics, the Consideration Memo indicated BC Hydro’s preferred option, but also provided that BC Hydro would carry forward additional options for sensitivity analysis as BC Hydro is seeking further stakeholder input before making a final determination for purposes of framing its 2015 RDA. This October 7, 2014 workshop Discussion Guide provides the sensitivity analysis that shows how the F2013 COS results change if either the preferred option or the alternative option(s) are adopted. In addition, this Discussion Guide addresses COS topics for which

[1] Copy available at http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/20140929-BCHydro-rda-workshop2-cos.PDF.

stakeholders requested more information. Table 1 summarizes the topics covered in this Discussion Guide:

Table 1 Preferred Options and Alternatives

	Preferred Option	Alternative(s) for Sensitivity analysis
Functionalization		
Demand Side Management (**DSM**)	90% Generation, 5% Transmission, 5% Distribution	Direct allocation of DSM costs to rate classes that receive DSM funding
Regulatory Accounts	Specific functionalization	N/A
Classification		
Heritage Hydro Generation	Load factor approach adjusted for Independent Power Producers (**IPPs**) supply	Variation on the load factor approach and capacity factor weighted by book value
Thermal Generation	Fort Nelson Generating Station (**FNG**); Prince Rupert Generating Station (**PRG**); and Burrard Thermal Generating Station (**Burrard**)	Specific to each of the three thermal generating stations
IPPs	Weighted energy and capacity approach	Load factor approach
Smart Meter Infrastructure (**SMI**)	SMI related costs classified as 100% customer	SMI related costs classified as 30% energy and 70% customer
Distribution	Substations and primary system classified 100% demand; Transformers classified 50% demand and 50% customer; Secondary/services asset category split 50% secondary and 50% services: Secondary portion classified 100% demand; Service portion classified 100% customer Meters classified 100% customer	100% demand classification for substations, primary system, transformers, secondary/services; 100% customer classification for services and meters
Allocation		
Distribution	Non-Coincident Peak (**NCP**) approach for substations, primary system and portion of secondary classified to demand; Transformers directly allocated; Customer allocator for portion of	NCP approach for substations, primary system, portion of transformers and secondary classified to demand; Customer allocator for portion of transformers and secondary classified

	Preferred Option	Alternative(s) for Sensitivity analysis
	secondary classified to customer; Weighted customer allocator for meters	to customer; Weighted customer allocator for meters
Customer Care	Weighted customer allocator (90% number of bills, 10% revenue) with 100% Classification to customer	"Bottom Up" customer allocator with 100% Classification to customer

2 DSM Functionalization

BC Hydro's preferred option where DSM is functionalized 90% generation, 5% transmission and 5% distribution (Option 1) is essentially a continuation of the 2007 RDA Direction 6 functionalization of all revenue requirement related to DSM as 90% Generation and 10% Transmission. Functionalizing DSM as mainly or wholly Generation has jurisdictional support. There is a minimal shift with how $100 million in DSM costs gets allocated using 100% Generation functionalization as compared to Option 1. Refer to Table 2 below.

Table 2 Non Generation DSM Functionalization

F2013 Percentage Allocators for $100 million	100% Generation	Preferred: 90% Generation, 5% Transmission, 5% Distribution	Difference
Residential	35.62	37.70	2.08
Small General Service (**SGS**) Under 35 kW	7.89	7.96	0.07
Medium General Service (**MGS**) < 150 kW	7.11	7.03	(0.08)
Large General Service (**LGS**) < 150 kW	21.64	21.24	(0.40)
Irrigation	0.14	0.14	0.00
Street Lighting	0.45	0.47	0.02
Transmission	27.15	25.45	(1.69)

Direct assignment (Option 2) would be a departure from the 2007 RDA decision. BC Hydro prefers Option 1 for the reasons set out in the Consideration Memo, namely that Option 2 results in a mismatch between the benefits and costs of BC Hydro's DSM initiatives (codes and standards, conservation rate structures and programs) and has little jurisdictional support.

Table 3 shows the Revenue-to-Cost (**R/C**) ratio impact of Option 1 and Option 2.

