BC hydro
FOR GENERATIONS

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September 24, 2015

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
2015 Rate Design Application (2015 RDA, Application)

BC Hydro writes to file its 2015 RDA pursuant to sections 58(1)(a) and 61 of the *Utilities Commission Act*. The 2015 RDA is filed in compliance with Direction 4 of BCUC Order No. G-13-14. The 2015 RDA contains: BC Hydro's F2016 Cost of Service study; BC Hydro's proposals for the default Residential, Small General Service, Medium General Service, Large General Service and Transmission Service rates; and BC Hydro's proposals for Transmission Service rate options.

BC Hydro takes this opportunity to raise the following two matters.

1 Requested Orders and Suggested Review Processes

Section 1.1.3 of the 2015 RDA provides a description of the main elements of the four requested orders. Copies of the four requested orders are found at Appendix A-1A to Appendix A-1D of the Application.

Sections 1.6.1 and 1.6.2 of the Application contain BC Hydro's suggested review processes for the 2015 RDA:

- Section 1.6.1 of the Application sets out the suggested review processes for all 2015 RDA matters except one, which is the subject of section 1.6.2 of the Application;
- Section 1.6.2 of the Application relates to BC Hydro's requested final order for approval of amendments to Rate Schedules (**RS**) 1500/1501/1510/1511 and RS 1600/1601/1610/1611 to change the pricing for customers without historical baselines from 85 per cent of monthly consumption billed at the Part 1 energy rates and 15 per cent of monthly consumption billed at the Part 2 energy rates (referred to as 85/15 Pricing in the Application) to 100 per cent of the monthly consumption billed at the Part 1 energy rate (100 per cent Part 1 Pricing) effective January 1, 2016.

2 Residential Inclining Block Rate Report to the Government of British Columbia

By letter dated August 17, 2015 (**Commission RIB Report Methodology Letter**; Exhibit B-1 in the BCUC RIB Rate Report proceeding), the Commission requested that BC Hydro provide its submissions to the Commission by September 30, 2015 on: methodologies for the report BC Hydro will submit to the Commission on the five questions posed by the Minister of Energy and Mines in his letter of July 6, 2015 (**Minister RIB Report Letter**); any other issues with the RIB rate that have not previously been adequately addressed but should be reported on in BC Hydro's report to the Commission and the Commission's report to the Government; and comments on the Commission's proposed process and suggested timing. Consistent with the Minister RIB Report Letter, which provides that the Commission should use the 2015 RDA review process to collect information for the Commission's report to Government, BC Hydro provides its submissions concerning the Commission RIB Report Methodology Letter in sections 5.5 and 5.6 of the 2015 RDA.

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

Yours sincerely,

Original signed

Tom Loski
Chief Regulatory Officer

cg/af

Enclosure

Copy to: BC Hydro Workshop Invitation List

BC hydro

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Chapter 1

Introduction

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1.1 Introduction, Purpose of Application and Orders Sought

British Columbia Hydro and Power Authority (**BC Hydro**) files its 2015 Rate Design Application (**2015 RDA, Application**) with the British Columbia Utilities Commission (**BCUC or Commission**) pursuant to subsection 58(1)(a) and section 61 of the *Utilities Commission Act*[1] (***UCA***) to request orders as summarized in section 1.1.3 below.

1.1.1 Purpose of Application

This is BC Hydro's first comprehensive RDA since 2007, and only the third such application in BC Hydro's history (the first RDA was filed in 1991; the regulatory context, including relevant prior Commission decisions, is summarized in section 2.3.1, while the current environment context is addressed in section 2.3.2 of the Application).

The purpose of the Application is to update BC Hydro's default rate structures and Electric Tariff Terms and Conditions to reflect current conditions. (The term 'default rate' is described in section 1.4 below). Five factors underpin the requests made in the Application:

- First, pursuant to Order No. G-13-14[2] the Commission required an updated RDA to be filed in Fiscal[3] (**F**) 2016. As part of this process it was essential for BC Hydro to evaluate cost allocation and rate structures;
- Second, customer expectations of BC Hydro are increasing, and BC Hydro is looking for ways to make it easier for customers to do business with BC Hydro. Rates are a core part of overall customer care, and the ability of customers to understand and react to the signals the rates are intended to send is in

1 R.S.B.C. 1996, c.473; copy available at https://www.canlii.org/en/bc/laws/stat/rsbc-1996-c-473/latest/rsbc-1996-c-473.html.

2 http://www.bcuc.com/Documents/Orders/2014/DOC_40515_G-13-14-BCH-RIB-Rate-Re-Pricing-Reasons.pdf.

3 All years in this Application are stated in fiscal years (F20xx) ending on March 31, unless otherwise noted.

BC Hydro's view critical to a positive customer experience. BC Hydro also seeks to achieve an appropriate foundation to later develop rate options for its Residential and General Service customers, as further elaborated below in section 1.5.2. BC Hydro undertook a comprehensive process of customer engagement in preparation for this Application, described in section 2.2.3 of the Application, and endeavoured to reflect consensus views arising from the stakeholder engagement processes throughout its proposals where those could be discerned;

- Third, BC Hydro is operating under 'rate caps' set out in Direction No. 7 to the Commission[4] for purposes of BC Hydro's Revenue Requirements Application (**RRA**) for F2017, F2018 and F2019 of 4 per cent, 3.5 per cent and 3 per cent respectively. In addition, the British Columbia (**B.C.**) Government conveyed a focus on Transmission Service customer rate design through the 2013 Industrial Electricity Policy Review (**IEPR**) task force process and its response. BC Hydro is to examine ways to provide its Transmission Service customers with more options to reduce their electricity costs (refer to section 2.3.1.8 of the Application). The rate caps are described in section 1.3 below;
- Fourth, a number of elements, including a change to the regulatory regime relating to self-sufficiency[5] and a lower customer demand (referred to as 'load') forecast, have reduced forecasted energy and capacity need, and resulted in a lower energy Long-Run Marginal Cost (**LRMC**) which reflects BC Hydro's cost

[4] B.C. Reg. 28/2014; https://www.canlii.org/en/bc/laws/regu/bc-reg-28-2014/latest/bc-reg-28-2014.html.

[5] The Electricity Self-Sufficiency Regulation, B.C. Reg. 315/2010, as amended by Order in Council (**OIC**) No. 036 (B.C. Reg. 16/2012), requires BC Hydro to achieve self-sufficiency by 2016 and each year after that, assuming its Heritage hydroelectric resources are capable of producing no more than what they can produce under "average water conditions"; copy at https://www.canlii.org/en/bc/laws/regu/bc-reg-315-2010/latest/bc-reg-315-2010.html. Until the 2012 amendments, the Electricity Self-Sufficiency Regulation required BC Hydro to plan for self-sufficiency based on an assessment of what the Heritage hydroelectric resources are capable of generating under the most adverse sequence of stream flows between October 1940 and September 2000, known as 'critical water conditions'. The 2012 change in planning from critical water to average water conditions increases the combined reliance on the Heritage hydroelectric system non-firm energy backed by market reliance in F2017 by about 4,100 gigawatt hours per year (**GWh/year**), thus reducing the need for new energy resources. Self-sufficiency is explained in section 2.2.1.2 of the Application in the context of BC Hydro's energy LRMC.

to acquire new B.C. based Demand Side Management (**DSM**) and/or supply-side resources as described in BC Hydro's 2013 Integrated Resource Plan (**IRP**). Refer to section 2.3.2.2 of the Application; and

- Fifth, BC Hydro proposed and after Commission approval implemented a number of new rate designs between 2005 and 2013, including the default Transmission Service Stepped Rate (Rate Schedule (**RS**) 1823), the Residential Inclining Block (**RIB**) rate, and the Medium General Service (**MGS**) and Large General Service (**LGS**) two part energy rates. These rate initiatives responded to B.C. Government policy imperatives contained in the 2007 Energy Plan to among other things explore the use of rates to assist with achieving aggressive conservation goals (the 2007 Energy Plan is described in section 2.2.2.4 of the Application). In light of the reduced forecasted energy and capacity need, and the various evaluations of these rate initiatives as referenced in Chapters 5, 6 and 7, this is an apt time to take stock, and consolidate where appropriate (in BC Hydro's view, this applies to RS 1823 and the default RIB rate) and amend where appropriate (this is the case for the MGS and LGS two part energy rates).

1.1.2 Chapter Structure

The remainder of this Chapter is structured as follows:

- Section 1.1.3 summarizes BC Hydro's requested orders;
- Section 1.2 provides an overview of BC Hydro as applicant;
- Section 1.3 examines the relationships between rate design and BC Hydro's RRA and 2013 IRP;
- Section 1.4 sets out definitions of commonly used rate design terminology;
- Section 1.5 discusses BC Hydro's rate design priorities and how the Application sets a foundation for future rate design initiatives;

- Section 1.6 contains BC Hydro's suggestions for the 2015 RDA regulatory review process; and
- Section 1.7 concludes this Chapter with a road map for the remainder of the Application.

1.1.3 Orders Sought

The ten major elements of the requested orders are summarized and follow the Application chapter structure.

Division of Street Lighting Rate Class

1. A final order approving the division of the existing Street Lighting rate class into two new rate classes: customer-owned Street Lighting and BC Hydro-owned Street Lighting.

   *Note: Currently BC Hydro has a single Street Lighting rate class as noted below in section 1.4 and in section 4.6 of the Application. BC Hydro submits there is a strong basis for creating a separate rate class for BC Hydro-owned Street Lighting given the significant differences in Revenue to Cost (**R/C**) ratios*[6] *between BC Hydro-owned and customer-owned Street Lighting, Commission comments in the 2007 RDA decision and other factors. Refer to section 4.6 of the Application. This would result in two Street Lighting rate classes: BC Hydro-owned Street Lighting and customer-owned Street Lighting rate class.*

Residential Rates

2. A final order approving the following pricing principles for RS 1101/1121 for each of F2017 to F2019 (**RIB Pricing Principles**): each pricing element of RS 1101/1121 (Step 1 energy rates, Step 2 energy rates and basic charge) will

[6] R/C ratios reflect the extent to which BC Hydro is collecting revenue relative to the costs allocated to each rate class. Refer to section 3.1.1 of the Application.

increase by the RRA rate increases ordered by the Commission in regard to BC Hydro's revenue requirements on April 1, 2016, 2017 and 2018.

Note: RS 1101 is the RIB rate, which is the default Residential rate. RS 1121 is the RIB rate for Multiple Residential Service. The RIB rate structure is a two-step inclining block rate with the first step called the Step 1 energy rate and the amount above that the Step 2 energy rate. The RIB rate was implemented on October 1, 2008.

The term 'pricing principles' refers to how the RRA rate increases, which are set by the Commission through BC Hydro's RRAs, are applied to each of the RIB rate's pricing elements. By Order No. G-13-14 the Commission approved pricing principles which uniformly increases the three pricing elements of the RIB rate by the amount of the approved F2015/F2016 RRA rate increases. The terms energy rate and basic charge are explained in section 1.4 below.

The current RS 1101 and RS 1121 pricing principles expire on March 31, 2016. BC Hydro's proposed RIB Pricing Principles for RS 1101 and RS 1121 for F2017-F2019 continue with the Order No. G-13-14 pricing principles as described in section 5.2.5.1 of the Application.

BC Hydro expects to be filing its F2017 RRA in late February 2016 and at that time will seek interim rate orders, to be effective April 1, 2016, including an interim order increasing the RIB rate pricing elements in accordance with the requested RIB Pricing Principles described above.

3. A final order approving new terms and conditions in RS 1105 that enable BC Hydro to interrupt the service (**Residential E-Plus Amendment**) as illustrated in Appendix F-1D effective upon the date of the Commission order.

Note: RS 1105 – Residential Service – Duel Fuel is an interruptible service (closed to new customers) commonly referred to as the Residential E-Plus rate under which customers pay a discounted rate on condition of having an *alternative fuel back-up heating system. BC Hydro is proposing to continue with RS 1105 with amendments to make the Residential E-Plus rate practically interruptible. Refer to section 5.3 of the Application. A black-lined copy of the current RS 1105 showing the proposed changes is included in Appendix F-1D for illustrative purposes.*

BC Hydro will address RS 1151 and RS 1161 – Exempt Residential Service; and RS 1107 and RS 1127 – Residential Service Zone II as part of Module 2; refer to section 1.5 of the Application.

Small General Service rates

4. A final order effective April 1, 2017 approving a one-time increase to the RS 1300, RS 1301, RS 1310 and RS 1311 (**RS 13xx**) basic charge that would allow the basic charge to recover approximately 45 per cent of BC Hydro's customer-related costs attributable to the Small General Service (**SGS**) rate class in the F2016 Cost of Service (**COS**) study, and a one-time offsetting decrease in the energy rate set to maintain forecast revenue neutrality based on the SGS revenue target calculated using any applicable rate increases arising from the F2017 RRA (**SGS Proposal**).

Note: BC Hydro is not proposing any changes to the rate structures for customers who take service under RS 13xx, which customers make up the SGS rate class, except a one-time increase to the basic charge cost recovery of customer-related costs from about 33 per cent to 45 per cent, offset by a one-time decrease in the energy rate to maintain forecast revenue neutrality. The current SGS rate design consists of a flat energy rate and a basic charge. Refer to section 6.2.1 of the Application. Rate design addresses the allocation of the costs to different rate classes through COS studies; BC Hydro's F2016 COS is described in Chapter 3 of the Application. Revenue neutrality is discussed in section 1.4 below.

Medium General Service rates

5. A final order effective April 1, 2017 approving a new rate for customers who take service under RS 1500, RS 1501, RS 1510 and RS 1511 (**RS 15xx**) with a flat demand charge set to recover approximately 35 per cent of BC Hydro's demand-related costs attributable to the MGS rate class in the F2016 COS study and a flat energy rate set to maintain forecast revenue neutrality based on the MGS revenue target calculated using any applicable rate increases arising from the F2017 RRA (**MGS Proposal**).

   Note: BC Hydro is applying to amend the rates for customers who take service under RS 15xx, which customers make up the MGS rate class. The new MGS rate structures would consist of a flat energy rate, a flat demand charge, a basic charge and a monthly minimum charge. This is one of the most substantial changes BC Hydro is proposing in the 2015 RDA. The current MGS rate design consists of a two-part energy rate implemented in stages with all MGS customers transitioned to the existing two-part rate by April 1, 2013, a three step demand charge (and a basic charge and monthly minimum charge). Black-lined copies of the current RS 15xx showing the proposed changes is included in Appendix F-1E for illustrative purposes.

   BC Hydro is also applying for one-time increase to the MGS demand charge recovery of demand-related costs from approximately 15 per cent to 35 per cent, and a flat energy rate to maintain forecast revenue neutrality. The term demand charge is explained in section 1.4 below.

   BC Hydro proposes a one-step transition from the current MGS rate structure to BC Hydro's proposed MGS rate structure. Refer to sections 6.3.1 and 6.5.1 of the Application.

Large General Service Rates

6. A final order effective April 1, 2017 approving a new rate structure for customers who take service under RS 1600, RS 1601, RS 1610 and RS 1611 (**RS 16xx**) with a flat demand charge set to recover approximately 65 per cent of BC Hydro's demand-related costs attributable to the LGS rate class in the F2016 COS study and a flat energy rate set to maintain forecast revenue neutrality based on the LGS revenue target calculated using any applicable rate increases arising from the F2017 RRA (**LGS Proposal**).

   Note: BC Hydro is applying to amend the rates for customers who take service under RS 16xx, which customers make up the LGS rate class. The new LGS rate structure would consist of a flat energy rate, a flat demand charge, a basic charge and a monthly minimum charge. This is another of the most substantial changes BC Hydro is proposing in the 2015 RDA. The current LGS rate design consists of a two-part energy rate implemented on January 1, 2011, a three step demand charge (and a basic charge and monthly minimum charge). Black-lined copies of the current RS 16xx showing the proposed changes is included in Appendix F-1E for illustrative purposes.

   BC Hydro is also applying for a one-time increase to the LGS demand charge recovery of demand-related costs from approximately 50 per cent to 65 per cent and a flat energy rate to maintain forecast revenue neutrality.

   BC Hydro proposes a one-step transition from the current LGS rate structure to BC Hydro's proposed LGS rate structure. Refer to sections 6.4.1 and 6.5.2 of the Application.

   There are a number of related approvals BC Hydro seeks as part of the MGS Proposal and LGS Proposal:

   - *Amendments to RS 1200/1201/1210/1211 (**RS 12xx**) eliminating the applicability of the rate to the large and medium general service control* *group of customers (**GS - Control Group Proposal**). Black-lined copies of the current RS12xx showing the proposed changes is included in Appendix F-1E;*

- *The elimination of RS 2600/2601/2610/2611(**RS 26xx**) (**GS – Distribution Utilities Proposal**);*
- *The elimination of Tariff Supplement No. (**TS**) 82 Rules for LGS Prospective Growth Applications (**TS 82 Proposal**).*

These respective approval requests are described in section 6.7 of the Application.

*BC Hydro is also requesting a separate final order for approval of amendments to RS 15xx and RS 16xx to change the pricing for customers without historical baselines from 85 per cent of monthly consumption billed at the Part 1 energy rates and 15 per cent of monthly consumption billed at the Part 2 LRMC-based energy rates (**85/15 Pricing**) to 100 per cent of the monthly consumption billed at the Part 1 energy rate (**100 per cent Part 1 Pricing**) effective January 1, 2016. This requested order is described further at the end of this section and in section 6.6 of the Application. Black-lined copies of the current RS 15xx and RS 16xx tariff pages showing the proposed changes are included in Appendix F-1A. There would be no need for either 85/15 Pricing or 100 per cent Part 1 Pricing if the Commission approves the MGS Proposal and the LGS Proposal, and thus this requested final order would be supplanted by the final order concerning MGS Proposal and the LGS Proposal effective April 1, 2017 if such final order is granted.*

Transmission Service Rates

7. A final order approving the following pricing principles for RS 1823 for each of F2017 to F2019:

- For F2017, set the Tier 2 rate to the lower end of BC Hydro's energy LRMC and the Tier 1 rate to reflect any RRA rate increase applicable to F2017 arising from the F2017 RRA according to the bill neutrality approach i.e., 90 per cent of the Tier 1 rate plus 10 per cent of the Tier 2 rate is equal to the flat rate (RS 1827 energy rate or the RS 1823 Energy Charge A). Other pricing elements (demand charge, energy rate applicable to RS 1823 customers that do not have a Customer Baseline Load (**CBL**) and monthly minimum charge) will increase by the same applicable F2017 RRA rate increase;
- For F2018 and F2019, each pricing element of RS 1823 (Tier 1 energy rate, Tier 2 energy rate, demand charge, energy rate applicable to RS 1823 customers that do not have a Customer Baseline Load (**CBL**) and monthly minimum charge) will increase by the same RRA rate increase ordered by the Commission in regards to BC Hydro's revenue requirements on April 1, 2017 and 2018 (collectively, the **RS 1823 F2017-F2019 Pricing Principles**).

Note: RS 1823 - Transmission Service – Stepped Rate is the default rate for Transmission Service customers implemented on April 1, 2006 pursuant to BCUC Order No. G-79-05.[7] *Energy rates and demand charges are also explained in section 1.4 below.*

The current RS 1823 pricing principles expire on March 31, 2016. The RS 1823 F2017-F2019 Pricing Principles are described in section 7.2.2 of the Application.

The RS 1823 F2017-F2019 Pricing Principles continue with the pricing principles implicit in subsection 3(c) of Direction No. 6[8] *to the Commission, which provides that the Commission must uniformly increase the pricing elements of RS 1823 by the amount of the approved F2015/F2016 RRA rate*

[7] Copy at http://www.bcuc.com/Documents/Orders/2005/DOC_8391_G-079-05_BCHydro_TSRA%20Reasons%20for%20Decision.pdf.

[8] B.C. Reg. 29/2014; https://www.canlii.org/en/bc/laws/regu/bc-reg-29-2014/latest/bc-reg-29-2014.html.

*increases, with a one-time F2017 adjustment to comply with subsection 3(1) of Direction No. 7 to the Commission. Subsection 3(1) of Direction No. 7 requires the Commission, in designing rates for BC Hydro's Transmission Service customers, to ensure that those rates are consistent with Recommendation #8 of the Commission's October 2003 Heritage Contract and Stepped Rates Report and Recommendations (**Heritage Contract Report**).*[9] *The B.C. Government accepted Recommendation #8, which provides that the Transmission Service stepped rate (RS 1823) should be implemented according to a number of principles, including that the Tier 2 rate should reflect BC Hydro's LRMC. Refer to section 2.2.1.3 of the Application for an overview of Direction No. 7. BC Hydro's energy LRMC range is described in section 2.3.2.2 of the Application.*

As noted above in respect of the RIB Pricing Principles, BC Hydro expects to be filing its F2017 RRA in late February 2016 and at that time will seek interim rate orders, to be effective April 1, 2016, including an interim order increasing the RS 1823 pricing elements in accordance with the requested RS 1823 F2017-F2019 Pricing Principles described above.

8. A final order approving a revision to the definition of "Availability" for clarity and a change in the RS 1852 definition of High Load Hours (**HLH**) to provide BC Hydro discretion to determine the HLH periods that will apply based on a customer location/region which affords BC Hydro the possibility to curtail to alleviate potential local or regional transmission constraints or take advantage of a market opportunity.

   Note: RS 1852, the Transmission Service - Modified Demand rate, is an interruptible rate. Refer to section 7.3.2 of the Application. HLH refers to the

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[9] *In the Matter of British Columbia Hydro and Power Authority: An Inquiry into a Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation Resources and Regarding Stepped Rates and Transmission Access, Report and Recommendations*, October 17, 2003, section 3.0, especially pages 58 to 62; https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/heritage-contract.pdf.

time of day in which peak demand occurs.[10] *A black-lined copy of the current RS 1852 showing the proposed changes is included in Appendix F-1C.*

*BC Hydro is not proposing any changes to the other four existing Transmission Service rates that are within scope for the 2015 RDA, namely RS 1825 Transmission Service Time of Use (**TOU**) Rate; RS 1827 Transmission Service – Rate for Exempt Customers; RS 1853 – Transmission Service – IPP Service Station; and RS 1880 - Transmission Service – Standby and Maintenance.*

RS 1891 – Shore Power Service (Transmission) was approved on June 25, 2015 by BCUC Order No. G-58-15[11] *and therefore is not part of the 2015 RDA because of its recent review and approval; refer to section 2.5 of the Application.*

9. A final order approving the Transmission Service freshet rate pilot for the period March 1, 2016 to December 31, 2017, identified as RS 1892 in Appendix F-1B, to be available to Transmission Service customers presently taking service under RS 1823 who apply to BC Hydro for this service. BC Hydro has committed to file with the Commission two preliminary evaluation reports by October 31, 2016 and October 31, 2017 respectively, and a final evaluation report by June 21, 2018.

Note: The two year freshet rate pilot is a new optional Transmission Service non-firm (interruptible) rate which offers market-priced energy to participating RS 1823 customers to encourage such customers to increase electricity consumption during BC Hydro's freshet period of May to July, as BC Hydro has a long-term recurring issue of energy oversupply during this period. The freshet rate pilot is for non-firm service; BC Hydro will agree to provide electricity under

10 Refer to the Glossary and Abbreviations at Appendix B to the Application.

11 Copy at http://www.bcuc.com/Documents/Proceedings/2015/DOC_43962_06-25-2015_BCH-Shore-Power-Decision_G-111-15.pdf.

the freshet rate pilot to the extent it has the energy and capacity to do so. The proposed freshet rate pilot is described in section 7.3.4 of the Application.

BC Hydro is requesting that the Commission approve the freshet rate pilot by February 1, 2016 to ensure BC Hydro has time to implement the Commission decision by March 1, 2016. BC Hydro sees March 1, 2016 as the deadline for participating in Year 1 and March 1, 2017 as the deadline for participating in Year 2 of the two year freshet rate pilot. BC Hydro's proposed regulatory review process in section 1.6.1 below is designed to ensure the freshet rate pilot is in place prior to the 2016 freshet May-July period.

*The freshet rate pricing will not change during the two year pilot as a result of RRA rate increases. This is because the freshet rate pilot pricing during the HLH and Light Load Hour[12] (**LLH**) of the freshet period is the greater of the ICE Mid-Columbia[13] (**Mid-C**) Peak and Mid-C Off-Peak weighted average index price that corresponds to the hour and $0 per kilowatt hour (/**kWh**), plus a wheeling rate of $3 per megawatt hour (/**MWh**) from Mid-C to the U.S.-B.C. border.*

Electric Tariff Terms and Conditions

10. A final order effective the date of the order approving the Terms and Conditions of the Electric Tariff[14] attached as Appendix G-1 to the Application.

*Note: BC Hydro is proposing to update various Electric Tariff Terms and Conditions of Service (**Terms and Conditions**) including new Standard Charges contained in section 11 of the Electric Tariff. Minimum Reconnection Charges in section 11.2 of the Electric Tariff are part of the Standard Charges and have been the subject of specific stakeholder engagement. BC Hydro*

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[12] Generally speaking, the time of day in which off-peak occurs.
[13] Mid-C is a wholesale electricity trading hub located in the United States (**U.S.**) Pacific Northwest.
[14] A link to BC Hydro's current Electric Tariff is https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf.

*seeks approval to revise the Minimum Reconnection Charges effective April 1, 2016; the effective date of the balance of the Terms and Conditions would be on the date of the final order. Proposed changes to Standard Charges, including Minimum Reconnection Charges, are described at section 8.3 of the Application. As noted in section 1.7.3 of the Application, the revised Terms and Conditions, which are administrative in nature, will be filed with BC Hydro's responses to the first round of Information Requests (**IRs**) as Appendix G-1.*

The scope of 2015 RDA Module 1 includes all of the Terms and Conditions with the exception of: section 8 governing Distribution extensions; section 9.2 (Resale of Electricity); section 10 concerning Rate Zone IB and Rate Zone II issues; and section 11.3 of the Electric Tariff (Transformer Rental Charge). RDA Module 2 will address these topics. Refer to section 1.5 below with respect to what RDA Module 2 is to consist of, and to section 8.1 of the Application for a more detailed description of the scope of 2015 RDA Module 1 review of the Terms and Conditions.

