2015 Rate Design Application

October 7, 2014 Workshop No. 4

Cost of Service (COS) Methodology

BC Hydro Summary and Consideration of Participant Feedback

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This memo documents customer stakeholder feedback concerning BC Hydro's October 7, 2014 Workshop No. 4 (the second COS methodology workshop) and BC Hydro's consideration of this input. Workshop No. 4 was held in Vancouver, B.C. with customers also being provided an opportunity to listen into the discussions remotely through a webinar. A Copy of the Workshop No. 4 presentation slides can be found on the BC Hydro regulatory website at http://www.bchydro.com/about/planning_regulatory/2015-rate-design.html. Customer input was received during the workshop as well as through feedback forms and written comments submitted during a subsequent 30-day comment period, which began with the posting of draft Workshop No. 4 notes on October 17, 2014.

The memo is structured as follows:

The main body, consisting of:

- Part 1, which summarizes those COS methodology items which BC Hydro believes are the subject of a fair degree of consensus
- Part 2, which addresses the five COS methodology items on which BC Hydro believes the parties have not reached a fair degree of consensus: Heritage hydro classification; Heritage thermal classification; Smart Meter Infrastructure (**SMI**) regulatory account cost classification and allocation; aspects of Distribution classification and allocation; and Customer Care cost allocation. Part 2 provides a summary of comments, grouped with respect to these five items, along with BC Hydro's consideration of input.

Attachment 1 includes the Workshop No. 4 notes which provide a more detailed description of issues (including questions and answers).

Attachment 2 contains the feedback forms received during the written comment period.

Attachment 3 presents an Independent Power Producer (**IPP**) cost of energy functionalization issue that has arisen as a result of BC Hydro responding to a comment raised by British Columbia Utilities Commission (**Commission, BCUC**) staff concerning the treatment of IPP costs deemed to be capital related under International Financial Reporting Standards (**IFRS**). For F2016, these IPP-related amounts (amortization, tax and finance charges) have been functionalized as Generation. The F2016 impact of this adjustment on Revenue to Cost ratios (**R/C**) ratios compared to perpetuating the prior treatment is detailed in Attachment 3.

Attachment 4 provides BC Hydro's response to marginal COS issues raised by Canadian Office and Professional Employees Union Local 378 (**COPE 378**) in its written comments provided on November 11, 2014.

1 COS Methodology Items With Fair Degree of Consensus

Based on input concerning the two COS methodology workshops (Workshop No. 2 and Workshop No. 4), BC Hydro believes that there is a fair degree of consensus on the following COS methodology items:

COS Methodology Item	BC Hydro Observation
Embedded COS Approach	With the exception of COPE 378, all stakeholders commenting on COS issues supported BC Hydro continuing with the embedded COS approach. COPE 378 advocates for a marginal COS approach. BC Hydro rejects a marginal COS approach for the reasons set out in Part 1 of BC Hydro's consideration memo concerning Workshop No. 2 (**Workshop 2 Consideration Memo**) and in Attachment 4 to this consideration memo.

COS Methodology Item	BC Hydro Observation
Demand Side Management (**DSM**) Functionalization	With the exception of British Columbia Old Age Pensioners Organization (**BCOAPO**), stakeholders providing Workshop No. 4-related written comments agreed with BC Hydro's proposal to modify Commission 2007 Rate Design Application (**RDA**) Direction 6 from functionalizing DSM-related costs as 90 per cent Generation and 10 per cent Transmission to functionalizing DSM-related costs as 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution. While BCOAPO agreed that functionalizing DSM costs between Generation, Transmission and Distribution using benefits accruing makes sense, it asked for more explanation regarding BC Hydro's proposed functionalization. BC Hydro provides this in section 1.1.
IPP Contracts Classification	Most stakeholders providing Workshop No. 4-related written comments agreed with BC Hydro's preferred Option 2 (value of capacity) to classify IPP costs. It is not clear to BC Hydro whether Commercial Energy Consumers Association of British Columbia (**CEC**) opposes Option 2, and if so, what CEC is proposing as an alternative. CEC states that it expects that the Alcan, Island Generation and biomass IPP contracts, which in contrast to most IPP contracts are not for intermittent resources and provide dependable capacity, "may be treated differently". As described in section 5.3 and Attachment 4 of the Workshop No. 2 Consideration Memo, BC Hydro took into account the nature of the Alcan, Island Generation and biomass contracts in arriving at its preference for Option 2. BC Hydro rejected Option 3 (contract structure) as an IPP classification method because it does not yield reasonable results. CEC also states that it expects "to link the IPP issue to BC Hydro capacity at its Mica and Revelstoke plants for a balance of equitable treatment". BC Hydro does not understand this comment. BC Hydro remains of the view that IPPs should be classified separately from BC Hydro Heritage hydroelectric assets such as Mica and Revelstoke Generating Stations because most IPP contracts provide a different product as they are for intermittent resources. This is the

COS Methodology Item	BC Hydro Observation
	reason BC Hydro rejected Option 5 (applying the load factor approach to IPPs). BCOAPO notes that Option 2 mixes marginal and embedded costs. BCOAPO observes that while the choice of using embedded or marginal values for IPP classification purposes does not materially impact the energy/demand split, BCOAPO is concerned that this could change if substantially more IPPs are added to the system. BC Hydro addresses this concern in section 1.2 of this memo.
Transmission Classification	With the exception of COPE 378, all stakeholders providing Workshop No. 2 and/or Workshop No. 4-related written comments on this topic thought reasonable BC Hydro's proposal to continue with the 2007 RDA decision approach that Transmission should be classified as 100 per cent demand-related because serving peak loads remains the primary planning consideration for capital expenditures on the transmission system. With the exception of CEC, those stakeholders that provided Workshop No. 4-related written comments agreed that radial lines should be treated the same as the overall transmission system. CEC maintains that radial lines that bring generation to loads may be candidates for different treatment. In response to CEC's comment, BC Hydro notes that the Revenue Requirement Application (**RRA**) includes an adjustment that functionalizes Generation Related Transmission Assets (**GRTA**) from Transmission into Generation. With the exception of GRTA functionalized to Generation in the RRA, BC Hydro agrees with the reasoning of BCOAPO (treat radial lines similar to overall Transmission given their small value).

COS Methodology Item	BC Hydro Observation
Customer Care Classification	With the exception of COPE 378, all stakeholders providing Workshop No. 2 and/or Workshop No. 4-related written comments on this topic agreed with BC Hydro's proposal to classify Customer Care costs 100 per cent as customer-related rather than the current 65 per cent demand/35 per cent customer classification mandated by Commission 2007 RDA Direction 4. Customer Care costs do not vary with demand, and a 100 per cent customer classification is consistent with how other utilities treat Customer Care costs.
Allocation of BC Hydro Generation and IPP Demand-related Costs and Transmission Costs	Parties providing Workshop No. 4-related written comments on this topic agreed with BC Hydro's proposal to continue with 2007 RDA Direction 3, which mandates a 4 Coincident Peak (**CP**) allocation of Generation demand-related and Transmission costs on the basis that winter peak occurred in each of the months from November through January in recent years and that the February peak is often close to the annual peak. While BC Hydro provided sensitivities at Workshop No. 4 (3CP, variations on 4CP), the results indicate little change from the current 4CP approach. BC Hydro agrees with BC Sustainable Energy Association and Sierra Club British Columbia's (**BCSEA**) point that simplicity favours the status quo.

1.1 BCOAPO Request Regarding Further Proposed DSM Functionalization Explanation

BC Hydro's rationale for its proposal starts with 2007 RDA Direction 6 functionalizing DSM-related costs as 90 per cent Generation and 10 per cent Transmission. The Commission in the 2007 RDA decision cited the BC Hydro, BCOAPO, CEC and Association of Major Power Consumers of British Columbia (then called Joint Industry Electricity Steering Committee) final arguments which agreed that DSM costs should be functionalized 90 per cent Generation and 10 per cent

Transmission, and found that DSM-capital related and operating costs are incurred to serve load and that these savings occur primarily in Generation.[1]

BC Hydro sees no compelling reason to propose discontinuance of that part of 2007 RDA Direction 6 functionalizing DSM-related costs as 90 per cent Generation. BC Hydro DSM initiatives are primarily energy-focused and are primarily undertaken to defer Generation resources. The DSM target, set in the 2013 Integrated Resource Plan (**IRP**), anticipates 7,800 gigawatt hours per year (**GWh/year**) of energy savings and 1,400 megawatts (**MW**) of associated capacity savings. These targeted energy and capacity savings are included in BC Hydro's load-resource balances with the result that BC Hydro avoids entering into new or renewing existing contracts for energy resources, and undertaking capacity-based Resource Smart additions to existing BC Hydro generating stations and/or entering into new contracts for capacity generation resources. In the 2013 IRP, BC Hydro states that prior to pursuing the DSM target it would require energy and capacity generation resources in F2016; after implementation of the DSM target BC Hydro anticipates requiring energy generation resources in F2022 and capacity generation resources in F2018.[2] BC Hydro also notes that most surveyed jurisdictions functionalize DSM as primarily Generation (including functionalizing DSM as 100 per cent Generation).

BC Hydro is of the view that DSM initiatives have some Transmission and Distribution deferral benefits and observes the following:

1. Generation, Transmission, and Distribution deferral benefits are included in DSM cost-effectiveness tests such as the Total Resource Cost test.

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[1] *In the Matter of British Columbia Hydro and Power Authority: 2007 Rate Design Application, Phase-1*, Decision, October 26, 2007 (**2007 RDA Decision**), page 93. BCOAPO noted in its 2007 RDA final argument that BC Hydro had, in its 1998 COS study, functionalized DSM as 90 per cent generation; refer to page 11 of BCOAPO's August 17, 2007 final argument.

[2] This is based on the no liquefied natural gas (**LNG**) scenario. Refer to Appendix 9A, Tables 1 and 2 of the 2013 IRP; copy available at https://www.bchydro.com/energy-in-bc/meeting_demand_growth/irp/document_centre/reports/november-2013-irp.html.

2. Several years ago, BC Hydro undertook preliminary high-level analysis on Transmission and Distribution DSM benefits and concluded the benefits are primarily found at a regional transmission and substation level (around $10 per kilowatt year (**/kW-year**)). These benefits are described in the DSM Expenditure Plan, which was filed as Appendix II[3] in BC Hydro's F2012 to F2014 Revenue Requirements Application (**F12-F14 RRA**). Qualitatively, BC Hydro believes there are some Transmission and Distribution benefits from DSM but acknowledges that it has more confidence in Generation capacity deferral benefits (around $55/kW-year based on Revelstoke Unit 6).

3. Updating the previous assessment of Transmission and Distribution benefits would be laborious and likely have no accuracy gain because of the number of assumptions required (i.e., savings from DSM initiatives would need to be disaggregated to individual substations or lines and an assessment of deferral potential would need to be made for each asset). Since there are more than 100 regional transmission lines, 200 distribution substations and 1500 distribution feeders this would be a significant undertaking yielding uncertain benefits.

Given the above observations, BC Hydro continues to believe a portion of DSM should be functionalized as Transmission- and Distribution- related but notes that allocation of the final 10 per cent wholly to Generation, wholly to Transmission, or as between Transmission and Distribution, will not materially impact the allocation of cost to rate classes; refer to section 2 of the Workshop No. 4 Discussion Guide.

[3] Refer to Attachment 6, Page 1 at: http://www.bcuc.com/Documents/Proceedings/2012/DOC_29900_B-1-3B_BCH-APPX-II.pdf.

1.2 BCOAPO and IPP Classification Option 2

BCOAPO is correct that BC Hydro's preferred Option 2 for classifying IPP costs is based on the 2013 IRP's Long-Run Marginal Cost (**LRMC**) for energy (upper end of $100 per megawatt hour (**/MWh**)) and for Generation-related capacity ($55/kW-year) in $2013. BC Hydro considered using embedded costs for valuing IPP energy and capacity contributions, but determined it is not possible to estimate the embedded cost of IPP capacity as both capacity and energy are combined within a single IPP price. As set out in BC Hydro's response to COS consultants' recommendation #4 in the Workshop No. 1 Discussion Guide, BC Hydro considered an additional sensitivity that was based on the 2009/2010 Clean Power Call (**CPC**) - $34/kW-year (based on Mica Unit 5) and $124/MWh ($2009) for capacity and energy respectively.

BCOAPO notes that the choice of using the 2013 IRP values or the CPC/Mica Unit 5 based values does not materially impact the energy/demand split. However, BCOAPO is concerned that this could change if substantially more IPPs are added to the system. BC Hydro does not foresee adding substantially more green-field IPPs to the system over the next ten years. The 2013 IRP recommends reliance on the DSM target, renewal of existing IPP contracts and external markets as a capacity-based bridging mechanism to meet the forecasted need for energy and capacity until Site C's earliest in-service date in F2024.[4] DSM and renewals of existing IPP contracts have unit energy costs significantly below green-field IPPs,[5] and result in the energy LRMC range for the next ten years of between $85/MWh to $100/MWh set out in the 2013 IRP.

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4 *Supra*, note 2, Chapter 9, Recommended Actions Nos 1, 4 and 7.

5 For example, BC Hydro's first IPP contract renewal after approval of the 2013 IRP was for $43.89/MWh ($2013) on a levelized basis for 166 GWh/year of firm energy for a term of just over 11 years; refer to Commission Order No. E-19-14, Appendix A, page 8 of 18 concerning Covanta Burnaby Renewable Energy, ULC's SEEGEN municipal solid waste incineration plant.

2 Five COS Methodology Items Which Do Not Have a Fair Degree of Consensus

2.1 BC Hydro Hydroelectric Generation Classification

2.1.1 Participant Comments

Stakeholders had different views on Heritage hydroelectric generation classification:

- Progress Energy Canada Ltd. (**PECL**) and Canadian Association of Petroleum Producers (**CAPP**) supported a capacity factor based approach weighted by book value (Option 3). PECL suggested that a load factor approach (Option 1) would disincent customers from maintaining a high load factor while CAPP stated the method would disincent participation in Time of Use (**ToU**) rates. Both PECL and CAPP suggested that a load factor method would inappropriately classify too much of the cost from new capacity units (i.e., Mica Units 5 and 6, and Revelstoke Unit 5) as energy rather than demand-related.
- BCSEA supported the load factor based approach proposed by BC Hydro (Option 1B). BCOAPO stated that a load factor approach makes sense, but raised concern with Option 1B to the extent there is a mismatch between customer load and IPP generation that may include reserves.
- CEC appears to favour a capacity factor approach, although it states that a load factor approach will continue to be of interest along with different capacity factor approaches that either include or exclude plant book values.

2.1.2 BC Hydro Consideration

The classification of BC Hydro's Heritage hydroelectric facilities is an important methodology within the COS study as the associated costs (capital costs and share of operation and maintenance (**O&M**), and taxes) exceed $1 billion or 25 per cent of BC Hydro's F2016 revenue requirement.

While BC Hydro continues to believe that Option 1B remains the best choice for reasons discussed in the Workshop No. 4 Discussion Guide, BC Hydro also believes that both the load factor and capacity factor approach have merit. For example, CAPP and PECL are correct in noting that Mica Units 5 and 6, Resource Smart upgrades to BC Hydro's Mica Generating Station with F2016-related costs, result in significant dependable capacity additions to BC Hydro's system (approximately 500 MW each) with virtually no energy gains. BC Hydro's next two largest Resource Smart upgrade opportunities – Revelstoke Unit 6 and G.M. Shrum Units 1 to 5 Capacity Increase - would also result in significant dependable capacity additions to BC Hydro's system (488 MW and 220 MW, respectively) with virtually no energy gains.[6] In addition, a capacity factor approach is used in other jurisdictions, although these jurisdictions are thermal as opposed to hydroelectric based.

As a result, BC Hydro will:

- Use Option 1B (55 per cent energy/45 per cent demand) in its F2016 COS study; but
- Will bring forward two sensitivities: Option 3 (45 per cent energy/55 per cent demand); and a 50 per cent energy/50 per cent demand split based on BC Hydro's historic classification of Heritage hydroelectric facilities. A 50 per cent energy/50 per cent demand split is a compromise approach that recognizes the limitations of both the load factor and capacity factor approaches and roughly represents an average of the Option 1B and Option 3 results.

In its 2015 RDA, BC Hydro will state that it does not oppose adoption of any of the Option 1B, Option 3 and 50 per cent energy/50 per cent demand approaches.

In response to PECL, BC Hydro believes that a load factor approach is a reasonable classification method because the existing Heritage hydroelectric system primarily

[6] Refer to section 3.4.2.3 of the 2013 IRP, *supra*, note 2.

serves system load. Although Option 1B increases the proportion of cost classified as energy relative to 2007 RDA Direction 5 (45 per cent energy/55 per cent demand), BC Hydro disagrees that this would provide a significant disincentive for high load factor customers to maintain their high load factors. Customer usage decisions are largely based on non COS factors such as rate design and overall energy costs relative to alternatives available.