Table 3 DSM Functionalization R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Preferred Option 1 DSM (90/5/5) (%)	Option 2 DSM (Direct Assignment) (%)
Residential	89.82	89.79	90.94
SGS	126.71	126.67	124.97
MGS	120.79	120.80	119.02
LGS	102.12	102.13	100.31
Irrigation	86.62	86.45	87.71
Street Lighting	115.66	115.66	118.50
Transmission	104.36	104.48	104.09

3 Regulatory Accounts Functionalization and Classification

At the June 19, 2014 workshop, stakeholders requested more information concerning regulatory account functionalization and classification.

Deferral accounts have historically been functionalized as 100% Generation and classified as 42% energy and 58% demand, which is the classification for the aggregate Generation costs using a plant-in-service ratio. Going forward, BC Hydro proposes to align Deferral account classification with total Cost of Energy which has a split of about 90% energy and 10% demand.

Regulatory accounts have historically been lumped together with Deferral accounts but not all of these accounts should be functionalized as Generation. For example, deferred amounts related to Storm Restoration are more closely aligned with Transmission and Distribution, SMI amounts are related to metering which is a Distribution cost, and Environmental Provisions related to transformer PCBs and asbestos are better aligned with Transmission and Distribution. These refinements result in small shifts that have a net impact of less than $20 million to each of the Generation, Transmission and Distribution functions.

Table 4 shows the R/C ratio impact of the proposed Deferral and Regulatory account adjustments.

Table 4 Deferral and Regulatory Accounts Functionalization R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Preferred Option (%)
Residential	89.8	89.7
SGS	126.7	126.8
MGS	120.8	120.8
LGS	102.1	102.2
Irrigation	86.6	87.3
Street Lighting	115.7	115.4
Transmission	104.4	104.6

4 Heritage Hydroelectric Generation Classification

The three Hydroelectric Generation classification options are described in the June 19, 2014 workshop Strawman Proposal Discussion Guide.[2] All three of the options BC Hydro put forward at the June 19, 2014 workshop are a methodological departure from 2007 RDA Direction 5, which classified Generation as a 45% energy/55% demand

[2] Available at: http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/strawman-proposal-concerning-dec-2013-cos-methodology-review.pdf.

based on recent and proposed upgrades to BC Hydro’s Revelstoke and Mica Generating Stations, which were predominantly capacity-related.

BC Hydro carried forward two options for further consideration. BC Hydro believes Option 1, a load factor approach, is most appropriate for the following reasons as compared to a capacity factor approach weighted by book value (Option 3):

1. Hydroelectric capacity, which is used in the denominator of the capacity factor calculation, is not used exclusively to meet peak loads in the winter season. It is also used to optimize the hydroelectric system and to earn trade income for all ratepayers throughout the year;
2. As noted by the three stakeholders supporting a load factor approach, there is reduced variability with the load factor approach:
    - The capacity factor calculation can be variable year over year because of the addition of hydroelectric generating capacity. Completion of Mica Units 5 and 6 in F2016 increases generation capacity by more than 800 MW and decreases the system capacity factor;
    - BC Hydro notes, however, that energy variability is mitigated somewhat because hydroelectric generation, used in the Revenue Requirement Application’s F2016 Cost of Energy forecast, is prepared using a 40 year average of streamflow conditions;
3. Load factor reflects actual retail usage of resources while the capacity factor reflects what resources are available to be used. BC Hydro believes that assigning hydroelectric costs based on the actual usage that is made of these resources rather than what is available to use is more appropriate;
4. The load factor approach has jurisdictional support (e.g., Newfoundland Power, Idaho Power, Avista).

BC Hydro identified two methods to calculate Option 1 as follows and selected Option 1B as the preferred option:

Option 1A - Under this method the overall system load factor would be calculated using F2016 forecasts for energy sales and peak load.

Option 1B - Given that BC Hydro proposed to classify IPPs separately from Heritage hydroelectric (see below), BC Hydro believes it may be appropriate to adjust the load factor calculation to remove the impact of IPPs serving load. Load factor would instead be calculated based on loads almost entirely served by Heritage hydroelectric supply.

The three options produce the following classifications of Heritage Hydroelectric Generation:

	Option 1A	Preferred Option 1B	Option 3
% Energy	61%	55%	45%
% Demand	39%	45%	55%

Table 5 shows the R/C ratio impact of BC Hydro's preferred option (Load factor approach – Option 1B), Option 1A and Option 3.