Draft forms of the requested orders are attached as Appendix A to the Application:

- Appendix A-1A: MGS and LGS 100 per cent Part 1 Pricing. BC Hydro's suggested regulatory review process for the 100 per cent Part 1 Pricing amendment is set out at section 1.6.2 below;
- Appendix A-1B: RS 1823 F2017-F2019 Pricing Principles; freshet rate pilot proposal; and RS 1852 amendments. BC Hydro's suggested regulatory review process for the RS 1823 F2017-F2019 Pricing Principles, freshet rate pilot proposal and RS 1852 amendments is described in section 1.6.1 below;
- Appendix A-1C: Proposed changes to the Minimum Reconnection Charges. BC Hydro's suggested regulatory review process for Minimum Reconnection Charges is described in section 1.6.1 below;

- Appendix A-1D: BC Hydro-owned Street Lighting rate class; RIB Pricing Principles; SGS Proposal; MGS Proposal; LGS Proposal; and Terms and Conditions (except the Minimum Reconnection Charges).

1.2 The Applicant

BC Hydro is a Crown corporation established in 1964 under the *Hydro and Power Authority Act*.[15] BC Hydro is the third largest electric utility in Canada with a customer base serving 94 per cent of B.C.'s population in a service area that encompasses most of B.C. with the exception of City of New Westminster (**New Westminster**) and the south-central part of the Province served by FortisBC Inc. (**FortisBC**).

BC Hydro's integrated electric system includes 30 hydroelectric generating facilities, two natural gas-fired generating facilities and a number of independent power producer (**IPP**) projects with whom BC Hydro contracts. BC Hydro delivers electricity over 72,000 kilometers of transmission and distribution lines:

- The transmission system includes facilities used to transmit electricity, usually at voltages greater than 69 kilovolts (**kV**);
- The distribution system includes electrical lines, cables, transformers and switches used to distribute electricity from substations to customers, generally at voltages lower than 69 kV.

The demand on BC Hydro's system for customers connected to the integrated system or 'grid' in F2015 was 9,676 megawatts (**MW**), which includes capacity sales by BC Hydro to other utilities such as New West and FortisBC. The total integrated system gross energy requirement, including sales by BC Hydro to other utilities, was

[15] Current version is R.S.B.C 1996, c.212; https://www.canlii.org/en/bc/laws/stat/rsbc-1996-c-212/latest/rsbc-1996-c-212.html.

55,345 GWh. The off-grid Non-Integrated Areas'[16] (**NIAs**) demand adds another 328 GWh resulting in 55,674 GWh of total gross requirement.

1.3 Relationship of Rate Design to BC Hydro's Revenue Requirement and Integrated Resource Plan

BC Hydro's RRAs and rate design are often compared to the making and serving of a pie. A RRA sets a public utility's revenue requirement (or the size of the 'pie'). The revenue requirement is the amount of revenue to be recovered in rates. Rate design addresses the allocation of the costs to different rate classes through COS studies (refer to section 1.4 below for a description of BC Hydro's rate classes). RDAs also set the rate design for collecting each customer's share of the pie served to their rate class. Importantly, this means that BC Hydro through the 2015 RDA is not seeking to increase the size of the pie, and a Commission decision on the 2015 RDA will not change BC Hydro's total revenue requirement. BC Hydro's F2016 revenue requirement has already been determined by the Commission pursuant to BCUC Order No. G-48-14.[17] BC Hydro is planning to submit its next RRA for the F2017-F2019 test period to the Commission sometime in February 2016.

BC Hydro's revenue requirement for F2016, the most current approved revenue requirement available, is used for the COS study in Chapter 3 of the Application. Section 9 of Direction No. 7 to the Commission provides that the Commission, when setting rates for BC Hydro for F2017, F2018 and F2019 must not allow rates to increase by more than 4 per cent in F2017, 3.5 per cent in F2018 and 3 per cent in F2019 on average when compared to the rates for BC Hydro immediately before the increase. These Direction No. 7-related rate increase figures are commonly referred to as 'rate caps', and they are used by BC Hydro when modelling various rate

[16] NIAs are not interconnected to BC Hydro's main electric system. In BC Hydro's Electric Tariff, NIAs consist of Zone II (Anahim Lake, Atlin, Bella Coola, Dease Lake, Ehlateese, Fort Ware, Haida Gwaii, Hartley Bay, Telegraph Creek District, Toad River and Tsay Keh) and Zone IB (Bella Bella). Refer to Appendix B, which is the Glossary and Abbreviations.

[17] Copy available at: http://www.bcuc.com/Documents/Orders/2014/DOC_41122_G-48-14_BCH-F15-16-RevenueRequirements.pdf.

designs to determine customer bill impacts. Refer to Chapters 5, 6 and 7 of the Application for further detail. Direction No. 7 and the legal context are described in section 2.2.1 of the Application.

BC Hydro prepares IRPs to address questions of how much, when and what resources should be advanced to meet its customers' electricity needs. BC Hydro submits its IRPs to the B.C. Minister of Energy and Mines in accordance with section 3 of the *Clean Energy Act*[18] (***CEA***) and the B.C. Lieutenant Governor in Council (**LGIC**) is the body responsible for approving BC Hydro's IRPs pursuant to section 4 of the *CEA*. BC Hydro's most recent IRP, the 2013 IRP, was approved by the LGIC on November 15, 2013.[19] The main link between the 2013 IRP and this Application is with respect to BC Hydro's LRMC. LRMC represents the price of the most cost-effective way of satisfying incremental customer demand where existing resources are insufficient to meet that demand, and is used by BC Hydro in rate design applications. Refer to section 2.3.2 of the Application for a discussion of BC Hydro's energy LRMC and capacity LRMC, and their application to rate design.

1.4 Rate Design Terminology

BC Hydro's rates determine the amount that is charged to customers for providing them with electricity. This section provides descriptions of rate design concepts used throughout the Application. Appendix B to the Application is a glossary containing additional definitions of rate design elements and concepts.

Rate Class – Electric utility customers are divided into classes of service or sectors based on consumption levels and patterns, and the associated impact on the utility's costs of providing the service. BC Hydro currently has seven rate classes for cost of service purposes as set out in Table 1-1, which also provides domestic revenues and sales volumes by rate class for F2015.

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18 S.B.C. 2010, c.22; https://www.canlii.org/en/bc/laws/stat/sbc-2010-c-22/latest/sbc-2010-c-22.html.

19 Order-in-Council (**OIC**) No. 514 (2013); https://a100.gov.bc.ca/appsdata/epic/documents/p371/1387903910668_e1ae08954fd45cd9010bfaf62057f0fc98622a796e4d242c0efecb3175f7f14a.pdf.

Table 1-1 Current BC Hydro Rate Classes

Rate Class	BC Hydro Observation	$ million F2015	GWh F2015
Residential	Includes customers under the RIB rate, such as apartments, town houses and single family dwellings. Excludes NIAs	1,580	16,459
SGS	Collectively, can be thought of as BC Hydro's commercial and small industrial customers, including but not limited to: hotels, motels, mobile home parks and similar establishments that do not qualify for Residential service; schools, churches, hospitals and recreational establishments; nursing homes, boarding homes and rooming houses; and marinas and yachts	411	3,934
MGS		301	3,329
LGS		779	10,885
Transmission Service	Customers served at transmission voltage level (69 kV and above)	769	14,986
Irrigation	Customers using electricity for irrigation and outdoor sprinkling during the 1 March to 31 October irrigation season	5	66
Street Lighting	Lighting of public highways, streets, lanes, municipal pathways, other outdoor lighting, traffic signals, traffic signs, traffic warning devices and other equipment for controlling or directing vehicles and pedestrians	36	230

The SGS, MGS and LGS rate classes are collectively referred to at times in this Application as General Service.

Chapter 4 of the Application contains more detailed descriptions of these seven rate classes and the analysis BC Hydro used to determine that these rate classes remain appropriate, with one exception. As noted in section 1.1.3 above, BC Hydro proposes to divide the existing Street Lighting class into two new rate classes: customer-owned Street Lighting and BC Hydro-owned Street Lighting. There are meaningful cost differences between these two types of service. Refer to section 4.6 of the Application.

Revenue Neutrality – Revenue neutrality is a concept that arises when the rate structure applicable to a rate class changes. A new rate structure is revenue neutral if it yields the same revenue that would have resulted from the rate structure that is being replaced for that class. All of BC Hydro’s proposed rates are forecast revenue neutral in this generic sense of the expression. However, revenue neutrality can be applied in different ways, as discussed in relation to each of BC Hydro’s rate designs for the five main rate classes in Chapters 5, 6 and 7 of the Application.

Default Rates and Optional Rates – Default rates are rates that all customers pay unless they have options and choose to opt for another rate. Optional rates are rates that customers can voluntarily choose to be on.

Energy Rate, Basic Charge and Demand Charge – Generally speaking BC Hydro’ s rates consist of an energy rate (all of BC Hydro’s Transmission Service, General Service and Residential rates have energy rates), which is the calculation of the amount of electricity kWh consumed during the billing period, and a basic charge to recover a part of the fixed costs of service which do not vary with usage such as metering and billing (BC Hydro’s default General Service and Residential rates have basic charges). BC Hydro’s Transmission Service (e.g., RS 1823 and RS 1827) and the LGS (RS16xx) and MGS (RS 15xx) default firm service rates have demand charges, whereas BC Hydro’s interruptible rates do not have a demand charge (e.g., RS 1880). Demand charges are based on the customer’s highest kilowatt (**kW**) demand during the billing period. Demand charges are used to help recover some of the demand-related costs of providing electricity service to customers. BC Hydro has to maintain sufficient capacity to satisfy all its customers’ needs at once and these costs are relatively fixed. Therefore demand charges do not vary according to customers’ consumption, but are applied to their demand on the system.

1.5 Rate Design Priorities and RDA Modules

1.5.1 BC Hydro's Rate Priorities

Rate design is a complex process that must take into account multiple and competing objectives and multiple stakeholder interests. BC Hydro's rate design proposals are evaluated in accordance with generally accepted rate design criteria. The eight rate design criteria are derived from Bonbright's *Principles of Public Utility Rates*[20] text and are described in section 2.4.1 of the Application. In light of the five factors identified in section 1.1.1 above, BC Hydro prioritizes the three Bonbright rate design criteria set out in Table 1-2.

Table 1-2 Three BC Hydro Prioritized Rate Design Criteria

Rate Design Criteria	Description
Customer understanding and acceptance/Practical and cost-effective to administer	Rates should be clear, transparent and cost-effective to implement.
Stable rates for customers	Overall, minimize unexpected changes that can be seriously adverse to existing customers: If existing rates are understandable and generally accepted, and continue to be useful, they should not be replaced with new rates; For those rates that do not meet the customer understanding and acceptance criterion and/or are no longer useful, replace or amend the rate so that the rate is simple, understandable, has public acceptability, and is feasible from an application and interpretation perspective.
Fair apportionment of cost among customers	BC Hydro uses the fairness criterion for intra-class purposes in the Application, and in particular to examine cost recovery through variable energy rates versus recovery of fixed costs through basic charges and/or demand

[20] James C. Bonbright, *Principles of Public Utility Rates* (1st Edition; Columbia University Press: New York, 1961), page 291. The eight criterion are: Price signals that encourage efficient use and discourage inefficient use; fair apportionment of costs among customers; Avoid undue discrimination; Customer understanding and acceptance/practical and cost effective to implement; Freedom from controversies as to proper interpretation; Recovery of the revenue requirement; Revenue stability; and Rate stability.

Rate Design Criteria	Description
	charges. As a result of the recent amendment[21] to Direction No. 7 to the Commission which provides that in setting rates for BC Hydro for F2017-F2019, the Commission must not set rates for the purposes of changing the R/C ratio for a class of customers.

1.5.2 Application as Foundation and RDA Modules

BC Hydro carried out stakeholder engagement with respect to the 2015 RDA from May 8, 2014 to mid-September 2015 using an array of input streams as described in section 2.2.3 of the Application. At the first 2015 RDA workshop (**Workshop 1**) on May 8, 2014, a number of stakeholders and Commission staff commented that given the broad scope of the 2015 RDA, it would make sense to undertake the 2015 RDA regulatory review in stages (referred to as 'modules'). Stakeholders identified Transmission extension policy and Distribution extension policy, which respectively govern new customer payments towards transmission and distribution infrastructure required to serve them, as candidates for a later module.[22] At Workshop 6 and Workshop 7, BC Hydro confirmed with stakeholders that Transmission extension policy and Distribution extension policy would be the subject of a later module (referred to as **Module 2**). At Workshop 9b BC Hydro identified the following as issues to be addressed as part of Module 2: (1) rate structures for NIAs; (2) Irrigation and Street Lighting rate structures; and (3) farm service issues.[23]

This Application is referred to in places as **2015 RDA Module 1**. The scope of 2015 RDA Module 1 consists of BC Hydro's F2016 COS study; proposals for Residential, SGS, MGS, LGS and Transmission Service default rates; and Transmission Service

[21] OIC No. 405; B.C. Reg. 140/2015, amending section 9 of Direction No.7, described in section 2.2.1.3 of the Application.

[22] Refer to pages 3-4 of the Workshop 1 consideration memo found at Appendix C-1A to the Application.

[23] Refer to the Workshop 9b presentation slide deck, slides 36 and 40, copy at Appendix C-3B to the Application; and to sections 7.1.2 and 7.2.2 of the Workshop 9a/9b consideration memo at Appendix C-3B. It would be difficult for farm Residential, farm General Service, Irrigation and NIA customers to understand and evaluate their preferences and for BC Hydro to evaluate trade-offs until final Residential, SGS, MGS and LGS default rate designs are resolved through BC Hydro's proposals and a Commission decision.

rate options. The principal reason for including Transmission Service rate options as part of Module 1 is that such options were identified and had the benefit of being examined as part of the 2013 IEPR task force process (the IEPR process, recommendations and B.C. Government responses are discussed in section 2.3.1.8 of the Application). 2015 RDA Module 1 supports and is in line with B.C. Government policy as described in section 2.2.2 of the Application, and is put forward by BC Hydro only after extensive engagement with stakeholders and customers.

BC Hydro’s preference is to use Module 1 to set the default Residential and General Service rate structures. In particular, BC Hydro believes that before it pursues optional rates for General Service customers it is imperative that the issues with the default rates for MGS and LGS customers be addressed (these problems are enumerated in sections 6.3 and 6.4 of the Application). Accordingly, BC Hydro plans to address voluntary Residential and General Service options as part of 2015 RDA Module 2. In this way, Module 1 sets the foundation for future BC Hydro proposals concerning Residential and General Service customers rate options to offer such customers additional choice.

BC Hydro currently provides customers choice through a variety of billing mechanisms and flexible payment arrangements such as Equal Payment Plan, a service available to customers to bill their estimated annual cost of service in equal monthly amounts over a 12 month period, and Pay As You Go Billing Plan (section 2.4.1 of the Electric Tariff), which allows monthly payments based on an estimate to be paid one month in advance. Refer to section 8.6.2 of the Application. Examples of optional Residential and General Service customer rates raised by stakeholders include:

- A rate for Electric Vehicle at home-charging;

- A voluntary prepayment option pursuant to which Residential customers pay for a set value of electricity in advance of consumption, rather than paying monthly or bi-monthly after electricity is used;
- Interruptible rate(s) for General Service customers.

BC Hydro foresees filing Module 2 with the Commission in the fall/winter of 2016, sometime after receiving Commission Module 1-related order(s); a review period to consider such order(s); and additional stakeholder engagement.

1.6 Proposed Regulatory Review Process for Application and Communications

1.6.1 Proposed Regulatory Review Process for Application Except for Medium General Service and Large General Service 100 per cent Part 1 Pricing

BC Hydro proposes a process of one round of Commission and Intervener IRs, followed by a Procedural Conference to determine: (1) whether expedited approval processes should be pursued for some elements of the Application including Streamlined Review Process(es) (**SRP**) and/or Negotiated Settlement Process(es) (**NSP**), with review of the remainder of the Application to proceed by way of a second round of IRs and an oral hearing; and (2) if interveners intend to file evidence. Refer to Table 1-3.

Table 1-3 Proposed Regulatory Review Process for Application Except for Medium General Service and Large General Service 100 per cent Part 1 Pricing

Process	Date
Filing of Application	September 24, 2015
Commission Issues Regulatory Timetable	October 6 ,2015
Round 1 Commission IRs	October 16, 2015
Round 1 Intervener IRs	October 23, 2015
BC Hydro Responses to Round 1 IRs	December 2, 2015
Procedural Conference	December 17, 2015

Based on stakeholder feedback, BC Hydro identified the following as SRP/expedited review candidates:

- Freshet rate pilot - As described above in section 1.1.3 above, BC Hydro is requesting approval for the freshet rate pilot by February 1, 2016. Accordingly, BC Hydro proposes that the freshet rate pilot regulatory review process consist of one round of IRs followed by a SRP in January 2016 so that the Commission can issue an order no later than February 1, 2016. This request is supported by Association of Major Power Consumers of British Columbia (**AMPC**)[24] and RS 1823 chemical producer and pulp and paper mill customers expressing an interest in the freshet rate pilot. Refer to AMPC's support letter at Appendix C-5E;
- RS 1823 F2017-F2019 Pricing Principles – As described in section 2.2.3.2 of the Application, this topic was the subject of two stakeholder workshops (Workshop 5 and Workshop 10). BC Hydro is of the view that the RS 1823 F2017-F2019 Pricing Principles do not warrant an oral hearing. BC Hydro suggests one round of IRs followed by a SRP in January 2016, in conjunction with the proposed freshet rate pilot SRP. AMPC supports BC Hydro's recommended process for review of the RS 1823 F2017-F2019 Pricing Principles. Refer to AMPC's support letter at Appendix C-5E;
- Other existing Transmission Service rates – The 2015 RDA stakeholder engagement process did not result in any significant issues being raised with respect to RS 1852, RS 1825, RS 1827, RS 1853 or RS 1880. As noted in section 1.1.3 above, BC Hydro is requesting amendments to RS 1852. BC Hydro suggests one round of IRs followed by a SRP in January 2016 for review of BC Hydro's requested RS 1852 amendments, in conjunction with the

[24] AMPC is an industry association that represents BC Hydro's major industrial load customers in matters of electricity regulation. AMPC members are Transmission Service and LGS customers of BC Hydro in the pulp and paper, forestry, mining, electrochemical, petrochemical and petroleum sectors, and collectively represent a significant majority of BC Hydro's large industrial load.

proposed SRP for the freshet rate pilot and RS 1823 F2017-F2019 Pricing Principles;

- Standard Charges – British Columbia Old Age Pensioners Organization *et al* (**BCOAPO**)[25] asked BC Hydro to consider an expedited review for the proposed Minimum Reconnection Charges, and wants the updated default Minimum Connection Charge in place before the 2015/2016 winter season. British Columbia Sustainable Energy Association and Sierra Club B.C. Chapter (**BCSEA**)[26] suggested that all the Standard Charges could be candidates for an expedited review. On July 31, 2015, BCOAPO provided BC Hydro with a letter reiterating its request that BC Hydro propose an expedited review for the proposed Minimum Reconnection Charges; a copy of this letter is found at Appendix C-3D. At Workshop 12 held on July 30, 2015, BC Hydro identified that there would be a $950,000 impact to net income in F2016 if the updated default Minimum Reconnection Charge was to be implemented on December 1, 2015. BC Hydro is of the view that the Minimum Reconnection Charges are candidates for an expedited review consisting of one round of IRs and a SRP in January 2016 so that the Commission can issue an order and BC Hydro can implement the requested Minimum Reconnection Charges on April 1, 2016.

At Workshop 12 Commission staff suggested that an early procedural conference could be held to discuss the relevancy of the F2016 COS given the recent amendment to section 9 of Direction No. 7, which provides that in setting rates for BC Hydro for F2017-F2019, the Commission must not set rates for the purposes of changing the R/C ratio for a class of customers (referred to as the **Rate Rebalancing Amendment**, discussed in section 2.2.1.3 of the Application). As described in Chapter 3 of the Application, the F2016 COS was used to inform rate

[25] BCOAPO is a group of community-based organizations who collectively represent the interests of BC Hydro's low and fixed income residential ratepayers.

[26] BCSEA is ratepayer group encompassing citizens, professionals and practitioners committed to promoting the understanding, development and adoption of sustainable energy, energy efficiency and energy conservation in B.C.

design, such as the level of demand charge cost recovery, and thus remains relevant to the 2015 RDA. In BC Hydro's view, the first Round of IRs should be issued on the F2016 COS and BC Hydro should respond to the Round 1 IRs before any procedural conference is held so that parties can better explore and consider F2016 COS-related issues. Thus BC Hydro recommends that the review process for the F2016 COS, which could consist of a NSP, is best addressed at the proposed December 2015 Procedural Conference after BC Hydro responds to Round 1 IRs.

There may be other parts of the Application rates that are suitable for SRP/NSP/expedited reviews. BC Hydro will continue to engage with those 2015 RDA stakeholders who intervene in the review of 2015 RDA Module 1 for purposes of the proposed December 2015 Procedural Conference.

1.6.2 Proposed Regulatory Review Process for Medium General Service and Large General Service 100 per cent Part 1 Pricing

As noted in section 1.1.3 above, BC Hydro is requesting final order for approval of the 100 per cent Part 1 Pricing effective January 1, 2016. As described in section 6.6 of the Application, a number of LGS and MGS customers have complained formally to the Commission and/or informally to BC Hydro about the 85/15 Pricing. As set out in Table 1-4, BC Hydro proposes a process of one round of Commission and Intervener IRs, followed by intervener submissions and BC Hydro reply submissions.

Table 1-4 Proposed Regulatory Review Process for Medium General Service and Large General Service 100 per cent Part 1 Pricing

Process	Date
Filing of Application	September 24, 2015
Commission Issues Regulatory Timetable	October 6, 2015
Round 1 Commission IRs	October 16, 2015
Round 1 Intervener IRs	October 23, 2015
BC Hydro Responses to Round 1 IRs	November 6, 2015
Intervener Written Submissions	November 13, 2015
BC Hydro Reply Submissions	November 20, 2015

1.6.3 Communications

All communications regarding this proceeding should be addressed to:

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1.7 Structure of Application

The Application consists of eight chapters and eight main appendices, as follows:

Chapter 2	Context for the Application – Stakeholder Engagement and Rate Design Evaluation Methodology
Chapter 3	Cost of Service
Chapter 4	Rate Class Determination
Chapter 5	Residential Rate Design
Chapter 6	General Service Rate Design
Chapter 7	Transmission Service Rate Design
Chapter 8	Electric Tariff Terms and Conditions
Appendix A	Drafts of Requested Orders
Appendix A-1A	MGS and LGS New Account 85/15 Pricing Amendments
Appendix A-1B	RS 1823 F2017-F2019 Pricing Principles; RS 1852 Amendments; and Freshet Rate Pilot
Appendix A-1C	Minimum Reconnection Charges
Appendix A-1D	Default Residential, Small General Service, Medium General Service and Large General Service Rates; Residential E-Plus Rate; BC Hydro Owned Street Lighting Rate Class; Electric Tariff Terms and Conditions
Appendix B	Glossary and Abbreviations
Appendix C	Appendix C contains all 2015 RDA-related stakeholder materials relating to Module 1 grouped by subject matter
Appendix C-1	Scope of 2015 RDA
Appendix C-2	Cost of Service
Appendix C-3	Residential Rates and Electric Tariff Terms and Conditions
Appendix C-4	General Service Rate Design
Appendix C-5	Transmission Service Rates

Appendix D	External Expert Curriculum Vitae (**CV**):
Appendix D-1A Appendix D-1B Appendix D-2	CV of Richard W. Cuthbert CV of Dr. Ren Orans Energy + Environmental Economics (**E3**) Literature Review for the Relative Elasticities of BC Hydro Small and Large Residential Customers ("Will Extending the RIB Rate Encourage Conservation?")
Appendix E	F2015 Cost of Service Model and Schedules
Appendix F	Rate Schedules:
Appendix F-1A Appendix F-1B Appendix F-1C Appendix F-1D Appendix F-1E	RS 15xx and RS 16xx – 85/15 Pricing Amendment RS 1892 – Freshet Energy RS 1852 Modified Demand RS 1105 Duel Fuel RS 15xx and RS 16xx – MGS Proposal and LGS Proposal, and associated amendments to RS 12xx (GS - Control Group Proposal*)* and elimination of RS 26xx
Appendix G	Electric Tariff Terms and Conditions
Appendix G-1A Appendix G-1B	Proposed Electric Tariff Terms and Conditions – [*Note to reader: the updated Terms and Conditions will be submitted with BC Hydro's responses to Round 1 IRs*] Derivation of proposed changes to the Standard Charges
Appendix H	Residential, General Service and Freshet Rates Modelling:
Appendix H-1A Appendix H-1B	Residential and General Service Rate Modelling Assumptions Example of Freshet Rate Billing

1.7.1 Stakeholder Engagement and Consideration Memos

The Application and its structure have been informed by the extensive stakeholder engagement conducted with respect to 2015 RDA Module 1 topics. In particular, analysis undertaken for the stakeholder engagement processes, particularly the topic-specific workshop consideration memos, are relied on and cross-referenced in the various Application chapters. For example, alternative rate designs vetted and rejected by general stakeholder consensus are not brought forward in the Application chapters for detailed analysis; rather, they are listed and the reader is directed to the appropriate consideration memo for the reasons why the particular alternative rate design was rejected.

1.7.2 Minister Residential Inclining Block Rate Letter

On July 6, 2015, the B.C. Minister of Energy and Mines sent a letter (**Minister RIB Report Letter**) to the Chair of the Commission requesting a report on several listed issues (set out as five questions) relating to BC Hydro's RIB rate and FortisBC's Residential Conservation Rate (copy at Appendix C-1D). The Minister RIB Report Letter provides that the Commission use the 2015 RDA regulatory review as the process to collect information from BC Hydro concerning the RIB rate for the Commission report rather than a separate process. The Commission in a letter dated August 17, 2015[27] (**Commission RIB Report Methodology Letter**) asked that by September 30, 2015 BC Hydro provide information on the methodologies it is using to gather information and report on the five questions posed in the Minister RIB Report Letter. Consistent with the Minister RIB Report Letter identifying the 2015 RDA as the venue for addressing the five questions as they relate to BC Hydro's RIB rate, BC Hydro provides the Commission-requested information in sections 5.5 and 5.6 of the Application.

1.7.3 Information Submitted with Round 1 IR Responses

BC Hydro's proposed changes to the Terms and Conditions for Module 1 purposes are discussed in section 8.5 of the Application. BC Hydro will submit the proposed changes to the Terms and Conditions (Appendix G-1), which are administrative in nature, as part of its responses to Round 1 IRs.