CAPP indicated there may be conflicts between the system load factor approach and ToU rates. BC Hydro does not believe there is a conflict because: 1) no industrial customers have chosen BC Hydro's existing voluntary industrial ToU rate (Rate Schedule (**RS**) 1825), and to date industrial customer feedback has been that BC Hydro should pursue a load curtailment program as opposed to a revamped RS 1825; 2) industrial customers already have a relatively flat load profile so any savings associated with a reduction in industrial 4CP demand from a ToU rate is likely to be marginal relative to potential savings from other customer classes with lower load factors; and 3) B.C. Government policy prohibits BC Hydro from pursuing mandatory ToU rates for its residential and commercial customers. The impact of voluntary ToU rates for residential and commercial customers on the system load factor is highly questionable. Stakeholders agreed with BC Hydro that a voluntary ToU rate for residential customers should not be pursued (refer to BC Hydro's consideration memo concerning Workshop No. 3 and the reasons BC Hydro provides for not pursuing a voluntary ToU rate for its residential customers). BC Hydro does not favour adopting a voluntary ToU rate for commercial customers for similar reasons but will explore this option at its upcoming Large General Service (**LGS**)/Medium General Service (**MGS**)/Small General Service (**SGS**) workshop on January 21, 2015.

BC Hydro acknowledges CAPP's concern with respect to potential LNG plants influencing the system load factor but notes that no LNG loads are included in the F2016 load forecast used to develop the COS study. According to the 2013 IRP, LNG load is not expected before F2020. In BC Hydro's view the impact of LNG is an issue that should be considered in future COS work.

With respect to BCOAPO's comments regarding Option 1B, BC Hydro notes that IPP supply is almost entirely used to meet domestic "customer load". During operations, BC Hydro relies upon Heritage resources to provide operating reserves because IPP supply is mostly intermittent with availability determined by environmental conditions such as river flow and wind speeds. A few IPP projects such as Island Generation are dispatchable but they are not set up for sufficiently fast acting dispatch that meets operating reserve requirements.

It is not clear what additional information CEC requires to form an opinion of the various options and methodologies suggested by BC Hydro. CEC appears not to favour the load factor approach; instead some form of capacity factor approach appears to be supported. CEC states that it "will look for capacity factor approaches which are not based on plant book values". In Workshop No. 2, BC Hydro explored a capacity factor approach which is not weighted by book value and uses an average capacity factor for the entire Heritage hydroelectric system (Option 2) in addition to a capacity factor approach that is weighted by book value (Option 3); refer to section 4 of the Workshop No. 2 Discussion Guide. As stated in the Workshop No. 2 Consideration Memo, BC Hydro is of the view that Option 3 is preferable to Option 2 because the value of each generating facility is an important driver of cost as facilities with higher book values will incur higher capital-related costs such as financing charges, depreciation and return on equity relative to facilities with lower book value. In any event, BC Hydro is of the view that the two COS study Heritage hydroelectric generation classification sensitivities (Option 3 and a 50 per cent energy/50 per cent demand split) provide a reasonable range in relation to BC Hydro's preferred Option 1B.

2.2 BC Hydro Thermal Generation Classification

2.2.1 Participant Comments

PECL stated there should be consistency between hydroelectric and thermal classification methods. CAPP suggested a capacity factor approach and noted this is consistent with its views on Heritage hydroelectric classification. BCOAPO and BCSEA supported BC Hydro's proposed treatment for the three Heritage thermal facilities, while CEC did not take a position and expressed interest in exploring how trade considerations may impact the choice of a classification method.

2.2.2 BC Hydro Consideration

BC Hydro agrees that consistency between Heritage hydroelectric and thermal classification methods is desirable where possible. However, BC Hydro has concerns with applying capacity factor approaches to the three Heritage thermal plants and these are discussed between pages 8 and 10 of the Workshop No. 4 Discussion Guide. In the case of Fort Nelson Generating Station (**FNG**), these concerns include the fact that there is a relationship between trade and the capacity factor calculation, which addresses CEC's comment. Using a capacity factor approach, surplus FNG generating capacity would effectively be classified as 100 per cent demand even though it may be used for trade purposes throughout the year. There will be no relationship between Burrard Thermal Generating Station (**Burrard**) and trade given that Burrard's generating capability will be retired.

In any event, BC Hydro notes that the classification method selected for three Heritage thermal plants does not change COS R/C ratios when reported to one decimal place.

2.3 SMI Classification and Allocation

2.3.1 Participant Comments

Stakeholders continue to have diverse opinions on the treatment of SMI-related regulatory account costs. PECL and CEC agreed with BC Hydro's proposed classification of SMI-related costs as 100 per cent customer. COPE 378 advanced that SMI was justified by system benefits such as outage detection and theft reduction rather than improvements or savings in metering or customers' consumption. BCOAPO noted that a 100 per cent customer classification (Option 1) is consistent with industry practice but felt that a 70 per cent customer/30 per cent energy classification (Option 3) reflects the rationale for implementing SMI and cost causality. BCOAPO also suggested a weighted metering allocator be used given that the difference in costs between the legacy meters is not likely the same as the difference in costs for the smart meters. BCSEA requested clarification on the distinction between SMI-related costs, SMI regulatory account amortization and SMI capital costs.

2.3.2 BC Hydro Consideration

Clarification of terminology

In response to BCSEA's request for clarification of SMI-related cost terminology, BC Hydro provides the following.

"SMI-related costs" include both:

- The operating costs deferred to the SMI regulatory account (as established in Commission Order No. G-64-09 and continued by Order Nos. G-115-11, G-77-12A, and G-166-13)
- "SMI capital costs", which are the non-deferred costs associated with financing, depreciation and return on equity charges for SMI capitalized assets (i.e.,

meters, communication equipment and associated software) that are included in BC Hydro's rate base.

"SMI regulatory account amortization" refers to the portion of the SMI regulatory account balance that is included in the current revenue requirement. The portion of costs related to SMI-related regulatory account recoveries is $31.3 million in F2016. This amount is the subject of the classification discussion that follows.

Classification: Preferred Option and COS Study Sensitivity

BC Hydro continues to believe that a 100 per cent customer classification is appropriate for SMI-related regulatory account costs for the reasons set out in the Workshop No. 4 Discussion Guide.

BC Hydro undertook additional jurisdictional analysis as part of developing this consideration memo with respect to SMI classification and allocation. BC Hydro contacted Georgia Power Company to better understand its rationale for classifying SMI costs as 100 per cent customer. Georgia Power Company stated that it did so because SMI meters are like any meter in that costs do not vary based on kilowatt (**kW**) or kilowatt hour (**kWh**) usage of a customer; rather, it is driven by the fact that each customer requires a meter. BC Hydro finds this reasoning persuasive. Although BC Hydro expects there to be loss reduction-related energy savings from SMI in F2016, these savings are estimates at the present time (line losses cannot be measured directly until BC Hydro has fully deployed system metering, anticipated to be December 2015). BC Hydro believes it would be prudent to wait three years before considering whether energy-related benefits from SMI should be incorporated in the COS classification methodology.

In response to BCOAPO and COPE 378's comments, BC Hydro provides the following options analysis:

- Under the **status quo**, the annual recovery of deferred SMI costs would be treated the same as any Distribution O&M cost. These costs would be classified as around 79 per cent demand-related and 21 per cent customer-related under the proposed COS methodology for classifying Distribution costs in F2016. BC Hydro does not believe it is reasonable to classify such a high portion of SMI costs as demand-related.
- **Option 1 (preferred):** The classification of meter-related costs as 100 per cent customer-related is simple and defendable from a historical cost allocation perspective, and has overwhelming jurisdictional support.
- **Option 2** was rejected by BC Hydro because 100 per cent classification to energy is unreasonable. This was discussed during Workshop No. 4.
- **Option 3 (Workshop No. 4):** The 70 per cent customer/30 per cent energy split previously proposed is based on F2016 data and so it would likely change considerably year over year. This method would assign an additional $2.5 million in costs to Transmission service customers, which in BC Hydro's view is not reasonable. However, given BCOAPO's and COPE 378's comments, BC Hydro developed two additional options (Options 4 and 5).
- **Option 4:** To account for the energy benefit associated with SMI, functionalize 5 per cent of the total cost as Generation, which is then classified as both energy and demand. This amount is notional but acknowledges that there is some amount of SMI cost that can be attributed to avoided Generation costs. While the impact is minimal, Option 4 takes a step towards addressing BCOAPO's and COPE 378's comments that the classification of SMI regulatory account costs should be aligned with what they characterized as the rationale for SMI.

- **Option 5:** Instead of functionalizing a portion as Generation, functionalize as 100 per cent Distribution and then classify as 95 per cent customer and 5 per cent energy. Although this ignores the minor capacity savings associated with the loss-reduction energy savings attributable to SMI, it is simpler than Option 4 calculation-wise and yields a similar allocation to rate classes.

BC Hydro will base its COS study on Option 1 while bringing forward Option 5 as a sensitivity. Table 1 demonstrates that SMI does not have a significant impact on COS results as Options 1, 3, 4, and 5 all lead to similar R/C ratios.

Table 1 SMI Classification Sensitivities – R/C Ratio Change from Status Quo

Rate Class	Status Quo (%)	Option 1 (%)	Option 3 (%)	Option 4 (%)	Option 5 (%)
Residential	91.8	91.5	91.7	91.5	91.5
SGS < 35 kW	118.5	118.6	118.6	118.6	118.6
MGS < 150 kW	124.3	125.0	124.7	124.9	124.9
LGS > 150 kW	98.1	98.7	98.5	98.7	98.7
Irrigation	93.0	93.8	93.8	93.8	93.8
Street Lighting	124.6	124.8	124.8	124.8	124.8
Transmission	105.4	105.4	105.1	105.4	105.4

Allocation

BC Hydro agrees with BCOAPO that customer related SMI costs should be allocated using a weighted customer allocation factor and proposes to use the weighted metering costs discussed in section 2.4.2 of this consideration memo. BC Hydro's jurisdictional review of Georgia Power Company and Florida Power & Light Company's SMI COS approach shows: (1) Georgia Power Company allocates SMI costs by the number of customers in the relevant rate classes;[7] and (2) Florida

[7] Georgia Power Service Commission Docket 36989: Georgia Power Company's 2013 rate case (http://www.psc.state.ga.us/factsv2/Docket.aspx?docketNumber=36989), direct testimony of Mr. Michael T. O'Sheasy, page 11 of 22 on COS allocators.

Light & Power Company allocates SMI costs to rate classes based on the fully loaded costs of the meters in service for each rate class.[8]

2.4 Distribution Classification and Allocation

2.4.1 Participant Comments

Generally, BCSEA expressed support for BC Hydro's proposed classification and allocation methods for the Distribution system. BCSEA indicated it was unclear on the merits of using customer weights to allocate service and meter related costs. CEC expressed interest in understanding BC Hydro's proposals in more detail, but made no specific requests for further information and did not suggest any alternative approaches. BCOAPO agreed with BC Hydro's proposal to classify substations as 100 per cent demand and meters as 100 per cent customer, but requested further clarification on the other classification and allocation proposals. BCOAPO's specific questions and BC Hydro's responses are shown in section 2.4.2.

2.4.2 BC Hydro Consideration

In response to CEC, BC Hydro notes that its proposal to sub-functionalize the Distribution system into: substations; primary system; transformers; secondary/services; and meters is 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.[9] The COS consultants suggested that as an alternative to the flawed minimum system and zero intercept classification methods, BC Hydro should consider sub-functionalizing its Distribution system costs and then use professional judgment to separate demand-related and customer-related Distribution costs. This type of methodology is widespread among U.S. electric utilities and distinguishes between plant in service that (1) provides service only to individual customers or customer-related plant in-service from (2)

[8] Florida Public Service Commission Docket 12005-EI: Florida Light & Power Company's 2012 application to increase rates (http://www.psc.state.fl.us/dockets/cms/docketdetails2.aspx?docket=120015), direct testimony of Mr. Joseph Ender, page 23 on COS methodology for distribution plant.

[9] 2007 RDA Decision, *supra* note 1, page 88.

plant in-service that is part of the interconnected distribution network or demand-related plant in-service. (Refer to section 8 of the Workshop No. 4 Discussion Guide for more discussion of this methodology). BC Hydro agrees with the COS consultants recommendation. The result is the Distribution classification and allocation summary found at slide 54 of the Workshop No. 4 presentation slide deck. BC Hydro is open to meeting with CEC so that CEC can elaborate on what further details it is looking for.

In response to BCSEA, since the October 7, 2014 COS workshop BC Hydro has explored using weighted customer allocators for both services and meters as follows.

Services – BC Hydro believes that it will be difficult to develop a weighted allocator with any precision because BC Hydro records the combined asset value of secondary and services in the same asset category and there is risk that the services portion will be over or understated. Refer to BC Hydro' response to BCOAPO's comments (sub bullet (d) below). BC Hydro questions the appropriateness of a weighted allocator for service connections as it would skew COS results if the relative costs between different types/sizes of service connections have changed over time.

BC Hydro considered whether service related costs should be allocated among all distribution customers or only customers whose service connections have been fully or partially paid for by BC Hydro. BC Hydro reviewed its past practices and determined that:

- three-phase customers have typically paid for their service connections
- prior to the late 1990s, most single phase customers were charged a flat $10 connection fee while BC Hydro paid the balance of service connection costs

- since the late 1990s, single phase customers have paid standard charges related to their service connections.

These observations suggest that BC Hydro's service related rate base is primarily made up of single phase service connection costs. However, BC Hydro is responsible for maintaining and replacing three phase service connections and these costs are often capitalized and included in rate base. As a result, the service-related rate base likely includes a mixture of single phase and three phase related costs and BC Hydro does not have the data to accurately determine the relative proportion of each.

Based on these facts, BC Hydro proposes to allocate service related costs to all distribution customers regardless of the phase level of their service connections. At this time, BC Hydro believes that allocation based on the number of service connections, by rate class and un-weighted by costs, is most appropriate.

Meters - Since Workshop No. 4, BC Hydro developed a weighted metering allocator by mapping rate classes to different types of metering and estimating the total installation cost (material, labor, vehicle, testing time). In the case of metering, the use of replacement costs to develop weighting factors is not a significant issue because smart meters were recently installed and the replacement costs will be close to the embedded, book value costs. BC Hydro will continue refining this analysis but currently estimates the following weighting factors by rate class:

Rate class	Residential	SGS	MGS	LGS	Irrigation
Weighting factor	1	2	6	6	2

BC Hydro's responses to specific questions posed by BCOAPO follow below.

(a) Can BC Hydro provide additional rationale for proposed 100 per cent demand for primary system and 50 per cent/50 per cent classification of transformers?

Of the three major functional areas within the COS (Generation, Transmission and Distribution), the distribution system is the most complex. There are many different types of assets on the distribution system that serve different purposes and have different cost drivers. Other than minimum system/zero intercept methods, which BC Hydro does not favour because they are labour intensive, and are deemed by the COS consultants to be difficult to complete because of issues in collecting the data necessary and the complexity of the studies themselves, BC Hydro is unaware of any technical, quantitative methods to classify Distribution costs. As described above in response to CEC, the COS consultants report that more U.S. electric utilities use professional judgment and are moving towards classifying distribution cost categories as either entirely demand-related or entirely customer-related rather than 'guessing' at appropriate splits between the demand and customer classification.

BCOAPO is correct that in contrast to substations where the overwhelming jurisdictional approach is to classify 100 per cent demand, utilities classify their distribution primary systems using different mixes of demand- and customer-related costs. BC Hydro's review of SaskPower's consultant Elenchus' 2013 survey of COS approaches suggests a significant presence of demand-related costs which exceeds in value any customer-related investment in primary systems. While the Elenchus survey notes that jurisdictions range from 45 per cent to 100 per cent in classification of primary lines as demand-related, the largest number of responding utilities classify primary lines as 90-100 per cent demand-related.[10] In any event, BC Hydro

[10] Elenchus survey conducted on behalf of SaskPower in January 2013 entitled "Review of Cost Allocation and Rate Design Methodologies: A Report Prepared by Elenchus Research Associated Inc.", page 22. Refer to Nova Scotia Power Inc.'s 2013 Cost of Service Study - Application (Exhibit N-1, Appendix 13.4 (http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_13_4.pdf) for the reference.

agrees with its COS consultants that the U.S. electric utility approach is the best way to inform professional judgment. Adoption of this approach results in classifying the primary system as 100 per cent demand because BC Hydro plans the primary system to meet expected peak demand.

BC Hydro proposes to directly assign transformer costs and confirms that it is adopting a 50 per cent demand/50 per cent customer classification solely for rate design purposes; to use BCOAPO's words, the 50 per cent demand/50 per cent customer classification should not impact the total costs allocated to each rate class because the direct assignment approach will be used for purposes of assigning costs among the rate classes. BC Hydro acknowledges that the classification is somewhat arbitrary but is within the range of classification splits adopted by surveyed electric utilities as reported in the Elenchus 2013 survey of COS approaches (with the largest number of responding utilities classify transformers as 90-100 per cent demand).

(b) How has BC Hydro dealt with unmetered loads or street lighting in its transformer analysis?

In the past BC Hydro examined the total load on a given transformer and determined that, on average, about 1 per cent of load could not be accounted for and was likely related to street lighting or other unmetered loads. Based on this, BC Hydro proposes to directly assign 1 per cent of transformer-related costs to street lighting while the other 99 per cent of cost will be directly assigned to the other distribution rate classes using BC Hydro's proposed Option 1.

(c) What are the cost differences between 1 and 3 phase transformers?