Table 5 Hydroelectric Classification R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Option 1A Load factor (total load) (%)	Preferred Option 1B Load Factor (IPP supply removed) (%)	Option 3 Capacity Factor (weighted by book value) (%)
Residential	89.8	90.9	90.5	90.0
SGS	126.7	126.1	126.4	126.6
MGS	120.8	120.3	120.5	120.7
LGS	102.1	101.3	101.6	102.0
Irrigation	86.6	82.3	84.1	85.8
Street Lighting	115.7	117.7	116.8	116.0
Transmission	104.4	102.3	103.2	104.0

5 Thermal Generation Classification

There are three BC Hydro owned thermal generating stations: FNG, PRG and Burrard. Of the three plants FNG has the most significant impact on BC Hydro's rates with a forecast F2016 rate base of approximately $150 million compared to about $9 million at PRG and $50 million at Burrard.

FNG

FNG is a 73 megawatt (**MW**) combined cycle gas turbine generating station. BC Hydro's preferred option (Option 1A) is to use a load factor approach to classify FNG's operating and maintenance (**O&M**) and capital generation costs. The load factor would be specific to the Fort Nelson service territory. In F2014 FNG had billed sales of 187 gigawatt hours (**GWh**) and a peak demand of 29 MW. This results in a 74% load factor which suggests 74% energy and 26% demand classification. Fuel costs would be classified as 100% energy.

Option 1B is to apply the system load factor to determine classify FNG related costs. Although this simplifies the COS analysis, BC Hydro questions whether it would be appropriate to apply an integrated system load factor (61% energy/39% demand classification) to FNG. Fort Nelson is not part of the BC Hydro Integrated system.

Option 2 is to use a capacity factor approach. BC Hydro does not believe a capacity factor approach is workable for FNG:

- Surplus FNG generation is often exported to Alberta for the benefit of all ratepayers;
- Under a capacity factor approach, surplus generating capacity would effectively be classified as 100% demand even though it may be used for trade purposes throughout the year;
- A capacity factor approach would result in about a 30% energy and 70% demand classification.

PRG

Of the three thermal plants, the 46 MW PRG has the smallest impact on the COS study. For simplicity, BC Hydro's preferred option (Option 1) is to use the system load factor, with no adjustment for IPP supply, to classify PRG's O&M and capital generation costs. This suggests about a 60% energy and 40% demand classification. Fuel costs would be classified as 100% energy.

Option 2 is to use a capacity factor approach. BC Hydro does not believe a capacity factor approach is workable for PRG:

- PRG's operation is not restricted to the winter period. Historically PRG operated intermittently throughout the year depending on system needs. For example, in F2014 more than half the annual generation occurred in the month of April. This suggests that classification should be a mixture of energy and demand;
- In the past 5 years PRG's generation has averaged about 3 GWh per year. Assuming 46 MW of dependable capacity from PRG, a capacity factor approach would suggest 1% energy and 99% demand classification.

Burrard

BC Hydro's preferred option is to classify Burrard O&M and capital costs as 100% demand with associated fuel costs treated as 100% energy:

- BC Hydro cannot rely on Burrard for firm energy per sections 3(5), 6(2)(b), and 13 of the *Clean Energy Act* (***CEA***);
- In F2016 BC Hydro no longer plans to rely on Burrard for generating capacity and this is reflected in the approved 2013 Integrated Resource Plan load/resource balances;
- Burrard will continue providing voltage support for the transmission system per section 13 of *CEA* and the B.C. Government's November 26, 2014 announcement

that Burrard's generating capability will be retired.[3] The transmission system is classified as 100% demand.

Refer to the Consideration Memo for further details.

6 IPP Classification

BC Hydro originally identified five options which are described in the 19 June workshop Strawman Proposal. BC Hydro carried forward three options for further consideration: Option 1 (value of energy and capacity); Option 2 (value of capacity); and Option 5 (load factor). The three options produce the following classifications of IPP supply. BC Hydro observes that Option 1 and Option 2 produce very similar results.

	Option 1	Option 2	Option 5
% Energy	94%	93%	60%
% Demand	6%	7%	40%

BC Hydro identified Option 2 as its preferred option for a number of reasons:

- Option 2 better aligns with BC Hydro's reliance on IPP resources with high dependable capacity (Alcan, Island Generation and biomass IPPs). Option 2 produces a slightly higher demand classification;
- Under Option 1, energy classification is based on the value of energy relative to capacity. Since incremental energy continues to be relatively more expensive than incremental capacity, the calculation is skewed towards an energy classification;
- Option 5 is provided for sensitivity purposes. Option 5 suggests that approximately 60% of IPP purchases be classified as energy with the remaining 40% classified as demand. Applying a 40% demand classification to intermittent IPPs is too high for reasons discussed in the 19 June workshop Strawman Proposal.