As described in section 8.6 of the Application, BC Hydro will also be including a low income terms and conditions business case. Engagement with BCOAPO is on-going on this topic, and BC Hydro's low income terms and conditions business case together with related stakeholder engagement will be provided as part of BC Hydro's responses to Round 1 IRs responses.

[27] Exhibit A-1 in the BCUC RIB Rate Report; http://www.bcuc.com/Documents/Proceedings/2015/DOC_44392_A-1_Establishing-Comment-Process.pdf.

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2015 Rate Design Application

Chapter 2

Stakeholder Engagement

and Rate Design Evaluation Methodology

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2.1 Introduction and Chapter Structure

This Chapter consists of four main sections as follows.

Section 2.2 describes the three main inputs BC Hydro used to review existing Transmission Service, LGS, MGS, SGS and Residential rate structures and Terms and Conditions, and develop and assess rate design alternatives, which are:

1. Legal regime (section 2.2.1). At Workshop 1, Commission staff recommended that BC Hydro focus on the changes to the legal landscape since the 2007 RDA;[28]
2. B.C. Government policy (section 2.2.2); and
3. Stakeholder feedback obtained through the processes detailed in section 2.2.3, including topic-specific workshops, focus groups and individual meetings. This feedback informed BC Hydro's proposals as further elaborated in Chapters 5, 6, 7 and 8.

Section 2.3 outlines the context for the Application. Participants in the 2015 RDA topic-specific workshop process asked BC Hydro to provide the following in the Application:

- Review of prior Commission decisions relevant to the 2015 RDA - BC Hydro set out a list of what it considered to be prior relevant Commission decisions at Workshop 1 for comment.[29] Participants generally agreed with the list. Commission staff suggested that BC Hydro also enumerate relevant directives contained in such decisions.[30] At Workshop 9a, Commission staff suggested BC Hydro examine two additional decisions:[31] the May 2014

[28] Commission staff written comments at Attachment 2 to the Workshop 1 consideration memo; copy at Appendix C-1A.

[29] Slide 3 of the' Introduction to and Context for BC Hydro's 2015 Rate Design Application' presentation slide deck; copy at Appendix C-1A.

[30] *Supra*, note 28.

[31] Attachment 1 to the April 28, 2015 Workshop 9a summary notes of the Workshop 9a/9b consideration memo (part 3, Q. 4), copy at Appendix C-2B.

BC Hydro-FortisBC Power Purchase Agreement (**PPA**) decision[32] and the 2014/2015 FortisBC Industrial Stepped Rates/Stand-By Rates decision.[33] Refer to section 2.3.1. Directives are grouped by subject matter and canvassed in Chapter 3 (COS), Chapter 5 (RIB rate and Residential E-Plus rate) and Chapter 6 (SGS/MGS/LGS); and

- Description of changes since the 2007 RDA - The two most frequently cited changes by stakeholders are the Smart Meter Infrastructure (**SMI**) initiative for its COS implications and BC Hydro's lower energy LRMC[34] – refer section 2.3.2.1 and 2.3.2.2 respectively.

Section 2.4 chronicles the evaluation methodology for rate design options:

- The eight Bonbright criteria for rate-making (section 2.4.1). Stakeholders assisted with the description and application of these criteria, and provided feedback on how BC Hydro should weigh the criteria;
- Jurisdictional review (section 2.4.2). Stakeholder engagement and external expert opinion was used to decide which jurisdictions to review for COS, Residential rate and General Service rate purposes;
- Rate modelling (section 2.4.3) for Residential, SGS, MGS and LGS rates, with results presented and discussed at topic-specific Workshops 3, 8a/8b, 9a/9b, 11a/11b and 12; and

[32] Refer to the Commission's decision in *In the Matter of British Columbia Hydro and Power Authority: Application for Approval of Rates between BC Hydro and FortisBC Inc. with regards to Rate Schedule 3808, Tariff Supplement No. 3 – Power Purchase and Associated Agreements, and Tariff Supplement No. 2 to Rate Schedule 3817*, Decision (**RS 3808 Decision**), section 7.2.3; http://www.bcuc.com/Documents/Proceedings/2014/DOC_41321_05-06-2014_BCH_PPA-RS%203808-TS-No-2-and-3_Decision.pdf; and *FortisBC – Application for Approval of Stepped and Stand-by Rates for Transmission Voltage Customers,* Decision, section 2.4.1 (**FBC Stepped Rate Decision**); http://www.bcuc.com/Documents/Proceedings/2014/DOC_41435_G-67-14_FBC-Stepped_Standby-Rates_WEB.pdf.

[33] FBC Stepped Rate Decision *supra*, note 32, section 2.4.1.

[34] Refer, for example, to Commission staff's written comments at Attachment 2 to the Workshop 3 consideration memo, Appendix C-2A: "One of the most important changes since the last rate design on the RIB rate is the downward revision of the BC Hydro estimate of LRMC".

- External expert reviews for the F2016 COS methodology, RIB rate, MGS rate and LGS rate (section 2.4.4).

Section 2.5 concludes this Chapter with a depiction of one of the two criteria BC Hydro applied to scope 2015 RDA Module 1 - whether a rate structure or issue had been recently reviewed by the Commission. (The other scoping criterion is B.C. Government policy, which as noted is described in section 2.2.2).

2.2 Three Main Inputs

2.2.1 Legal Regime

2.2.1.1 Rate-Setting under the Utilities Commission Act

The rate setting function of the Commission is governed by sections 58 to 61 of the *UCA*:

- Section 58 addresses the process by which the Commission is engaged to determine (on its own motion or through a complaint by a public utility or interested person) that existing rates in effect and collected or any rates charged or attempted to be charged for a service by a public utility are unjust, unreasonable, insufficient, unduly discriminatory or in contravention of the *UCA*. In the case of 2015 RDA Module 1, subsection 58(1)(a) of the *UCA* is engaged as the Commission ordered BC Hydro to file a RDA in F2016 that includes revisiting the RIB Step 1/Step 2 threshold, assessing the interaction of the RIB basic charge and rate structure as well as consideration of a minimum charge, and recommending RIB pricing principles to apply beyond F2016;[35]
- Subsections 59(1) and 59(2) place constraints on public utilities and inform the Commission's decision-making in setting rates pursuant to section 60. Public utilities must not make, demand or receive "an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service by it" in B.C.;

[35] Commission Order No. G-13-14, page 3.

- The Commission has considerable discretion in designing rates pursuant to section 60 of the *UCA*. Subsection 60(1)(b) provides that the Commission "must have due regard in the setting of a rate that: (i) it is not unjust and unreasonable within the meaning of section 59, (ii) provides the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demand; and (iii) to encourage public utilities to increase efficiency, reduce costs and enhance performance"; and
- Section 61 places requirements on public utilities to file rate schedules with the Commission, to receive the Commission's consent before rescinding or amending a schedule, and to charge only those rates that are in accordance with the filed schedules.

For ease of reference BC Hydro refers to the legal test that its proposed rates in the 2015 RDA, and the rates to be set by the Commission, must be 'fair, just and not unduly discriminatory'.

2.2.1.2 Clean Energy Act

Subsection 6(2) of the *CEA* provides that BC Hydro must be self-sufficient by 2016 and each year after that by "holding the rights to an amount of electricity that meets the electricity supply obligations *solely from electricity generating facilities within the Province*" [emphasis added]. Thus BC Hydro cannot plan to rely on the spot market to meet its customers' forecasted energy demand. BC Hydro's energy LRMC must be based on the cost to acquire new B.C.-based DSM and/or supply-side resources. Refer to section 2.3.2.2 below for a discussion of BC Hydro's energy LRMC.

Section 2 of the *CEA* sets out 16 "British Columbia's energy objectives", including the following objectives referenced in various 2015 RDA topic-specific workshops:

- 2(b) - to take demand-side measures and to conserve energy (collectively referred to as Demand Side Management (DSM) in this Application), including the objective of BC Hydro reducing its expected increase in demand for electricity by the year 2020 by at least 66 per cent;

- 2(c) - to generate at least 93 per cent of the electricity in B.C. from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;[36]
- 2(e) - to ensure that BC Hydro's ratepayers receive the benefits of the heritage assets and to ensure that the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act*[37] continue to accrue to BC Hydro's ratepayers;
- 2(f) - to ensure BC Hydro's rates remain among the most competitive of rates charged by public utilities in North America;[38]
- 2(h) - to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas (**GHG**) emissions in B.C.; and
- 2(k) - to encourage economic development and the creation and retention of jobs.

BC Hydro's view is that these British Columbia's energy objectives are not legally binding on the Commission for rate design purposes:

- Subsections 44.2(5.1)(a), 46(3.3)(a) and 71(2.21)(a) of the *UCA* expressly provide that the Commission "must consider and be guided by … [the] British Columbia's energy objectives" for purposes of adjudicating BC Hydro's DSM expenditure schedules, Certificate of Public Convenience and Necessity applications and those Electricity Purchase Agreement (**EPA**) filings subject to a hearing;

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36 Other than electricity to serve demand from facilities that liquefy natural gas for export by ship: refer to the British Columbia's Energy Objectives Regulation, B.C. Reg. 234/2012; https://www.canlii.org/en/bc/laws/regu/bc-reg-234-2012/latest/bc-reg-234-2012.html.

37 S.B.C. 2003, c.83; http://www.bclaws.ca/Recon/document/ID/freeside/00_03086_01.

38 The Rate Comparison Regulation, B.C. Reg. 119/2011 provides that BC Hydro is to provide the B.C. Minister of Energy and Mines with a report that includes a comparison of BC Hydro's rates with those of at least one public utility in each of 15 other jurisdictions in North America, including the provinces of Alberta, Manitoba, Ontario and Quebec, and the states of Washington, Oregon and California; https://www.canlii.org/en/bc/laws/regu/bc-reg-140-2009/latest/bc-reg-140-2009.html. BC Hydro used the Rate Comparison Regulation to inform the scope of its various jurisdictional assessments as described in section 2.4.2 of the Application.

- There is no corresponding requirement set out in sections 58 to 61 of the *UCA*, which contain the rate setting provisions.

The net result in BC Hydro's view is that the Commission may, but is not obliged to, consider and be guided by the British Columbia's energy objectives, subject to the proviso that in the event of a conflict between an energy objective and a rate-setting provision of the *UCA*, the latter must prevail.

2.2.1.3 Direction No. 7, the Heritage Contract and Rate Rebalancing

On March 6, 2014 Direction No. 7 to the Commission was enacted. Direction No. 7 repeals Heritage Special Direction No. HC2 (**HC2**) and re-enacts the essential elements of the Heritage Contract formerly enshrined in HC2. The Heritage Contract is attached as Appendix A to Direction No. 7. The first and most important element of the Heritage Contract is that BC Hydro's rates are established on a cost of service basis and not market prices (refer to subsection 5(d) of Direction No. 7). This means that BC Hydro's customers get the full benefit of BC Hydro's Heritage Resources.[39] Another important corollary element is the principle that new customers should be able to benefit from the low-cost Heritage Resources, as shown on Schedule B to the Terms of Reference attached to the Commission's Heritage Contract Report as Appendix A.[40]

Direction No. 7 has a number of other provisions relevant to 2015 RDA Module 1:

- Subsection 3(1) – In designing rates for BC Hydro's Transmission Service customers, the Commission must ensure those rates are consistent with Recommendations #8 to #15 in the Heritage Contract Report. Recommendation #8 is relevant to the default stepped rate[41] for Transmission Service customers (RS 1823): (i) the Tier 2 rate should reflect the cost of new supply; (ii) the

[39] BC Hydro's Heritage Resources are defined in section 1 of Direction No. 7 by reference to Schedule A to the Heritage Contract inquiry; copy can be found at link provided in footnote 40 below.

[40] Heritage Contract Report, *supra*, note 9 in Chapter 1. http://www.bcuc.com/Documents/Decisions/2003Dec/Heritage%20LGIC%20Rpt-Recommend.pdf.

[41] The term 'default rate' is described in section 1.4 of the Application: "Default rates are rates that all customers pay unless they have options and choose to opt for another rate".

quantity of power being sold to Transmission Service customers at Tier 1 of RS 1823 should be set at 90 per cent, and the Tier 2 quantity should make up the remaining 10 per cent (referred to as the **Tier 1/Tier 2 90/10 split**); and (iii) the Tier 1 rate should be derived from the Tier 2 rate and the Tier 1/Tier 2 90/10 split to achieve revenue neutrality to the extent reasonably possible. As a result, the Commission cannot change the Tier 1/Tier 2 90/10 split. Refer to section 7.2.1 of the Application for details. Recommendation #15 concerns the Exempt Rate (RS 1827). Refer to section 7.5.1 of the Application;

- Section 9 – In the revenue requirement context, the Commission must not allow rates to increase by more than 4 per cent in F2017, 3.5 per cent in F2018 and 3 per cent in F2019 on average, compared to the rates of BC Hydro immediately before the increases;
- Section 10 – The Commission must set the Deferral Account Rate Rider (**DARR**) for F2015 and future years of BC Hydro at 5 per cent, and must not order any change to the DARR except on application by BC Hydro;
- Section 14 – The Commission is to issue an order cancelling BC Hydro's retail access program.[42] In addition, except on application by BC Hydro, the Commission must not set rates for BC Hydro that would result in direct or indirect provision of unbundled transmission service to retail customers in B.C. or to those who supply such customers. BC Hydro is not proposing retail access as part of the 2015 RDA for the reasons set out in section 7.3.3.1 of the Application.

On July 15, 2015 B.C. Reg. 140/2015 was deposited, amending section 9 of Direction No. 7 by providing that in setting rates for BC Hydro for F2017-F2019, the Commission must not set rates for the purposes of changing the R/C ratio for a class of customers (referred to as the **Rate Rebalancing Amendment**). As a result, BC Hydro is not proposing rate rebalancing as part of 2015 RDA Module 1. The

[42] This was done pursuant to Commission Order No. G-36-14.

effect of the Rate Rebalancing Amendment was explored with stakeholders at Workshop 12. In BC Hydro's view, and as described in section 3.1 of the Application, there is value in reviewing the F2016 COS as part of the 2015 RDA; among other things, the F2016 COS informs rate design such as the appropriate level of demand charge cost recovery. As part of Workshop 12, BC Hydro proposed to submit a F2019 COS with the Commission. Refer to section 3.1.2 of the Application. In addition, BC Hydro sought stakeholder input as to what F2016 COS review process BC Hydro should recommend to the Commission. As set out in section 1.6.1 of the Application, BC Hydro proposes that the F2016 COS be subject to one round of IRs with the possibility of a NSP.

2.2.1.4 Special Direction No. 10

The 2012 amendments to Special Direction No. 10 to the Commission[43] (**SD 10**) are relevant to the discussion of the lower energy LRMC in section 2.3.2.2 below. Sections 1 and 3 of SD 10 provide that the Commission, in setting rates for BC Hydro, must use the planning criterion of average water. As detailed in footnote 15 in Chapter 1 in respect of the Electricity Self-Sufficiency Regulation, the 2012 change in planning criterion increases the combined reliance on BC Hydro's Heritage hydroelectric system non-firm energy backed by market reliance in F2017 by about 4,100 GWh/year, reducing the need for new energy resources.

2.2.2 Government Policy

At Workshop 1, BC Hydro identified the following as B.C. Government policy: postage stamp rates (section 2.2.2.1); no mandatory TOU rates for Residential or General Service customers (section 2.2.2.2); and rates for Northwest Transmission Line (**NTL**) and liquefied natural gas (**LNG**) customers as the subject of B.C. Government and not Commission determinations (section 2.2.2.3). The relevant Policy Actions from the most recent B.C. Government Energy Plan – *The BC Energy*

[43] B.C. Reg. 245/2006, as amended by OIC No. 035 (B.C. Reg. 17/2012, deposited February 3, 2012).

Plan: A Vision for Clean Energy Leadership (the **2007 Energy Plan**)[44] are summarized in section 2.2.2.4 below.

The B.C. Ministry of Energy and Mines provided BC Hydro with a letter dated September 17, 2015 (**MEM Policy Letter**) stating that:

- Postage-stamp rate-making continues to be B.C. Government policy;
- The benefits of the Heritage Assets should continue to accrue to all BC Hydro customers on the basis of their energy consumption and peak demand, and that the benefits should not be re-allocated between customer groups on a different basis or withheld from new customers. This issue is addressed in section 2.3.1.3 below in the context of the 2003 Heritage Contract proceeding; and
- Re-iterating the previous Government decision that it will not be referring the RS 1823 Tier 1/Tier 2 90/10 split, or New Westminster's and University of British Columbia (**UBC**)'s exemption from RS 1823 or other stepped rates, to the Commission for review and recommendations under section 5 of the *UCA*. The MEM Policy Letter also states that the B.C. Government is of the view that the Commission's rationale for exempting Simon Fraser University (**SFU**) and Vancouver Airport Authority (**YVR**) from RS 1823 and other stepped rates continues to apply. Refer to section 2.2.2.5 below.

A copy of the MEM Policy Letter is found at Appendix C-1C of the Application.

2.2.2.1 Postage Stamp Rates

Postage stamp rates are a method of cost allocation where any rate class charge is the same anywhere on the interconnected system, regardless of the geographical region in BC Hydro's service area. The underlying premise is that all customers jointly develop electricity resources and should equally share in the costs. As noted

44 http://www.energyplan.gov.bc.ca/.

by Canadian Association of Petroleum Producers[45] (**CAPP**) in its written feedback concerning Workshop 1, postage stamp is the accepted approach to rate-making in the majority of North American jurisdictions.[46]

The application of postage stamp rates to BC Hydro's service area has been in place for decades and continues to remain a cornerstone of rate design for BC Hydro. At Workshop 1 and Workshop 7, BC Hydro indicated that postage stamp rates were a fundamental B.C Government rate design policy, subject only to two discrete and generally accepted exceptions:

- BC Hydro limits the amount that it will contribute toward the cost of new extensions, effectively limiting the postage stamp treatment of the cost of extensions. As discussed in section 1.5 of the Application, Transmission and Distribution extension policy is a Module 2 issue; and
- In Zone II, BC Hydro limits the amount of energy available at Zone I rates. Again, as discussed in section 1.5 of the Application, Zone II (NIA) rate design is a Module 2 issue.

The B.C. Government confirmed on a number of occasions its support for postage stamp rates:

- As indicated below in Table 2-2, the IEPR Task Force recommended continued use of postage stamp rates and the B.C. Government responded on November 13, 2013 that "Government will continue to use postage stamp rates";

[45] CAPP represents companies that explore for, develop and produce natural gas and crude oil throughout Canada, and in BC Hydro's service area CAPP members take service under RS 1823 and the LGS rate. CAPP's written feedback is found at Attachment 2 to Workshop 1 consideration memo, Appendix C-1A.

[46] Manitoba has legislated postage stamp rate making for Manitoba Hydro; refer to subsection 39(2.1) of the *Manitoba Hydro Act*, C.C.S.M., c.H190; https://web2.gov.mb.ca/laws/statutes/ccsm/h190e.php. So too has Quebec: refer to article 49(11) (the Régie de L'Énergie shall "maintain, subject to any government order to the contrary, uniform rates throughout the territory served by the electric power transmission system") and article 52.1 ("rates applicable to a class of customers must be uniform throughout the electric power distribution system, with the exception of independent electric power distribution system north of the 53rd parallel") of the *Act Respecting the Régie de L'Énergie*, S.Q. c.R-6.01.

- The B.C. Ministry of Energy and Mines (**MEM**) in April, July and October 2013 reaffirmed its support for postage stamp rates as part of the 2013/2014 FortisBC Energy Application for Reconsideration and Variance of Commission Order No. G-26-13 Common Rates, Amalgamation and Rate Design Application.[47] MEM's April 15, 2013 letter to FortisBC states that "Government policy has been to promote access to energy services on a postage stamp basis so that all British Columbians benefit from access to services at the lowest average cost". In the April 15, 2013 letter, MEM references three examples of confirmation of the B.C. Government's postage stamp policy: the 1962 decision as part of BC Hydro's creation to establish postage stamp rates for all residential customers served by BC Hydro; the 1975 extension of postage stamp rates for all BC Hydro customers; and the May 27, 2003 statement by the then Minister of Energy and Mines confirming the B.C. Government's position with regard to postage stamp rates for BC Hydro (refer to next bullet); and
- The B.C. Minister of Energy and Mines' May 27, 2003 letter to the Union of British Columbia Municipalities states that "[e]lectricity rates will be set on a postage stamp basis. This means that all [BC Hydro] customers within a particular customer class will receive the same rate, regardless of their location in the Province".[48]

In consequence of two consecutive Commission decisions in the 2007 RDA[49] and 2008 RIB[50] (described below in sections 2.3.1.5 and 2.3.1.6 respectively) rejecting

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47 The July 9, 2013 MEM intervention letter is Exhibit C3-1 in the 2013/2014 FortisBC Energy Application for Reconsideration and Variance of Order No. G-26-13 Common Rates, Amalgamation and Rate Design Application proceeding (http://www.bcuc.com/Documents/Proceedings/2013/DOC_35100_C3-1_MEM_IntervenerReg.pdf). MEM's April 15, 2013 letter to FortisBC is attached to the intervention letter. A copy of MEM's October 30, 2013 Final Submission is found at http://www.bcuc.com/Documents/Arguments/2013/DOC_37100_10-30-2013_MEM_Final-Submission.pdf.

48 Exhibit B-47 in the 2007 RDA proceeding; http://www.bcuc.com/Documents/Proceedings/2007/DOC_16012_B-47_Undertaking-filing-ltr-UBCM.pdf.

49 *In the Matter of British Columbia Hydro and Power Authority: 2007 Rate Design Application*, Phase 1, Decision, October 26, 2007 (**2007 RDA Decision**), page 205; copy available at

arguments in favour of departures from postage stamp rates on the basis of insufficient evidence, it is apparent that the onus of demonstrating the need for change rests on any party advocating a departure from postage stamp ratemaking.

BC Hydro employed postage stamp ratemaking to reject consideration of regionally-differentiated Residential and General Service default rates.

2.2.2.2 Mandatory Residential and Commercial Time of Use Rates

At Workshop 1, BC Hydro confirmed that it continues to be B.C. Government policy that mandatory TOU rates for Residential and/or General Service customers is not an option for BC Hydro. As its name suggests, under a ‘mandatory default rate’ customers would have no option to opt out to another rate. BC Hydro referenced the B.C. Minister of Energy and Mines’ June 19, 2013 letter to the IEPR Task Force[51] which states that the IEPR Task Force’s examination of TOU rates “is to stay strictly within the bounds of industrial customers only” as an example of the B.C. Government’s policy on this issue.

At Workshop 3 BC Hydro noted its residential rate jurisdictional assessment, which showed that Ontario is the only Canadian jurisdiction implementing default TOU rates for electric utility residential and commercial customers.[52]

BCSEA stated that TOU rates for Residential and/or General Service customers as potential alternatives should be in scope for the 2015 RDA. Commission staff asked whether and BC Hydro confirmed that optional TOU rates for Residential and/or General Service customers are in scope. BC Hydro received stakeholder input on

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

[50] *In the Matter of British Columbia Hydro and Power Authority: Residential Inclining Block Rate Application*, Reasons for Decision to Order No. G-124-08, dated September 24, 2008 (**2008 RIB Decision**), page 80; http://www.bcuc.com/Documents/Proceedings/2008/DOC_19754_BCH-RIB-Decision-WEB.pdf

[51] Copy at http://www.empr.gov.bc.ca/EPD/Documents/Letter%20from%20Minister%20Bennett%20to%20IEPR%20Task%20Force.pdf.

[52] The Ontario Auditor General’s 2014 annual report concluded that Ontario’s mandatory residential and commercial customer TOU rates may not be designed to effectively reduce peak demand as intended: *Annual Report of the office of the Auditor General of Ontario*, Chapter 3, section 3.11; copy available at http://www.auditor.on.ca/en/reports_en/en14/311en14.pdf.

Residential and General Service voluntary TOU rates at Workshop 3 and Workshop 8b respectively. Potential Residential and General Service voluntary options, including optional TOU rates, will be examined as part of Module 2.

2.2.2.3 NTL and LNG Rates

While the following specific rates are not part of the 2015 RDA, the principles informing them are in scope:

- TS 37: Subsection 8(2) of the *CEA* states that the Commission must set under the *UCA* a rate as proposed by BC Hydro with respect to NTL, which is a 287 kV transmission line between Skeena substation and Bob Quinn Lake in the northwest part of BC Hydro's service area. In April 2013 the Commission approved TS 37 setting out terms and conditions applicable to certain BC Hydro customers receiving electricity service or generator interconnection service by means of NTL.[53] TS 37 allows BC Hydro to recover the actual costs of NTL from customers using the capacity of the transmission line. In the absence of TS 37, NTL customers would be subject to TS 6 which governs customer payments towards new transmission required to serve them, and thus the principles informing TS 37 are of relevance to Transmission Extension policy which is the subject of 2015 RDA Module 2;
- LNG rates: The B.C. Government decided that it will direct both BC Hydro and the Commission with respect to any Electricity Supply Agreements with LNG proponents. On November 4, 2014 the B.C. Government announced the Domestic Long-Term Sales Contracts Regulation[54] under section 9 of the *CEA*, which provides that a rate for LNG facilities must include: (i) a demand charge equivalent to the RS 1823 demand charge; (ii) the greater of the energy charges set out in Schedule 1 to the Regulation or the RS 1823 energy charges. The Domestic Long-Term Sales Contract Regulation also establishes

[53] Commission Order No. G-52-13, and in particular Appendix A, page 5 of 6; http://www.bcuc.com/Documents/Orders/2013/DOC_34215_G-52-13_BCH_TS37.pdf.

[54] B.C. Reg. 201/2014; copy available at https://www.canlii.org/en/bc/laws/regu/bc-reg-201-2014/latest/bc-reg-201-2014.html.

that costs of interconnecting with the BC Hydro transmission system and any system upgrades required to serve new LNG facility loads will be borne by LNG proponents.

2.2.2.4 2007 Energy Plan

On February 27, 2007 the B.C. Government released the 2007 Energy Plan. Policy Action 4 is the only policy action that references utility rates:

> Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.

Examples cited in the 2007 Energy Plan include stepped rates (referred to as inclining block rates) for other rate classes after the 2006 implementation of RS 1823 for Transmission Service customers; interruptible/curtailable rates; clean electricity rates; and tariffs focused on promoting energy efficient new construction.