Since Workshop No. 4, BC Hydro examined this issue in more detail and determined that its draft transformer analysis is appropriate and that there is no need to specifically account for the number or cost of three phase transformers. For example, BC Hydro's analysis shows that the total cost of 50 kilovolt ampere (**kVA**) single phase overhead transformers is about $3,300 (materials + labor) while the cost of a 150 kVA three phase overhead transformer is about $9,400 (materials + labor). Since the cost per kVA of a three phase transformer is approximately the same as the cost per kVA of a single phase unit, BC Hydro believes there is no issue with continuing to assume single phase costs for transformers less than 100 kW in its direct assignment analysis.

Since Workshop No. 4, BC Hydro determined that its transformer Geographic Information System data is reasonably accurate and notes that the data is relied upon for important applications such as outage management.

*(d) Are the kilometers (**km**) of secondary/services roughly the same and could that inform the proposed split between these cost categories?*

Table 2 shows the km length of overhead and underground secondary and services.

Table 2 Overhead and Underground Secondary and Services

	Overhead (km)	Underground (km)
Secondary	15,087	3,680
Services	14,321	6,291

In preparation for Workshop No. 4, BC Hydro developed its 50 per cent secondary/50 per cent services sub-functionalization of this asset category based, in part, by the fact that km shown in Table 2 are roughly equal between secondary and services. Since most customers make Contribution in Aid of Construction-type payments for their service connections and $/km embedded costs for secondary costs are likely higher than services, the 50/50 split may understate the secondary component. However, this is offset by the fact that services are being added to the BC Hydro system at a faster rate than secondary. In recent years, for every km of secondary added approximately 1.8 to 2 km of services has been added. Unfortunately, unless BC Hydro used replacement costs on a $/km basis there is no quantitative method to split this asset category. BC Hydro and the COS consultants have concerns with using replacement costs in an embedded COS study. Given the above issues, BC Hydro continues to believe that a 50 per cent secondary/50 per cent services split remains the best option.

(e) What is included in Meters and, where is the cost of the communication infrastructure reflected?

In Question 7 of the Workshop No. 4 summary notes, found at Attachment 1 to this consideration memo, BC Hydro was asked to clarify the SMI meter-related costs, and in particular whether SMI-related telecommunication software is captured in meter costs or SMI regulatory costs. BC Hydro responded that these types of costs are capitalized as part of BC Hydro's rate base rather than deferred in the SMI regulatory account. BC Hydro confirms that communication infrastructure and the associated telecommunication software are not included in the SMI regulatory account and are instead capitalized as part of BC Hydro's rate base.

*(f) Has BC Hydro considered a modified Non Coincident Peak (**NCP**) allocator for demand-related distribution categories?*

The current methodology for assigning Distribution demand-related costs is based on rate class load profiles for a single year. Each rate class is assigned a 1NCP per centage allocator based on its annual peak load as a proportion of the sum of all the rate classes' annual peak load, which is in line with industry practice. Table 3 provides the 1NCP calculated allocators with the month the peak occurred for each rate class for the last five years.

Table 3 1NCP Calculated Allocators, F2010 to F2014

Annual Peak Load	F2010 (%)	F2011 (%)	F2012 (%)	F2013 (%)	F2014 (%)
Residential	57.58	55.78	57.70	54.50	57.20
Month of peak	December	November	January	January	December
SGS	10.45	11.17	10.92	10.37	10.15
Month of peak	December	January	January	January	February
MGS	7.98	8.62	9.02	9.13	8.04
Month of peak	December	February	January	January	February
LGS	22.82	23.31	21.35	24.84	23.37
Month of peak	July	January	January	August	December
Lighting	0.65	0.68	0.65	0.71	0.84
Month of peak	January	January	January	January	January
Irrigation	0.52	0.45	0.36	0.44	0.39
Month of peak	July	July	July	July	July

For F2016, BC Hydro proposes to create five-year averages for its load-profile based allocators which would smooth annual weather-related variances. Using the 1NCP method, the five-year average allocators are set out in Table 4.

Table 4 Five-Year Average 1NCP, F2010 to F2014

Five-Year Average 1NCP	F2010 to F2014 (%)
Residential	56.59
SGS	10.62
MGS	8.55
LGS	23.11
Lighting	0.71
Irrigation	0.43

In response to BCOAPO's inquiry regarding consideration of possible modifications of the NCP allocator, BC Hydro calculated a 3NCP allocator,[11] both annually and a five-year average, for the F2010-F2014 period as set out in Table 5.

[11] The 3NCP was calculated for each rate class by adding the three highest monthly peak demands and dividing by the sum of the three highest monthly peak demands across all rate classes.

BC Hydro prefers 3NCP over 4NCP because the Irrigation rate class season is typically three months.

Table 5 3NCP Calculated Allocators, F2010 to F2014

3NCP Load	F2010 (%)	F2011 (%)	F2012 (%)	F2013 (%)	F2014 (%)
Residential Months of peaks	54.40 December January November	54.80 November December January	55.51 January November December	53.52 January December November	55.90 December February November
SGS Months of peaks	11.02 December January April	11.44 January November February	11.34 January March February	10.69 January February December	10.28 February December November
MGS Months of peaks	8.46 December June July	8.84 February November July	9.20 January December September	9.24 January December November	8.21 February December January
LGS Months of peaks	24.83 July June December	23.75 January November February	22.86 January September December	25.35 August September December	24.35 December February September
Lighting Months of peaks	0.71 January December February	0.70 January December February	0.70 January December February	0.74 January December February	0.86 January December February
Irrigation Months of peaks	0.57 July June August	0.47 July June August	0.39 July June August	0.45 July June August	0.40 July June August

Using the 3NCP method, the five-year average allocators are set out in Table 6.

Table 6 Five-Year Average 3NCP, F2010 to F2014

Five-Year Average 3NCP	F2010 to F2014 (%)
Residential	54.85
SGS	10.96
MGS	8.79
LGS	24.21
Lighting	0.74
Irrigation	0.46

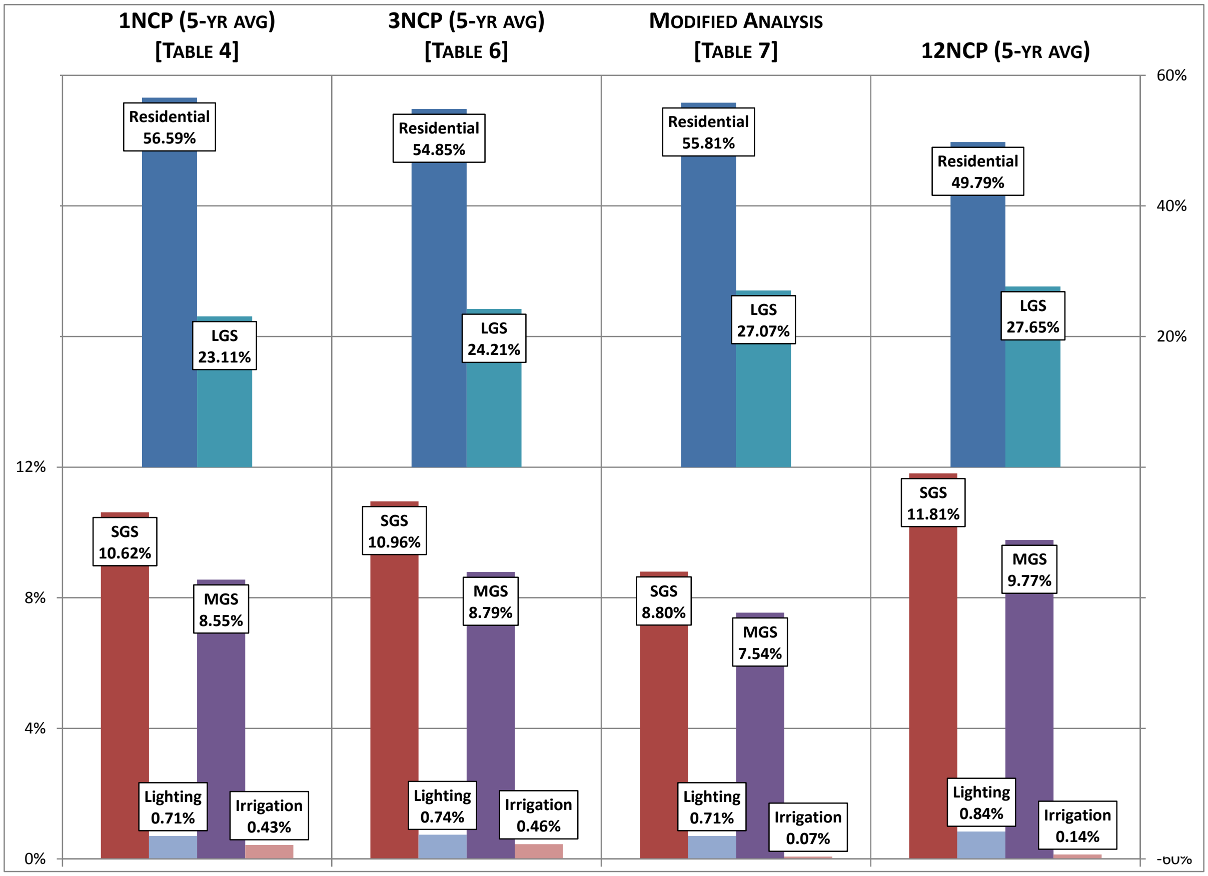
To evaluate different NCP approaches, BC Hydro used "bottom up" analysis, which was previously done as part of the Workshop No. 4 presentation (refer to slides 33 to 44) where BC Hydro explained why it was not feasible to directly allocate primary system costs to distribution rate classes. The bottom up analysis involves estimating a rate class's share of feeder peak load for each of the ~1500 distribution feeders. To date, this data does not include the Street Lighting rate class; however, it provides a view of NCP load, by rate class and by feeder, to compare to BC Hydro's proposed rate class allocator. A calculation is provided in Table 7 which adjusts for the Street Lighting rate class data, assuming a five-year 1NCP allocation for that rate class only.

Table 7 Share of Feeder Peak Loads Across the ~1500 Distribution Feeders, by Rate Class

Rate Class	Unadjusted Analysis (%)	Modified Analysis (%)
Residential	56.21	55.81
SGS	8.86	8.80
MGS	7.60	7.54
LGS	27.26	27.07
Street Lighting		0.71
Irrigation	0.08	0.07

The results are summarized in Figure 1. 12NCP has been included as a comparison to the load analysis results, which could be interpreted to suggest that a rate class with a flatter load profile (LGS) may be under-allocated costs using a 1NCP allocation.

Figure 1 1NCP, 3NCP and 12NCP Comparison



BC Hydro proposes to continue with a 1NCP allocator as this most closely approximates BC Hydro's planning criteria used for the design and construction of Distribution facilities. The 1NCP allocator provides the best representation of diversified class loads on the Distribution system. In BC Hydro's view use of a 3NCP (or a 12NCP) allocator results in averaging which is inconsistent with how BC Hydro plans its Distribution system and would dilute this estimate away from class peak demand levels. Furthermore, a 1 NCP approach produces results reasonably close to the bottom up analysis conducted across the ~1500 distribution feeders.

2.5 Customer Care Allocation

2.5.1 Participant Comments

BCOAPO asked BC Hydro to confirm whether the meter reading costs shown in Figure 1 of the Workshop No. 4 Discussion Guide were based on all meters or only those without a functioning smart meter. CAPP had reservations with BC Hydro's approach and argued that the 10 per cent weighting with a revenue allocator will over assign Customer Care costs to Transmission service customers. CEC stated that Customer Care costs should be split on the basis of different service provided to customers and suggested the 90 per cent/10 per cent weighting between number of customers and revenue should be refined if possible. BCSEA asked for clarification on why the 90 per cent/10 per cent weighting should be maintained.

2.5.2 BC Hydro Consideration

Concerning BCOAPO's question, the meter reading costs shown in Figure 1 of the Workshop No. 4 Discussion Guide are related to non-communicating meters that require manual meter reading. These do not include meter reading costs associated with the Meter Choices program as those costs (net of the meter reading revenues received from the Meter Choices program) are included in the SMI regulatory account.

BC Hydro provided a rationale for the 90 per cent/10 per cent allocator through the 'bottom up' analysis shown in Figure 1 of the Workshop No. 4 Discussion Guide. In response to CAPP, BC Hydro incurs costs specific to Transmission service customers for Key Account management, billing and management of hourly interval consumption data (Information Technology infrastructure, etc). The 10 per cent allocator assigns approximately $2 million Customer Care costs to Transmission service customers, which aligns with the bottom up analysis of Customer Care cost ($2.26 million) shown in Table 8 of the Workshop No. 4 Discussion Guide.

3 COS Methodology Conclusions

Based on adoption of recommendations from BC Hydro's COS consultants, Cuthbert Consulting, Inc. and NewGen Strategies and Solutions, LLC[12] contained in the 20 December 2013 *Final Report: Cost of Service Methodology Review* (a copy of which was circulated to Workshop No. 2 participants), BC Hydro's jurisdictional assessment and the 2015 RDA stakeholder engagement process, BC Hydro proposes methodology changes to certain directives from the 2007 RDA Decision relating to DSM functionalization, BC Hydro Heritage hydroelectric Generation classification, IPP contract classification, Distribution classification and allocation, and Customer Care classification. Refer to Table 8.

12 BC Hydro retained SAIC Energy, Environment & Infrastructure in October 2012 (**SAIC**); SAIC became Leidos Engineering in September 2013; and the two primary Leidos Engineering consultants became Cuthbert Consulting, Inc. and NewGen Strategies and Solutions, LLC after the COS Methodology Review was finalized in December 2013.

Table 8 Summary of COS Methodology Changes

2007 RDA Direction	Proposed COS Methodology Change
Direction 6 – Functionalize DSM 90% to Generation and 10% to Transmission	Functionalize DSM to 90% Generation, 5% Transmission and 5% Distribution on the basis that while DSM initiatives are primarily undertaken to defer Generation resources, they have some Transmission and Distribution deferral benefits
Direction 5 – Classify Heritage hydroelectric Generation 45% energy/55% demand on the basis that future Resource Smart additions at Revelstoke and Mica Generating Stations are predominantly capacity-related	Use BC Hydro's integrated system Load Factor calculation based on loads almost entirely served by Heritage hydroelectric supply (the impact of IPPs serving load is removed) resulting in a 55% energy/45% demand split
Direction 8 – Classify IPP purchases 100% energy. BC Hydro is directed to prepare a study for its next RDA that examines and quantifies the capacity benefits associated with IPP contracts	Use an approach where the relative portion of IPP costs allocated to demand is based on the relative portion of capacity benefits from the IPP contract portfolio over IPP costs, resulting in a 93% energy/7% demand split
Direction 4 – Classify Distribution costs 65% demand/35% customer. BC Hydro is directed to conduct a minimum system and zero intercept analysis for inclusion in its next RDA	Sub-functionalize the Distribution system: (1) classify substations and the primary system as 100% demand using NCP allocator; (2) direct assign transformers, with 50% demand/50% customer classification for rate design purposes; (3) classify the secondary system as 100% demand and services as 100% customer and use appropriate allocators; and (4) classify meters as 100% customer and allocate on a weighted customer basis. (The result is about 76% demand and 24% customer split). BC Hydro conducted a minimum study and zero intercept analysis, but has not used the results given the shortcomings outlined at Workshop No. 2 and Workshop No. 4
Direction 4 – Classify Customer Care costs 65% demand/35% customer	Classify Customer Care costs 100% customer as such costs do not vary with demand levels (or energy usage) but only in proportion to the number if customers on the BC Hydro system

There are also two main methodology changes that do not relate to the 2007 RDA COS-related directions referenced above:

- IPP capital leases - these costs are currently spread across multiple business groups. For COS purposes, they should be considered entirely Generation related. Refer to Attachment 3 to this memo.

- Information Technology (**IT**) cost functionalization - 100 per cent of IT costs were functionalized to Generation. These costs are now functionalized across all business groups.

At this time, the preferred COS methodology produces the following R/C ratios by rate class:

Table 9 R/C Ratio Comparison

	R/C Ratios		
	DRAFT F2016 COS Results (%)		F2013 COS (%)
Rate Class	**Using BC Hydro Proposed Methodology[13]**	**Using 2007 RDA Methodology[13]**	**Using the 2007 RDA Methodology; Filed on February 8, 2014 with the Commission**
Residential	93.2	91.8	89.8
SGS	113.3	118.5	126.7
MGS	123.0	124.3	120.8
LGS	100.4	98.1	102.1
Irrigation	90.2	93.0	86.6
Street Lighting	127.2	124.6	115.7
Transmission	101.6	105.4	104.4

BC Hydro anticipates posting the F2016 COS study model in the last week of January 2015 for comment.

[13] Using F2016 financial and load information consistent with the RRA Plan.