Table 6 shows the R/C ratio impact of Options 1, 2 and 5.

[3] http://www.newsroom.gov.bc.ca/downloads/Presentation.pdf; refer to slide 21.

Table 6 IPP Classification R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Option 1 (Energy and Capacity Value) (%)	Preferred Option 2 (Capacity Value) (%)	Option 5 (Load Factor) (%)
Residential	89.8	89.6	89.5	88.2
SGS Under 35 kW	126.7	126.8	126.9	127.6
MGS	120.8	120.9	120.9	121.5
LGS	102.1	102.3	102.4	103.4
Irrigation	86.6	87.6	87.9	93.9
Street Lighting	115.7	115.2	115.1	112.8
Transmission	104.4	104.8	105.0	107.7

7 SMI Regulatory Account Classification

The SMI regulatory account captures operating costs and accelerated depreciation of retired legacy meters, the balance of which started being amortized in F2015. Capital costs associated with SMI are included in Distribution costs (which has its own functional classification) and not recorded as deferred spending.

BC Hydro assessed three options for classifying SMI-related costs: Option 1 (100% customer cost); Option 2 (100% energy); and Option 3 (30% energy and 70% customer), which reflects the forecast increase in energy sales as a proportion of SMI costs in F2016. BC Hydro rejected Option 2 for the reasons set out in the Consideration memo. BC Hydro carried forward Option 1 and Option 3 for further consideration.

BC Hydro prefers Option 1 as it is consistent with how meters are classified, and has jurisdictional support (Ontario Energy Board,[4] Georgia Power Company and Florida Light & Power Company). Option 3 is not stable in the near-term as forecast energy

[4] Ontario Energy Board, G-2011-0001 Guideline: Smart Meter Funding and Cost Recovery – Final Disposition (December 15, 2011); http://www.ontarioenergyboard.ca/oeb/_documents/regulatory/oeb_guideline_g-2011-0001_smartmeters.pdf.

sales attributable to system benefits of SMI and deferral net additions and recoveries are variable.

There is no impact of re-classifying the SMI regulatory account in F2013 because no amortization had occurred in that year. In F2016, recoveries associated with amortization of the SMI deferral account are forecast to be $31.3 million while the remainder of SMI-related costs (amortization of capital assets) are included in the Distribution-related costs in the revenue requirement.

8 Distribution Classification and Allocation

At the 19 June 2014 workshop, BC Hydro outlined its reservations with using a minimum system method and its variant the zero intercept method. The Leidos COS methodology review included a jurisdictional assessment presented at the June 19, 2014 workshop which showed that several U.S. public utilities have rejected both the minimum system and zero intercept methods.[5] In addition to the reasons advanced at the June 19, 2014 workshop, BC Hydro notes that minimum size calculation can cause the customer allocator to 'double-count' demand. Since the minimum size facility is capable of carrying some load, this 'minimum' facility is not a pure customer cost. An excessive amount of costs will be allocated to low usage customers because a portion of the demand carrying capacity of the system will be allocated on a customer basis. Because this problem is widely recognized, the zero intercept methodology was devised; the zero intercept uses regression analysis to statistically extrapolate what the cost of the facility might be if it did not have any load carrying capability. Zero-intercept methods in general are critiqued because of their lack of realism. The abstract notion of a distribution facility which has no load carrying capability is fiction.

[5] Refer to BC Hydro's June 3, 2014 letter to COS workshop participants; copy available at the BC Hydro 2015 RDA website at http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/cos-workshop-cover-letter.pdf. Many of the U.S. decisions cite Bonbright's rejection of both the minimum system and zero intercept methods; refer to James C. Bonbright, *Principles of Public Utility Rates* (Columbia University Press, 1961), page 347.