At Workshop 8a, BC Hydro set out its position that Policy Action No. 4 of the 2007 Energy Plan does not oblige the Commission to ignore the eight Bonbright rate design criteria in favour of a conservation objective or to prioritize the Bonbright efficiency criterion over the other seven criteria. BC Hydro implemented an inclining block rate for its Residential customers in October 2008 (the RIB rate; refer to section 2.3.1.6 below). BC Hydro also explored the possibility of inclining block rates for its General Service customers, but as noted in Chapter 6 of the Application, BC Hydro concludes such rate structures are not viable given the heterogeneous nature of each of the SGS, MGS and LGS rate classes. BC Hydro also explored optional interruptible rates and what is referred to as an optional 'Efficiency Rate Credit' for General Service customers, and an optional clean energy credit for its Residential customers. As described in section 1.5.2 of the Application, BC Hydro will address optional rates for General Service and Residential customers as part of 2015 RDA Module 2.

2.2.2.5 Direction No. 7, the RS 1823 Tier 90/10 Split and RS 1827

As described below in section 2.3.1.4, the default Transmission Service rate is RS 1823, under which a specific CBL is determined for each Transmission Service customer representing the customer's normal or historic annual energy consumption. A customer purchases energy at the Tier 1 rate up to 90 per cent of its CBL and at the Tier 2 rate above 90 per cent of CBL (this the Tier 1/Tier 2 90/10 split referred to in section 2.2.1.3 above).

At Workshops 5 and 10 BC Hydro set out its view that the Commission cannot unilaterally amend the Tier 1/Tier 2 90/10 split under its section 58 to 61 *UCA* rate setting power; instead, the Commission can only be given jurisdiction to review and make recommendations concerning these issues through a section 5 *UCA* inquiry review process, and only the LGIC can refer this matter to the Commission under section 5 of the *UCA*. At Workshop 10 BC Hydro confirmed that the B.C. Government has no plans to refer the RS 1823 Tier 1/Tier 2 90/10 split to the Commission for a section 5 *UCA* review. The MEM Policy Letter reiterates this. Consequently, the Tier 1/Tier 2 90/10 is referenced in this Application (and in particular, in section 7.2) for background purposes only.

Similarly, at Workshops 5 and 10, BC Hydro reiterated its legal position with respect to RS 1827. As discussed above in section 2.2.1.3, subsection 3(1) of Direction No. 7 states that "[i]n designing rates for the authority's transmission rate customers, the commission must ensure that those rates are consistent with Recommendations #8 to #15 inclusive in the [Heritage Contract Report]". The B.C. Government accepted Recommendation #15, which provides "[t]hat Aquila [now FortisBC], [New Westminster] and UBC, as entities that distribute all or a significant portion of their load to others, be exempted from the application of stepped rates at this time and form a new rate schedule(s)":

- It is BC Hydro's view that the Commission cannot unilaterally transfer New Westminster and/or UBC to RS 1823 or set a stepped rate similar to RS 1823 for New Westminster and/or UBC under its section 58 to 61 *UCA* rate setting power; instead, the Commission can only be given jurisdiction to review and make recommendations concerning this issue through a section 5 *UCA* inquiry review process, and only the LGIC can refer this matter to the Commission under section 5 of the *UCA*. In section 3 of the Workshop 10 consideration memo found at Appendix C-5B, BC Hydro confirmed that the B.C. Government communicated to BC Hydro that it has no plans to refer the exemption for New West and UBC from stepped rates to the Commission for a section 5 *UCA* review. The MEM Policy Letter reiterates this;

- The Commission has jurisdiction under sections 58 to 61 of the *UCA* with regard to SFU and YVR. The Commission established their exemption from stepped rates in Commission Order No. G-10-06,[55] on the basis that SFU and YVR share similar characteristics to New Westminster and UBC in that they distribute a significant portion of their load to others, and that exempting SFU and YVR is consistent with Recommendation #15. The MEM Policy Letter states that the B.C. Government is of the view the rationale for exempting SFU and YVR from RS 1823 and other stepped rates continues to apply.

2.2.3 Stakeholder Engagement

For purposes of the 2015 RDA, BC Hydro developed three main avenues to engage with its customers and stakeholders:

1. Topic specific workshops (section 2.2.3.2);
2. Customer focus groups (section 2.2.3.3); and
3. Face-to-face meetings (section 2.2.3.4).

BC Hydro's stakeholder engagement process with Residential E-Plus customers is recounted in section 2.2.3.5, and information sessions are outlined in section 2.2.3.6 below. BC Hydro also established a process for capturing stakeholder comments

[55] Copy available at http://www.bcuc.com/Documents/Orders/2006/DOC_10718_G-010-06_BCH_Transmission%20Service%20Rates.pdf.

and documenting how these comments were used in BC Hydro's development of its preferred solutions; refer to section 2.2.3.2below.

2.2.3.1 Participant Funding

BC Hydro's 2015 RDA stakeholder engagement process began in May 2014 with a workshop to introduce the scope of the 2015 RDA (Workshop 1). Multiple stakeholders indicated that BC Hydro should make participant funding available to qualifying stakeholders who participate in pre-application workshops and provide feedback given the significant amount of engagement BC Hydro planned for the 2015 RDA. Several stakeholders also noted that their participation in the 2015 RDA engagement activities would be subject to obtaining such funding. On June 26, 2014 BC Hydro wrote to stakeholders informing them that BC Hydro would provide funding to participants and their consultants to enable participation in the pre-application workshops, and that funding would be based on the Commission's Participant Assistance/Cost Awards (**PACA**) Guidelines.[56] A copy of this letter is included in Appendix C-1A of the Application.

2.2.3.2 Topic-Specific Workshops

The topic-specific workshops provided a forum for BC Hydro to share detailed information through presentations about proposed changes affecting specific customer groups, to answer questions and receive detailed feedback on proposals. Attendance at topic-specific workshops averaged 35 participants and included participants from stakeholder groups, customers and Commission staff. Workshops ranged in length from about three to seven hours and participants were able to attend in-person or via webinar.

BC Hydro employed the following cycle for obtaining feedback and providing BC Hydro's consideration of feedback: (1) circulate materials, including presentation slide decks, in advance of each workshop; (2) post draft workshop summary notes to

[56] Copy available at http://www.bcuc.com/Documents/Guidelines/2014/DOC_5014_G-72-07_PACA_2007_Guidelines.pdf.

the BC Hydro 2015 RDA website recording stakeholder questions and BC Hydro's responses; (3) establish a 30 to 45-day written comment period commencing with the posting of draft workshop summary notes; and (4) generate what are referred to as 'consideration memos' for each workshop except the last workshop (Workshop 12). The consideration memos summarize feedback received and BC Hydro's consideration of the feedback, and explained how feedback was used to further the development of alternatives and/or narrow the number of alternatives brought forward for additional analysis. BC Hydro considered all input it received. Where it conflicts, BC Hydro gave more weight to the views of customers who takes service under the particular rates being assessed except on issues where there could be cost implications for other rate classes.

BC Hydro's goal was to hold two workshops on each of the following Module 1 areas: (1) scope; (2) COS; (3) Residential rates; (4) General Service rates; and (5) Transmission Service rates. BC Hydro held 12 topic-specific workshops between May 8, 2014 and July 30, 2015 as set out in Table 2-1 (note that Workshops 6 and 7 are not included as they concerned the Module 2 issues of Transmission and Distribution extension policies).

Table 2-1 2015 RDA Topic-Specific Workshops

Workshop Number	Title	Description
1	BC Hydro Rate Design Workshop No. 1, May 8, 2014	Identified preliminary scope of 2015 RDA: All seven customer classes, Transmission and Distribution Extension policies and Electric Tariff Terms and Conditions. Also set out for discussion what BC Hydro considered to be out of scope topics (refer to section 2.5 of this Chapter).
2	COS Workshop No. 1, June 19, 2014	Reviewed BC Hydro's COS methodology, discussed Cuthbert Consulting Inc. and NewGen Strategies and Solutions, LLC's (**COS Consultants**) jurisdictional review of other utilities COS methodologies and the COS Consultant's recommendations on possible changes to BC Hydro's COS methodology.
3	Residential Rates Workshop No. 1, June 15, 2014	Reviewed charges contained in the Terms and Conditions and potential amendments, identified the Bonbright criteria for residential rate evaluation

Workshop Number	Title	Description
		(refer to section 2.4.1 below), provided Residential customer consumption profiles, identified and evaluated alternative designs to the RIB rate and alternative means of delivering the RIB rate as well as discussing other issues such as the use of the energy LRMC.
4	COS Workshop No. 2, October 7, 2014	Identified BC Hydro's preferred COS methodology in each of the steps of functionalization, classification and allocation. Provided stakeholders a draft of the F2016 COS model including a summary of the F2016 R/C ratios for each of the seven rate classes.
5	Transmission Service Rate Workshop No. 1, October 22, 2014	Provided legal and regulatory context related to the Transmission Service rates. Reviewed options identified through IEPR Task Force process to help industrial customers manage their electricity bills. Other Transmission Service rates were also reviewed.
8(a)	LGS/MGS/SGS Workshop No. 1, Session 1 - Regulatory history concerning and the issues arising out of the current LGS/MGS/SGS rate structures, January 21, 2015	Reviewed regulatory history of the three default General Service rates as well as providing a summary of the characteristics of each General Service rate class.
8(b)	LGS/MGS/SGS Workshop No. 1, Session 2- Alternatives to the current LGS/MGS/SGS rate structures, February 11, 2015	Provided an overview of alternative development and identified the rate structure objectives to evaluate and compare alternatives. Walked through the bill impact analysis of screened-in alternatives. Criteria used to screen-out alternatives were also explained.
9(a)	Residential Rates Workshop No. 2, Session 1, April 28, 2015	Identified the status quo RIB rate as BC Hydro's preferred residential rate design as well as alternatives for a number of standard charges. Confirmed through the Workshop 9a/9b consideration memo that based on stakeholder feedback, BC Hydro would include in the 2015 RDA a three step rate and a flat rate as viable alternatives to the RIB rate.
10	Transmission Service Rates and Freshet Rate Workshop No. 2, May 7, 2015	Identified BC Hydro's preferred alternative for aspects of RS 1823 over which the Commission has jurisdiction: the RS 1823 F2017-F2019 Pricing Principles and the continued use of bill neutrality. Also provided further information on two potential optional rates, Real Time Pricing (**RTP**) and a freshet rate, including how a freshet rate pilot may be structured. Other Transmission Service rate issues were discussed including the continuation of RS 1827.

Workshop Number	Title	Description
9(b)	Residential Rates Workshop No. 2, Session 2, May 21, 2015	Reviewed alternative means of delivering the RIB rate as well as rate issues to be dealt with in Module 2 including Residential voluntary rate options, NIA rates and farms and irrigation customer service issues.
11(a)	LGS/MGS/SGS Workshop No. 2, Session 1, June 25, 2015	Presented rate class segmentation analysis and identified BC Hydro's preferred alternatives for SGS as well as the MGS energy rate. Sought feedback on MGS demand structure alternatives.
11(b)	LGS/MGS/SGS Workshop No. 2, Session 2, June 26, 2015	Presented alternatives for LGS energy and demand rate structured and sought feedback. Potential General Service optional rates that will be part of Module 2 were also presented.
12	BC Hydro's Rate Classes and Application Structure, July 30, 2015	Outlined the structure of the 2015 RDA Module 1. Discussed the implications of the Rate Rebalancing Amendment for the F2016 COS. Identified that BC Hydro was leaning toward a flat LGS energy rate with a flat demand charge as its preferred alternative, and raised the possibility of creating separate rate class(es) for New Westminster and FortisBC.

The workshop materials, including consideration memos, are found at Appendix C to the Application grouped by subject matter (Scope – Appendix C-1 (Workshop 1 and Workshop 12; COS – Appendix C-2 (Workshop 2 and Workshop 4); Residential rate – Appendix C-3 (Workshop 3 and Workshop 9a/9b); General Service rates – Appendix C-4 (Workshop 8a/8b and Workshop 11a/11b); and Transmission Service rates – Appendix C-5 (Workshop 5 and Workshop 10).

The workshops provided customers and stakeholders a forum to bring their issues forward and assisted BC Hydro in identifying issues with current rates and in reducing the number of alternative rate designs advanced for further consideration. This was particularly important for Residential rate design, where as described in section 2 of the Workshop 3 consideration memo, a number of alternatives were raised in the 2008 RIB proceeding (the 2008 RIB Decision is described below in section 2.3.1.6). Refer to section 5.2.4 of the Application for additional detail. Another example concerns Transmission rate options. As a result of AMPC and RS 1823 customer input, BC Hydro focused on developing the freshet rate pilot and a load curtailment pilot described in section 2.3.1.8 below to the exclusion of revising RS 1825, the existing Transmission Service TOU rate, and/or developing a Transmission Service RTP rate; refer to section 7.3 of the Application.

BC Hydro also made a number of changes to its rate design proposals contained in this Application as a result of workshop input, including but not limited to:

- Set the default Minimum Reconnection Charge at $30 on the basis of cost categories – refer to section 8.3.2 of the Application;
- Increase the SGS basic charge cost recovery – refer to section 6.2.3.2 of the Application; and
- Increase the MGS and LGS demand cost recovery – refer to sections 6.3.4.2 and 6.4.4.2 of the Application.

2.2.3.3 Customer Focus Group Sessions

Focus groups allow for the capturing of participant answers to questions in their own words as well as the opportunity for them to provide context around their answers. Using focus groups to gather qualitative data on the customer experience is a widely used strategy which allows organizations to develop products and services that meet customer requirements. Customer expectations change over time so it is important to stay on top of understanding the customer perspective.

BC Hydro held three sets of customer focus group sessions: two sets of focus groups for Residential customers and one set for LGS/MGS customers. A third party facilitated the focus groups to obtain customer feedback without customers needing to have detailed knowledge of rate design. Copies of the final reports for the two Residential focus groups sessions are found at Appendix C-3C. The LGS/MGS customer focus group report is found at Appendix F to the *F2014 Evaluation of the Large and Medium Service Conservation Rates* report (**F2014 LGS and MGS Evaluation Report**) circulated to stakeholders prior to Workshops 8a/8b; a copy of the F2014 LGS and MGS Evaluation Report is found at Appendix C-4A of the Application. The following summarizes the three focus group sessions.

August 2014 Residential Focus Group Sessions

The first set of Residential focus group sessions was held throughout August 2014. Six focus groups were held: two physical groups in Vancouver with residents of the Lower Mainland; two physical groups in Nanaimo; and two online groups with residents from the Interior, Northern B.C. and Vancouver Island/Gulf Islands. The total number of participants was 54; participants were BC Hydro Residential customers, homeowners and renters, mixed ages and gender, mixed employment status and occupations including retirees, and mixed cultural backgrounds including First Nations.

The purpose of the first Residential focus group was to canvass participants on their: values (as part of BC Hydro's determination of how to prioritize the eight Bonbright criteria); awareness of the two step RIB rate; and views on various Electric Tariff Standard Charge topics such as new account charges, reconnection/disconnection charges and late payment charges. A summary of findings is as follows. Focus group participants ranked fairness (customers want to believe they are being charged fair and equal Residential rates) and customer understanding and acceptance most highly. With respect to Standard Charges: (1) there was low demand to pay electricity bills with credit cards; no participant would pay a fee to pay electricity bills with credit cards; (2) Nearly all participants agreed that customers who are late with a payment should pay a charge unless the cost of recovering the charge is greater than the charge itself; (3) Nearly all participants agreed that the customer who is disconnected and/or reconnected should pay all the associated costs (participants did not want costs to be absorbed by BC Hydro); and (4) only customers who have bad credit or no credit history should be charged a security deposit. These findings were factored into the Workshop 3 consideration memo determinations, most notably with respect to BC Hydro's decision to not advance a credit card-related charge for electricity bill credit card payments. Refer to Chapter 8 for greater detail.

February 2015 Residential Focus Group Sessions

The February 2015 second set of Residential focus group sessions consisted of six focus groups held as follows: two physical groups in Vancouver with residents of the Lower Mainland (Group 1 – apartment dwellers, Group 2 house dwellers); two physical groups in Nanaimo (Group 1 – apartment dwellers, Group 2 house dwellers); and two online groups with residents from the Interior, Northern B.C. and Vancouver Island/Gulf Islands (Group 1 – apartment dwellers, Group 2 house dwellers). The total number of participants in the focus groups was 50 (24 apartment dwellers and 26 house dwellers). Participants were BC Hydro Residential customers, homeowners and renters, mixed ages and gender, mixed employment status and occupations including retirees, and mixed cultural backgrounds including First Nations.

This second set of Residential focus group sessions were held to seek customer feedback on: (1) what customers value in rate design; (2) awareness of the RIB rate; and (3) reaction to a three step rate. BC Hydro used the February 2015 second Residential focus group session to gauge whether reaction differs based on customer dwelling type, and how the rate designs might affect different customer groups (low income, average, apartment, large dwelling, etc.). In summary: before reviewing the RIB rate and three step rates, most participants valued fairness above all other values, while after viewing rate design, efficiency emerged as the most important value followed closely by fairness; most participants were aware of the total amount of their electricity bills as opposed to the RIB rate structure; and most participants reject a three step rate as too complicated. Refer to section 5.2 of the Application for greater detail.

September 2014 LGS/MGS Focus Groups

The specific objectives of the research were to explore:

- LGS and MGS customer opinions of both the LGS and MGS two part energy rates and demand charges, including understanding of: areas of perceived complexity; the extent that each of the energy rates and demand charges serve as an incentive to conserve; and customers' internal mechanisms of acting on each;
- Other reported drivers and enablers of conservation, including: the extent to which price, total bill amount, etc. serve as an incentive to conserve;
- Reported barriers to conservation, including confusion around the LGS and MGS rates and the lack of access to funding for energy efficiency upgrades; and
- Customer preferences and support of alternative rate structures.

In view of the study objectives, the types of participants, logistics and cost implications, focus groups drawn from the greater Vancouver area were considered the best approach to achieve the research objectives. Based on the quantitative research concerning customer awareness, understanding and support of the LGS and MGS rates, four independently moderated groups were chosen: one government/public sector (such as municipalities) group, and three non-government/non-public sector groups based on size.

A summary of the findings is as follows. Further details are found in sections 6.3.3 and 6.4.3 of the Application:

- Customer attitudes and opinions of the LGS and MGS rates:
  - Unprompted, only a couple of customers were able to correctly explain how the rate structures worked.
- Mechanism for conservation:

- Most customers reportedly look at their electricity bills, but this is mainly in regards to total dollar amount;
- The LGS and MGS rates were rarely mentioned as a motivator for conservation.

- Reported barriers of managing electricity use:
    - Conservation is a low operational priority, mainly because cost of energy is considered to be low;
    - The perceived complexity of the LGS and MGS rates do not promote customer engagement and are widely seen as disempowering.
- Preferences for alternative rate structures:
    - Eliminate the baseline (flat energy rate);
    - Inclining block rate.

2.2.3.4 Face-to-Face Meetings

BC Hydro held a series of face-to-face meetings with individual stakeholders to further explore rate design issues as listed below. These face-to-face meetings resulted in BC Hydro examining potential new initiatives it was not originally contemplating. An example is the development and review of a business case for low income terms and conditions with BCOAPO, which as indicated in section 1.7.3 of the Application, engagement with BCOAPO on this topic is on-going. Another example relates to RDA Module 2. Through meetings with Commercial Energy Consumers Association of British Columbia[57] (**CEC**) described below, BC Hydro identified a number of potential General Service customer rate options it will explore in more detail in the stakeholder engagement process leading up to Module 2.

[57] CEC is composed of members which are commercial customers of BC Hydro.

Transmission Service

- Series of regional meetings with Transmission Service customers in Prince George, Quesnel, Kamloops, Vancouver, Calgary and Nanaimo concerning RS 1823, potential Transmission Service rate options and Transmission extension policy during the May to June 2014 (a summary engagement report of these sessions is found at Appendix C5-C);
- Meeting with AMPC concerning the proposed load curtailment pilot on June 27, 2014;
- Meetings with AMPC, CAPP and Mining Association of BC[58] (**MABC**) to discuss RS 1823 pricing principles, load curtailment and Transmission extension policy on September 18, 2014, October 9, 2014 and September 30, 2014 respectively (copy of summary notes for these meetings found at Appendix C-5D);
- Meetings with the four Transmission Service customers exempt from RS 1823 currently taking service under RS 1827 (New Westminster on September 3, 2014, UBC and SFU on August 27, 2014, and YVR on October 2, 2014). A copy of the slide deck presentation to YVR, which is representative of the three presentations, is found at Appendix C-5D). Additional information concerning RS 1827 and the four exempt Transmission Service customers is found in sections 2.3.1.4 and 7.5 of the Application;
- Series of meetings with AMPC and various RS 1823 customers on the freshet rate pilot proposal as follows (refer to the Workshop 10 consideration memo for greater detail at Appendix C-5B):
  - February 26, 2015 – meetings with ERCO Worldwide (**ERCO**) and Canexus Corporation (**Canexus**), two chemical manufacturing and handling companies with facilities in North Vancouver (both companies) and Nanaimo (Canexus), to discuss the freshet rate concept;

[58] MABC represents the interests of coal, metal, industrial mineral companies and smelters in B.C. and in BC Hydro's service area MABC members take service under RS 1823 and the LGS rate.

- March 19, 2015 – presentation to AMPC concerning the freshet rate concept which included discussion of whether there was interest in a RTP rate;
- April 1, 2015 – meeting with AMPC's consultant to discuss freshet rate baseline options;
- April 17, 2015 – conference call with Catalyst Paper (**Catalyst**), a pulp and paper company operating three mills located in Crofton, Port Alberni and Powell River, regarding freshet rate baseline options;
- May 4, August 28, September 3 and September 15, 2015 – meeting with AMPC to further discuss freshet rate issues, including billing, baseline options and the proposed wheeling charge. A copy of the September 15, 2015 presentation to AMPC is found at Appendix C-5D of the Application.

General Service Rates

- Meetings with CEC on November 10, 2014 and April 22, 2015 to discuss potential LGS/MGS rate options as outlined in section 6 of the Workshop 8a/8b consideration memo at Appendix C-4A; and
- Two sessions focused on MGS and LGS energy rate structure alternatives with the following organizations whose members are comprised of LGS and MGS customers: (1) Session of May 7, 2015 with Building Owners and Managers Association of British Columbia (**BOMA**),[59] and 14 LGS and MGS customer attendees; and (2) Session of May 22, 2015 with BC Food Processors Association (**BCFPA**),[60] Canadian Manufacturers and Exporters (**CME**)[61] and 20 LGS and MGS customer attendees. Refer to the Workshop 8a/8b consideration memo found at Appendix C-A for additional detail, and to Appendix C-4C for a copy of the presentation.

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[59] BOMA is the largest commercial real estate industry association in B.C.; https://www.boma.bc.ca/.

[60] BCFPA is a non-profit organization dedicated to representing the food, beverage and natural health products processing industries; http://www.bcfpa.ca/home.

[61] CME is Canada's largest trade and industry association; http://www.cme-mec.ca/.

Residential Rates and Electric Tariff Terms and Conditions

- Meeting with BCOAPO on June 11, 2014 to discuss the default Minimum Reconnection Charge and the disconnection process (copy of the summary notes for this meeting are contained at Appendix C-3D);
- Meeting with Canadian Office and Professional Employees Union Local 378[62] (**COPE 378**) to discuss the RIB rate and a flat rate alternative, and RIB rate evaluation issues (copy of the summary notes for this meeting at Appendix C-3D); and
- Meeting with BCOAPO on August 18, 2015 to discuss the Electric Tariff Late Payment Charge and default Minimum Reconnection Charge, the BC Hydro low income rate/low income DSM program jurisdictional review, and development of the low income terms and conditions business case.

2.2.3.5 Other Public Engagement Streams: Residential E-Plus Customers

BC Hydro's engagement with Residential E-Plus customers is described in sections 5.1 and 5.2 of the Workshop 9a/9b consideration memo at Appendix C-3B. Engagement for 2015 RDA purposes commenced with a letter dated February 24, 2015 (included in Attachment 7 to the Workshop 9a/9b consideration memo) asking for feedback on the Residential E-Plus rate. In this letter to E-Plus customers, two options for the E-Plus rate were put forward, and E-Plus customers were requested to provide feedback in a mail-in form, an online form and/or at two open houses held in Nanaimo and Victoria on April 1 and April 2, 2015. BC Hydro informed E-Plus customers that it would formulate its preferred 2015 RDA E-Plus proposal after June 30, 2015. Approximately 3,700 Residential E-Plus customers responded to the letter (about 45 per cent of the total number of Residential E-Plus customers), with the vast majority of respondents supporting the option that maintained the E-Plus rate under the same terms and conditions.

[62] COPE 378 is the certified bargaining agent for BC Hydro employees.

At Workshop 12, BC Hydro set out that its preferred E-Plus rate option was to continue with the Residential E-Plus rate with amendment to the terms and conditions to make the rate truly interruptible. BC Hydro developed this preferred Residential E-Plus rate design after considering all the feedback received, and in particular, to the issue that the E-Plus rate should serve a useful function. On August 26, 2015, BC Hydro sent a letter to the Residential E-Plus customers (found at Appendix C-3E) informing them of BC Hydro's preferred Residential E-Plus rate design and that it would be filing its RDA in September 2015. Refer to section 5.3 of the Application.

2.2.3.6 Other Public Engagement Streams: Information Sessions

In response to stakeholders requests, BC Hydro hosted an information session on its Residential End Use Survey (**REUS**) on November 25, 2014 (a copy of the presentation slide deck is found at Appendix C-3F). The REUS provides residential customer level data that is not available to BC Hydro from billing data, including with respect to dwelling type, electric heat, low income and household size. This information from the 2014 REUS was used in BC Hydro's residential rate modelling and provided information about the impact on specific residential customer segments for each rate design alternative as described in section 2.4.3 below.[63] A description of the 2014 REUS is provided in section 5.5 of the Application, and copy of the 2014 REUS is found at Appendix C-3F.

BC Hydro also hosted information sessions concerning its transmission load interconnection process and distribution extension policy. As these are RDA Module 2 matters, they are not referred to in this Application.

[63] Modelling provided during the Stakeholder engagement process was based on the 2012 REUS as it was the most recent available. The 2014 REUS became available in late August 2015 and is used to inform the modelling in the Application. The 2012 and 2014 REUS methodologies are identical.

2.3 Context for Application

2.3.1 Regulatory Context: Prior Commission RDA and Rate Structure Decisions and the 2013 Industrial Electricity Policy Review

The following section summarizes aspects of prior Commission decisions concerning BC Hydro rate designs relevant to the 2015 RDA Module 1.