2015 Rate Design Application

October 7, 2014 Workshop No. 4
Cost of Service (COS) Methodology

BC Hydro Summary and Consideration of Participant Feedback

Attachment 1

Workshop No. 4 Notes

BC Hydro Rate Design Workshop

SUMMARY 7 OCTOBER 2014 9 AM TO 11:30 AM BC Utilities Commission 1125 Howe Street, Vancouver, 12th Floor

TYPE OF MEETING	2015 RDA Workshop No. 4, October 7, 2014
FACILITATOR	Anne Wilson, BC Hydro
PARTICIPANTS	ARC Resources Ltd., Association of Major Power Consumers of British Columbia (AMPC), B.C. Ministry of Energy and Mines, BC Sustainable Energy Association and Sierra Club of Canada BC Chapter (BCSEA), British Columbia Old Age Pensioners' Organization (BCOAPO), British Columbia Rapid Transit Company Ltd., British Columbia Utilities Commission (BCUC) staff, Canadian Association of Petroleum Producers (CAPP), Canadian Natural Resources Ltd., Canadian Office and Professional Employees Local Union 378 (COPE 378), City of Vancouver, Clean Energy Association of BC, CLEAResult Consulting, Consumers Association of British Columbia (CEC), Encana Corporation, FortisBC Inc., Linda Dong Associates, Manitoba Hydro, Midgard Consulting Inc., Teck Resources Limited, University of British Columbia, Valard, Weisberg Law Corporation, West Fraser Mills
BC HYDRO ATTENDEES	Gordon Doyle, Justin Miedema, Dani Ryan, Janet Fraser, Craig Godsoe, Bryan Hobkirk Richard Cuthbert of Cuthbert Consulting, Inc.
AGENDA	1. Introduction 2. Background 3. Issues Previously Canvassed at 19 June COS workshop – Functionalization 4. Issues Previously Canvassed at 19 June COS workshop – Classification 5. Issues Previously Canvassed at 19 June COS workshop – Allocation 6. Distribution Classification and Allocation 7. Closing comments (next steps) & workshop adjourned

MEETING MINUTES

ABBREVIATIONS

AMPC	Association of Major Power Consumers of BC
BCH	BC Hydro
BCOAPO	BC Old Age Pensioners Organization
BCSEA	BC Sustainable Energy Association and Sierra Club of Canada BC Chapter
BCUC	BC Utilities Commission
CAPP	Canadian Association of Petroleum Producers
CEC	Commercial Energy Consumers Association of BC
COS	Cost of Service
CP	Coincident Peak
DSM	Demand Side Management
IPP	Independent Power Producer
IRP	Integrated Resource Plan
LRMC	Long-Run Marginal Cost
MW	Megawatt
NCP	Non Coincident Peak
R/C ratios	Revenue-to-Cost ratios
RDA	Rate Design Application
SMI	Smart meter Infrastructure
SOP	Standing Offer program

1. Introduction

Gordon Doyle opened the meeting by canvassing the stakeholder feed-back received as part of the June 19, 2014 COS workshop (Workshop No. 2). He referenced the three documents for the October 7, 2014 workshop (Workshop No. 4): the Consideration Memo concerning Workshop No. 2; the Discussion Guide entitled "Preferred Options and Sensitivity Analysis"; and the slide deck presentation. The central idea behind Workshop No. 4 is to identify BCH's preferred option for each of the main COS elements, together with other options brought forward for sensitivity analysis.

Gord outlined the two main remaining steps in terms of stakeholder feed-back with respect to COS issues: (1) Workshop No. 4 subject matter, whether at the workshop itself or as part of the 30 day written comment period starting with the posting of Workshop No. 4 meeting notes sometime the week of 13 October; and (2) Draft COS study, which BCH anticipates posting to the RDA website sometime during the late November-early December period. Stakeholders would be notified when the draft COS study is posted for comment.

2. Presentation: Issues Previously Canvassed at 19 June COS workshop – DSM Functionalization

Dani Ryan outlined BC Hydro's preferred option where DSM is functionalized 90% generation, 5% transmission and 5% distribution. The alternative of directly assigning DSM costs to customer classes was reviewed. BCH is concerned that direct assignment results in a significant mismatch between benefits and costs if there was to be direct allocation.

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	FEEDBACK	RESPONSE
1.	**AMPC** asked if the DSM costs are for a particular year. AMPC also asked if the benefits and costs are calculated using a Total Resource Cost test-type methodology.	The costs are a Present Value calculation for the period F2008-F2016. Similar to the Total Resource Cost test the benefits are the avoided cost of energy and capacity supply using BC Hydro's energy and capacity LRMCs set out in the 2013 IRP, while the costs are those paid by the utility.

3. Presentation: Issues Previously Canvassed at 19 June COS workshop – Heritage Hydro Classification

Dani Ryan identified BCH's preferred option for classifying BCH Heritage hydro resource costs as using load factor excluding IPPs (Option 1B) resulting in a 55% energy/45 % demand split. Two other options – BCH Integrated system wide load factor including IPPs resulting in a 61% energy/39% demand split (Option 1A) and capacity factor adjusted for book value resulting a 45% energy/55% demand split, were also discussed.

	FEEDBACK	RESPONSE
1.	**CEC** asked why a capacity factor approach is valid.	BCH's COS consultants, on the basis of jurisdictional assessment, suggested capacity factor as one approach to examine. The capacity factor approach is typically used by utilities whose systems are not hydro-based. The COS consultants recommend a load factor approach for the reasons set out in the slide deck and the Discussion Guide.
2.	**BCUC staff** commented that the capacity factors on slide 12 for Revelstoke and Mica Generating Stations look low.	The capacity factors for Revelstoke and Mica Generating Stations reflect the additions of Revelstoke Unit 5 at about 500 MW and of Mica Units 5 and 6 at about 1000 MW. The size of these additions lowers the capacity factor as these additions come with little energy.
3.	**BCOAPO** asked if Fort Nelson Generating Station is excluded from the system load factor.	Yes, Fort Nelson Generating Station is excluded from the system load factor because the Fort Nelson service area is not part of BCH's Integrated system.

4. Presentation: Issues Previously Canvassed at 19 June COS workshop – IPP Classification

Justin Miedema set out BCH's preferred option for classifying IPP costs using IPP costs net of the value of capacity (Option 2). Option 1 (value of energy) and Option 5 (load factor) were discussed. Option 1 and 2 produce virtually identical energy/demand splits (94%/6% and 93%/7% respectively). Option 5 results in a 60% energy/40% demand split which is not reasonable for the many IPP resources that are intermittent and provide little or no dependable capacity.

	FEEDBACK	RESPONSE
1.	**West Fraser** asked if SOP-related contracts are included in the IPP Cost of Energy.	*Revised Response:* Yes, the SOP contracts are included in the IPP Cost of Energy.
2.	**CEC** and **AMPC** questioned how Island Generation is operated vs. how BCH uses it for planning purposes.	*Revised Response:* Island Generation is a 275 MW combined cycle gas-turbine facility and is treated as a base-load facility for planning purposes (e.g., planning to operate Island Generation at a 90% capacity factor if needed). Island Generation is dispatchable and is displaced if the market is available and economic.

5. Presentation: Issues Previously Canvassed at 19 June COS workshop – SMI Classification

Dani Ryan presented BCH's preferred option of classifying SMI regulatory account costs as 100% customer-related as this is consistent with other jurisdictions and with how meters generally are classified. Dani explained why BCH rejects Options 2 (100% energy), and outlined another option – Option 3 – consisting of a 30% energy/70% customer split.

BC Hydro Rate Design Workshop

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	FEEDBACK	RESPONSE
1.	**COPE 378** reiterated its opposition to Option 1 on the basis that it does not reflect the rationale for SMI.	BCH commits to carrying forward Option 3 for sensitivity analysis. Option 3's 30%/70% alternative was developed by comparing F2016 SMI energy related benefits of about $40 million with total F2016 SMI costs of about $130 million. The primary source of energy benefits is incremental revenue from customers switching to paid service (i.e. reduction in theft). The total estimated costs include depreciation, financing charges and return on equity on SMI related assets along with recoveries from the SMI regulatory account.
2.	**AMPC** reiterated its view that Option 1 is the appropriate way to classify SMI costs as there is nothing conceptual different between SMI and meters generally.	
3.	**BCUC staff** requested clear identification of the SMI regulatory account items. BCUC staff remarked that Option 3 is still a 'live issue'.	The SMI regulatory account was established pursuant to BCUC Order G-64-09 for the purpose of deferring SMI-related operating costs. **Attachment 1** sets out the major components of the account along with estimated F2016 balances.

6. Presentation: Issues Previously Canvassed at 19 June COS workshop – Allocation of Generation Demand and Transmission

Dani Ryan outlined that there was good agreement on use of 4CP to allocate Generation demand and Transmission costs, but that there were requests from COPE 378, AMPC and CEC for 4CP sensitivities. Dani presented BCH's preferred option – continue with the BCUC 2007 RDA decision's 4CP, and described two 4CP sensitivities and use of 3CP.

	FEEDBACK	RESPONSE
1.	**CEC** asked why only 5 years data were used for the slide presentation.	BCH has relied on 30 years of data as set out in Workshop No. 2 consideration memo. BCH used 5 years for presentation purposes, and 5 years is representative.

7. Presentation: Distribution: General, Substations and Meters

Justin Miedema introduced BCH's approach to Distribution. Consistent with the COS consultants' recommendation, BCH sub-functionalized its Distribution system into: substations; primary system; transformers; secondary system and services; and meters.

Consistent with other jurisdictions and the COS consultants recommendations, BCH proposes to classify substations as 100% demand and allocate costs using NCP; and classify meters as 100% customer and allocate costs on a weighted customer basis.

	FEEDBACK	RESPONSE
1.	**BCOAPO** asked what type of NCP is used to allocate the Distribution demand costs.	Similar to other electric utilities, BCH uses an annual NCP for its COS.
2.	**BCOAPO** asked BCH to clarify what makes-up meter costs, and in particular whether SMI-related telecommunication software is captured in meter costs or SMI regulatory costs.	These types of costs have been categorized as meter related and are capitalized as part of BC Hydro's rate base rather than deferred in the SMI regulatory account.

8. Presentation: Distribution – Primary System

Justin Miedema described how the primary system accounts for 49% of Distribution costs and thus was a focus for BCH. BCH proposed to classify the primary system as 100% demand as the primary system is sized to meet the peak demand of customers.

BCH examined two options for allocating Distribution primary system costs: Option 1 – direct assignment; and Option 2 – use of NCP. Justin discussed BCH's concerns with Option 1, and in particular the problems with using replacement costs to value individual primary system feeders. BCH prefers Option 2 as a result.

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	FEEDBACK	RESPONSE
1.	**CEC** asked about use of the term 'deflation'; is it meant to capture an inflation adjustment or depreciation?	The term is used to refer to depreciation. BCH notes that an inflation adjustment is also required. BCH notes that Hydro Quebec uses replacement costs, estimates the age of the Distribution assets, and uses the Handy-Whitman Index of Public Utility Construction Costs.
2.	**BCUC staff** questioned whether the replacement costs would have to be reconciled with the embedded revenue requirement.	Yes.
3.	**CLEAResult** questioned the data gaps for older Distribution primary assets.	Most utilities have gaps in information in this area as information is not recoded on a feeder-by-feeder basis. There is a significant difference in the quality of information over time; BCH has detailed information for the last 10-15 years or so.

9. Presentation: Distribution – Transformers

Justin Miedema explained that transformers account for 17% of Distribution costs and so were also a focus for BCH.

BCH examined two options for allocating Distribution primary system costs: Option 1- direct assignment, with a 50% demand/50% customer split for purposes of rate design; and Option 2 – classify as 50% demand/50% customer and use NCP allocate the demand portion and an appropriate customer allocator. BCH prefers Option 1 as it is feasible in the case of transformers to directly assign costs – the costs are a lot less variable than with the primary system as material costs account for about 90% of transformer-related costs.

	FEEDBACK	RESPONSE
1.	**BCOAPO** asked for further detail as to the proposed 50% demand/50% customer split, and noted that the Discussion Guide indicates that other jurisdictions appear to classify transformers as greater than 50% demand.	The Discussion Guide does note that many utilities classify transformers as 70% or greater demand. However, practice ranges widely and there are utilities that classify transformers as 100% customer. BCH will provide greater detail on the proposed 50% demand/50% customer split.

10. Presentation: Distribution – Secondary System and Services

Justin Miedema outlined that this joint category accounts for less than 15% of Distribution costs. BCH proposes a high level assumption of classifying the secondary system as 100% demand to be allocated NCP; and to classify services as 100% customer and allocated accordingly.

11. Closing Comments

Gordon Doyle reiterated the two main remaining steps in terms of stakeholder feed-back with respect to COS issues.

	FEEDBACK	RESPONSE
1.	**BCSEA** what portion of the COS costs have the biggest impact.	Heritage hydro Generation classification costs.
2.	**BCSEA** asked how much impact the three options for classifying Heritage hydro Generation costs on R/C ratios.	Looking at Table 5 in the Discussion Guide, there is about a 1% difference.

BC Hydro Rate Design Workshop

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	FEEDBACK	RESPONSE
3.	**CAPP** requested that BCH provide the Heritage hydro classification cost in a manner similar to the DSM-related Table 2 of the Discussion Guide, and commented that providing information for other COS elements in a form similar to Table 2 might be helpful.	**Attachment 1** contains the requested information for Heritage hydroelectric classification. BC Hydro has also provided information for IPP classification costs in a similar format as IPP costs are the second largest F2013 COS item at $760 million.
Anne Wilson thanked everyone for making the time to participate in the workshop. Meeting adjourned at 11:30 AM.		

BC Hydro Rate Design Workshop

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Attachment 1

SMI Regulatory Account

Additional details on the SMI Regulatory Account are provided in Table 1. Additional information on the regulatory account can be found at http://www.bcuc.com/Documents/Proceedings/2011/DOC_27644_B-1_BCH-SMI_RAC_F201-Expenditures-App.pdf
and BC Hydro's F2012 to F2014 Revenue Requirements Application (RRA), Section 7.3.17 at page 7-18, which can be found at http://www.bcuc.com/Documents/Proceedings/2011/DOC_27065_B-1_BCHydro_F12_F14-RR-application.pdf

Table 1

Major Components of the SMI Regulatory Account	**Estimated Closing Balance for F2016 $millions**
SMI program costs that were deferred in the F2009 to F2011 period	59
SMI costs ($123m) net of benefits ($52m) covering the F2012 to F2014 period	71
Accelerated amortization of obsolete legacy meters	56
Deferred amortization of SMI assets (F2012 - F2014)	44
Deferred Return on Equity (F2012 - F2014)	26
Deferred Finance Charges (F2012 - F2014)	26
Interest	42
Less Amortization of Regulatory Account	(35)
Miscellaneous	(3)
Total (Consistent with Line 105, Schedule 2.2 of the F2015-F2016 RRA)	**286**

Hydroelectric Classification

BC Hydro estimates that about $1,034 million (O&M + capital related costs) is associated with the hydroelectric system in the F2013 COS study. Table 2 below shows the cost assigned to each rate class under the different hydroelectric classification options. For more information please refer to pages 5 to 7 of the Discussion Guide.

Table 2

$million	**Base F2013 COS**	**Option 1A**	**Preferred Option 1B**	**Option 3**
Residential	433	412	419	430
Small General Service Under 35 kW	77	79	78	77
Medium General Service < 150 kW	71	72	71	71
Large General Service > 150 kW	206	212	210	206
Irrigation	1	1	1	1
Street Lighting	6	6	6	6
Transmission	241	254	250	243
Total	**1,034**	**1,034**	**1,034**	**1,034**

BC Hydro Rate Design Workshop

SUMMARY 7 OCTOBER 2014 9 AM TO 11:30 AM BC Utilities Commission 1125 Howe Street, Vancouver, 12th Floor

IPP Classification

Approximately $760 million is associated with IPPs and Long Term purchase commitments in the F2013 COS study. Table 3 below shows the cost assigned to each rate class under different IPP classification options. For more information on please refer to pages 10 and 11 of the Discussion Guide.

Table 3

$million	**Base F2013 COS**	**Option 1**	**Preferred Option 2**	**Option 3**
Residential	271	276	277	304
Small General Service Under 35 kW	60	60	60	58
Medium General Service < 150 kW	54	54	54	53
Large General Service > 150 kW	165	163	163	155
Irrigation	1	1	1	1
Street Lighting	3	4	4	4
Transmission	206	203	203	186
Total	**760**	**760**	**760**	**760**

2015 Rate Design Application

October 7, 2014 Workshop No. 4
Cost of Service (COS) Methodology

BC Hydro Summary and Consideration of Participant Feedback

Attachment 2

Feedback Forms and Written Comments

2015 RDA – October 7, 2014 Cost of Service Workshop #2 Feedback Form

Name/Organization: B.C. Sustainable Energy Association/Sierra Club B.C.

This feedback form refers to four documents which are posted in the Cost of Service (COS) section of the RDA website:

- Consideration Memo for the June 19th COS workshop;
- Discussion Guide for the October 7th COS workshop;
- Presentation slide deck for the October 7th COS workshop;
- The draft meeting notes for the October 7th COS workshop.