Instead, most utilities surveyed use professional judgment to separate demand-related and customer-related distribution costs rather than relying on minimum system or zero intercept analyses. For classification purposes, the Leidos COS methodology review states that utilities in the U.S. distinguish between identifiable plant in service that (1) provides service only to individual customers or customer-related plant in service, from (2) plant in-service that is part of the interconnected distribution network or demand-related plant in service. Typically, customer-related plant in service includes service and meters (allocated on the basis of weighted customer count) and demand-related plant in service includes substations, lines and transforms (allocated on the basis of NCP).[6] The January 2013 Elenchus COS methodology survey conducted on behalf of SaskPower[7] found that most surveyed utility classify distribution system components and service as follows: substation 100% demand, primary lines and distribution transformers between 70% and 100% demand, secondary line costs between 50% to 100% demand, and service and meter costs are classified as 100% customer. The June 2012 Christensen survey stated that Manitoba Hydro classifies substations as 100% demand; poles and wires as 60% demand; line transformers as 100% demand; service drops as 100% customer; and meters as 100% customer.[8]

BC Hydro acted on the Leidos recommendation to sub-functionalize its Distribution system and to consider direct assignment. The results of this work are described in the slide-deck presentation accompanying this Discussion Guide. BC Hydro accepted the Leidos recommendation of classifying substations as 100% demand and of classifying costs for services and meters as 100% customer.

6 Leidos, “Final Report: Cost of Service Methodology Review for British Columbia Hydro and Power Authority” (December 20, 2013), page 4-5; copy available at the BC Hydro 2015 RDA website at http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/cos-workshop-leidos-final-report.pdf.

7 “Review of Cost Allocation and Rate Design Methodologies: A Report Prepared by Elenchus Research Associated Inc.”, pages 21-24; copy available at http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_13_4.pdf.

8 “Review of Cost-of-Service Methods of Manitoba Hydro”, pages 17-18; Copy available at http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_13_4.pdf.

BC Hydro proposes (Option 1) to classify substations and the primary system as 100% demand using NCP as the allocator; to use a direct assignment method for transformers (with a 50% demand/50% customer classification); to classify the secondary system as 100% demand using appropriate allocators; and to classify meters as 100% customer on a weighted customer basis.

Table 7 compares BC Hydro’s preferred option for distribution classification and allocation against an alternative approach (Option 2) with 100% demand classification for substations, primary system, transformers, secondary/services, and 100% customer classification for services and meters.

Table 7 Distribution R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Preferred Option 1 (%)	Option 2 (%)
Residential	89.82	92.0	94.0
SGS Under 35 kW	126.71	123.6	125.7
MGS	120.79	113.6	111.7
LGS	102.12	99.6	94.7
Irrigation	86.62	80.4	78.1
Street Lighting	115.66	117.0	113.9
Transmission	104.36	104.4	104.4

9 Customer Care Allocation

As part of the June 19, 2014 workshop, some participants requested further information concerning customer care cost allocation and in particular whether a weighted customer and/or direct assignment approach was being contemplated. BC Hydro proposes to continue allocating customer care-related costs on a weighted basis with:

- 90% of the weight based on the number of bills issued to customers;
- 10% based on revenue.

BC Hydro completed a more detailed analysis for the various categories of customer care cost (call center, billing, credits and collections, meter reading and O&M). Cost drivers were examined for each cost category to derive a “bottom up” allocation to rate classes. The results of the more detailed analysis are shown in Figure 1.