2.3.1.1 1991 RDA

The following two elements of the Commission's decision concerning the 1991 RDA[64] have a bearing on 2015 RDA Module 1 as they relate to General Service rates, and to 'rate shock' and the 10 per cent bill impact test:

- BC Hydro proposed to phase out the declining block energy rates then in place for its Residential and General Service customers. The Commission agreed that declining block rate structures are inappropriate for Residential and GS customers in the face of increasing electricity supply costs and the then direction of B.C. Government policy.[65] The Commission approved a gradual flattening of energy rates for General Service customers, noting that a 35 per cent rate increase to some customers if rates were to be flattened in one step would constitute rate shock. The Commission also highlighted General Service rate design issues, including diversity of load size; and
- BC Hydro grounded the 1991 RDA on four policy objectives, including that no customer bills should increase by more than 10 per cent. The 10 per cent level was a guideline. Reference was also made to a 'two-times rule' which states that if as a result of rate design bills were to increase by more than double the increase received on average by bills within the rate class, this would begin to

64 Commission Order No. G-36-92 and *In the Matter of a Rate Design Application by British Columbia Hydro and Power Authority*, Decision, April 24, 1992 (**1991 RDA Decision**); copies available at BC Hydro's 2015 RDA website http://www.bchydro.com/about/planning_regulatory/2015-rate-design/resources.html.

65 As set out in Special Direction No. 3, OIC 1418/1989 (required BC Hydro's rates contribute to conservation and the efficient use of energy; recognize the higher cost of new electricity supply; provide for smooth and stable increases; and are otherwise fair, just and reasonable). Special Direction No. 3 was revoked by OIC 1684/1992; copies available at http://www.bcuc.com/Documents/SpecialDirections/OIC_1684-SD-8%20BCUC.pdf.

> encroach on the realm of rate shock. The Commission accepted that in the circumstances of the 1991 RDA the two-times rule could be used as a "rough guideline", noting that it appeared to give BC Hydro more flexibility within the context of a potential 7 per cent revenue requirements increase.[66]

In the Commission's decisions concerning BC Hydro's 1993 and 1994 RRAs, the Commission directed BC Hydro to achieve flat rates for its General Service customers.[67] BC Hydro revised the rates leading to the 14,800 kWh threshold found in the existing MGS and LGS Part 1 energy rates. The existing MGS and LGS rates are described in sections 6.3.2.1 and 6.4.2.1 of the Application.

2.3.1.2 1995 Industrial Service Options Application

The BC Hydro 1995 Industrial Service Options Application is relevant because of the RTP option – RS 1848. On July 17, 1996, the Commission issued its decision[68] approving RS 1848. As noted in Attachment 5 to Workshop 5 consideration memo at Appendix C-5A, at the time market prices were lower than BC Hydro's standard rates, and many large industrial customers wanted access to these prices. At one point in time, up to 25 to 30 accounts (out of a total of 100 eligible Transmission Service accounts) were enrolled. However, following the 2000/2001 crisis in the Western power market, all enrolled Transmission Service customers subsequently dropped off of RS 1848. Some of these customers previously negotiated reductions in their CBL to increase the amount of energy that could be purchased at market prices that were below the applicable firm rate; however, this strategy left them exposed when market prices dramatically rose.

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66 1991 RDA Decision, page 17, section 2.3.3.

67 Commission Order No. G-116-93 (http://www.bcuc.com/Documents/Orders/1993/DOC_36681_G-116-93_BCH_increaserates.pdf) and section 8.3.1 of the Decision; and Commission Order No. G-89-94 (http://www.bcuc.com/Documents/Orders/1994/DOC_36474_G-89-94_BCH_increaserates.pdf) and section 7.2.2 of the Decision;

68 *In the Matter of British Columbia Hydro and Power Authority: Industrial Service Options Application*, Decision, July 17, 1996; copy available at http://www.bcuc.com/Documents/Decisions/1996/DOC_263_07-17-1996_BCH_Industrial%20Service%20Options%20Application.pdf.

BC Hydro applied to terminate RS 1848 as part of its 2005 Transmission Service Rate Application and the Commission approved termination through Commission Order No. G-79-05;[69] refer to section 2.3.1.4 below. Refer also to section 7.3.3.2 of the Application for the reasons why BC Hydro is not proposing a new RTP option for Transmission Service customers at this time.

2.3.1.3 2003 Heritage Contract and TSR Stepped Rates Inquiry

On March 3, 2003 the B.C. Government directed the Commission to convene a public inquiry and provide recommendations relating to a Heritage Contract for BC Hydro's existing generation resources and to a stepped rate for Transmission Service customers (referred to as the **Heritage Contract Inquiry**). On October 17, 2003 the Commission issued the Heritage Contract Report,[70] and on November 28, 2003 the B.C. Government circulated its response to the Commission recommendations. The relevant Commission recommendations and B.C. Government responses are set out in Table 2-2.

[69] http://www.bcuc.com/Documents/Orders/2005/DOC_8391_G-079-05_BCHydro_TSRA%20Reasons%20for%20Decision.pdf
[70] *Supra*, note 9.

Table 2-2 Relevant Commission Heritage Contract Inquiry Recommendations and B.C. Government Responses

Commission Recommendation	B.C. Government Response
#1 - That the Heritage Contract attached as Appendix B to the [Heritage Contract Report] be legislated as contemplated in the [2002] Energy Plan.	The Heritage Contract attached hereto will be legislated as contemplated in the [2002] Energy Plan. The attached version contains a number of changes from the version recommended by the Commission which are reflected in the balance of this document. *BC Hydro Note:* The Heritage Contract has been legislated in perpetuity pursuant to OIC 849/2008 (November 28, 2008). As discussed above in section 2.2.1.3, the Heritage Contract is attached as Appendix A to Direction No. 7.
#6 – That the Commission allocate the benefits of the Heritage Resources among customer classes as part of its ratemaking jurisdiction pursuant to the [*UCA*].	Accepted. No government direction is necessary. This is consistent with normal regulatory board functioning and provides the necessary flexibility to allow Heritage Contract benefits to track the constant changes in electricity use that occur in different customer classes. *BC Hydro Note*: As set out above and in Attachment 3 to the Workshop 3 consideration memo (copy found at Appendix C-3A), there are a number of important elements to the Heritage Contract scheme for purposes of the 2015 RDA: • BC Hydro's rates are established on a cost of service basis; • New customers should be able to benefit from the Heritage Resources. In BC Hydro's view, the Commission is left with discretion to design rates for BC Hydro's customers that balance the competing interests of different rate classes, and to allocate the benefits of the Heritage Resources between rate classes subject to the two elements identified above. BC Hydro notes the MEM Policy Letter, which states that it continues to be B.C. Government policy that the benefits of the Heritage Assets should continue to accrue to all BC Hydro customers on the basis of their energy consumption and peak demand, and that the benefits should not be re-allocated between customer groups on a different basis or withheld from new customers
#8 – That stepped rates be implemented according to the principles and considerations set forth in Chapter 3 [of the Heritage Contract Report]. The principles are repeated below for convenience: The Tier 2 rate should reflect the long-term opportunity cost of new supply, where long-term is understood to include the acquisition cost required to obtain that supply; The quantity of power being sold to industrial customers at Tier 1 of the stepped rate should be initially set at 90 per cent, and the Tier 2 quantity should make up the remaining 10 per cent; and The Tier 1 rate should be derived from the Tier 2 rate and the Tier 1/Tier 2 [90/10 split] to achieve, to the extent reasonably possible, revenue neutrality.	Accepted. Further, the prospective Tier 2 rate should be published periodically, even if no change is being made to the actual rate charged, for the purpose of providing a public benchmark against which others can make investment decisions on conservation or alternative supply. The Tier 2 rate will reflect the cost of new supply more closely than would be the case if it were based on market indexes (Mid-C market). The Tier 1/Tier 2 [90/10 split] provides a good balance between providing incentives and imposing unnecessary hardship. *BC Hydro Note*: refer to sections 2.3.1.4 and 7.2.1 of the Application for additional detail.

Commission Recommendation	B.C. Government Response
#9 – That a report be submitted to the Government of a three year review of the impacts of the stepped rates, including customers' demand response and the percentage of customers' loads served by third-party suppliers.	Accepted. *BC Hydro Note*: refer to sections 2.3.1.4 and 7.2.1 of the Application for additional detail.
#10 – That prior to the completion of the rate design hearing the initial determination of the stepped rates and [TOU] be based on the same revenue requirement used for the determination of [RS] 1821 rates.	Accepted. This is a practical approach that is consistent with the desire to make changes revenue neutral to the extent possible.
#11 – That load aggregation within multiplant ownership be allowed so long as it is restricted to operating units.	Load aggregation within multiplant ownership will be allowed so long as it is restricted to operating units and that the units aggregated would qualify individually for stepped rates and [TOU] rates.
#12 – That the [CBL] used for applying stepped rates to industrial customers should be based on past experience adjusted for anomalies and reviewed annually. Further, that the Commission will continue to approve CBLs and resolve disputes as necessary.	Accepted. Adjustments to CBLs will be required on an ongoing basis and a well-defined dispute resolution mechanism will be beneficial.
#13 – That [TOU] rates should be implemented at the same time as stepped rates.	Accepted. It will be important to design stepped rates and [TOU] rates together to ensure that customer choice between them does not shift costs to other customers. It is expected that there will be some measure of integration between the rates to achieve this. *BC Hydro Note*: refer to sections 2.3.1.4 and 7.3.1 of the Application for additional detail.
#14 – That industrial and large commercial customers eligible for BC Hydro's [RS] 1821 be required, at their election, to take service from BC Hydro from either the stepped rate or the [TOU] rate. [RS] 1821 should be terminated.	Accepted and further that the stepped rates and [TOU] rates will be subject to conditions the Commission considers appropriate from time to time for application to the rates of BC Hydro for industrial and large commercial customers and as currently found in [TS] 5 and [TS] 6 to BC Hydro's [Electric Tariff]. *BC Hydro Note*: In section 2.4.2 of the Workshop 5 consideration memo at Appendix C-5A, BC Hydro identified Recommendation #14 as a potential legal issue with respect to a Transmission Service RTP; refer to section 7.3.3.2 of the Application.
#15 – That Aquila [now FortisBC], [New Westminster] and [University of British Columbia (**UBC**)], as entities that distribute all or a significant portion of their load to others, be exempted from the application of stepped rates at this time, and form a new rate schedule(s).	Accepted. These customers are effectively distributors who sell the electricity they purchase onwards to end-use customers. Only the end-use customers can control the amount of electricity purchased by the distributors and the distributors' purchases will therefore not be influenced by the wholesale rate structure. *BC Hydro Note*: refer to sections 2.3.1.4 and 7.5.1 of the Application for additional detail.

As described above in section 2.2.1.3, the end result of the Heritage Contract Inquiry was HC2, which has since been replaced by Direction No. 7. Direction No. 7 sets out directions to the Commission with respect to RS 1823 and the implementation of the Heritage Contract.

2.3.1.4 2005 Transmission Service Rate Application

On March 10, 2005 BC Hydro filed its Transmission Service Rate (**TSR**) Application. Among other things, BC Hydro asked for approval of the following which the Commission approved pursuant to Commission Order No. G-79-05 after a NSP and Negotiated Settlement Agreement (**NSA**):

- Default RS 1823, pursuant to which the Tier 2 rate is set as a signal of BC Hydro's energy LRMC. The pricing principles for RS 1823 were subsequently re-set to reflect BC Hydro's latest reference for LRMC through the Commission review of BC Hydro's 2008 TSR Re-pricing Application and subsequent Commission Order No. G-97-08.[71] BC Hydro also submitted to the Commission a TSR three-year summary report on September 30, 2009 which was an input into the Commission's own review, resulting in the Commission's *Report to the Government on the British Columbia Hydro and Power Authority Transmission Service Rate Program*[72] dated December 30, 2009 (**Commission 2009 TSR Report**). The Commission considered the CBL Determination Guidelines (TS 74) five times between 2008 and 2013.[73] Refer to section 7.2 of the Application for more detail;
- RS 1825 (TOU rate) and TOU Transmission Service Agreement (TS 70). Refer to section 7.3.1 of the Application for the reasons why BC Hydro is not proposing any changes to RS 1825 at this time;
- RS 1827 (exempt customers). RS 1827 is currently applicable to four transmission-voltage customers who have been exempted from stepped

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[71] http://www.bcuc.com/Documents/Orders/2008/DOC_19036_G-97-08_BCH_Transmission_Svce_Rate-Reasons-for-Decision.pdf

[72] http://www.bcuc.com/documents/reports/bcuc-tsr-evaluation-report-december_31_2009.pdf.

[73] F2008: TS 74 amendment for CBL aggregation notice and leap year – approved by Commission Order No. G-69-08; F2009: TS 74 amendment for updated CBL adjustment practices – approved by Commission Order No. G-16-10; F2010: TS 74 amendment for plant capacity increases with DSM – approved by Commission Order No. G-21-10; F2012: TS 74 amendments for customer-funded DSM project recognition, duration and expiry; tariff principles; operating hour changes and other clarity-related change – approved by Commission Order No. G-103-12; F2013: TS 74 amendments for RS 1823 customers with self-generation – approved by Commission Order No. G-19-14.

(inclining block) rates: New Westminster, UBC, SFU and YVR.[74] The issue of exemption from stepped rates arose during the 2003 Heritage Contract Inquiry. As noted above in Table 2-2 above, Recommendation #15 of the Heritage Contract Report recommends exemption of New Westminster and UBC from the application of stepped rates on the basis that they are entities that distribute all or a significant portion of their load to others. This recommendation is incorporated into subsection 3(1) of Direction No. 7. Accordingly, a new rate for New Westminster and UBC, RS 1827, was created. During the NSA, SFU and YVR indicated they would seek an exemption from stepped rates since they have similar characteristics to the two customers already exempted. The Commission confirmed exemption of SFU and YVR by way of Commission Order No. G-10-06.[75] Refer to section 7.5 of the Application for discussion of additional background to and BC Hydro's proposal for RS 1827;

- Amendments to RS 1852 (Modified Demand Transmission). RS 1852 is a non-firm (interruptible) rate available at BC Hydro's discretion to Transmission Service customers in locations: (1) that are transmission-constrained; and/or (2) market opportunities arise which allow for a different HLH time period. Refer to section 7.3.2 of the Application;
- Amendments to RS 1880 (Transmission Service Standby and Maintenance Supply). As part of the 2005 TSR Application NSA, it was agreed that RS 1880 would be addressed in a subsequent Commission review process as some stakeholders were concerned with BC Hydro's proposal to base the RS 1880 energy rate on the Mid-C hourly index due to potential price volatility. In the 2005 Transmission Service Outstanding Matters Application, BC Hydro

[74] Note that the exemption originally extended to Aquila, now FortisBC. In May 2013, BC Hydro applied to the Commission to replace the PPA with FortisBC under RS 3808. The PPA incorporates a two tranche pricing structure –Tranche 1 up to 1,041 GWh/year reflects an energy charge equal to that of BC Hydro's customers on RS 1827. The Tranche 2 price reflects BC Hydro's energy LRMC. The Commission approved the new PPA through Commission Order No. G-60-14; http://www.bcuc.com/Documents/Proceedings/2014/DOC_41321_05-06-2014_BCH_PPA-RS%203808-TS-No-2-and-3_Decision.pdf.

[75] http://www.bcuc.com/Documents/Orders/2006/DOC_10727_G-019-06_BCH_Transmission%20Service%20Outstanding%20Matters%20Appl.pdf

proposed that the RS 1880 energy rate should be the same as the RS 1823 Tier 2 price, a per incident Administrative Charge of $150 and no demand charge. BC Hydro's proposal for RS 1880 was approved by the Commission pursuant to Commission Order No. G-19-06. Refer to section 7.4.2 of the Application for a discussion of additional background to and BC Hydro's proposal for RS 1880; and

- Termination of a number of Transmission Service rate schedules, including RS 1848 discussed in section 2.3.1.2 above, and RS 1844 (Turbine Turndown Energy Rate) due to lack of use. BC Hydro examined RS 1844 as part of the development of its Transmission Service freshet rate pilot proposal described in section 7.3.4 of the Application.

2.3.1.5 2007 Rate Design Application

The 2007 RDA was BC Hydro's first comprehensive RDA since 1991. The scope included six of seven BC Hydro rate classes – Transmission Service rate structures were not addressed as these had been reviewed in 2005 – and BC Hydro's Distribution extension provisions found in section 8 of the Electric Tariff. The Transmission extension provisions in TS 6 were not part of the 2007 RDA review. The principal 2007 RDA issues were:

- BC Hydro's COS. One intervener advocated a marginal COS approach to allocate BC Hydro's revenue requirement which the Commission rejected. Other COS issues included Heritage hydroelectric cost classification, Generation demand and Transmission cost allocation, and Distribution cost classification and allocation. Refer to section 3.5.2 of the Application for a description of how the Commission's COS-related directives contained in its decision concerning BC Hydro's 2007 RDA[76] have been addressed;
- LGS rate restructuring: BC Hydro proposed to flatten the LGS demand and energy charges (the LGS rate class was defined in the 2007 RDA as customers

[76] *Supra*, note 49.

with demand at 35 kW and over). BC Hydro considered that the proposed three year phase-in provided an appropriate balance between sending more efficient price signals and mitigating the impact on adversely affected customers. The proposed LGS rate was denied. 2007 RDA Direction 19 provided that BC Hydro was to file with the Commission an application for a rate structure or rate structures that “encourage conservation without unduly benefitting or harming any of its customers in the [LGS] class” and this led to BC Hydro’s 2009 LGS Application described in section 2.3.1.7 below;

- E-Plus rates: BC Hydro proposed to phase-out E-Plus rates over a 10-year period from April 1, 2008 to March 31, 2018. The Commission denied BC Hydro’s proposal. Pursuant to 2007 RDA Direction 14, BC Hydro was instructed to “pay more attention to the exercise of its rights under the [E-Plus] Rate Schedules and to invest the necessary time and resources to ensure that its E-Plus customers comply with the Special Conditions of the [E-Plus] Rate Schedules …”. The Commission approved restricting the ability to transfer the E-Plus rate to a new customer by amending the Availability clause to state that the E-Plus rate is available “only in Premises where there has been no change in customer since April 1, 2008”. Refer to section 5.3.2 of the Application for a description of how BC Hydro responded to 2007 RDA Direction 14 and for BC Hydro’s proposal with respect to its E-Plus rates;
- Standard charges: BC Hydro proposed updates to the standard charges set out in section 11 of the Electric Tariff to reflect then current costs. BC Hydro’s 2015 RDA proposals for Electric Tariff terms and conditions, including standard charges, is contained in Chapter 8 of the Application;
- Distribution extension policy: BC Hydro proposed to simplify and improve the transparency of its Distribution extension policy. This subject is not addressed any further given that BC Hydro will be addressing Distribution extension policy as part of 2015 RDA Module 2 (refer to section 1.5.2 of the Application).

The Commission in the 2007 RDA Decision (page 57) concluded that rate design applications should be informed by the views of BC Hydro's customers prior to the filing of the application. BC Hydro designed an extensive 2015 RDA stakeholder engagement process including offering PACA funding for purposes of its pre-filing topic-specific workshops. Refer to section 2.2.3 above.

The Commission concluded that the eight Bonbright criteria are consistent with the *UCA*'s fair, just and not unduly discriminatory test.[77] BC Hydro proposed a 10 per cent maximum bill impact threshold as part of the Bonbright customer understanding and acceptance criterion. Specifically, BC Hydro endeavored to limit bill impacts arising from its proposals to no more than 10 per cent per year, exclusive of any changes arising from RRA-related increases. The 10 per cent bill impact test was not a rule intended to be binding in every circumstance. For example, BC Hydro submitted that it is acceptable for bill impacts to exceed 10 per cent per year where the absolute dollar value of the increase is very small. BC Hydro was criticized for excluding RRA increases from the 10 per cent maximum bill impact test, and in response, the 10 per cent bill impact test used to develop the 2015 RDA is inclusive of RRA increases. Refer to the discussion of the Bonbright criteria in section 2.4.1 below.

2.3.1.6 2008 Residential Inclining Block Rate

BC Hydro's RIB rate was approved by Commission Order No. G-124-08[78] and made effective on October 1, 2008. The RIB rate is a two-step inclining block rate, with the first portion called the Step-1 energy rate and the amount above that the Step-2 energy rate. The Commission established the Step-1 energy rate/Step-2 energy rate threshold at 1,350 kWh per two-month billing period, being more or less 90 per cent of the median consumption of BC Hydro's residential customers of about 760 kWh per month.[79] In support of this threshold the Commission cited RS 1823 which sets

[77] 2007 RDA Decision, *supra* note 49, page 58.
[78] http://www.bcuc.com/Documents/Proceedings/2008/DOC_19585_G-124-08_BCH_RIB.pdf.
[79] *Supra*, note 50, pages 106 to 107.

individual thresholds at 90 per cent of each customer's baseline. The Commission concluded that a suitable 'cap' for the Step-2 energy rate was BC Hydro's most recent estimate of new supply at plant-gate grossed up for line losses. BC Hydro used the levelized weighted-average plant-gate price of its most recent power acquisition process at the time as a proxy for its energy LRMC for rate setting purposes. The Commission found that the estimate of new supply at plant gate should not include the incremental cost of transmission or distribution.[80] Further, in its decision concerning BC Hydro's 2008 RIB application, the Commission found Bonbright's eight rate design criteria to be consistent with the *UCA* test of 'fair, just and not unduly discriminatory' and form an appropriate foundation for inclining block rate structures.[81]

Since 2008, the RIB rate has been reviewed three times in Commission processes as follows:

- On March 3, 2010, BC Hydro requested approval for F2011 pricing principles under which BC Hydro would uniformly increase the three components of the RIB rate by the amount of the approved F2011 RRA rate increase.[82] In the subsequent Commission Order No. G-47-10 issued on March 15, 2010, the Commission granted approval for BC Hydro to apply its interim F2011 rate increase uniformly across the RIB basic charge, the Step-1 energy rate and Step-2 energy rate. The F2011 RRA and the F2011 pricing principles applicable to the RIB were resolved through the Commission's approval of the F2011 RRA NSA;[83]
- On December 21, 2010, BC Hydro filed an application for approval of RIB pricing principles from F2012 onward under which BC Hydro would uniformly

80 *Ibid*, pages 107 to 108.
81 *Ibid*, page 51.
82 F11 RRA, Appendix A1; http://www.bcuc.com/Documents/Proceedings/2010/DOC_24719_B-1_BCHydro-F11RR-Application.pdf.
83 Commission Order No. G-180-10; http://www.bcuc.com/Documents/Orders/2010/DOC_26533_G-180-10_BCH-F2011-Revenue-Requirements-Reasons-WEB.pdf.

increase the three components of the RIB rate by the amount of any approved general rate increase. BC Hydro used the levelized weighted-average plant-gate price of the 2009 Clean Power Call, the most recent power acquisition process at the time, as a proxy for its LRMC for rate setting purposes. Commission Order No. G-45-11 set the following RIB rate pricing principles for the F2012 to F2014 period: Step-2 energy rate increases up to the higher of the Class Average Rate Change[84] (**CARC**) or 10 per cent bill impact, subject to the Step-1 energy rate increasing by no less than the annual rate of inflation; and the Step-1 energy rate calculated residually but increases by no less than the annual rate of inflation. In its Reasons for Decision accompanying Commission Order No. G-45-11, the Commission emphasized that the LRMC for new supply is the "appropriate referent for the Step-2 energy rate".[85] The Commission also found in its 2012 decision concerning FortisBC's 2011 RIB application that pricing electricity above LRMC is not economically efficient;[86]

- On November 1, 2013, BC Hydro filed its 2013 RIB Rate Re-Pricing Application. BC Hydro requested approval for F2015-F2016 pricing principles under which BC Hydro would uniformly increase the three components of the RIB rate by the amount of the approved F2015/F2016 RRA rate increase. BC Hydro did not seek any change to the RIB rate other than the proposed pricing principles. The Commission approved BC Hydro's proposed pricing

[84] Note that as a result of the Rate Rebalancing Amendment, for purposes of this Application, CARC can arise from any or all of the following: revenue requirement changes and rate rider changes.

[85] Commission Order No. G-45-11, Reasons for Decision, Appendix A (**2011 RIB Re-Pricing Decision**), page 3 of 19; http://www.bcuc.com/Documents/Proceedings/2011/DOC_27176_G-45-11_BCH-RIB-Re-Pricing-Reasons.pdf.

[86] The Commission determined that the LRMC of new supply "continues to be the appropriate referent for the Block-2 energy rate" and stated that it "accepts Fortis' submission that pricing electricity above FortisBC's long-run marginal cost is not economically efficient" in its decision concerning Fortis' RIB; *In the Matter of FortisBC Inc. Residential Inclining Block Rate*, Decision, January 13, 2012, page 40; http://www.bcuc.com/Documents/Proceedings/2012/DOC_29557_FBC%20Inc-RIB_Decision-WEB.pdf.

principles, and as described in section 1.1.1 of the Application, ordered BC Hydro to file a RDA in F2016.[87]

In the 2008 RIB Decision,[88] the Commission noted that BC Hydro did not explain how stakeholder engagement activities informed its selection of the RIB as the preferred alternative. In both this Chapter in section 2.2.3, and in the remaining chapters, BC Hydro explains how its extensive 2015 RDA stakeholder engagement process was used to, among other things, identify issues with current rate structures and to narrow the alternatives to be examined in detail.

2.3.1.7 2009-2010 LGS and MGS

On October 16, 2009 BC Hydro filed its Large General Service Application (**LGS Application**) seeking approval of:

- Initial segmentation of the then existing LGS rate class into two rate classes – LGS with monthly peak demand of 150 kW or more in the preceding 12 month period, and MGS with monthly peak demand between 35 kW and 150 kW;
- A two part baseline energy rate structure for LGS. The first part (Part 1) would be applied against the historic consumption level (baseline) of each account. The second part (Part 2) would be equal to BC Hydro's energy LRMC and would be applied against the difference between the account's currently monthly (billed) energy consumption and its baseline. A Part 2 charge would be incurred when billed consumption exceeds the baseline, and a credit would be earned when billed consumption is less than the baseline;
- A flat energy rate for MGS, phased-in over a six-year period; and
- No changes to other rare structure elements such as demand charges.

[87] Commission Order No. G-13-14; http://www.bcuc.com/Documents/Proceedings/2014/DOC_40513_G-13-14-BCH-RIB-Rate-Re-Pricing-SRP-Reasons.pdf.