October 7th COS Workshop #2 Feedback Form

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Functionalization	
Demand Side Management (DSM) BC Hydro's preferred option is to functionalize DSM 90% Generation, 5% Transmission, and 5% Distribution (Option 1 in the discussion Guide). Do you agree with BC Hydro's preferred option? If not, why not, and what option do you suggest? Refer to pages 10-12 of the Consideration Memo, pages 3-4 of the Discussion Guide, and slides 7-9 of the October 7th presentation.	BCSEA-SCBC agree that BC Hydro's preferred approach to functionalization of DSM (90% generation, 5% transmission, 5% distribution) is an appropriate functionalization of the system benefits of DSM.
Classification	
Generation - Heritage Hydro BC Hydro presented three options to classify operation and maintenance (O&M) and capital related costs associated with BC Hydro's Heritage hydroelectric plants: Option 1A – load factor using total system load; Option 1B – load factor based on load served almost entirely by the hydroelectric system (i.e., total F2016 load minus Independent Power Producer (IPP) supply); Option 2 – capacity factor weighted by plant book value. Option 1B is BC Hydro's preferred option. Do you agree it should be used for Heritage Hydro Classification? If not, please indicate which option you suggest with reasons. Refer to pages 13-14 of the Consideration Memo, pages 5-7 of the Discussion Guide, slides 11-16 of the October 7th presentation and Attachment 1 to the October 7th COS workshop draft meeting notes.	BCSEA-SCBC support Option 1B (Heritage Hydro classified by load factor based on load served by the hyroelectric system: 55% energy, 45% demand).

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation – BC Hydro Thermal BC Hydro preferred option is to classify: • Prince Rupert Generating Station using the system load factor; • Fort Nelson Generation Station using the load factor in the Fort Nelson service territory; • Burrard Thermal Generating Station as 100% demand; • Fuel costs associated with running the plants would continue to be classified as 100% energy related. Do you agree with the proposed classification of thermal plant? If not, why not? Refer to pages 14-16 of the Consideration Memo and pages 8-10 of the Discussion Guide.	BCSEA-SCBC agree with BC Hydro's preferred option regarding the classification of BC Hydro's thermal plant.
Generation – IPPs Do you agree with BC Hydro's proposal to use Classification Option #2 which produces about a 93% energy/7% demand split? If you do not agree with Option 2, please suggest an alternative classification approach and provide reasons. Refer to Attachment 4 and pages 16-17 of the Consideration Memo, pages 10-11 of the Discussion Guide, slides 17-19 of the October 7th presentation, and Attachment 1 to the October 7th COS workshop draft meeting notes.	BCSEA-SCBC agree with BC Hydro's preferred option #2, to classify IPP generation on the value of capacity, 93% energy, 7% demand.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Smart Meter Infrastructure (SMI) Do you agree with BC Hydro's proposal to classify SMI regulatory account costs as 100% customer? Refer to pages 22-23 of the Consideration Memo, pages 11-12 of the Discussion Guide, slide 24 of the October 7th presentation and Attachment 1 to the 7 October COS workshop draft meeting notes.	BCSEA-SCBC request clarification of the distinction here between "SMI-related costs," SMI regulatory account amortization, and SMI capital costs.
Allocation	
Generation and Transmission Demand Should the 4 Coincident Peak methodology continue to be used to allocate generation and transmission demand-related costs to customer classes? If not, why not? Refer to pages 25-27 of the Consideration Memo and slides 26-30 of the October 7th presentation.	BCSEA-SCBC support continued use of a 4 Coincident Peak methodology (5-year average of Nov to Feb monthly peaks) to allocate generation and transmission demand. They are open to consideration of the merits of probability-based modifications. However, simplicity favours the status quo methodology.
Transmission – radial lines Do you agree with BC Hydro's preferred option to allocate all transmission related costs (including those associated with radial lines) using the same methodology? Refer to the question above which deals with Generation and Transmission allocation, and slide 31 of the October 7th presentation.	BCSEA-SCBC support BC Hydro's preferred option to allocate transmission related cost associated with radial lines to transmission, in the interests of simplicity.

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Distribution Classification and Allocation: Introduction BC Hydro proposed to use Distribution customer base to categorize distribution O&M and capital related costs into substations, primary, transformers, secondary/services and meters. Using this categorization, BC Hydro proposed to classify: • substations and primary lines as 100% demand; • transformers as 50% demand and 50% customer (this classification is guided by the draft direct assignment results and would be used for rate design purposes); • secondary as 100% demand; • services as 100% customer; • meters as 100% customer. BC Hydro proposed to split the secondary/services asset category as 50% secondary and 50% services. Do you have any comments on BC Hydro's proposed Distribution sub-functionalization? Refer to pages 20-22 of the Consideration Memo, pages 12-14 of the Discussion Guide and slides 20-23 and 32-54 of the October 7th presentation.	It is understood that BC Hydro proposes to categorize secondary and services on a combined basis, then split secondary/services 50:50 between secondary and services. BCSEA-SCBC don't object to that approach.
Substations and Primary Lines Do you agree that costs associated with substations and the Distribution primary system be classified as 100% demand and allocated using a Non-Coincident Peak (NCP) allocator?	BCSEA-SCBC are inclined to support BC Hydro's proposal to classify substations and the primary system as 100% demand with a NCP allocator.

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Transformers Do you agree with BC Hydro's proposal to directly assign transformers to customer classes by using GIS information to map customers to transformers and then pro-rating the transformer's cost by the rate classes that use the unit (Option 1)? Assuming the final direct assignment results reasonably indicate a 50% demand/50% customer classification for transformers, will you agree with the proposed classification? If you don't agree with Option 1, should BC Hydro adopt Option 2 classify transformers as 100% demand and use a NCP allocator? If you do not agree with Options 1 or 2, please suggest other methods to classify and allocate transformer related costs.	BCSEA-SCBC are inclined to support Option 1, direct assignment of transformer costs to customer classes, on the understanding that this can be done easily and accurately.
Secondary and Services Note that Table 1 (Preferred Option) of the Discussion Guide has been modified to reflect 100% classification of Secondary to demand instead of 50% demand and 50% customer. This proposal is consistent with the 7 October 2014 presentation material. Do you agree that the secondary/services asset category be split 50% secondary and 50% services? Do you support BC Hydro's proposal to classify the secondary portion as 100'% demand and the services portion as 100% customer? If not, please suggest other methods to determine this split. Do you agree the portion classified to demand be allocated using a NCP allocator while the customer portion be allocated using either a customer allocator or a weighted customer allocator?	We understand that BC Hydro proposes to split the combined secondary/services asset category 50:50, and then to classify the notional secondary component as 100% demand and to assign the notional services portion as 100% customer. BCSEA-SCBC are inclined to agree with that approach. BCSEA-SCBC agree with the secondary component, classified as demand, being allocated on a NCP basis. We are not clear on the merits and implications of using a customer allocator compared to a weighted customer allocator.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Meters Should meter related costs be classified as 100% customer and allocated using a weighted customer allocator?	Allocating distribution meters as 100% customer accords with BC Hydro's consultant's recommendation. As noted above, we are not clear on the merits and implications of using a customer allocator compared to a weighted customer allocator.
Customer Care Allocation Should BC Hydro continue allocating customer care costs using a weighted allocator based 90% on the number of bills and 10% on revenue by rate class? Refer to page 24 of the Consideration Memo and pages 14-16 of the Discussion Guide.	BC Hydro says in the Discussion guide p.15 that the comparison of the results of the Bottom Up approach to the 90% number/ 10% revenue approach supports continuation of the latter approach. We are not sure how that conclusion was arrived at.

Additional Comments, Items you think should be in-scope, not currently identified:

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:____ Date: ___________________________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

You can return completed feedback forms by:

Mail: BC Hydro, BC Hydro Regulatory Group – “Attention 2015 RDA”, 16th Floor, 333 Dunsmuir St. Van. B.C. V6B-5R3

Fax number: 604-623-4407 – “Attention 2015 RDA”

Email: bchydroregulatorygroup@bchydro.com

Form available on Web: http://www.bchydro.com/about/planning_regulatory/regulatory.html

Any personal information you provide to BC Hydro on this form is collected and protected in accordance with the ***Freedom of Information and Protection of Privacy Act***. BC Hydro is collecting information with this for the purpose of the 2015 RDA in accordance with BC Hydro’s mandate under the ***Hydro and Power Authority Act***, the BC Hydro Tariff, the ***Utilities Commission Act*** and related Regulations and Directions. If you have any questions about the collection or use of the personal information collected on this form please contact the BC Hydro Regulatory Group via email at: bchydroregulatorygroup@bchydro.com

2015 RDA – October 7, 2014 Cost of Service Workshop #2 Feedback Form

Name/Organization: Sarah Khan and Erin Pritchard, BC Old Age Pensioners' Organization *et al.*

This feedback form refers to four documents which are posted in the Cost of Service (COS) section of the RDA website:

- Consideration Memo for the June 19th COS workshop;
- Discussion Guide for the October 7th COS workshop;
- Presentation slide deck for the October 7th COS workshop;
- The draft meeting notes for the October 7th COS workshop.

October 7th COS Workshop #2 Feedback Form

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Functionalization	
Demand Side Management (DSM) BC Hydro's preferred option is to functionalize DSM 90% Generation, 5% Transmission, and 5% Distribution (Option 1 in the discussion Guide). Do you agree with BC Hydro's preferred option? If not, why not, and what option do you suggest? Refer to pages 10-12 of the Consideration Memo, pages 3-4 of the Discussion Guide, and slides 7-9 of the October 7th presentation.	• The proposal to functionalize DSM costs between Generation, Transmission and Distribution based on benefits accruing to each makes sense. • However, there is no explanation or rationale for the 90%/5%/5% assignment proposed. • The June 19, 2014 Workshop Feedback Memo (page 10) correctly notes that Manitoba Hydro currently directly assigns DSM costs to customer classes. However, Manitoba Hydro is initiating a stakeholder process to review its Cost of Service practices and the treatment of DSM has already been flagged as an issue.
Classification	

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation - Heritage Hydro BC Hydro presented three options to classify operation and maintenance (O&M) and capital related costs associated with BC Hydro's Heritage hydroelectric plants: Option 1A – load factor using total system load; Option 1B – load factor based on load served almost entirely by the hydroelectric system (i.e., total F2016 load minus Independent Power Producer (IPP) supply); Option 2 – capacity factor weighted by plant book value. Option 1B is BC Hydro's preferred option. Do you agree it should be used for Heritage Hydro Classification? If not, please indicate which option you suggest with reasons. Refer to pages 13-14 of the Consideration Memo, pages 5-7 of the Discussion Guide, slides 11-16 of the October 7th presentation and Attachment 1 to the October 7th COS workshop draft meeting notes.	• The proposal to use Option #1 (Load Factor method) makes sense. • BCH is proposing a slight variation on the initial Load Factor method - Option 1B where the load factor calculation is adjusted to remove the impact of IPPs. There is a conceptual mismatch between the two in that the load factor method is based on "customer load" whereas the IPP adjustment is based on plant output. The mismatch occurs in that generation on the system not only meets load but also provides reserves (in the event of plant outages). Not clear if/how BCH addresses this.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation – BC Hydro Thermal BC Hydro preferred option is to classify: • Prince Rupert Generating Station using the system load factor; • Fort Nelson Generation Station using the load factor in the Fort Nelson service territory; • Burrard Thermal Generating Station as 100% demand; • Fuel costs associated with running the plants would continue to be classified as 100% energy related. Do you agree with the proposed classification of thermal plant? If not, why not? Refer to pages 14-16 of the Consideration Memo and pages 8-10 of the Discussion Guide.	• There are three thermal stations and BCH has a separate proposed treatment for each. • The plant and O&M costs for the largest one (FNG) would be classified based on the load factor for the Fort Nelson service territory. This is a reasonable approach and consistent with BCH's approach for its main integrated system. • Burrard plant and O&M costs would be classified 100% as demand and fuel costs as 100% energy. This is to recognize the fact that the plant will not be relied on for firm energy or capacity and is really used for voltage support (i.e, a transmission service). One could quibble that all O&M costs are not demand related. However, some of the energy costs could be attributed to voltage support – so the approach proposed by BCH is a simplified trade-off.
Generation – IPPs Do you agree with BC Hydro's proposal to use Classification Option #2 which produces about a 93% energy/7% demand split? If you do not agree with Option 2, please suggest an alternative classification approach and provide reasons. Refer to Attachment 4 and pages 16-17 of the Consideration Memo, pages 10-11 of the Discussion Guide, slides 17-19 of the October 7th presentation, and Attachment 1 to the October 7th COS workshop draft meeting notes.	• BCH is proposing to adopt Option #2 – where the capacity portion is based on the capacity benefits relative to the cost of IPPs. As noted in the BCOAPO feedback comments this results in the calculation being an inconsistent mix of marginal and embedded costs. • BCH claims that the results of using Option1 (marginal values for both capacity and energy) skews the results towards energy (Discussion Memo, page 10). However, one could also observe that it appropriately reflects the value of energy as opposed to capacity. But, as noted in Table 6 of the Discussion memo the results are not that much different. However, this could change if/as substantially more IPP are added to the system.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Smart Meter Infrastructure (SMI) Do you agree with BC Hydro's proposal to classify SMI regulatory account costs as 100% customer? Refer to pages 22-23 of the Consideration Memo, pages 11-12 of the Discussion Guide, slide 24 of the October 7th presentation and Attachment 1 to the 7 October COS workshop draft meeting notes.	• In the earlier discussion materials (and the feedback forms) it was assumed that this referred to the new SMI infrastructure that BCH has installed. This appears to be consistent with the FeedBack Memo, page 22-23. However, in the Discussion Guide (page 11) it now appears that what is being dealt with here are the legacy costs of the old meters that have been retired due to the implementation of AMI. At the workshop, BCH said that these costs include both legacy and current operating costs, and BCH has provided materials in Attachment 1 detailing the costs. Based on the cost details, its appears that the majority of the costs are associated with the new smart meters. • BCH proposes 100% customer classification for SMI regulatory account costs. However, to the extent that different types of legacy meters or new smart meters (with different costs) were used for different classes – the subsequent allocation should be on a customer-weighted basis recognizing these differences in costs. Furthermore, the difference in cost/meter between classes for the legacy meters is not likely the same as the difference in costs for the new smart meters, so a composite weighting factor would be required. With respect to the choice between Options 1 and 3, while industry practice supports the adoption of Option 1, Option 3 is conceptually attractive as it reflects the rationale for implementing SMI and, hence, cost causality.
Allocation	

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation and Transmission Demand Should the 4 Coincident Peak methodology continue to be used to allocate generation and transmission demand-related costs to customer classes? If not, why not? Refer to pages 25-27 of the Consideration Memo and slides 26-30 of the October 7th presentation.	• BCH proposes to use a 4 Coincident Peak (Nov. to February) methodology to allocate the demand costs associated with Generation and Transmission, and to use a 5-year average. • Coincident peaks are generally used for these assets and the data appears to support the use of four months.
Transmission – radial lines Do you agree with BC Hydro's preferred option to allocate all transmission related costs (including those associated with radial lines) using the same methodology? Refer to the question above which deals with Generation and Transmission allocation, and slide 31 of the October 7th presentation.	• Given the small value for the lines involved, BCH is not proposing to pursue direct allocation. They will be treated the same as the overall transmission system. This appears to be reasonable.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Distribution Classification and Allocation: Introduction BC Hydro proposed to use Distribution customer base to categorize distribution O&M and capital related costs into substations, primary, transformers, secondary/services and meters. Using this categorization, BC Hydro proposed to classify: • substations and primary lines as 100% demand; • transformers as 50% demand and 50% customer (this classification is guided by the draft direct assignment results and would be used for rate design purposes); • secondary as 100% demand; • services as 100% customer; • meters as 100% customer. BC Hydro proposed to split the secondary/services asset category as 50% secondary and 50% services. Do you have any comments on BC Hydro's proposed Distribution sub-functionalization? Refer to pages 20-22 of the Consideration Memo, pages 12-14 of the Discussion Guide and slides 20-23 and 32-54 of the October 7th presentation.	• BCH's proposal to adopt the six sub-functions – substations, primary lines, transformers, secondary lines, servicea and meters – is reasonable. BCH has looked into using direct assignment for primary feeder costs. The problem is that they do not track embedded costs by feeder – and so replacement costs needed to be used to value each feeder. Each customer class' contribution to the peak on each feeder is then used to allocate that feeder's costs to customer classes. • Slide #42 sets out a number of issues with the approach. • Given these issues BCH has decided not to pursue direct assignment but rather treat the costs as 100% demand related and allocate to classes based on each class' NCP. • The question that arises is which NCP allocation method should be used – just 1 NCP (i.e. the highest annual value) or a say 4 NCP (average of 4 highest monthly values). Clarification required along with rationale for choice.
Substations and Primary Lines Do you agree that costs associated with substations and the Distribution primary system be classified as 100% demand and allocated using a Non-Coincident Peak (NCP) allocator?	• BCH proposes to classify substation and its primary system as 100% demand related. • The proposal to classify substations a 100% demand is consistent with general practice elsewhere. However, the rationale for classifying primary lines as 100% demand-related is not as obvious – as general industry practice varies.