Figure 1 Customer Care Costs Allocation

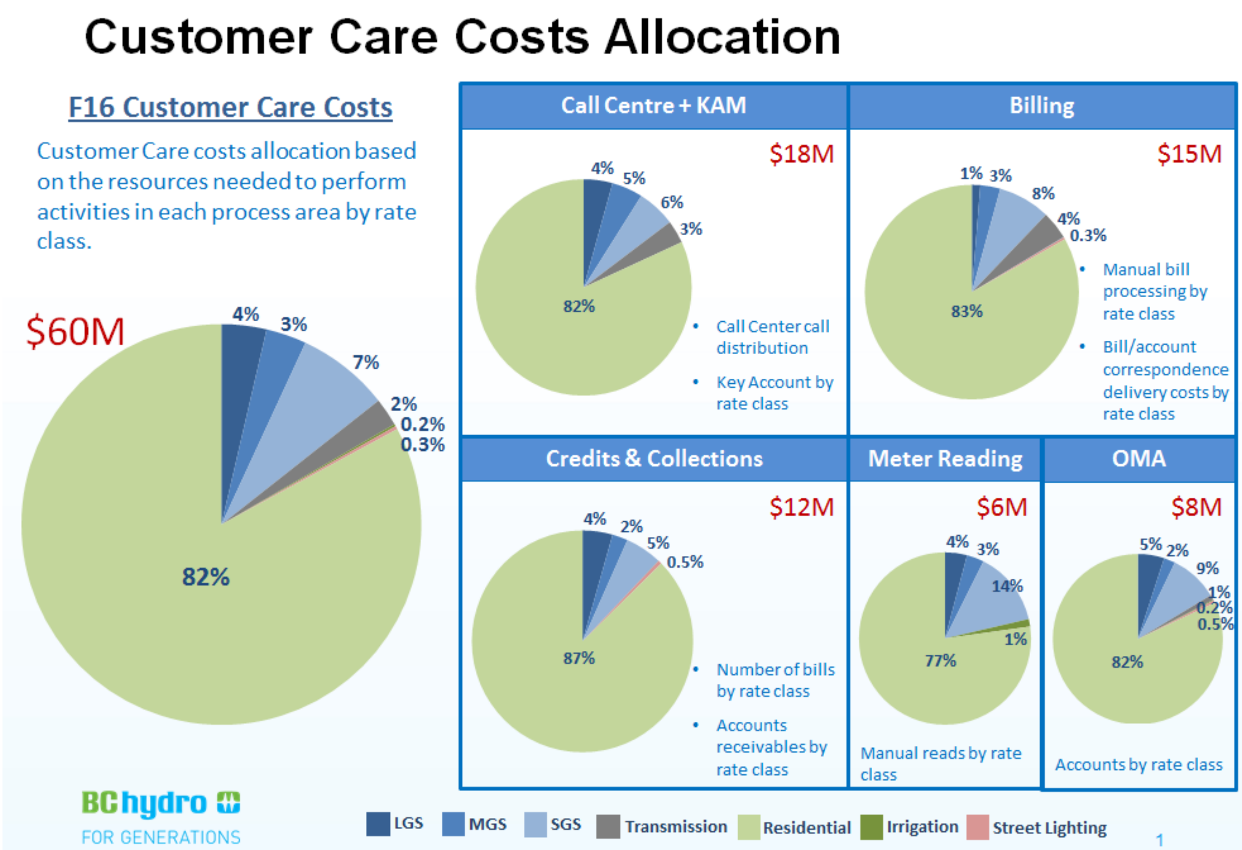

Table 8 compares the weighted allocator used in the F2013 COS study with the more detailed “bottom up” analysis and demonstrates that the 90% number of bills/10% revenue weighting factor approach used in the 2007 RDA remains appropriate.

Table 8 Customer Care Weighted Allocator Comparison

Rate Class	F2013 COS Weighted Customer Care Allocator (90%/10%) (%)	Bottom up analysis by customer care category (%)
Residential	82.86	82.91
GS Under 35 kW	9.24	7.48
MGS < 150 kW	1.42	3.28
LGS > 150 kW	3.55	3.63
Irrigation	0.06	0.19
Street Lights	1.02	0.26
Transmission	1.85	2.26
Total	100.00	100.00

Table 9 compares BC Hydro's preferred option using a 90% number of bills/10% revenue weighting factor against the "bottom up" option.

Table 9 Customer Care Weighted Allocator R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio 65% demand/ 35% customer classification (%)	Preferred Option Using 90%/10% Weighted Allocator 100% customer classification (%)	Alternative Option Using Bottom Up analysis 100% customer classification (%)
Residential	89.82	88.6	88.6
SGS Under 35 kW	126.71	127.1	128.0
MGS	120.79	124.1	122.8
LGS	102.12	104.8	104.8
Irrigation	86.62	92.0	89.1
Street Lighting	115.66	114.6	118.7
Transmission	104.36	104.1	104.0

10 Preferred Alternatives R/C ratio analysis

Table 10 shows the R/C ratio impact on the F2013 COS study if all of BC Hydro's preferred alternatives are selected.

Table 10 Preferred Alternatives R/C Ratio Analysis

Customer Class	Base F2013 R/C Ratio (%)	Preferred Option (%)
Residential	89.8	91.0
SGS Under 35 kW	126.7	123.8
MGS	120.8	116.4
LGS	102.1	101.9
Irrigation	86.6	83.5
Street Lighting	115.7	116.5
Transmission	104.4	103.6