[88] 2008 RIB Decision, pages 42 to 43.

The LGS Application proceeded to a NSP with the result that the parties agreed to a two-part baseline rate structure for both the new LGS and MGS rate classes. The Commission approved the resulting NSA pursuant to Commission Order No. G-110-10[89] on June 29, 2010. Refer to sections 6.3.2 and 6.4.2 of the Application for a detailed description of the existing LGS and MGS rate structures, including implementation dates and evaluations.

2.3.1.8 2013 Industrial Electricity Policy Review

On February 1, 2013, the B.C. Government struck a task force to review existing industrial electricity policy. The IEPR task recommendations and B.C. Government responses that informed 2015 RDA Module 1 (numbered in accordance with the B.C. Government issued IEPR backgrounder)[90] are set out in Table 2-3.

Table 2-3 Relevant IEPR Task Force Recommendations and B.C. Government Responses

IEPR Task Force Recommendation	B.C. Government Response
IEPR Recommendation 9: Continue using postage stamp rates.	Government will continue to use postage stamp rates. *Note: Refer to section 2.2.2.1 above.*
IEPR Recommendation 10: End use rates which have no impact on ratepayers could be considered but those which impact ratepayers and are directed by Government should be paid for by taxpayers and not ratepayers.	A rate design review process will be launched to examine ways to provide industrial customers with more options to reduce their electricity costs.
IEPR Recommendation 11: BC Hydro should develop a revised retail access program.	A rate design review process will be launched to examine ways to provide industrial customers with more options to reduce their electricity costs. *Note: As described above in section 2.2.1.3, the Commission is prevented by section 14 of Direction No. 7 from setting rates for BC Hydro that would result in the direct or indirect provision of unbundled transmission service to retail customers in its service area or those who supply such customers, except on application by BC Hydro. This covers the two forms of physical retail access reviewed by the IEPR task force – namely, physical access to the spot market, or to B.C.-based IPP and generation other than*

89 http://www.bcuc.com/Documents/Orders/2006/DOC_10727_G-019-06_BCH_Transmission%20Service%20Outstanding%20Matters%20Appl.pdf

90 http://www.newsroom.gov.bc.ca/2013/11/10-year-plan.html

IEPR Task Force Recommendation	B.C. Government Response
	BC Hydro's. In BC Hydro's view Direction No. 7 does not prevent the Commission from setting a RTP rate because Transmission Service customers would be buying some portion of electricity from BC Hydro (based on Mid-C or other market pricing). Refer to section 7.3.3.2 of the Application.
IEPR Recommendation 12: Government need not act on the Commission 2009 TSR Report until "BC Hydro's surplus has diminished and the effect of the other recommendations in this report can be seen".	Government accepts this recommendation. *Note*: *BC Hydro's energy load-resource balances (**LRBs**) are discussed in section 2.3.2 below in the context of LRMC for rate making purposes*.
IEPR Recommendation 13: BC Hydro should work with its industrial customers and the Commission to develop options that take advantage of industrial power consumption flexibility such as TOU rates and interruptible rates.	A rate design review process will be launched to examine ways to provide industrial customers with more options to reduce their electricity costs. BC Hydro will implement a voluntary load curtailment program with industrial customers starting in 2015. *Note*: *BC Hydro initiated a two to three-year load curtailment program pilot on August 19. As discussed in Attachment 1 to the Workshop 5 Consideration Memo (copy at Appendix C-5A of the Application), BC Hydro is of the view the load curtailment pilot is a program as referenced in the definition of "demand-side measure" in section 1 of the CEA, and therefore expenditures associated with the load curtailment pilot are the subject of a DSM expenditure determination request submitted to the Commission under subsection 44.2(1)(a) of the UCA. The load curtailment pilot is not a "rate" as defined by section 1 of the UCA because the essential element of a rate is "compensation of a public utility", and under the load curtailment pilot there is no compensation of BC Hydro; rather, BC Hydro pays participating Transmission Service customers to be on stand-by for curtailable events. Nor is load curtailment a "service" as defined by section 1 of the UCA.* *BC Hydro is not revising RS 1825, the existing Transmission Service TOU rate, at this time for the reasons set out in section 7.3.1 of the Application. BC Hydro is proposing a new Transmission Service rate option – a freshet rate described in section 7.3.4 of the Application*.

2.3.2 Current Environment Context

2.3.2.1 Smart Meter Infrastructure

BC Hydro's installation of smart meters is 99 per cent complete with over 1.9 million meters installed throughout BC Hydro's service area. The new metering system allowed BC Hydro to better understand the load characteristics of its distribution voltage customers and to more accurately allocate costs within the F2016 COS study described in Chapter 3 of the Application. For example, in the 2007 RDA BC Hydro's COS study relied on a load research sample of about 400 residential customers and about 1,100 commercial customers. The collection of this data was done annually, took several months to complete and was labor intensive. Because the sample was so small, the customer class profiles created were general, sample redesign was not financially feasible and sample bias could have been an issue. With smart metering, BC Hydro has been able to analyze daily consumption patterns for each individual customer while using a sample of approximately 45,000 customers to analyze hourly load shapes and conduct more in-depth load research. The additional data from smart metering has increased the accuracy of BC Hydro's load profile information which is a key input into cost allocation with the F2016 COS study. With the capability to create almost on-demand detailed customer load profiles, COS analysis, rate design and peak load forecasting can be improved. Going forward, BC Hydro will be able to use smart metering information to measure losses on individual feeders and further improve the distribution loss assumptions that are used in the F2016 COS study and some rates within the Electric Tariff.

The implementation of smart meters has changed the manner in which BC Hydro can disconnect and reconnect customers. Prior to the implementation of smart meters customers were physically disconnected by a BC Hydro technician going to the property and disconnecting service. With smart meters customers are disconnected and reconnected remotely through a signal sent to the meter. As a result, the cost drivers for the default Minimum Reconnection Charge has changed. This is further discussed in section 8.3.2 of the Application. Smart meters also played a role in determining BC Hydro's preferred rate design for RS 1105, the Residential E-Plus rate discussed above in sections 2.2.3.5 and 2.3.1.5. BC Hydro proposes to amend Special Condition 1 of RS 1105 to make the rate truly interruptible; refer to section 5.3 of the Application. Residential E-Plus interruptions would be enacted remotely by BC Hydro for those Residential E-Plus customers with smart meters that have remote disconnect/reconnect (**RDR**) capability.

2.3.2.2 Energy Long-Run Marginal Cost

As described above in sections 2.3.1.4 (for RS 1823), 2.3.1.6 (for the RIB rate) and 2.3.1.7 (for LGS and MGS rates) above, various Commission rate design decisions have referenced BC Hydro's energy LRMC for rate-making purposes.

As pointed out by Commission staff at Workshop 3, one of the most significant changes since the establishment of rate structures for BC Hydro's Residential, MGS and LGS customers between 2008 and 2010 has been the reduction in BC Hydro's energy LRMC as set out in the 2013 IRP.

LRMC can be defined as the change in the long-run total cost resulting from a change in the quantity of output produced. In short, LRMC represents the price of the most cost-effective way of satisfying incremental customer demand where existing resources are insufficient to meet that demand. The standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand in which all capital and operating production inputs can be considered variable. BC Hydro uses an approach where the incremental resource acquisitions needed to supply future requirements are priced on a levelized unit energy cost (**UEC**) basis to aid in comparing resources with differing attributes.

BC Hydro uses the energy LRMC in its 2013 IRP to signal the value that should be placed on acquiring new energy resources. Over the next ten year period, these energy resources include DSM savings (through BC Hydro DSM programs, government codes and standards and BC Hydro rate structures such as RS 1823 and the RIB rate),[91] and renewals of existing EPAs with IPPs.

[91] *CEA* section 1 defines "demand-side measure" in part to mean "a rate, measure, action or program undertake to: (a) to conserve energy or promote energy efficiency; (b) to reduce the energy demand a public utility must serve; or (c) to shift the use of energy to periods of lower demand …". Codes and standards are public policy

LRMC and Integrated Resource Plan Energy Load-Resource Balance

While there has always been considerable uncertainty regarding the future long-run cost of new B.C.-based supply, the 2013 IRP is the first time that DSM and individually negotiated renewals of existing IPP EPAs whose terms expire over the next ten years or so are the marginal resources. The remainder of this section highlights the LRMC based on the 2013 IRP's recommended actions for meeting the forecasted energy gap from F2017 onwards.

As described in section 2.3.1.6 above, prior to BC Hydro's 2013 RIB Re-Pricing Application, BC Hydro's RIB and RS 1823 rates used the weighted-average plant-gate price[92] of BC Hydro's most recent IPP power acquisition process for energy as a proxy for its energy LRMC. BC Hydro had a significant projected need for new resources over the past 10 years and the marginal resource was the acquisition of green-field clean or renewable IPPs.[93] The last energy LRMC reflected the results of the most recent, broadly-based power acquisition process (e.g., the 2009 Clean Power Call results). Green-field clean or renewable IPPs were the marginal resource since there were insufficient cost-effective alternative resources available to provide the needed supply for customers that met the requirements of the *CEA*, and in particular the subsection 2(c) *CEA* "British Columbia's energy objective to generate at least 93% of electricity in British Columbia from clean or renewable resources …".

Modifications to the *CEA* self-sufficiency requirements referenced in section 1.1.1 of the Application,[94] and a lower load forecast, resulted in a reduced forecasted need for new energy resources. The next green-field IPP clean or renewable power

instruments enacted by governments to influence energy efficiency. Examples include building codes, energy efficiency regulations, tax measures, and local government zoning and building permitting processes.

92 Plant-gate estimates exclude any incremental delivery costs of either transmission or distribution.

93 The term 'clean or renewable resource' is defined in section 1 of the *CEA* to mean "biomass, biogas, geothermal heat, hydro, solar, wind or any other prescribed resource". The Clean or Renewable Regulation, B.C. Reg. 81/2011 adds biogenic waste, waste heat and waste hydrogen to this list. Natural gas-fired generation is not a prescribed clean or renewable resource.

94 As noted in section 1.1.1 of the Application, the Electricity Self-Sufficiency Regulation as amended by B.C. Reg. 16/2012 (OIC No. 036 (2012)) requires BC Hydro to plan to average water conditions as opposed to critical water conditions.

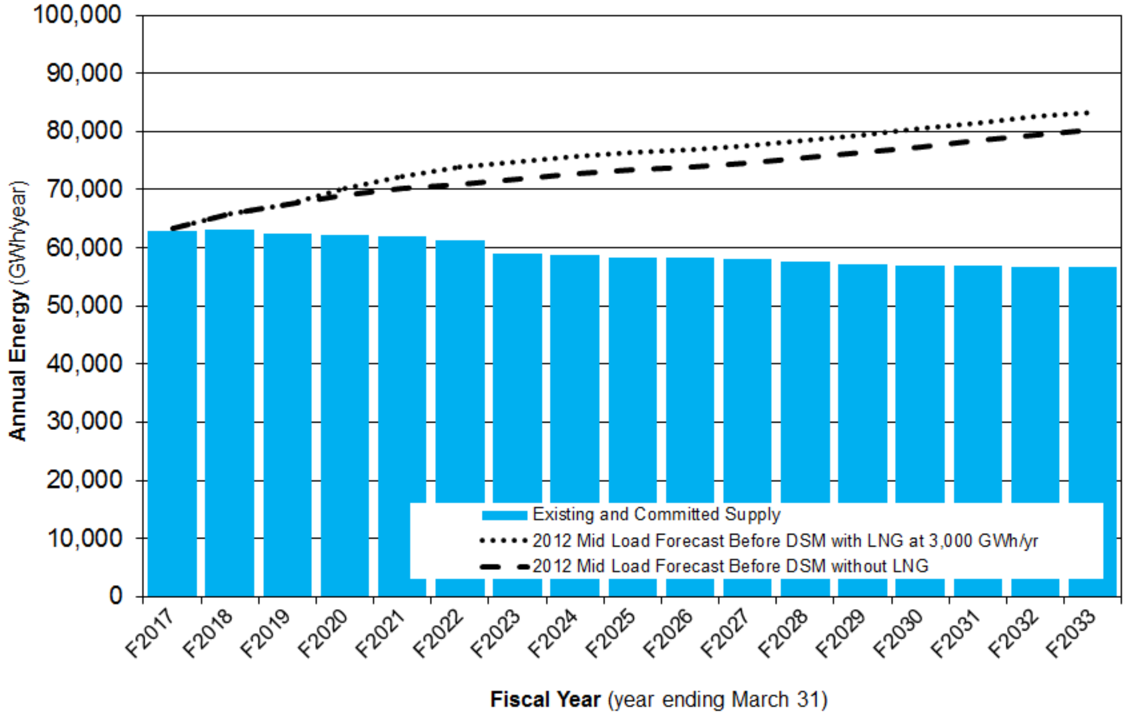
acquisition process is not expected within the 20-year planning horizon assuming all Site C units come into service in F2025, unless LNG needs exceed about 3,000 GWh/year. Even with this amount of LNG load, the need for such an acquisition process is not until F2032. As described further in this section, BC Hydro currently has sufficient alternative cost-effective B.C.-based resources to meet expected future energy needs without LNG demand by:

- Pursuing the DSM target (2013 IRP Recommended Action 1); and
- Undertaking IPP EPA renewals and Site C (2013 IRP Recommended Actions 4 and 6) as the main elements to fill the identified energy gap after pursuit of the DSM target.

BC Hydro estimates that LNG projects could add between about 800 GWh to 6,600 GWh/year of additional energy demand, corresponding to about 100 MW to 800 MW of additional peak demand. Supplying the low- to mid-range of LNG load (up to about 3,000 GWh/year) will not have a material impact on the energy LRMC because BC Hydro has enough energy resources to serve such LNG load with the pursuit of the cost-effective B.C.-based resources listed above. However, potential LNG load is one source of demand uncertainty and therefore LRMC uncertainty.

The 2013 IRP provides the analysis underpinning the energy LRB for BC Hydro's integrated system. A LRB is the difference between: (1) BC Hydro's annual load forecast, which projects BC Hydro customer demand over a 20-year period (in the case of the 2013 IRP this is the December 2012 Load Forecast) and (2) supply from existing and committed DSM and supply-side resources. There is a deficit or gap (i.e., a shortfall) if forecasted customer energy demand exceeds the existing and committed resources available to serve such load. Figure 2-1 is derived from the 2013 IRP and shows that there is a need for new energy resources beginning in F2017 without future DSM initiatives (including rate structures such as the RIB rate and RS 1823).

Figure 2-1 Energy LRB: Before Implementation of 2013 IRP Recommended Actions



The 2013 IRP proposes that BC Hydro meet the forecasted energy gap for the next 20 years predominantly by pursuing the DSM target, renewing some existing EPAs at the time they expire and Site C:

- The IRP provides that Recommended Action 1 on DSM would deliver electricity savings at an average UEC of about $32/MWh (on a Total Resource Cost (**TRC**)[95] basis) with a range of costs among different initiatives; Table 9-7 of the 2013 IRP provides that the net TRC[96] range for DSM programs is $6/MWh to $113/MWh ($F2013). BC Hydro tested varying levels of DSM in the 2013 IRP

[95] The TRC measures the overall economic cost of a DSM initiative from a resource options perspective, including both participant and utility costs. As discussed at Workshop 9a, BC Hydro is guided by the TRC test as described by the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001); copy available at California Energy Commission's website at www.energy.ca.gov.

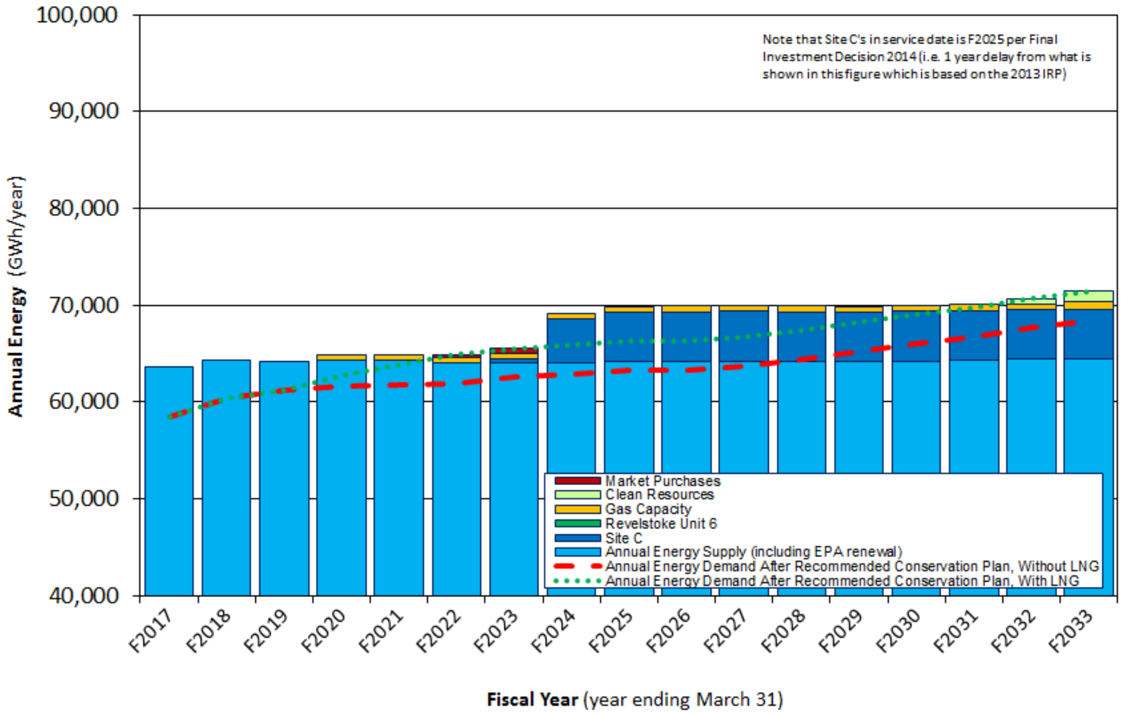
[96] Net TRC shown is net of generation, transmission and distribution capacity benefits, non-energy benefits and natural gas savings benefits.

and concluded that pursuit of IRP Recommended Action 1 is more cost-effective than a DSM option called DSM Option 3 that would see an increase in expenditures on programs but entail no changes to BC Hydro's rate structures. The IRP determined that DSM Option 3 is a viable resource (i.e., a resource that can be considered under prudent utility planning). Hence not all viable DSM savings are being acquired and DSM is a marginal resource; and

- BC Hydro is pursuing EPA renewals on a cost-of-service basis. Other considerations will be past performance, certainty of continued operation and system support characteristics. BC Hydro expects that EPAs will be renewed where the cost-of-service is less than BC Hydro's opportunity cost for replacement supply. On average bioenergy EPA renewals are expected to be approximately $95/MWh and run-of-river renewals are expected to be approximately $70/MWh ($F2016).

The energy LRB after implementation of IRP recommended actions (DSM, EPA renewal planning assumptions and Site C) with and without LNG is depicted in Figure 2-2.

Figure 2-2 Energy LRB: After Implementation of 2013 IRP Recommended Actions



Non-Firm Rates and Market Pricing

The wholesale electricity market (referred to as spot market) provides short-term energy at a variable price floating with the market. There is an argument that the reference for the cost of providing energy for non-firm (interruptible) service is the spot market. This issue is discussed in sections 6.8 and 7.4 of the Application in the context of BC Hydro's three existing non-firm, self-generation-related rates: RS 1253 (Distribution Service – IPP Station Service), RS 1853 (Transmission Service - IPP Station Service) and RS 1880 (Standby and Maintenance).

However, the spot market is not the appropriate referent for firm service energy rate pricing. A long-run view of the cost of new supply for a period of at least ten years is appropriate for designing rates because there is a need for some stability in rates. Using the spot market would result in a highly variable, confusing price signal.

Table 2-4 below summarizes market price volatility in 2015 (January and July for both HLH and LLH (all values are in USD/MWh)).

Table 2-4 Market Prices, January-July 2015

	HLH ($)	LLH ($)
Maximum	95.41	37.84
Minimum	5.72	0.24
Average	26.45	19.43

Furthermore, the spot market does not meet the definition of self-sufficiency described above in section 2.2.1.2.

Summary: Energy LRMC

DSM and EPA renewals are marginal resources until about F2030, after which BC Hydro would require green-field clean or renewable IPPs. In the 2013 IRP, the energy LRMC was reduced from the levelized weighted-average plant-gate price for firm energy grossed up for line losses arising 2009 Clean Power Call to about $100/MWh. This reduced value informed the levels of DSM modelled in the 2013 IRP and the upper price limit on IPP EPA renewals. Depending on the amount of LNG load that BC Hydro ultimately serves and whether non-LNG load growth occurs as expected, the LRMC may be reduced to about $85/MWh and still provide an adequate supply of resources for expected load through the same period. The energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030.

Adjustments to Energy LRMC for Rate-Making Purposes

When the LRMC for ratemaking purposes was based on power acquisition processes (e.g., 2008 RIB Application), the green-field IPP acquisition-related plant gate prices were grossed up for line losses. The current energy LRMC range of 8.5 cents/kWh to 10.0 cents/kWh is based on DSM and IPP EPA renewals adjusted for delivery to the Lower Mainland, and therefore BC Hydro only adjusts for distribution-related losses for Distribution service.

The 2013 IRP energy LRMC range is in $F2013. Several participants in the 2015 RDA workshop process described in section 2.2.3.2 above commented that the 2013 IRP energy LRMC range should be inflated for rate-making purposes. BC Hydro used the B.C. Consumer Price Index (**CPI**) for this purpose as follows: F2014: -0.3 per cent; F2015: 1.3 per cent; F2016: 1.9 per cent; F2017-F2019: 2.0 per cent.[97] The resulting inflation adjusted energy LRMC range for the 2015 RDA rate pricing principle period of F2017-F2019 is set out in Table 2-5.

Table 2-5 Inflation Adjusted Range in Energy LRMC for Transmission Service

Fiscal Year	Lower End of Energy LRMC Range (cents/kWh)	Upper End of Energy LRMC Range (cents/kWh)
F2013	8.5	10.0
F2014	8.47	9.97
F2015	8.58	10.10
F2016	8.75	10.29
F2017	8.92	10.5
F2018	9.10	10.71
F2019	9.28	10.92

BC Hydro reviewed distribution losses and finds that they are still reasonably close to 6 per cent of distribution load. The source of distribution loss information is described in section 3.8.2.1 of the Application. The resulting distribution loss and inflation adjusted energy LRMC range for the 2015 RDA rate pricing principle period of F2017-F2019 is set out in Table 2-6.

[97] The F2014 and F2015 actuals are from BC Stats May 2015; inflation rates for F2016-F2019 are from December 2014 BC Treasury Board.

Table 2-6 Inflation Adjusted Range in Energy LRMC for Distribution Service

Fiscal Year	Lower End of Energy LRMC Range (cents/kWh)	Upper End of Energy LRMC Range (cents/kWh)
F2013	8.5	10.0
F2013 (*Distribution loss 6 per cent*):	*9.01*	*10.60*
F2014	9.03	10.62
F2015	9.17	10.79
F2016	9.36	11.01
F2017	9.46	11.13
F2018	9.65	11.35
F2019	9.84	11.58

2.3.2.3 Capacity Long-Run Marginal Cost

As shown in the 2013 IRP, the next generation capacity resources that could be developed and are being advanced for contingency planing purposes are:

- Revelstoke Unit 6 (**Rev 6**) with a Unit Capacity Cost (**UCC**) of $50 to $55 per kilowatt-year (**/kW-year**). Rev 6 would add 488 MW of dependable capacity to the BC Hydro system;
- Natural gas-fired simple-cycle gas turbine generators (**SCGTs**) with a UCC of $88/kW-year. In the case where the expected LNG load of 3,000 GWh/year materializes, there is a need for about 400 MW of new system generating capacity resources. The 2013 IRP identified SCGTs located on the north coast to meet this need because of additional reliability benefits in that region.

For purposes of this Application and as identified in the 2013 IRP, the LRMC for capacity resources is based on Rev 6. Rev 6 is the most cost-effective generation capacity resource on a unit cost basis.

The 2013 IRP energy LRMC range identified above is for annual firm energy and does not include avoided generation capacity costs. The question of whether the LRMC for RIB ratemaking should include a capacity value was raised by stakeholders at Workshops 1 and 3. BC Hydro indicated that including a capacity value based on the Rev 6 UCC would increase the energy LRMC by about $11/MWh ($F2013).[98] BC Hydro referenced FortisBC's 2015/2016 DSM filing, which used a LRMC of $99/MWh for firm energy. FortisBC stated that this LRMC is inclusive of generation capacity with no need for adjustment to capture avoided generation capacity costs. FortisBC included a capacity estimate of $35.60/kW-year as a proxy to represent the value of avoided transmission and distribution capital expenditures due to DSM program energy conservation to arrive at an overall LRMC $112/MWh figure.[99] BC Hydro noted at Workshop 3 that the Commission in the 2008 RIB Decision decided that estimate of supply at plant gate should not include the incremental cost of transmission or distribution.[100]

Several Workshop 3 participants advanced two grounds for including a generation capacity value in the energy LRMC for purposes of the RIB Step 2 rate: (1) the RIB rate contains no demand charge; and (2) while the RIB is an energy conservation rate, it delivers anticipated capacity savings. In section 4.1.2 of the Workshop 3 consideration memo (copy at Appendix C-3A), BC Hydro communicated its view that adding a capacity value to signal these savings could confuse the pricing of the RIB with its purpose, which is energy conservation not peak capacity reduction. BC Hydro also referenced the 2011 RIB Re-Pricing Decision where the Commission stated that the RIB Step 2 rate should be based on a "price signal for customers to understand *what is happening to the cost of energy* they will consume in the future" [emphasis added].[101] Use of BC Hydro's energy LRMC for energy conservation rate structures such as the RIB rate is consistent with past Commission RIB decisions noted in section 2.3.1.6 above. However, to illustrate the impacts of the addition of a generation capacity value to the LRMC, BC Hydro included the upper end of the energy LRMC range with a generation capacity value (the Rev 6 UCC) in various figures in Chapter 5.

[98] Based on a ratio between Residential load and system coincidence peak.
[99] FortisBC, Application for DSM Expenditure Schedules for 2015 and 2016, page 12; http://www.bcuc.com/Documents/Proceedings/2014/DOC_41917_B-1_FBC-2015-16-DSM-Application.pdf.
[100] *Supra*, note 50, pages 107 to 108.
[101] *Supra*, note 85, page 3 of 19.