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Transformers Do you agree with BC Hydro's proposal to directly assign transformers to customer classes by using GIS information to map customers to transformers and then pro-rating the transformer's cost by the rate classes that use the unit (Option 1)? Assuming the final direct assignment results reasonably indicate a 50% demand/50% customer classification for transformers, will you agree with the proposed classification? If you don't agree with Option 1, should BC Hydro adopt Option 2 classify transformers as 100% demand and use a NCP allocator? If you do not agree with Options 1 or 2, please suggest other methods to classify and allocate transformer related costs.	• BCH proposes to classify these assets as 50% demand and 50% customer. Since direct allocation is proposed for these assets, can BCH confirm that this choice of classification percentages should not impact the total costs allocated to each class. • Not at all clear what the basis is for 50/50 as the examples in the Discussion Guide (page 13) all suggest a % for demand that would be higher than 50%. BCH has already committed to providing greater detail on the proposed 50% demand/50% customer split. • While the approach used by BCH is characterized as "direct assignment", many transformers are shared and BCH has allocated the costs for each transformer to the customer classes using it on the basis of energy by class. • It would be helpful if BCH could confirm if/how the allocation was done to unmetered loads such as streetllghts. • What are the cost differences between 1 and 3 phase transformers (Slide #51) and will this refinement be completed for the draft COS study to come?

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Secondary and Services Note that Table 1 (Preferred Option) of the Discussion Guide has been modified to reflect 100% classification of Secondary to demand instead of 50% demand and 50% customer. This proposal is consistent with the 7 October 2014 presentation material. Do you agree that the secondary/services asset category be split 50% secondary and 50% services? Do you support BC Hydro's proposal to classify the secondary portion as 100'% demand and the services portion as 100% customer? If not, please suggest other methods to determine this split. Do you agree the portion classified to demand be allocated using a NCP allocator while the customer portion be allocated using either a customer allocator or a weighted customer allocator?	• BCH proposed to classify 50% of the asset value as secondary and 50% as services. • Secondary costs would be 100% demand while service cost would be 100% customer. • It is not clear what the basis is for the 50/50 split. BCH notes that it does not record asset values as between secondary and services. But it does know the km for each. The question is "are the km for each" roughly the same, and do they support the 50/50 split. A second issue is that frequently customers are required to pay for some if not all of their "services" costs – it would be helpful if BCH could clarify how much of an issue this is for BCH. BCH uses the annual NCP by class to allocate the secondary asset costs to customer classes. Again, it would be useful for BCH to explain why this allocator was chosen as opposed to an NCP allocator that averaged the value for a number of the highest months.
Meters Should meter related costs be classified as 100% customer and allocated using a weighted customer allocator?	• What is included in Meters and, if not here, where is the cost of the communication infrastructure for AMI reflected? • Classifying these costs as 100% customer –related is reasonable. However, BCH needs to explain how the weights for each customer class are to be determined
Customer Care Allocation Should BC Hydro continue allocating customer care costs using a weighted allocator based 90% on the number of bills and 10% on revenue by rate class? Refer to page 24 of the Consideration Memo and pages 14-16 of the Discussion Guide.	• BCH undertook a detailed analysis to check the reasonableness of its use of an allocation based 90% on number of bills issued and 10% on revenue. The results were similar. • It is not clear from Figure 1 in the Discussion Guide whether the detailed analysis assumed manual meter reads for all customers – or just fort those who will not (in F16) have functioning Smart Meters. If the former – then the analysis may be somewhat dated and not reflective of the future.

Additional Comments, Items you think should be in-scope, not currently identified:

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:_______"Sarah Khan"________________________________ Date: ____November 17, 2014___________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

You can return completed feedback forms by:

Mail: BC Hydro, BC Hydro Regulatory Group – "Attention 2015 RDA", 16th Floor, 333 Dunsmuir St. Van. B.C. V6B-5R3

Fax number: 604-623-4407 – "Attention 2015 RDA"

Email: bchydroregulatorygroup@bchydro.com

Form available on Web: http://www.bchydro.com/about/planning_regulatory/regulatory.html

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2015 RDA – October 7, 2014 Cost of Service Workshop #2 Feedback Form

Name/Organization: Canadian Association of Petroleum Producers

This feedback form refers to four documents which are posted in the Cost of Service (COS) section of the RDA website:

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- Discussion Guide for the October 7th COS workshop;
- Presentation slide deck for the October 7th COS workshop;
- The draft meeting notes for the October 7th COS workshop.

October 7th COS Workshop #2 Feedback Form

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Functionalization	
Demand Side Management (DSM) BC Hydro's preferred option is to functionalize DSM 90% Generation, 5% Transmission, and 5% Distribution (Option 1 in the discussion Guide). Do you agree with BC Hydro's preferred option? If not, why not, and what option do you suggest? Refer to pages 10-12 of the Consideration Memo, pages 3-4 of the Discussion Guide, and slides 7-9 of the October 7th presentation.	CAPP supports BC Hydro's preferred option as this reflects the fact that although BC Hydro DSM initiatives have an energy focus and are primarily undertaken to defer Generation resources, these initiatives also have some Transmission and Distribution deferral benefits.
Classification	

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation - Heritage Hydro BC Hydro presented three options to classify operation and maintenance (O&M) and capital related costs associated with BC Hydro's Heritage hydroelectric plants: Option 1A – load factor using total system load; Option 1B – load factor based on load served almost entirely by the hydroelectric system (i.e., total F2016 load minus Independent Power Producer (IPP) supply); Option 2 – capacity factor weighted by plant book value. Option 1B is BC Hydro's preferred option. Do you agree it should be used for Heritage Hydro Classification? If not, please indicate which option you suggest with reasons. Refer to pages 13-14 of the Consideration Memo, pages 5-7 of the Discussion Guide, slides 11-16 of the October 7th presentation and Attachment 1 to the October 7th COS workshop draft meeting notes.	CAPP has concerns with BC Hydro's preferred approach and these concerns are amplified by the fact that this item has a significantly larger potential cost/rate impact compared to the other issues being explored in this workshop. BC Hydro is proposing a system load factor approach (albeit with an adjustment that excludes load served by IPP supply) which CAPP believes may create a conflict with the goal of reducing peak usage on the system through iniatives such as Time of Use rates. System Load Factor equals average energy use in a period divided by peak use in the period. Subscribing to TOU rates would reduce the denominator which in turn increases system load factor and thus increases energy classification under this particular approach. This penalizes users who use the system at high levels in both peak and offpeak periods when the utility is trying to encourage more balanced load factor profiles through TOU. Similarly when a utility adds to the capacity of its system based on growing customer demand then more costs should be considered demand related. However, under the system load factor approach this change in cost classification would not necessarily occur thus giving an inappropriate price signal. CAPP would also note that to the extent LNG plants are built then these facililities' ancillary loads are expected to have very high load factors. Since the pricing of these plants will not be based on any heritage facilities then their loads should not be included in calculated the SLF in any future period. CAPP supports option 2 as this doesn't result in a conflict of goals as described above and also provides a resulting cost classification that is similar to the status quo and so avoids a dramatic cost shift among customer classes.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation – BC Hydro Thermal BC Hydro preferred option is to classify: • Prince Rupert Generating Station using the system load factor; • Fort Nelson Generation Station using the load factor in the Fort Nelson service territory; • Burrard Thermal Generating Station as 100% demand; • Fuel costs associated with running the plants would continue to be classified as 100% energy related. Do you agree with the proposed classification of thermal plant? If not, why not? Refer to pages 14-16 of the Consideration Memo and pages 8-10 of the Discussion Guide.	Consistent with its position on classifying Heritage Hydro generation costs, CAPP supports using the Capacity factor approach to classify BC Hydro Thermal generation plant costs.
Generation – IPPs Do you agree with BC Hydro's proposal to use Classification Option #2 which produces about a 93% energy/7% demand split? If you do not agree with Option 2, please suggest an alternative classification approach and provide reasons. Refer to Attachment 4 and pages 16-17 of the Consideration Memo, pages 10-11 of the Discussion Guide, slides 17-19 of the October 7th presentation, and Attachment 1 to the October 7th COS workshop draft meeting notes.	CAPP is supportive of BC Hydro's preferred option to Classify IPP contracts on the value of capacity which results in 7% of the costs being classified as demand. IPPs do contribute to the capacity of the sytem and as such this should be recognized in the cost classification approach.

October 7th COS Workshop #2 Feedback Form

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Smart Meter Infrastructure (SMI) Do you agree with BC Hydro's proposal to classify SMI regulatory account costs as 100% customer? Refer to pages 22-23 of the Consideration Memo, pages 11-12 of the Discussion Guide, slide 24 of the October 7th presentation and Attachment 1 to the 7 October COS workshop draft meeting notes.	
Allocation	
Generation and Transmission Demand Should the 4 Coincident Peak methodology continue to be used to allocate generation and transmission demand-related costs to customer classes? If not, why not? Refer to pages 25-27 of the Consideration Memo and slides 26-30 of the October 7th presentation.	CAPP supports BC Hydro's preferred option to use the 5-year average of 4 montly peaks for November through February. Although timing of annual peaks varies from year to year due to different weather patterns, viewing data over a five year period shows that each of the four winter months contains periods of peaks system use.
Transmission – radial lines Do you agree with BC Hydro's preferred option to allocate all transmission related costs (including those associated with radial lines) using the same methodology? Refer to the question above which deals with Generation and Transmission allocation, and slide 31 of the October 7th presentation.	CAPP agrees given the small portion of overall book value that these radial lines account for, they should be treated the same for cost allocation purposes as the overall transmission system.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Distribution Classification and Allocation: Introduction BC Hydro proposed to use Distribution customer base to categorize distribution O&M and capital related costs into substations, primary, transformers, secondary/services and meters. Using this categorization, BC Hydro proposed to classify: • substations and primary lines as 100% demand; • transformers as 50% demand and 50% customer (this classification is guided by the draft direct assignment results and would be used for rate design purposes); • secondary as 100% demand; • services as 100% customer; • meters as 100% customer. BC Hydro proposed to split the secondary/services asset category as 50% secondary and 50% services. Do you have any comments on BC Hydro's proposed Distribution sub-functionalization? Refer to pages 20-22 of the Consideration Memo, pages 12-14 of the Discussion Guide and slides 20-23 and 32-54 of the October 7th presentation.	
Substations and Primary Lines Do you agree that costs associated with substations and the Distribution primary system be classified as 100% demand and allocated using a Non-Coincident Peak (NCP) allocator?	

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Transformers Do you agree with BC Hydro's proposal to directly assign transformers to customer classes by using GIS information to map customers to transformers and then pro-rating the transformer's cost by the rate classes that use the unit (Option 1)? Assuming the final direct assignment results reasonably indicate a 50% demand/50% customer classification for transformers, will you agree with the proposed classification? If you don't agree with Option 1, should BC Hydro adopt Option 2 classify transformers as 100% demand and use a NCP allocator? If you do not agree with Options 1 or 2, please suggest other methods to classify and allocate transformer related costs.	
Secondary and Services Note that Table 1 (Preferred Option) of the Discussion Guide has been modified to reflect 100% classification of Secondary to demand instead of 50% demand and 50% customer. This proposal is consistent with the 7 October 2014 presentation material. Do you agree that the secondary/services asset category be split 50% secondary and 50% services? Do you support BC Hydro's proposal to classify the secondary portion as 100'% demand and the services portion as 100% customer? If not, please suggest other methods to determine this split. Do you agree the portion classified to demand be allocated using a NCP allocator while the customer portion be allocated using either a customer allocator or a weighted customer allocator?	

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Meters Should meter related costs be classified as 100% customer and allocated using a weighted customer allocator?	
Customer Care Allocation Should BC Hydro continue allocating customer care costs using a weighted allocator based 90% on the number of bills and 10% on revenue by rate class? Refer to page 24 of the Consideration Memo and pages 14-16 of the Discussion Guide.	Although the ultimate impact on rates is minor CAPP would note the revenue weighted element of the calculation will allocate costs to those customer classes characterized by large revenues per customer that will not be representative of the actual costs incurred to generate the bills to that customer class. Despite this reservation CAPP is prepared to support the status quo.

Additional Comments, Items you think should be in-scope, not currently identified:

October 7th COS Workshop #2 Feedback Form

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:____ Date: ________________________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

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2015 RDA – October 7, 2014 Cost of Service Workshop #2 Feedback Form

Name/Organization:

Commercial Energy Consumers (CEC)

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- Discussion Guide for the October 7th COS workshop;
- Presentation slide deck for the October 7th COS workshop;
- The draft meeting notes for the October 7th COS workshop.

October 7th COS Workshop #2 Feedback Form

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Functionalization	
Demand Side Management (DSM) BC Hydro's preferred option is to functionalize DSM 90% Generation, 5% Transmission, and 5% Distribution (Option 1 in the discussion Guide). Do you agree with BC Hydro's preferred option? If not, why not, and what option do you suggest? Refer to pages 10-12 of the Consideration Memo, pages 3-4 of the Discussion Guide, and slides 7-9 of the October 7th presentation.	Generally DSM represents about 85% energy savings, hence Generation functionalization makes sense. The other 15% of savings is capacity which is provided by Generation Transmission and Distribution. The split seems reasonable.
Classification	
Generation - Heritage Hydro BC Hydro presented three options to classify operation and maintenance (O&M) and capital related costs associated with BC Hydro's Heritage hydroelectric plants: Option 1A – load factor using total system load; Option 1B – load factor based on load served almost entirely by the hydroelectric system (i.e., total F2016 load minus Independent Power Producer (IPP) supply); Option 2 – capacity factor weighted by plant book value. Option 1B is BC Hydro's preferred option. Do you agree it should be used for Heritage Hydro Classification? If not, please indicate which option you suggest with reasons. Refer to pages 13-14 of the Consideration Memo, pages 5-7 of the Discussion Guide, slides 11-16 of the October 7th presentation and Attachment 1 to the October 7th COS workshop draft meeting notes.	The CEC does not expect to favour Option 1A at this time. Option 1 analysis will be of interest to the CEC as will capacity factor approaches. The CEC will look for capacity factor approaches which are not based on plant book values, but will also be interested in the book value understanding because of the relationship of this capacity to IPP energy.

October 7th COS Workshop #2 Feedback Form

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Generation – BC Hydro Thermal BC Hydro preferred option is to classify: • Prince Rupert Generating Station using the system load factor; • Fort Nelson Generation Station using the load factor in the Fort Nelson service territory; • Burrard Thermal Generating Station as 100% demand; • Fuel costs associated with running the plants would continue to be classified as 100% energy related. Do you agree with the proposed classification of thermal plant? If not, why not? Refer to pages 14-16 of the Consideration Memo and pages 8-10 of the Discussion Guide.	The CEC is interested in exploring whether or not arguments with regard to trade are more related to mitigation of excess capability as opposed to design requirements which maybe should prevail. • PRG the CEC understands is required to support demand • BTGS the CEC understands is required to support transmission capacity • FNG the CEC understands is required for local energy and capacity • Fuel supporting demand requirements may be associated more with the demand requirements
Generation – IPPs Do you agree with BC Hydro's proposal to use Classification Option #2 which produces about a 93% energy/7% demand split? If you do not agree with Option 2, please suggest an alternative classification approach and provide reasons. Refer to Attachment 4 and pages 16-17 of the Consideration Memo, pages 10-11 of the Discussion Guide, slides 17-19 of the October 7th presentation, and Attachment 1 to the October 7th COS workshop draft meeting notes.	The CEC understands IPPs to be intermittent with little capacity. The CEC expects to link the IPP issue to BC Hydro capacity at is Mica and Revelstoke plants for a balance of equitable treatment. The CEC expects that Alcan, ICG and biomass IPPs may be treated differently.

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Smart Meter Infrastructure (SMI) Do you agree with BC Hydro's proposal to classify SMI regulatory account costs as 100% customer? Refer to pages 22-23 of the Consideration Memo, pages 11-12 of the Discussion Guide, slide 24 of the October 7th presentation and Attachment 1 to the 7 October COS workshop draft meeting notes.	Yes. SMI should be 100% customer.
Allocation	
Generation and Transmission Demand Should the 4 Coincident Peak methodology continue to be used to allocate generation and transmission demand-related costs to customer classes? If not, why not? Refer to pages 25-27 of the Consideration Memo and slides 26-30 of the October 7th presentation.	The evidence supports 3CP or 4WCP as the drivers of the system peak requirements leaning largely to December & January.
Transmission – radial lines Do you agree with BC Hydro's preferred option to allocate all transmission related costs (including those associated with radial lines) using the same methodology? Refer to the question above which deals with Generation and Transmission allocation, and slide 31 of the October 7th presentation.	BC Hydro has some radial lines which are primarily in place to bring generation to loads or the BC Hydro system. These may be candidates for different treatment. Potentially the transmission lines may be more appropriately associated to the applicable generation.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Distribution Classification and Allocation: Introduction BC Hydro proposed to use Distribution customer base to categorize distribution O&M and capital related costs into substations, primary, transformers, secondary/services and meters. Using this categorization, BC Hydro proposed to classify: • substations and primary lines as 100% demand; • transformers as 50% demand and 50% customer (this classification is guided by the draft direct assignment results and would be used for rate design purposes); • secondary as 100% demand; • services as 100% customer; • meters as 100% customer. BC Hydro proposed to split the secondary/services asset category as 50% secondary and 50% services. Do you have any comments on BC Hydro's proposed Distribution sub-functionalization? Refer to pages 20-22 of the Consideration Memo, pages 12-14 of the Discussion Guide and slides 20-23 and 32-54 of the October 7th presentation.	The CEC is interested in the current methodology detail which is not evident in the discussion material. The CEC does not expect to favour the Option 2 approaches and will be looking at alternatives to the BC Hydro preferred Option 1 dealing with understaning the change proposed in more detail.
Substations and Primary Lines Do you agree that costs associated with substations and the Distribution primary system be classified as 100% demand and allocated using a Non-Coincident Peak (NCP) allocator?	The CEC will be interested in alternatives to the 100% demand allocation.