2.4 Rate Assessment Methodology

In addition to using stakeholder input and prior Commission decisions to assess rate designs, BC Hydro employed the following:

- The eight Bonbright criteria (section 2.4.1);
- Jurisdictional reviews for COS, and Residential, General Service and Transmission service rate design (section 2.4.2);
- Rate design modelling for rate estimation and assessment of customer impacts (section 2.4.3); and
- External expert review (section 2.4.4).

2.4.1 Bonbright Criteria

Rate design is a complex process that must take into account multiple and competing objectives and multiple stakeholder interests. As described in sections 2.3.1.5 and 2.3.1.6 above, the Commission has accepted that the eight Bonbright criteria are consistent with the *UCA*'s fair, just and not unduly discriminatory test. At Workshop 1, BC Hydro provided a description of the Bonbright criteria and proposed ways to apply the criteria to rate structures generally.

BC Hydro grouped the eight criteria into four categories for stakeholder engagement purposes: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

The eight Bonbright criteria are described in Table 2-7, together with BC Hydro's proposed application for Module 1 purposes. Note that the Bonbright criteria are presented in no particular order and are numbered solely for ease of reference.

Table 2-7 Bonbright Criteria and Application for Rate Design Evaluation

Bonbright Criteria	Grouping	BC Hydro Proposed Application of Criteria to Rate Structures Generally
1. Price signals that encourage efficient use and discourage inefficient use	Economic Efficiency	Energy LRMC reference; energy conservation (total GWh).
2. Fair apportionment of costs among customers	Fairness	Inter-class: COS and resulting R/C ratios; Intra-class: Cost causation, including cost recovery through fixed versus variable charges; bill impact to analyze cost shifts within the particular rate class. *Note that revenue neutrality as described in section 1.4 of the Application and referenced under the Bonbright recovery of revenue requirement criterion below can be a measure of fairness as its purpose in rate design is to avoid cost-shifting between the rate classes.*
3. Avoid undue discrimination	Fairness	Proposed measurement is the same as for Bonbright criteria (2). The meaning of undue discrimination has been the subject of a significant amount of case law and it is a matter of the Commission's opinion as to what constitutes 'undue discrimination'. Generally speaking, BC Hydro's accepts Bonbright's view that rates are unduly discriminatory when they have a serious distortion effect on the relative use of the service. This means rate structures must not be divorced from the nature and quality of the associated service, including cost of service.
4. Customer understanding and acceptance, practical and cost effective to implement	Practicality	BC Hydro and stakeholder opinion with BC Hydro giving greater weighting to the views of customers taking service under the particular rate structure being assessed unless there are cost implications for other customer classes; Maximum and customer bill impact (%, including the 10% bill impact test); One-time implementation and sustaining costs (quantified if possible, qualitative ranking otherwise); Jurisdictional references provided the different legal and regulatory regimes, and customer characteristics, are taken into account (refer to section 2.4.2 below).
5. Freedom from controversies as to proper interpretation	Practicality	Proposed measurement is the same as for Bonbright criteria (4).

Bonbright Criteria	Grouping	BC Hydro Proposed Application of Criteria to Rate Structures Generally
6. Recovery of the revenue requirement	Stability	Forecast revenue neutrality. This concept is introduced in section 1.4 of the Application and discussed in Chapters 5, 6 and 7.
7. Revenue stability	Stability	Proposed measurement is the same as for Bonbright criteria (6).
8. Rate stability	Stability	Design, pricing and transition certainty; Degree of rate structure changes relative to the Status Quo rate structure being assessed. *Note: As set out in Table 1-2 in Chapter 1, overall BC Hydro seeks to minimize unexpected changes that can be seriously adverse to existing customers.*

2.4.1.1 Application of Bonbright Criteria and Stakeholder Input

Role of Jurisdictional Assessment

In response to comments from AMPC, BC Hydro modified its proposed application of the Bonbright criteria to include relevant jurisdictional assessment as part of the customer understanding and acceptance criterion. Refer to section 2.4.2 for additional detail.

Ten Per Cent Bill Impact Test

BC Hydro defines bill impact is the percentage change in a customer's annual bill from one year to the next if consumption stays the same. As discussed in Chapters 5 and 6, BC Hydro uses the 10 per cent bill impact test as an 'amber signal' rather than a stop or go constraint. For example, BC Hydro believes that it is acceptable for bill impacts to exceed 10 per cent per year where the absolute dollar value of the increases is very small.

Several stakeholders questioned BC Hydro's proposed application of the 10 per cent bill impact test forming part of the customer understanding and acceptance criterion, and in particular whether inclusion of RRA increases would use up room available to accommodate rate design impacts. As referenced above in section 2.3.1.6, since the 2008 RIB Decision BC Hydro has used a 10 per cent maximum impact test inclusive of 'all-in' costs consisting of: RRA increases (the Direction No. 7 rate caps of 4 per cent in F2017, 3.5 per cent in F2018 and 3 per cent in F2019 on average described in section 2.2.1.3 above); the DARR; and rate changes due to rate design. Given the Rate Rebalancing Amendment discussed in section 2.2.1.3, rate rebalancing is not included in the 10 per cent bill impact test.

The 10 per cent bill impact test is applied to the single most adversely impacted customer (sometimes referred to as the 100th percentile customer on bill impact) for modelling purposes. The customer with the most adverse bill impact is the customer with the largest percentage increase in the customer's annual bill from one year to the next if consumption stays the same. Use of the customer with the most adverse impact as part of the bill impact test is consistent with BC Hydro's 2013 RIB Re-Pricing Application. Some stakeholders suggested using the 95 percentile or 90 percentile. After calculating the bill impacts of all customers and then sorting from the highest percentage increase to the lowest percentage increase, the customer that is 95 per cent of the way up the ranking would be the 95th percentile customer on bill impact. In BC Hydro's view, applying the 10 per cent test to any threshold level other than the most adversely impacted customer will lead to definitional problems or will have unintended consequences.

Efficiency

During the 2013 RIB Re-Pricing Application SRP, BC Hydro agreed with Commission staff that how the Bonbright efficiency criterion is applied to the RIB rate and other rate structures was in scope. As raised by Commission staff at Workshop 9a, the main Bonbright efficiency criterion issue concern:

- Whether or not BC Hydro's energy LRMC remains the appropriate referent for the Step 2 of the RIB rate; and
- Whether BC Hydro should consider the effects of a particular rate on (i) efficient customer consumption and investment decisions including the potential to

impact fuel switching from electricity to natural gas; (ii) efficient utility investment and operational decisions, and (iii) innovation.[102]

In BC Hydro's view, considering the effects of a particular rate is a different issue than using LRMC as a basis for designing a rate. The Commission found on three occasions that LRMC is the appropriate reference for Step 2 (2008 RIB Decision and the 2011 RIB Re-Pricing Decision discussed in section 2.3.1.6 above; and FortisBC 2011 Residential Conservation Rate Application Decision[103]) as it sends a signal to customers as to the price of acquiring marginal energy. Any lower price would incentivize inefficient electricity usage, and any higher price would discourage or unfairly penalize efficient usage. BC Hydro does not see a principled basis for setting the RIB Step 2 price without using LRMC as a referent. At Workshop 3 BC Hydro agreed with BCSEA that the pricing of the Step 2 rate in reference to the energy LRMC should not be regarded as a hard and fast rule. Refer to Attachment 1 (page 12) to the Workshop 9a/9b Consideration Memo (copy at Appendix C-3B of the Application); and to section 3.1.2 of the Workshop 3 Consideration Memo (copy at Appendix C-3A) for additional detail.

In BC Hydro's view, it is sufficient to consider that from the utility viewpoint of efficient investment and operational decisions, the RIB rate (and RS 1823 and DSM programs/codes and standards)-related savings decrease the amount of supply side energy and capacity resources that would be required to meet service obligations.

Additional Rate Design Criteria

Several stakeholders asked BC Hydro whether new criteria in addition to Bonbright could assist with rate design, although no examples were provided other than by BCOAPO advancing that BC Hydro's low-income customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an

[102] Refer to the RS 3808 Decision, section 7.2.3, note 32; and FBR Stepped Rate Decision, section 2.4.1, note 32.

[103] *In the Matter of FortisBC Inc. Residential Inclining Block Rate*, Decision, page 40; http://www.bcuc.com/Documents/Proceedings/2012/DOC_29557_FBC%20Inc-RIB_Decision-WEB.pdf.

affordable cost. As described in section 5.4 of the Application, BCOAPO ties affordability to low income rates, which are likely to be seen as unduly preferential to low-income customers or unduly discriminatory to the remaining customers who subsidize those rates because the low income rate would be based on the personal characteristics of the customer, divorced from the cost to deliver electricity to the premises.

Accordingly, BC Hydro is of the view that the eight Bonbright criteria suffice for Module 1 purposes as they have the advantage of being widely accepted by jurisdictions for rate deign purposes and are sufficiently flexible such that other criteria or tests are not required.

2.4.1.2 Bonbright Criteria Weighting

BC Hydro does not see the Bonbright recovery of the approved revenue requirement criterion to be the primary focus of the Application. The Commission may not lawfully set rates that recover more or less than BC Hydro's revenue requirement; refer to section 5(d) of Direction No. 7. Thus this was not a criterion that is traded-off against the other Bonbright criterion. The sole issue concerning this criterion is the application of revenue neutrality to RS 1823, as discussed in section 7.2.3 of the Application. In addition, the Bonbright avoid undue discrimination criterion was not traded-off given that it is part of the *UCA* fair, just and not unduly discriminatory test set out above in section 2.2.1.1.

In section 1.5.1 of the Application, BC Hydro set out that it prioritizes the Bonbright customer understanding and acceptance, stable rates for customers, and fair apportionment of costs among customers criteria for purposes of 2015 RDA Module 1. BC Hydro sought feedback on its rate priorities as part of Workshop 12. BCSEA commented that while it believed that the Bonbright efficiency criterion is important, it is evident that the complex LGS and MGS rates are not achieving the energy savings results predicted at the time of the 2009 LGS Application, and accordingly BCSEA supports moving to simplified LGS and MGS flat energy rate structures to improve customer understanding of the rates. AMPC supports BC Hydro's rate priorities, and states that in its view in the past BC Hydro has given too much weight to the economic efficiency criterion. Commission staff ask whether BC Hydro should have different rate priorities for the different rate classes, and give an example involving the LGS and MGS rate classes: if the demand response of these customers is low, does this suggest that LRMC-based rate pricing should be given a lower priority? These written comments are found at Appendix C-1B of the Application. BC Hydro's weighting of the Bonbright criteria is discussed in the individual rate design chapters (Chapter 5 – Residential; Chapter 6 – General Service Classes; and Chapter 7 – Transmission Service).

2.4.2 Jurisdictional Reviews

The Commission found in the 2007 RDA Decision that relevant examples of rate designs from other jurisdictions should be taken into consideration.[104] As described above in section 2.4.1.1, BC Hydro considers jurisdictional assessment as part of the Bonbright customer understanding and acceptance criterion. What is considered to be a relevant jurisdiction may differ depending on which BC Hydro rate is examined.

2.4.2.1 Cost of Service

As noted in section 2.4.4 below, BC Hydro engaged the COS Consultants[105] to assist in completing BC Hydro's COS study, including the provision of COS-related jurisdictional assessment described in section 3.5 of the Application. The COS consultants examined nine Canadian and U.S. utilities in jurisdictions with characteristics similar to BC Hydro (e.g., winter peaking, except Idaho Power which is dual peaking; and hydroelectric based), including Manitoba Hydro, Hydro Quebec and Newfoundland Power, all of which have generation facilities located far from

[104] 2007 RDA Decision, *supra* note 49, page 57.

[105] 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 discussed in section 3.5 of the Application was finalized in December 2013.

load. In response to stakeholder feedback at Workshop 3 (refer to Attachment 1 to the Workshop 3 Consideration Memo found at Appendix C2-A), BC Hydro augmented the list of utilities reviewed by the COS Consultants; for example, BC Hydro looked at Alberta Electric System Operator, and other utilities which completed fairly recent COS such as FortisBC, Nova Scotia Power, New Brunswick Power and SaskPower.

2.4.2.2 Residential and General Service Rates

On March 12, 2015 BC Hydro circulated for stakeholder comment its list of jurisdictions to be examined for purposes of BC Hydro's Residential rates:

- For Canada, the goal is geographic diversity while recognizing that BC Hydro is a vertically integrated monopoly. BC Hydro proposed surveying public utilities in all provinces except Ontario and Alberta (different market structures[106]) and Prince Edward Island (size);
- For the U.S., BC Hydro used the Rates Comparison Regulation[107] enacted under the *CEA*, the fact that BC Hydro is part of the Western Electricity Coordinating Council (**WECC**),[108] and size as inputs with the result that BC Hydro proposed an assessment of the relevant residential rates of several public utilities in Washington State, Oregon and California as well as Idaho, Colorado and New Mexico.

[106] In the mid-1990s, Alberta deregulated generation, mandated open access for regulated transmission and distribution and introduced a real-time electricity spot market. Alberta has a competitive wholesale and retail electricity market. In 1998, Ontario unbundled transmission, generation and dispatch, and in 2002 Ontario introduced competitive wholesale and retail markets. Today, Ontario operates under a hybrid structure where there is wholesale and retail competition, but a large amount of generation remains regulated or subject to long-term government-backed contracts. The remaining provinces have government- or investor-owned vertically integrated public utility structures which offer bundled services at regulated rates.

[107] B.C. Reg. 119/2011; copy available at https://www.canlii.org/en/bc/laws/regu/bc-reg-119-2011/latest/bc-reg-119-2011.html. Section 2 of this Regulation provides that an annual report to the B.C. Minister of Energy and Mines concerning average prices for BC Hydro's residential, commercial and industrial customers in comparison to other North American public utilities.

[108] The Western Interconnection is the geographic area within which WECC promotes reliability, and is composed of two Canadian provinces, B.C. and Alberta; parts of 14 western U.S. states (California, Nevada, Arizona, Utah, Idaho, Oregon, Washington state, Wyoming, most of Montana, Colorado and New Mexico, and a part of South Dakota, Nebraska and Texas); and the northern portion of Baja California, Mexico. The WECC is the body that sets electricity system operating performance and reliability standards for members in Western Canada and the Western U.S.

The selected public utilities together with the number of customers they serve are listed at slides 28 to 31 of the Workshop 9A slide deck presentation found at Appendix C-3B). BC Hydro asked if stakeholders agreed with the proposed residential rate jurisdictional selection, and if stakeholders wanted a survey of low income rates including statutory underpinnings. No stakeholder disagreed with the proposed residential rate jurisdictional selection:

- Commission staff recommended that BC Hydro also reference Ontario's Regulated Price Plan,[109] which BC Hydro has done; refer to section 2.2 of the Workshop 9a/9b consideration memo at Appendix C-3B. The jurisdictional survey showed that with the exception of Yukon which has a three step rate for residential customers and Ontario which has mandated default TOU rates for the Regulated Price Plan, all surveyed Canadian electric utilities have either a two step inclining block rate or flat energy rate; and
- Several stakeholders asked BC Hydro to conduct a survey of low income rates together with a description of the relevant legislation, which BC Hydro completed and shared with BCOAPO for input. Refer to section 2.2.2 of the Workshop 9a/9b consideration memo and sections 5.4 and 8.6.1 of the Application. A copy of the low income rate jurisdictional review is found at Appendix C-3D.

At Workshop 11a/11b, BC Hydro proposed the same jurisdictions for purposes of the SGS, MGS and LGS default rates and General Service rate options. No stakeholder disagreed with BC Hydro's proposal. The jurisdictional review of General Service rates revealed that with one exception (Ontario has inclining block rates but is phasing them out), all Canadian electric utilities surveyed have either a flat energy rate or declining energy rate for their General Service customers. BC Hydro is the

[109] The vast majority of Ontario electric utility residential and commercial customers pay TOU rates under the 'Regulated Price Plan' developed by the Ontario Energy Board in 2005. Fewer than one in ten residential and commercial customers get their power from an electricity retailer; these customers sign a contract and pay a fixed rate that is separate from TOU pricing.

only electric utility in North America with baseline rates for General Service customers.

2.4.2.3 Transmission Service Rates

As described above in section 2.3.1.4, the essential elements of RS 1823, the default Transmission Service rate, are legislated pursuant to subsection 3(1) of Direction No. 7. Accordingly BC Hydro did not undertake a jurisdictional assessment for purposes of informing its proposal with respect to those elements of RS 1823 over which the Commission has jurisdiction (the pricing principles for F2017-F2019 and the definition of revenue neutrality; refer to section 7.1.2).

BC Hydro did undertake jurisdictional assessment to assist with developing Transmission Service rate options. BC Hydro reviewed Canadian jurisdictions with market structures similar to BC Hydro (vertically integrated monopolies) and set out the results in section 2 of its Workshop 5 consideration memo (found at Appendix C-5A of the Application). This jurisdictional review found that most surveyed Canadian electric utilities offer their industrial customers interruptible rates and/or ‘surplus’ rates (pursuant to which surplus energy is supplied only if it can be provided with available resources over and above the requirement of other firm commitments), but not RTP or TOU rates. This is consistent with BC Hydro’s existing Transmission Service rate options and the freshet rate pilot. Refer to section 7.3 of the Application.

2.4.3 Rate Modelling

The quantitative outcomes with respect to Residential and General Service rates presented at Workshops 3, 8a/8b, 9a/9b, 11a/11b and 12, and shown in this Application, come from a suite of simulation models falling into two categories:

- rate estimation; and
- assessment of customer impacts.

BC Hydro creates these models using a combination of software packages. A multi-departmental modelling team consisting of expert analysts, economists and accountants are involved in this process, and they evaluate each design by combining the quantitative outcomes with qualitative assessments.

In estimating rates, BC Hydro develops quantitative models focused on implementing the key features of each rate design alternative, such as the pricing principles and bill impact constraints, while ensuring revenue neutrality relative to the particular status quo rate structure.

In assessing customer impact, BC Hydro develops quantitative models that simulate a rate change from the status quo design at year 0 to an alternative design in year one on a representative sample of accounts under each rate class. The bill differences are estimated by assuming no changes in annual energy consumption. For the Residential sector, BC Hydro uses a representative sample of 10,000 to illustrate the overall population impact. This is followed by using the representative sample from the REUS to assess impacts by customer segments, such as low income, electrical heating and housing types. For the commercial sector (LGS/MGS), BC Hydro uses a cleaned sample created from the latest available billing data to perform impact analysis on both the general population and by customer type. BC Hydro has also engaged stakeholders in workshops, focus groups and interviews to assess customer response to each rate design alternative, such as ease of understanding and perceived fairness.

Once the quantitative and qualitative outcomes are available, BC Hydro interprets them together and provides a performance evaluation of each rate design under the Bonbright criteria for presentation in the Application.

The Residential, MGS and LGS rate modelling assumptions were described at the workshops referenced above, and are found at Appendix H-1A.

2.4.4 Use of External Experts

In addition to undertaking a comprehensive internal analysis of its existing rates, BC Hydro retained outside expertise to assist in developing rate designs appropriate for the future.

In Table 2-1 above it is noted that BC Hydro retained the COS Consultants to evaluate BC Hydro's COS methodology. The COS Consultants made a number of recommended changes contained in the December 20, 2013 *Final Report: Cost of Service Methodology Review* (**COS Methodology Review**) (discussed in section 3.1 of the Application; copy found at Appendix C-2A). A copy of the CV for Richard Cuthbert is found at Appendix D-1A. Richard Cuthbert has over 25 years of experience with advising electric and water utilities in the areas of rates, COS analysis, cost of capital studies and various other financial and economic analyses.

BC Hydro retained E3 to assist with review of:

- The following classification aspects of BC Hydro's existing seven rate class: the LGS and MGS rate classes, and in particular whether the existing LGS and MGS rate classes should be merged into a single rare class and/or whether the existing LGS rate class should be divided (referred to as '**segmented**') so that larger LGS accounts would form a new '**XLGS**' rate class' as described in section 4.3.2.2 of the Application; and
- The existing default Residential (RIB rate), SGS, MGS and LGS rates, and alternatives to these default rates, as described in Chapters 5 and 6 of the Application. This work included assisting BC Hydro with its Residential and General Service jurisdictional assessments described in section 2.4.2 above.

A copy of the CV for Dr. Ren Orans is found at Appendix D-1B of the Application. Dr. Orans has over 25 years of experience in the electric utility business, having worked extensively in utility rate design and ratemaking, transmission pricing and planning, and integrated resource planning.

2.5 Scoping

At Workshop 1, BC Hydro identified two general categories of topics BC Hydro believes are out of scope for purposes of developing the 2015 RDA:

- Matters recently reviewed by the Commission. This is discussed further below; and
- Rate designs which are contrary to or the subject of B.C. Government policy or enactment. A related out-of-scope category consisting of matters that are the subject of Subsection 3(1) of Direction No. 7, namely the RS 1823 Tier 1/Tier 2 90/10 split and the exemption of New Westminster and UBC from RS 1823 and Transmission Service stepped rates. Refer to section 2.2.2.5 above.

BC Hydro explained that the term ‘out-of-scope’ applied to development of BC Hydro’s 2015 RDA, but not necessarily to the subsequent Commission review of the 2015 RDA. BC Hydro recognizes that the Commission has broad discretion with respect to the setting of the 2015 RDA review scope.

BC Hydro indicated the following Commission decisions as falling into this category:

1. The May 6, 2014 RS 3808 Decision concerning BC Hydro’s application to replace the 1993 PPA between BC Hydro and FortisBC under RS 3808 with a new PPA;
2. The Commission’s April 25, 2014 decision concerning BC Hydro’s application for approval of charges related to the Meter Choices Program;[110]

[110] In the Matter of British Columbia Hydro and Power Authority: Application for Approval of Charges Related to the Meter Choices Program, Decision, April 25, 2014 (**Meter Choices Program Decision**); copy available at http://www.bcuc.com/Documents/Proceedings/2014/DOC_41266_04-25-2014_BCH%20Meter%20Choices_Decision_G-59-14.pdf; May 15, 2014 errata at http://www.bcuc.com/Documents/Proceedings/2014/DOC_41357_05-15-2014_ERRATA_BCH-Meter-Choices-Program-Decision.pdf.

3. The July 25, 2014 and July 9, 2015 RS 1289 Commission decisions concerning BC Hydro's applications for changes RS 1289 (Net Metering Service);[111] and
4. The Commission's various CBL-related decisions and the recent Contracted Generator Baseline proceedings, given the fact that CBLs had recently been reviewed by the Commission and has been the subject of five of Commission decisions (refer to section 2.3.1.4 above).

In addition, the Commission's June 25, 2015 decision[112] approving BC Hydro's application for shore power rates (RS 1280, RS 1891 and TS 86) is out of scope for the 2015 RDA given how recent the Commission review was. This issue was addressed in section 4.2 of the Workshop 10 consideration memo at Appendix C-5B.

Stakeholders generally supported this category. BCOAPO suggested that RS 3808 should be in scope for the COS study. In section 1 of the Workshop 1 consideration memo (copy at Appendix C1-A), BC Hydro agreed that while RS 3808 is out of scope for rate design purposes because of the recent Commission review, it would be included in COS. Refer also to section 4.4 of the Application. BCSEA stated that CBL determinations could impact further development of RS 1823 and therefore should be in scope. In section 1 of the Workshop 1 consideration memo, BC Hydro responded that it did not see value in revisiting TS 74 given the Commission's numerous reviews of CBLs (refer to section 2.3.1.4 above), and noted the majority of participants commenting on this topic agreed Transmission Service-related CBLs should be out of scope. BC Hydro committed to providing CBL description as context for its examination of Transmission Service rates; this is done in section 7.2 of the Application.

[111] Commission Order No. G-104-14 and accompanying Reasons for Decision (http://www.bcuc.com/Documents/Proceedings/2014/DOC_41819_G-104-14_BCH_RS1289-Net-Metering_Decision.pdf); and Commission Order No. G-116-15 (http://www.bcuc.com/Documents/Orders/2015/DOC_44073_G-116-15_BCH-RS1289-NetMetering-Amendments.pdf).

[112] Commission Order No. G-111-15 and Reasons for Decision; http://www.bcuc.com/Documents/Proceedings/2015/DOC_43962_06-25-2015_BCH-Shore-Power-Decision_G-111-15.pdf.

2015 Rate Design Application

Chapter 3

Cost of Service

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3.1 Introduction and Structure of Application

The three sequential steps employed in the development of BC Hydro's rates are: (1) revenue requirement determination; (2) COS development; and (3) rate design studies. This Chapter presents BC Hydro's F2016 COS study. The F2016 COS study model is found at Appendix E.

3.1.1 F2016 Cost of Service Study

One of the main purposes of a COS study is to appropriately allocate costs to BC Hydro's rate classes:

- Costs by rate class can be compared with revenue by rate class to calculate R/C ratios for individual rate classes. The R/C ratios reflect the extent to which BC Hydro is collecting revenue relative to the costs allocated to each rate class. For example, a R/C ratio less than one indicates that the revenue collected under existing rates is not sufficient to recover the costs assigned to the rate class under the approved COS methodology. As noted in section 2.2.1.3 of the Application, the LGIC recently issued the Rate Rebalancing Amendment which prevents the Commission from setting rates for F2017 to F2019 for the purpose of changing R/C ratio for a class of customers. However, determining R/C ratios is not the sole purpose of the COS study;
- After costs are assigned to rate classes, the F2016 COS study is used as a foundation for the calculation of rates. For example, rate design is informed by a comparison of energy, demand and customer-related costs, as identified in the F2016 COS study, and revenue from energy, demand and basic charges. The energy, demand and customer cost allocation to each of the seven existing rate classes is set out in Table 3-7 at the end of this Chapter.

3.1.2 F2019 Cost of Service Study Proposal

At Workshop 12, BC Hydro discussed the Rate Rebalancing Amendment and BC Hydro's proposal to review COS methodologies again and file a F2019 COS study with the Commission for review in F2019.[113] The F2019 COS would be the subject of stakeholder engagement prior to filing and would include a rate rebalancing proposal if appropriate.

BC Hydro would continue to submit Fully Allocated COS results with the Commission every year pursuant to 2007 RDA Direction 2. The Fully Allocated COS would reflect any Commission findings concerning the F2016 COS.