October 7th COS Workshop #2 Feedback Form

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Transformers Do you agree with BC Hydro's proposal to directly assign transformers to customer classes by using GIS information to map customers to transformers and then pro-rating the transformer's cost by the rate classes that use the unit (Option 1)? Assuming the final direct assignment results reasonably indicate a 50% demand/50% customer classification for transformers, will you agree with the proposed classification? If you don't agree with Option 1, should BC Hydro adopt Option 2 classify transformers as 100% demand and use a NCP allocator? If you do not agree with Options 1 or 2, please suggest other methods to classify and allocate transformer related costs.	The CEC is interested in seeing the analysis of GIS specific allocation. A key question will be allocating what cost or cost pool is used. The CEC is interested in Option 2 analysis, which here says 100% demand, but in the workshop slide 52 say says 50% demand/50% customer.
Secondary and Services Note that Table 1 (Preferred Option) of the Discussion Guide has been modified to reflect 100% classification of Secondary to demand instead of 50% demand and 50% customer. This proposal is consistent with the 7 October 2014 presentation material. Do you agree that the secondary/services asset category be split 50% secondary and 50% services? Do you support BC Hydro's proposal to classify the secondary portion as 100'% demand and the services portion as 100% customer? If not, please suggest other methods to determine this split. Do you agree the portion classified to demand be allocated using a NCP allocator while the customer portion be allocated using either a customer allocator or a weighted customer allocator?	The CEC is uncertain about the proposed 50% demand /50% customer allocation and is uncertain about the 50% secondary /50% services split and the secondary 100% demand, and services as 100%. The CEC will be interested in alternatives but at this point has not formulated the specifics of alternatives.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Meters Should meter related costs be classified as 100% customer and allocated using a weighted customer allocator?	Yes, meters should be 100% customer allocated.
Customer Care Allocation Should BC Hydro continue allocating customer care costs using a weighted allocator based 90% on the number of bills and 10% on revenue by rate class? Refer to page 24 of the Consideration Memo and pages 14-16 of the Discussion Guide.	No. Customer care should be split based on the different service. TSR customers have more intensive service. RIB customers are largely call centre service along with SGS & MGS. LGS have key account managers. This data should be available. 90% customer 10% revenue should be refined if possible.

Additional Comments, Items you think should be in-scope, not currently identified:

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I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:__David Craig____Date: _November 17, 2014__________________________

Thank you for your comments.

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2015 RDA – October 7, 2014 Cost of Service Workshop #2 Feedback Form

Name/Organization:

Quail Worth & Allevato, representing COPE local 378

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October 7th COS Workshop #2 Feedback Form

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Functionalization	
Demand Side Management (DSM) BC Hydro's preferred option is to functionalize DSM 90% Generation, 5% Transmission, and 5% Distribution (Option 1 in the discussion Guide). Do you agree with BC Hydro's preferred option? If not, why not, and what option do you suggest? Refer to pages 10-12 of the Consideration Memo, pages 3-4 of the Discussion Guide, and slides 7-9 of the October 7th presentation.	
Classification	
Generation - Heritage Hydro BC Hydro presented three options to classify operation and maintenance (O&M) and capital related costs associated with BC Hydro's Heritage hydroelectric plants: Option 1A – load factor using total system load; Option 1B – load factor based on load served almost entirely by the hydroelectric system (i.e., total F2016 load minus Independent Power Producer (IPP) supply); Option 2 – capacity factor weighted by plant book value. Option 1B is BC Hydro's preferred option. Do you agree it should be used for Heritage Hydro Classification? If not, please indicate which option you suggest with reasons. Refer to pages 13-14 of the Consideration Memo, pages 5-7 of the Discussion Guide, slides 11-16 of the October 7th presentation and Attachment 1 to the October 7th COS workshop draft meeting notes.	

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Generation – BC Hydro Thermal BC Hydro preferred option is to classify: • Prince Rupert Generating Station using the system load factor; • Fort Nelson Generation Station using the load factor in the Fort Nelson service territory; • Burrard Thermal Generating Station as 100% demand; • Fuel costs associated with running the plants would continue to be classified as 100% energy related. Do you agree with the proposed classification of thermal plant? If not, why not? Refer to pages 14-16 of the Consideration Memo and pages 8-10 of the Discussion Guide.	
Generation – IPPs Do you agree with BC Hydro's proposal to use Classification Option #2 which produces about a 93% energy/7% demand split? If you do not agree with Option 2, please suggest an alternative classification approach and provide reasons. Refer to Attachment 4 and pages 16-17 of the Consideration Memo, pages 10-11 of the Discussion Guide, slides 17-19 of the October 7th presentation, and Attachment 1 to the October 7th COS workshop draft meeting notes.	

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Smart Meter Infrastructure (SMI) Do you agree with BC Hydro's proposal to classify SMI regulatory account costs as 100% customer? Refer to pages 22-23 of the Consideration Memo, pages 11-12 of the Discussion Guide, slide 24 of the October 7th presentation and Attachment 1 to the 7 October COS workshop draft meeting notes.	No. A 100% customer classification ignores the rationale for SMI and for incurring the cost of the migration including early retirement of analogue meters. That rationale was not primarily based on improvements or savings in the metering or customers' consumption. The justification for SMI rested more on system benefits, including superior outage detection and reducing electricity theft. It should be noted that reducing theft is essentially energy related. It should also be noted that to the extent that SMI was justified on the basis of illicit marijuana grow-ops, those operations are by their nature commercial ones and do not represent consumption for residential purposes. SMI should be classified as both customer and energy-related.
Allocation	
Generation and Transmission Demand Should the 4 Coincident Peak methodology continue to be used to allocate generation and transmission demand-related costs to customer classes? If not, why not? Refer to pages 25-27 of the Consideration Memo and slides 26-30 of the October 7th presentation.	
Transmission – radial lines Do you agree with BC Hydro's preferred option to allocate all transmission related costs (including those associated with radial lines) using the same methodology? Refer to the question above which deals with Generation and Transmission allocation, and slide 31 of the October 7th presentation.	

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Distribution Classification and Allocation: Introduction BC Hydro proposed to use Distribution customer base to categorize distribution O&M and capital related costs into substations, primary, transformers, secondary/services and meters. Using this categorization, BC Hydro proposed to classify: • substations and primary lines as 100% demand; • transformers as 50% demand and 50% customer (this classification is guided by the draft direct assignment results and would be used for rate design purposes); • secondary as 100% demand; • services as 100% customer; • meters as 100% customer. BC Hydro proposed to split the secondary/services asset category as 50% secondary and 50% services. Do you have any comments on BC Hydro's proposed Distribution sub-functionalization? Refer to pages 20-22 of the Consideration Memo, pages 12-14 of the Discussion Guide and slides 20-23 and 32-54 of the October 7th presentation.	
Substations and Primary Lines Do you agree that costs associated with substations and the Distribution primary system be classified as 100% demand and allocated using a Non-Coincident Peak (NCP) allocator?	

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Transformers Do you agree with BC Hydro's proposal to directly assign transformers to customer classes by using GIS information to map customers to transformers and then pro-rating the transformer's cost by the rate classes that use the unit (Option 1)? Assuming the final direct assignment results reasonably indicate a 50% demand/50% customer classification for transformers, will you agree with the proposed classification? If you don't agree with Option 1, should BC Hydro adopt Option 2 classify transformers as 100% demand and use a NCP allocator? If you do not agree with Options 1 or 2, please suggest other methods to classify and allocate transformer related costs.	
Secondary and Services Note that Table 1 (Preferred Option) of the Discussion Guide has been modified to reflect 100% classification of Secondary to demand instead of 50% demand and 50% customer. This proposal is consistent with the 7 October 2014 presentation material. Do you agree that the secondary/services asset category be split 50% secondary and 50% services? Do you support BC Hydro's proposal to classify the secondary portion as 100'% demand and the services portion as 100% customer? If not, please suggest other methods to determine this split. Do you agree the portion classified to demand be allocated using a NCP allocator while the customer portion be allocated using either a customer allocator or a weighted customer allocator?	

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October 7th COS Workshop #2 Feedback Form

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Meters Should meter related costs be classified as 100% customer and allocated using a weighted customer allocator?	
Customer Care Allocation Should BC Hydro continue allocating customer care costs using a weighted allocator based 90% on the number of bills and 10% on revenue by rate class? Refer to page 24 of the Consideration Memo and pages 14-16 of the Discussion Guide.	

Additional Comments, Items you think should be in-scope, not currently identified:

1. BC Hydro's June 19 Workshop Summary and Consideration of Participant Feedback makes the point (p.2) that a Marginal Cost approach will require a mechanism to adjust the MC COS results to capture only the revenue requirement. Another way of saying that is that an explicit method is required to allocate the benefits of low cost heritage power. With the Embedded Cost approach those benefits are allocated implicitly by the assumptions and calculations in allocating embedded costs. What Hydro characterizes as a problem with the MC approach is arguably an advantage since the benefits of low cost heritage power would then be explicitly allocated in a well considered manner in accordance with BCH and government objectives, and not obscured in the EC methodology.

2. The Summary points out on p.3 that all Canadian and most US Northwest utilities use the embedded cost approach. However, there are utilities like Seattle City Light and Portland General Electric that use the MC approach and make a strong case why it is beneficial, especially in times like the present when embedded and marginal energy costs are so different. WE expect that BC Hydro would acknowledge that many utilities are concerned about the efficiency and conservation problems raised by the embedded cost approach. Change from the status quo is always more difficult than maintaining it, but that does not mean it is not desirable.

3. It is not surprising that intervenors like AMPC don't support the MC approach (p. 3) because large industrials realize disproportionate benefit from low cost heritage power with the embedded cost approach. They do so because it is in the energy charge where the difference between embedded and marginal costs are so great

4. The Summary states at page 5 that there is no evidence that an MC approach would yield any meaningful efficiency or conservation gain. We disagree. First, the biggest distortion caused by the embedded cost approach is within the industrial sector, where elasticities are expected to be greater than with the other sectors. It is particularly problematic when embedded cost-based industrial rates attract new electric intensive industry despite the marginal cost implications. Second, Hydro's concern that the benefits of the MC approach are diluted when rates are adjusted to the total revenue requirement prejudges how that adjustment is done. It can be done in ways that minimize the 'dilution' effect.

5. The Summary states a concern that the MC approach would result in more volatile rates (p.6). But that is the point. When Marginal Costs change rates should change as well, to better signal customers the consequences of their demands for electricity. It is the unresponsiveness of the embedded cost approach despite a tripling of marginal energy costs over the last decade that is causing huge inefficiencies in the demand for electricity and conservation programs.

6. The Summary states that the embedded cost approach is easier (p.7). That may or may not be true, but regardless, that would only be relevant if there weren't other more important considerations -- like the efficiency of the price signals BC Hydro is sending to the most electric-intensive users. Being easy but wrong is of little value.

October 7th COS Workshop #2 Feedback Form

7. The Summary suggests that it would be too complicated to do a MC study as we requested (p.8). However, BC Hydro recognizes a MC approach would have a significant impact (relative increase) on the allocation of revenue requirements to industrial customers. Thus it is clear that Hydro has information which could be brought to bear on what an MC approach would do (and they do have previous studies on this). We ask that BC Hydro provide at least some rough estimates of the impact an MC approach would have relative to their embedded analysis approach for all customer classes.

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Signature:_____ ______________________________Date: __November 11, 2014___________________

Thank you for your comments.

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2015 RDA – October 7, 2014 Cost of Service Workshop #2 Feedback Form

Name/Organization: Progress Energy Canada Ltd. (PECL)

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	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Functionalization	
Demand Side Management (DSM) BC Hydro's preferred option is to functionalize DSM 90% Generation, 5% Transmission, and 5% Distribution (Option 1 in the discussion Guide). Do you agree with BC Hydro's preferred option? If not, why not, and what option do you suggest? Refer to pages 10-12 of the Consideration Memo, pages 3-4 of the Discussion Guide, and slides 7-9 of the October 7th presentation.	PECL agrees with BC Hydro's preferred option as a reasonable reflection of the actual benefits of the DSM program.
Classification	
Generation - Heritage Hydro BC Hydro presented three options to classify operation and maintenance (O&M) and capital related costs associated with BC Hydro's Heritage hydroelectric plants: Option 1A – load factor using total system load; Option 1B – load factor based on load served almost entirely by the hydroelectric system (i.e., total F2016 load minus Independent Power Producer (IPP) supply); Option 2 – capacity factor weighted by plant book value. Option 1B is BC Hydro's preferred option. Do you agree it should be used for Heritage Hydro Classification? If not, please indicate which option you suggest with reasons. Refer to pages 13-14 of the Consideration Memo, pages 5-7 of the Discussion Guide, slides 11-16 of the October 7th presentation and Attachment 1 to the October 7th COS workshop draft meeting notes.	After reviewing all the available material, PECL does not agree with BC Hydro's preferred option and proposes that BC Hydro adopt Option 2 to classify Heritage Hydro costs. The proposed reclassification penalizes customers with high load factors, which effectively becomes a disincentive for customers to achieve the flattest possible demand profile. PECL notes that BC Hydro is making significant investments at Revelstoke and Mica to increase capacity at those facilities without increasing energy, which implies that peak demand requirements are driving capital expenditures at the heritage hydro sites. High load factor customers help to mitigate such requirements because of their flat demand profiles. PECL is also concerned that BC Hydro's preferred option represents a departure from the existing practice that will cause a step change cost reallocation between customer classes.

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	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Generation – BC Hydro Thermal BC Hydro preferred option is to classify: • Prince Rupert Generating Station using the system load factor; • Fort Nelson Generation Station using the load factor in the Fort Nelson service territory; • Burrard Thermal Generating Station as 100% demand; • Fuel costs associated with running the plants would continue to be classified as 100% energy related. Do you agree with the proposed classification of thermal plant? If not, why not? Refer to pages 14-16 of the Consideration Memo and pages 8-10 of the Discussion Guide.	Thermal generation cost allocation should follow the same general approach as the capacity factor approach PECL supports using for the heritage hydro asset allocation.
Generation – IPPs Do you agree with BC Hydro's proposal to use Classification Option #2 which produces about a 93% energy/7% demand split? If you do not agree with Option 2, please suggest an alternative classification approach and provide reasons. Refer to Attachment 4 and pages 16-17 of the Consideration Memo, pages 10-11 of the Discussion Guide, slides 17-19 of the October 7th presentation, and Attachment 1 to the October 7th COS workshop draft meeting notes.	PECL agrees with BC Hydro's proposed Option #2 classification approach for IPPs.

	Comments **(Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).**
Smart Meter Infrastructure (SMI) Do you agree with BC Hydro's proposal to classify SMI regulatory account costs as 100% customer? Refer to pages 22-23 of the Consideration Memo, pages 11-12 of the Discussion Guide, slide 24 of the October 7th presentation and Attachment 1 to the 7 October COS workshop draft meeting notes.	PECL agrees with BC Hydro's proposed classification
Allocation	
Generation and Transmission Demand Should the 4 Coincident Peak methodology continue to be used to allocate generation and transmission demand-related costs to customer classes? If not, why not? Refer to pages 25-27 of the Consideration Memo and slides 26-30 of the October 7th presentation.	PECL agrees with BC Hydro's continued use of the 4CP methodology to allocate generation and transmission demand related costs.
Transmission – radial lines Do you agree with BC Hydro's preferred option to allocate all transmission related costs (including those associated with radial lines) using the same methodology? Refer to the question above which deals with Generation and Transmission allocation, and slide 31 of the October 7th presentation.	PECL agrees that radial assets should be treated using the same cost classification methodology as the bulk transmission system assets.

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Distribution Classification and Allocation: Introduction BC Hydro proposed to use Distribution customer base to categorize distribution O&M and capital related costs into substations, primary, transformers, secondary/services and meters. Using this categorization, BC Hydro proposed to classify: • substations and primary lines as 100% demand; • transformers as 50% demand and 50% customer (this classification is guided by the draft direct assignment results and would be used for rate design purposes); • secondary as 100% demand; • services as 100% customer; • meters as 100% customer. BC Hydro proposed to split the secondary/services asset category as 50% secondary and 50% services. Do you have any comments on BC Hydro's proposed Distribution sub-functionalization? Refer to pages 20-22 of the Consideration Memo, pages 12-14 of the Discussion Guide and slides 20-23 and 32-54 of the October 7th presentation.	N/A
Substations and Primary Lines Do you agree that costs associated with substations and the Distribution primary system be classified as 100% demand and allocated using a Non-Coincident Peak (NCP) allocator?	N/A

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Transformers Do you agree with BC Hydro's proposal to directly assign transformers to customer classes by using GIS information to map customers to transformers and then pro-rating the transformer's cost by the rate classes that use the unit (Option 1)? Assuming the final direct assignment results reasonably indicate a 50% demand/50% customer classification for transformers, will you agree with the proposed classification? If you don't agree with Option 1, should BC Hydro adopt Option 2 classify transformers as 100% demand and use a NCP allocator? If you do not agree with Options 1 or 2, please suggest other methods to classify and allocate transformer related costs.	N/A
Secondary and Services Note that Table 1 (Preferred Option) of the Discussion Guide has been modified to reflect 100% classification of Secondary to demand instead of 50% demand and 50% customer. This proposal is consistent with the 7 October 2014 presentation material. Do you agree that the secondary/services asset category be split 50% secondary and 50% services? Do you support BC Hydro's proposal to classify the secondary portion as 100'% demand and the services portion as 100% customer? If not, please suggest other methods to determine this split. Do you agree the portion classified to demand be allocated using a NCP allocator while the customer portion be allocated using either a customer allocator or a weighted customer allocator?	N/A

	Comments (Please do not identify third-party individuals in your comments. Comments bearing references to identifiable individuals will be discarded due to privacy concerns).
Meters Should meter related costs be classified as 100% customer and allocated using a weighted customer allocator?	N/A
Customer Care Allocation Should BC Hydro continue allocating customer care costs using a weighted allocator based 90% on the number of bills and 10% on revenue by rate class? Refer to page 24 of the Consideration Memo and pages 14-16 of the Discussion Guide.	N/A

Additional Comments, Items you think should be in-scope, not currently identified:

October 7th COS Workshop #2 Feedback Form

CONSENT TO USE PERSONAL INFORMATION

I consent to the use of my personal information by BC Hydro for the purposes of keeping me updated about the 2015 RDA. For purposes of the above, my personal information includes opinions, name, mailing address, phone number and email address as per the information I provide.

Signature:____ Date: ______________________

Thank you for your comments.

Comments submitted will be used to inform the RDA Scope and Engagement process, including discussions with Government, and will form part of the official record of the RDA.

You can return completed feedback forms by:

Mail: BC Hydro, BC Hydro Regulatory Group – "Attention 2015 RDA", 16th Floor, 333 Dunsmuir St. Van. B.C. V6B-5R3

Fax number: 604-623-4407 – "Attention 2015 RDA"

Email: bchydroregulatorygroup@bchydro.com

Form available on Web: http://www.bchydro.com/about/planning_regulatory/regulatory.html

Any personal information you provide to BC Hydro on this form is collected and protected in accordance with the ***Freedom of Information and Protection of Privacy Act***. BC Hydro is collecting information with this for the purpose of the 2015 RDA in accordance with BC Hydro's mandate under the ***Hydro and Power Authority Act***, the BC Hydro Tariff, the ***Utilities Commission Act*** and related Regulations and Directions. If you have any questions about the collection or use of the personal information collected on this form please contact the BC Hydro Regulatory Group via email at: bchydroregulatorygroup@bchydro.com

2015 Rate Design Application

October 7, 2014 Workshop No. 4
Cost of Service (COS) Methodology

BC Hydro Summary and Consideration of Participant Feedback

Attachment 3

IPP Capital Lease Costs Functionalization

As noted in section 8.13.1 of the F12- F14 RRA, the cost of energy for IPPs does not include those amounts deemed to be capital leases under IFRS accounting treatment. As a result of the unique treatment of capital lease costs in the RRA, only some of these amounts have been functionalized to Generation in past COS studies. Going forward, BC Hydro believes all of these costs should be considered Generation-related.

Table 1 provides an estimate of total IPP costs including the capital lease costs between F2011 and F2016.

Table 1 IPP Costs

Costs ($ million)	F2011	F2012	F2013	F2014	F2015	F2016
IPP Cost of Energy	675.1	735.3	760.4	859.5	1028.6	975.5
IPP Capital Lease	39.1	70.6	59.0	57.8	134.3	159.2
Total IPP Cost	714.2	805.9	819.4	917.3	1,162.9	1,134.7

For F2016, these IPP-related amounts (amortization, tax and finance charges) have been functionalized as Generation. The F2016 impact of this adjustment compared to perpetuating the prior treatment is set out in Table 2. This analysis isolates the impact of the different treatment to IPP capital leases and does not include the impact of BC Hydro's other preferred methodologies.

Table 2 R/C Ratio Impact of IPP Lease Functionalization

	DRAFT F2016 COS Results Using 2007 RDA Methodology	
Rate Class	Before Correcting for IPP Lease Functionalization (%)	After Correcting for IPP Lease Functionalization (%)
Residential	91.8	93.2
SGS	118.5	119.4
MGS	124.3	124.3
LGS	98.1	97.5
Irrigation	93.0	94.1
Street Lighting	124.6	126.9
Transmission	105.4	101.7

2015 Rate Design Application

October 7, 2014 Workshop No. 4
Cost of Service (COS) Methodology

BC Hydro Summary and Consideration of Participant Feedback

Attachment 4

BC Hydro Response to Marginal COS Issue Raised by COPE 378

In its written comments concerning Workshop No. 4, COPE 378 lists seven items regarding a marginal COS approach under the heading “Items you think should be in scope, not currently identified”. BC Hydro is of the view that the issue of whether to use a marginal COS approach to allocate BC Hydro’s revenue requirement is in scope for the 2015 RDA. However, BC Hydro rejects the use of a marginal COS approach for this purpose for the reasons set out in the Workshop No. 2 Consideration Memo. BC Hydro responds to COPE 378 marginal COS items 1, 2, 4 and 7 below.

COPE 378 Item 1 – The Workshop No. 2 Consideration Memo states that a marginal COS approach requires a mechanism to force projected revenues under marginal COS to equal the COMMISSION set revenue requirement. COPE 378 states that “another way of saying that is that an explicit method is required to allocate the benefits of low cost heritage power”.

COPE 378 Item 2 - “What [BC] Hydro characterizes as a problem with the marginal COS approach is arguably an advantage since the benefits of low cost Heritage power would then be explicitly allocated in a well-considered manner in accordance with BC Hydro and Government objectives, and not obscured in the embedded COS methodology”.

BC Hydro response - COS allocations do more than allocate the benefit of Heritage resource energy. A marginal COS study would necessitate development of allocation factors for all Commission set revenue requirements (established using embedded costs), many of which are not Heritage resource energy costs.

BC Hydro does not agree that a marginal COS-based allocation of Heritage resource energy accords with B.C. Government objectives:

- There exists an explicit method for allocating the benefits of Heritage resource energy. As noted in Attachment 3 to BC Hydro’s consideration memo concerning Workshop No. 3, in BC Hydro’s embedded COS study, the costs of both Heritage resource energy and non-Heritage resource energy are allocated to the customer classes on the energy consumption and peak demand of each customer class. As a result, each class receives a share of the benefits of the Heritage resources based on the class' share of total consumption and peak demand. This method for allocating the benefits of Heritage resource energy existed at the time the B.C. Government legislated the Heritage Contract in perpetuity in 2008,[1] and at the time the B.C. Government decided to continue the Heritage Contract provisions formerly found in Heritage Special Direction No. HC2 into Direction No. 7 in 2014.[2]

- Policy Action 4 of the 2007 Energy Plan calls for utilities to explore "new rate structures that encourage energy efficiency and conservation" [emphasis added]. This is what BC Hydro has done in respect of the 2008 Residential Inclining Block rate, for example. It is the rate design exercise that uses the results of a COS study that has value in establishing rates that could encourage conservation and efficiency. That is, regardless of the R/C ratio of a rate class, rate design is still required to establish efficient rates. As described in the Workshop No. 2 Consideration Memo, a majority of utilities, including so-called "marginal cost" utilities such as New York, design rate structures with marginal cost pricing while allocating revenue requirement on the basis of embedded costs. There is ample evidence that rate design based on embedded COS can provide efficient rates that reflect the cost of new supply. Additionally, marginal COS allocations are not transparent to customers. Rate structure design, where the consequences of consumption decisions are more readily apparent and transparent to customers, provide the means for encouraging energy efficiency and conservation.

COPE 378 Item 4 – The Workshop No. 2 Consideration Memo states at page 5 "that there is no evidence that a [marginal COS] approach would yield any meaningful efficiency or conservation gain. We disagree. First, the biggest distortion caused by the embedded cost approach is within the industrial sector, where elasticities are expected to be greater than with the other sectors. It is particularly problematic when embedded

[1] Order-in-Council (**OIC**) 849/2008 (November 28, 2008).
[2] OIC 097/2014 (March 6, 2014).

cost-based industrial rates attract new electric intensive industry despite the marginal cost implications. Second, [BC] Hydro's concern that the benefits of the [marginal COS] approach are diluted when rates are adjusted to the total revenue requirement prejudges how that adjustment is done. It can be done in ways that minimize the 'dilution' effect".

BC Hydro Response - BC Hydro has not prejudged how marginal COS results would be reconciled with its revenue requirement. The Workshop No. 2 Consideration Memo noted that with an embedded COS, one is starting with real, financially-based utility revenue requirement amounts that can be allocated to customer classes based on actual usage of the utility system resources. In contrast, calculations of Long-Run Marginal Costs on a per kWh, per kW and per customer basis inevitably results in a revenue total that is different from the utility revenue requirement. The Workshop No. 2 Consideration Memo at pages 7 to 8 outlines the three methods that are most frequently used to reconcile marginal COS results with the utility revenue requirement that is to be recovered:

- qualitative inverse elasticity method (also referred to as 'Ramsey Pricing') where the customer classes with the highest price elasticity are set closest to marginal COS results, and those with lower price elasticity are set farther from marginal COS results
- quantitatively-derived inverse elasticity method
- equal proportion method (sometimes referred to as the 'equal percentage marginal cost' or **EPMC**) where each customer classes' marginal COS results are adjusted by the same percentage to achieve the overall embedded COS revenue requirement.

There is a dilution effect regardless of which method is chosen to reconcile the marginal COS results with the utility revenue requirement.

It is not clear which method COPE 378 asserts will result in minimization of the dilution effect. COPE 378 references elasticities, and so perhaps the reference is to the inverse elasticity method. With the inverse elasticity method, the reconciliation process allocates a lower portion of the cost differential between the marginal COS and the embedded revenue requirement to those customer classes with the highest price elasticity levels, thereby setting their allocated COS closer to marginal cost levels than is allocated to those customer classes with lower price elasticity.

The inverse elasticity and EPMC reconciliation methods were canvassed by COPE 378's consultant Dr. Shaffer in his evidence submitted as part of the 2007 RDA. In his 2007 RDA evidence, Dr. Shaffer advocated for the use of an EPMC approach. Dr. Shaffer noted that the inverse elasticity method raises significant fairness issues and that it is difficult to measure customer class price elasticity levels accurately, with the result that this method has been used less frequently than EPMC:[3]

> Implementation of this inverse elasticity rule is problematic. Firstly, it offers greatest discounts to those classes of customers that are least willing or able to adjust their electricity consumption regardless of the price. It is not clear that this would be considered an equitable way to distribute the benefit of low cost heritage assets. Secondly, it requires generally accepted, reliable estimates of the price elasticity of demand. While there are many estimates of the price elasticity of electricity demand, and some acceptance of general findings, there is no consensus on specific estimates for specific classes of service or customer. Moreover, the ranges of estimates for different customer classes commonly overlap. They do not indicate a clear justification to allocate more of the discount to one class of customer over another.
>
> In response to these circumstances, the California Public Utilities Commission instituted an [EPMC] marginal cost approach. [Emphasis added].

BC Hydro does not believe that customers should be allocated more costs because they are more responsive to the price of electricity solely on the basis of purported

[3] Refer to Exhibit C6-5 in the Commission 2007 RDA proceeding (available at http://www.bcuc.com/Documents/Proceedings/2007/DOC_15489_C6-5_BCOAPO_Evidence.pdf), page 5.

higher efficiency levels. Nor does BC Hydro believe that more Heritage resource energy should be allocated to customer classes with allegedly lower price elasticity levels.

COPE 378 Item 7 – "The [Workshop No. 2 Consideration Memo] suggests that it would be too complicated to do a [marginal COS] study as we requested (page 8). However, BC Hydro recognizes a [marginal COS] approach would have a significant impact (relative increase) on the allocation of revenue requirements to industrial customers. Thus it is clear that Hydro has information which could be brought to bear on what an [marginal COS] approach would do (and they do have previous studies on this). We ask that BC Hydro provide at least some rough estimates of the impact a [marginal COS] approach would have relative to their embedded analysis approach for all customer classes".

BC Hydro Response – BC Hydro disputes that it has "information which could be brought to bear on what an [marginal COS] approach would do" as it has not conducted a full marginal COS study that would be necessary to make such an assessment. COPE 378 is perhaps referring to page 8 of the Workshop No. 2 Consideration Memo, where BC Hydro noted that there was 2007 RDA testimony from an intervener witness (Mr. Colin Fussell) that under the EPMC reconciliation approach, the Transmission service customer class would see a large increase in rates because they have high load factors and are using proportionately more energy, and that at the time, the marginal cost of energy was considerably higher than the embedded cost.[4] BC Hydro also noted there was no testimony on the subject of transmission, distribution or customer marginal costs.

To be responsive to COPE 378, BC Hydro provides an additional 2007 RDA reference - BC Hydro's response to Commission Panel Information Request 1.1.0,[5] where BC Hydro provided an example from that time that showed an EPMC reconciliation approach would redistribute the benefits of the Heritage Resource energy, with more of

[4] Refer to the 2007 RDA Decision, page 61.

[5] Exhibit B-10 in the 2007 RDA proceeding; http://www.bcuc.com/ApplicationView.aspx?ApplicationId=145.

the benefits being allocated to distribution-connected customers and fewer of the benefits being allocated to transmission-connected customers. This result occurred because under the EPMC reconciliation approach the benefit of the Heritage Resource energy would be effectively allocated based on the total costs of serving each rate class, rather than based on the energy consumed by each rate class. Since distribution-connected customers have higher total costs than transmission-connected customers, under the EPMC reconciliation approach the distribution-connected customers would receive a greater share of the benefits of the Heritage Resource energy.

In the 2007 RDA proceeding, BC Hydro submitted that it is not appropriate to allocate the benefits of the Heritage Resources based on the total costs of serving each rate class, since the Heritage Resources only relate to the Generation function. BC Hydro submitted that it is more appropriate to allocate the benefits of the Heritage Resources based on the energy consumed by each rate class, rather than based on the total costs of serving each rate class. BC Hydro continues to be of the view that the EPMC reconciliation approach if used would not provide an equitable allocation of the benefits of the Heritage Resources.

As noted in the Workshop No. 2 Consideration Memo, there are many types of marginal costs associated with electric utility operations, and there are a number of issues with respect to the definition and identification of both the marginal investment and operating expenses necessary to provide electricity to customers, as well as issues with the appropriate definition of marginal customer investment and operating costs. There are also significant issues concerning the marginal COS allocations of certain costs to customer classes that are similar in complexity to the issues necessarily raised in preparing an embedded COS analyses.

As one example of this complexity, under a marginal COS approach demand costs would need to be determined and segregated by function into Generation, Transmission and Distribution classifications. Calculating the additional costs necessary in providing an additional kW of demand (or kWh of energy) is not accomplished without the necessity of significant analysis and assumptions: these costs differ depending on the sources and timing of their production (Generation), the distance and sizing involved in their bulk movement from generating facilities to major load centres (Transmission), and the configuration and variety of facilities employed in their continued movement to customers (Distribution, both primary and secondary).

Additional issues include: (1) differentiating growth–related projects from sustaining projects for all elements of service; (2) the appropriate time period for the analysis (i.e., inclusion of growth projects with in-service dates over what period of time); (3) the evaluation of regional transmission lines and substation costs as well as distribution substations and trunk-line feeders that vary by area; (4) how the marginal costs of local distribution facilities that vary by customer type and location will be included in the marginal COS analysis; and (5) how would marginal customer costs be determined and differentiated from non-marginal customer costs, including what customer operating expenses are necessary and legitimate marginal costs.

Further complicating a marginal COS analysis is the fact that there is not one accepted methodology for conduction marginal COS analyses. As evidence of this, determination of marginal Transmission and Distribution capacity costs has been acrimonious in California despite the fact that the marginal COS approach has been the methodology in California for over 30 years. One method followed by some is termed "Regression/Real Economic Carrying Charge" (**RECC**).[6] RECC uses a regression approach to estimate the marginal investment per kW of peak demand and then amortizes (levelizes) this investment cost by multiplying by the RECC, yielding an annual dollar amount per kW-year which is equivalent in real terms to the investment in dollars per kW. The advocates of RECC state that this approach captures the full cost, rather than the deferral value, for each year of amortization. Another method followed by others is the present worth (**PW**); the term "PW" is not used here in its usual sense

[6] An article by Roger L. Conkling entitled "Marginal Cost Pricing for Utilities: A Digest of the California Experience" in *Contemporary Economic Policy* (Volume 17:1, January 1999) summarizes, among other things, the competing marginal transmission capacity cost approaches; copy available at http://www.freepatentsonline.com/article/Contemporary-Economic-Policy/54140870.html.

as this method seeks to estimates the opportunity cost of deferring Transmission and Distribution investments due to a change in load growth, taking into account both the timing and magnitude of such changes.

As discussed previously in the Workshop No. 2 Consideration Memo, BC Hydro considered the likely necessary costs that would be required as well as the complexity a marginal COS study would entail, and the limited possible benefits that might result from the preparation of a marginal COS study as part of the present effort. BC Hydro concludes that the evidence does not support the value of preparing such a study at present.