3.1.3 Structure of Chapter

The remainder of this Chapter is organized as follows:

- In the COS study, cost causation is based on each customer class's usage of the BC Hydro system as forecast for F2016. Section 3.2 provides an overview of the three steps BC Hydro followed in developing its COS study, namely functionalization, classification and allocation;
- The F2016 revenue requirement, the most current approved[114] revenue requirement available, is described in section 3.3. A COS study begins with the utility's revenue requirement. The revenue requirement includes cost of energy, operations, maintenance and administration (**O&M**) expenses, taxes, depreciation and amortization, financing charges and Return on Equity (**RoE**);
- The COS study allocates the revenue requirement among the existing seven rate classes. (Chapter 4 provides the analysis BC Hydro used to determine that these rate classes remain appropriate for RDA Module 1 purposes, with the exception noted in section 1.1.3 of the Application concerning BC Hydro-owned Street Lighting). A fundamental issue is whether BC Hydro's revenue requirement should be allocated using the traditional, widely-followed embedded COS approach or a marginal COS approach, which

[113] Refer to slide 10 of the Workshop 12 presentation deck found at Appendix C-1B to the Application.

[114] Commission Order No. G-48-14; copy available at http://www.bcuc.com/Documents/Orders/2014/DOC_41122_G-48-14_BCH-F15-16-RevenueRequirements.pdf.

examines the future costs of supplying an additional kWh, kW or customer. BC Hydro rejects marginal COS for revenue requirement allocation purposes for the reasons set out in section 3.4, including widespread stakeholder support for the embedded COS approach. Consistent with the 2007 RDA Decision BC Hydro has prepared its COS study on an embedded-cost basis for the 2015 RDA;

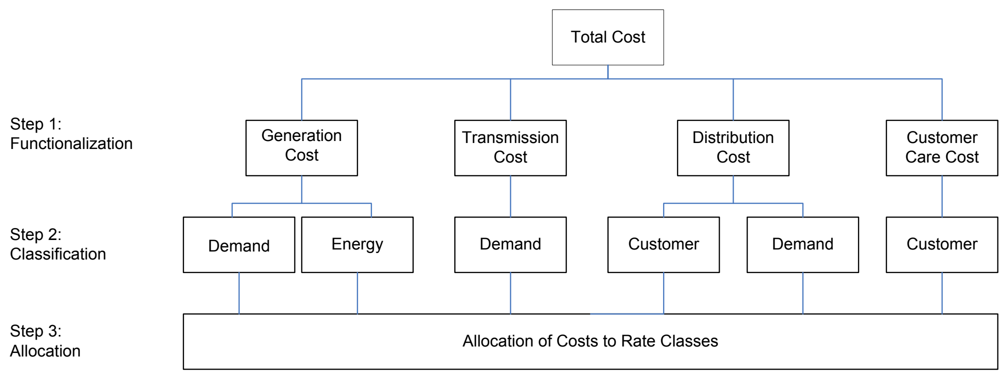
- Section 3.5 canvasses the guiding principles used to develop the F2016 COS study, including use of 2007 RDA Decision COS-related Directions 1-10 and 14 as a starting point; adoption of recommendations from the COS Consultants[115] contained in the COS Methodology Review (copy found at Appendix C-2A); BC Hydro's jurisdictional assessment; and 2015 RDA stakeholder engagement feedback. Section 3.5 also provides a summary of F2016 COS methodology changes as compared to the 2007 RDA Decision. Section 3.5 concludes with a description of BC Hydro's existing seven rate classes and the load profile data used for classification of demand-related costs in the F2016 COS study;
- Sections 3.6, 3.7 and 3.8 address respectively functionalization, classification and allocation of costs with a focus on the five COS study methodology items which did not have a fair degree of stakeholder consensus in the 2015 RDA stakeholder engagement process (BC Hydro regulatory account functionalization (section 3.6.7); Heritage hydro classification (section 3.7.1); SMI classification (section 3.7.8); and Distribution classification and allocation (sections 3.7.7 and 3.8.4)); and
- Section 3.9 concludes with the resulting customer class R/C ratios for F2016 and the F2016 classification of energy, demand and customer costs for each of the seven existing rate classes.

[115] As described in section 2.4.4 of the Application, BC Hydro retained SAIC in October 2012; 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. A copy of the CV for Richard Cuthbert is found at Appendix D-1A.

3.2 Fiscal 2016 Cost of Service Study Three Step Process

BC Hydro's F2016 COS study takes the F2016 revenue requirement and seeks to transparently allocate those costs to the seven rate classes. This analysis provides a determination of the level of cost responsibility of each rate class and the revenue adjustments required to meet the cost of service. Where possible, costs are assigned directly to rate classes. Costs not directly assigned are allocated to rate classes in the widely-adopted three-step process summarized in Figure 3-1.

Figure 3-1 Cost Allocation Methodology



- Costs are functionalized into the following operating function categories: Generation, Transmission, Distribution and Customer Care. This is described in section 3.6;
- Costs by function are classified into three categories: energy (variable costs that vary with kWh provided), demand (fixed costs that vary with kW demand) or customer-related (costs that are sensitive to connecting customers to BC Hydro's network irrespective of the customer's load, such as metering services and billing costs). Classification is addressed in section 3.7;
- The energy, demand and customer categories are allocated to the seven rate classes on the basis of their respective energy use, demands or customer number (or other established allocator base). Refer to section 3.8.

3.3 Base Year (F2016)

In the case of BC Hydro, the subject of the F2016 COS study is BC Hydro's F2016 RRA. BC Hydro has an approved revenue requirement of $4,459.7 million for F2016.

Historically, BC Hydro prepared COS studies using actual revenues, costs, energy sales and customer load profiles from a recently completed fiscal year. If BC Hydro followed past practice, the COS study would have been based on F2014 actuals because F2015 information would not be available in time for the 2015 RDA filing. There would have been a three-year misalignment between BC Hydro's rates and a COS study based on actual costs (F2014). To avoid this disconnect, BC Hydro prepared the F2016 COS study on a forecast basis using F2016 forecast information from the approved F2016 RRA. Some historical information, such as load profiles by rate class, is used in the F2016 COS study and this is discussed in section 3.5.4.

Further information concerning BC Hydro's F2016 RRA as used in the F2016 COS study is found in sections 3.6.5, 3.7 and 3.8.

3.4 Categories of Cost of Service: Embedded and Marginal

One consideration in COS analysis is to determine if there are costs which can be directly assigned to a particular rate class. Direct assignment of costs is typically limited to costs clearly caused by only a single rate class. An example is BC Hydro-owned Street Lighting. However, most utility investments serve many rate classes which use utility facilities differently, so direct assignment of costs is not possible.

Most electric utilities use an embedded COS that breaks down the complexities of non-direct assignment costs by function and classification of cost causation. An embedded COS study begins with development of the utility's revenue requirement, based on historic or forecast accounting costs and usage patterns. Another approach for assigning utility costs is through a marginal COS, which assigns costs based on the additional cost incurred to provide an increment of a good or service (i.e., kWh, kW and customer). Both embedded COS and marginal COS require a large number of assumptions. Marginal COS requires generally-accepted methodologies for defining and measuring LRMCs for energy, generation capacity resources, transmission, distribution and customer-related service. Marginal COS results in a revenue requirement total that is different from the utility's approved revenue requirement as forecast marginal costs are almost always different than embedded costs. To deal with this discrepancy, the resulting marginal cost-based revenue requirement levels by rate class are adjusted either up or down to ensure that rates overall will recover no more than what the approved revenue requirement dictates. This adjustment process would cause dilution and variation from any pricing signals that might reflect 'true' marginal costs and it would introduce greater subjectivity as there are multiple ways to make the adjustment.

With the exception of one participant (COPE 378),[116] stakeholders commenting at 2015 RDA Workshops 1, 2 and/or 4 and related written processes agreed with BC Hydro's preference to prepare an embedded COS study. In the 2007 RDA Decision, the Commission concluded there had been no widespread adoption of marginal COS methods, and through 2007 RDA[117] Directions 2 through 10 and 14 instructed BC Hydro to continue using the embedded COS approach. The Commission also accepted the embedded COS approach as part of its decision concerning FortisBC's 2009 Rate Design/COS Application.[118]

There is ample basis to continue to design rate structures with marginal cost pricing while allocating BC Hydro's revenue requirement on an embedded cost basis. All

[116] As part of its Workshop 12 written feedback, COPE 378 advised that given the Rate Rebalancing Amendment, COPE 378 no longer plans to litigate marginal COS versus embedded COS approach as part of RDA Module 1. However, COPE 378 states that in its view, marginal COS must be addressed as part of the F2019 COS. A copy of COPE 378's Workshop 12 written comments is found at Appendix C-1B.

[117] 2007 RDA Decision, pages 206 to 208.

[118] *In the Matter of An Application by FortisBC Inc. for Approval of a 2009 Rate Design and Cost of Service Analysis*, Decision, October 19, 2010 (**2009 FBC RDA Decision**), section 2.0; copy available at http://www.bcuc.com/Documents/Proceedings/2010/DOC_26325_FortisBC-2009-RDA_WEB.pdf.

Canadian and most U.S. Pacific Northwest utilities use embedded COS approaches. No jurisdiction has adopted marginal COS for revenue requirement allocation since the 2007 RDA Decision. At least one jurisdiction - Illinois Commerce Commission - reverted back to the traditional method of embedded COS.[119] Refer to Part 1 of the Workshop 2 consideration memo at Appendix C-2A and Attachment 4 of the Workshop 4 consideration memo at Appendix C-2B for a detailed discussion of why BC Hydro rejects marginal COS for revenue requirement allocation purposes.

3.5 Fiscal 2016 Cost of Service Study Development

The COS Consultants reviewed BC Hydro's COS analyses, models, spreadsheets used in ratemaking processes, and also undertook discussions with relevant BC Hydro business units whose costs impact the COS study. The focus was key issues from the 2007 RDA Decision, such as Heritage hydro and IPP classification, and Distribution sub-functionalization, classification and allocation. The COS Consultants also reviewed COS methodologies used by nine electric utilities in ten jurisdictions: Avista Corporation (**Avista**; filings with the Idaho Public Utilities Commission and Washington Utilities and Transportation Commission); Bonneville Power Administration (**BPA**); Hydro-Québec Distribution; Idaho Power Company (**Idaho Power**, filing with the Idaho Public Utilities Commission); Manitoba Hydro; Newfoundland Power Inc. (**Newfoundland Power**); Portland General Electric Company; Puget Sound Energy; and Seattle City Light.[120]

BC Hydro undertook additional jurisdictional review to respond to feedback at Workshop 2 that BC Hydro should examine Manitoba Hydro in greater detail as a similar electric utility and review additional electric utilities for Distribution COS

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[119] Compare Illinois Commerce Commission in 1989 to 1990 (*Re Commonwealth Edison Co*., 117 P.U.R. 4th 107 (1990) and Illinois Commerce Commission decision in 2001/2003 rejecting Commonwealth Edison Co.'s proposal to use a marginal COS approach; Order No. 01-0423, beginning at page 134.

[120] The criteria for selection of jurisdictions to be reviewed was: primarily hydro generation based; preference for winter peaking jurisdictions; preference for embedded COS methodology but not excluding utilities that use marginal COS; preference for providing vertically integrated services; and relatively large sized utilities in terms of revenue (greater than $500 million revenues) and customers served (greater than 100,000 customers).

information. The following reports and other materials comprised this additional jurisdictional assessment:

1. Concentric Energy Advisors, Inc. *Class Cost Allocation Study Prepared for New Brunswick Power Corporation* dated September 2014;[121]

2. 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.*;[122]

3. Christensen survey conducted on behalf of Manitoba Hydro in June 2012 entitled *Review of Cost-of-Service Methods of Manitoba Hydro*;[123] and

4. FortisBC's 2009 Rate Design/COS Application.[124]

3.5.1 Conclusions from COS Consultants' Methodology Review

The COS Methodology Review concludes that BC Hydro's COS methodology is generally consistent with standard embedded COS methodologies. The one exception is classification of Customer Care costs as 65 per cent demand and 35 per cent customer as mandated by 2007 RDA Direction 4; all electric utilities surveyed classify Customer Care costs as 100 per cent customer. The COS Methodology Review makes 18 recommendations. BC Hydro largely concurs with these recommendations.

Copies of the COS Methodology Review and BC Hydro's response to the 18 recommendations contained in the Workshop 2 Discussion Guide are found at Appendix C-2A to the Application. The COS methodology also benefited from

[121] http://www.nbeub.ca/opt/M/browserecord.php?-action=browse&-recid=456 (Concentric Energy Advisors Report).

[122] Refer to Nova Scotia Power Inc.'s 2013 Cost of Service Study - Application (Exhibit N-1, Appendix H) which can be found on the Nova Scotia Utility and Review Board website (http://uarb.novascotia.ca/fmi/iwp/cgi?-db=UARBv12&-loadframes) under Case M05473.

[123] Copy available at http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_13_4.pdf.

[124] http://www.bcuc.com/Documents/Proceedings/2009/DOC_23627_B-1_FortisBC%202009%20Rate%20Design%20Application.pdf.

stakeholder input received as part of Workshop 2 and Workshop 4 as noted throughout this Chapter.

3.5.2 F2016 Cost of Service Study and 2007 Rate Design Application Decision Directions

Based on the COS Methodology Review, its own jurisdictional assessment and the 2015 RDA stakeholder engagement process, BC Hydro proposes methodology changes to the 2007 RDA Decision as summarized in Table 3-1.

Table 3-1 Summary of 2007 RDA-Related COS Methodology Changes

2007 RDA Direction	COS Methodology Change Proposed in 2015 RDA
Direction 6 – Functionalize DSM 90 per cent to Generation and 10 per cent to Transmission	Functionalize DSM to 90 per cent Generation, 5 per cent Transmission and 5 per cent Distribution on the basis that while DSM initiatives are primarily undertaken to defer Generation resources, they have some Transmission and Distribution deferral benefits. See section 3.6.6.
Direction 5 – Classify Heritage hydroelectric Generation 45 per cent energy/55 per cent demand on the basis that future Resource Smart additions at Revelstoke and Mica Generating Stations are predominantly capacity-related	Use BC Hydro integrated system Load Factor[125] calculation based on loads almost entirely served by Heritage hydroelectric supply (the impact of IPPs serving load is removed) resulting in a 55 per cent energy/45 per cent demand split. See section 3.7.1.
Direction 8 – Classify IPP purchases 100 per cent energy. BC Hydro is directed to prepare a study for its next RDA that examines and quantifies the capacity benefits associated with IPP EPAs	Use an approach where the fraction of IPP costs allocated to demand equals the ratio of IPP capacity benefits from the IPP EPA portfolio over IPP costs, resulting in a 93 per cent energy/7 per cent demand split. See section 3.7.3.
Direction 4 – Classify Distribution costs 65 per cent demand/35 per cent 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 10 per cent demand using Non-Coincident Peak[126] (**NCP**) allocator; (2) direct assign transformers, with 50 per cent demand/50 per cent customer classification for rate design purposes; (3) classify the secondary system and services as 50 per cent demand/50 per cent customer and use appropriate allocators; and (4) classify meters as 100 per cent customer on a weighted customer basis. BC Hydro conducted a minimum (system) study and zero intercept analysis, but has not used the results given the shortcomings outlined in section 3.7.7.
Direction 4 – Classify Customer Care costs 65 per cent demand/35 per cent customer	Classify Customer Care costs 100 per cent customer as such costs do not vary with demand levels (or energy usage) but only in proportion to the number of customers on the BC Hydro system. See section 3.7.9.

125 Load Factor is the ratio of the average demand supplied during a given period to the peak demand occurring during the same period. Refer to Glossary and Abbreviations at Appendix B of the Application.

126 NCP demand is a customer's or rate class's maximum demand, regardless of when the BC Hydro system peak occurs.

There is one methodology change that does not relate to the 2007 RDA COS-related directions referenced above; it concerns IPP capital lease costs referenced in section 3.6.1 and summarized here. IPP capital lease costs were spread across multiple business groups in the previous COS study methodology. For F2016 COS purposes, they are considered entirely Generation-related. Refer to Attachment 3 to the Workshop 4 consideration memo at Appendix C-2B for additional detail.

Finally, a number of COS R/C ratios changed (irrespective of any proposed changes to the F2016 COS study methodology) despite using the same (2007 RDA Decision) methodology as the F2014 Fully Allocated COS.[127] This occurs for a variety of reasons including:

- Changes in the relative proportions of Generation, Transmission, Distribution and Customer Care costs;
- The energy allocator has been updated using forecast F2016 sales by rate class;
- Demand allocators (4 Coincident Peak[128] (**CP**) and NCP) have been updated; and
- Forecast revenues by rate class have changed as they are based on F2016 sales rather than actual F2014 energy consumption and revenues.

The remainder of this section outlines the seven existing rate classes, and describes the load data concerning energy and capacity use for each of the rate classes.

3.5.3 Existing Rate Classes

Customers of electric utilities differ in their requirements for electricity. Such differences are reflected in both the timing and magnitude of requirements. Electric

[127] The F2014 FACOS was submitted to the Commission on April 30, 2015. A copy is found at the BC Hydro 2015 RDA website; http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-04-30-bch-f2014-facos.pdf.

[128] CP demand is a customer's or customer class's demand at the time of BC Hydro's system peak demand.

utility customers are segmented into rate classes for technical, administrative and/or regulatory reasons. Segmentation of customers is typically based on criteria such as maximum kW demand; voltage level of service; and/or embedded COS.

As described in section 1.4 of the Application, BC Hydro serves seven rate classes:

- Residential;
- Three General Service categories which are a heterogeneous mix of commercial and institutional customers, segmented based on monthly peak demand – SGS, MGS and LGS. The segmentation of the General Service category was part of BC Hydro's 2009 LGS Application and is described in more detail in section 4.3 of the Application;[129]
- Transmission voltage service;
- Irrigation; and
- Street Lighting.

This Chapter describes how costs are allocated to the existing seven rate classes. The COS analysis is one input into BC Hydro's analysis in Chapter 4 of whether the existing seven rate classes remain appropriate.

3.5.4 Load Data

With the emergence of SMI, load research work at BC Hydro has changed. Prior to 2013, BC Hydro collected interval data from a sample of approximately 1,500 customer locations dispersed throughout its service area. The collection process took several months to complete and was labor intensive to collect. Because the sample was so small, the rate class profiles created were general, sample redesign was not financially feasible and there was a risk of sample bias. BC Hydro estimates this load research data barely met minimum standards of 90 per cent confidence of

[129] Refer to Appendix J of Exhibit B-1 in the 2009 LGS Application proceeding; http://www.bcuc.com/Documents/Proceedings/2009/DOC_23224_2009_10_16%20APPL_09LGS.pdf.

repeatability (confidence level) with 10 per cent accuracy. As a result of these numerous drawbacks, BC Hydro could not create accurate load profiles for smaller customer segments such as Residential E-Plus or Irrigation customers in past COS studies.

As described in section 2.3.2.1 of the Application, since the implementation of SMI in F2014 SMI daily register reads are available for almost all BC Hydro customers. Ratio expansions[130] can be done on a daily basis rather than an annual or monthly basis as they were in the past. Also, BC Hydro has a statistical sample of about 45,000 customers with hourly load information from which it can conduct more detailed load research. With the capability to create almost on-demand detailed customer load profiles, regulatory analysis, rate design and peak load forecasting have been improved. BC Hydro estimates that the new hourly sample of 45,000 would yield within 1 per cent accuracy at 99 per cent confidence level.

3.6 Functionalization

Step 1 in the embedded COS approach is functionalizing the revenue requirement. Two functionalization issues arose during the 2015 RDA stakeholder engagement process relating to DSM (for which there was a fair degree of consensus) and BC Hydro's regulatory accounts; refer to sections 3.6.5 and 3.6.6.

3.6.1 Generation

The Generation function includes all costs associated with the production of energy, including Heritage resource and IPP energy. The Generation function also includes:

- Some transmission costs incurred to connect Heritage generation assets to the transmission grid (referred to as Generation Related Transmission Assets

[130] Ratio Expansion (Combined Ratio Estimation) is a modeling technique involving stratified random sampling that is widely used in Load Research. Its principle use is to expand sample data to system parameters and to estimate the reliability of the results. It is a statistical modeling technique to obtain a population demand value (kW) by utilizing a known population of billing values (kWh) with a representative sample of metered kW and kWh measurements. Class demand estimates for rates classes and other populations with 'known' total energy use are adjusted by the ratio of demand to energy use for the stratified sample.

(**GRTA**)), BC Hydro determined that actual GRTA costs ranged between $42.6 million and $44.2 million in the F2012 to F2014 period. As a result, BC Hydro believes the existing $43.3 million estimate continues to be appropriate; and

- As noted in section 3.5.2 above, IPP capital lease costs.

The subsidiary net income, which is derived primarily from Powerex Corp. (**Powerex**), is assigned to the Generation function on the basis that the income is associated with energy sales.

3.6.2 Transmission

The Transmission function includes all costs relating to the delivery of electricity from the generation interface to the distribution network load centres, including the costs of operating and maintaining transmission lines, poles, towers, substations, etc. Transmission is generally those lines measured at 69 kV and above.

3.6.3 Distribution

The Distribution function provides the service of receiving bulk electricity and distributing it to customers taking service from the distribution system. Primary distribution voltage levels are normally from 12 kV to 25 kV. The distribution system includes Substation Distribution Assets, step down transformation, secondary cables for customers who accept secondary service and service connections. The costs of metering electricity from the distribution system are also included as part of the Distribution function.

BC Hydro has sub-functionalized the distribution system into: substations; primary system; transformers; secondary/services; and meters based on the advice of the 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.

3.6.4 Customer Care

The Customer Care function includes services related to revenue collection and customer account and relationship management, as well as planning and sustainment of the Information Technology (**IT**) infrastructure required to deliver these services. Revenue collection activities include meter reading, bill generation and delivery, billing exception identification and resolution, payment processing, collections and investigation of electricity theft. Customer account and relationship management are provided through mass market contact channels (call centre, internet portal) and dedicated account representatives for BC Hydro's largest customers, as well as resolution of claims and complaints.

3.6.5 Functionalization Procedure and the Revenue Requirement

In most cases the F2016 COS utilizes the functionalization provided by the F2016 RRA. The RRA disaggregates BC Hydro's costs into Cost of Energy, O&M, taxes, depreciation, financing costs and RoE, and then apportions the costs between the following functional areas: Generation, Transmission, Distribution (Transmission and Distribution are referred to collectively as **T&D**) and Customer Care:

- Cost of Energy is functionalized entirely to Generation in the F2016 COS study;
- O&M costs are functionalized using Schedules 5.0 to 5.4 of the F2015-F2016 RRA Financial model,[131] which map business groups to different functional areas. When a particular business group provides services to multiple functional areas, the RRA maps it according to the functional area that best captures a majority of the costs incurred. For example, the BC Hydro Environmental Risk Management (**ERM**) business group is functionalized entirely to the Generation function, even though about 10 to 15 per cent of ERM's O&M costs are likely T&D related. Similarly, BC Hydro Aboriginal

[131] See Appendix C of BC Hydro's F2015-F2016 RRA at: http://www.bcuc.com/Documents/Proceedings/2014/DOC_40964_03-07-2014_BCH-F2015-16RevenueRequirementsApplication.pdf.

Relation's operating costs are functionalized entirely to T&D even though some of the operating cost is likely Generation-related;

- The remaining cost categories (taxes, depreciation, financing cost and RoE) are functionalized directly using the revenue requirement. Taxes are directly functionalized on schedule 6.0 (Lines 30 to 35) of the RRA financial model. Depreciation, financing cost and RoE are all functionalized using BC Hydro's asset records and rate base on schedules 7.0 (Lines 60 to 65), 8.0 (Lines 87 to 92), and 9.0 (Lines 63 to 68) of the RRA model.

For COS purposes, BC Hydro considered using 'bottom up' methods to estimate the proportion of work that spans multiple functional areas, but observed that the approach would be administratively complex without a corresponding gain in accuracy. In most cases BC Hydro chose to functionalize business group costs entirely to the predominant functional area for the following reasons:

1. With the exception of IT-related costs, the total dollars from business groups that span multiple functional areas are relatively small ($40 million in F2016 which represents less than 1 per cent of the F2016 revenue requirement);
2. The difference between splitting the costs among multiple functional areas versus functionalizing to a primary group has a negligible impact on the R/C ratios in the F2016 COS study. For example, shifting $5 million from Generation to Distribution has at most a 0.18 per cent change, depending on the rate class. Together with point 1 above, this suggests any gains in F2016 COS study accuracy from this approach would be minimal;
3. There are offsetting effects as some of the groups functionalized to Generation include T&D-related work (i.e., ERM) while some groups functionalized to T&D (i.e., Aboriginal Relations) include Generation-related work; and

4. Splitting the costs for some business groups may not be stable as the proportions of cost associated with different lines of business change year over year.

Similar issues exist with IT related costs. These are discussed below in greater detail.

3.6.5.1 Information Technology

In February 2015 AMPC submitted comments on BC Hydro's draft F2016 COS model and noted that "IT costs are becoming a significant cost element" before requesting that "BC Hydro prepare a study that more accurately assigns IT costs to all significant users of IT services including and specifically identifying metering, billing, customer service and distribution operations and planning". Operating costs associated with IT are approximately $112 million in the F2016 COS study and these are currently treated like a corporate expense and functionalized to all business groups using a high level O&M allocator.

In response to AMPC's request, BC Hydro examined operating IT costs to assess the feasibility of getting a more detailed 'bottom up functionalization'. BC Hydro relied on professional judgement to estimate the functional split shown in Table 3-2.

Table 3-2 IT Functionalization

$ million	Generation (G), Transmission T), Distribution (D), Corporate (Co), Customer (Cu), and General (Ge)					
	G (%)	T (%)	D (%)	Cu (%)	Co (%)	Ge (%)
Bottom up functionalization	5	5	10	4	4	71
Bottom up functionalization based on COS functions	18.8[132]	22.1	41.5	17.7		
Status Quo Functionalized by Corporate O&M	30.0	29.7	30.3	9.9		

[132] Generation percentage calculated by adding a pro-rata share of Corporate and General costs to the 5 per cent share of cost functionalized as Generation in the bottom up method.

Costs were functionalized according to the main beneficiary of the services – Generation, Transmission, Distribution, etc. Where possible, costs were functionalized directly.

BC Hydro has the following concerns with this approach and believes treating IT costs as a corporate expense for F2016 COS study purposes is most appropriate:

- About 71 per cent of the costs have been classified as General because the costs overlap across all functions. Approximately 80 per cent of General category costs (80 per cent of $80 million or $65 million) relates to IT infrastructure, network operations, and enterprise applications that benefit all business groups;
- IT operating costs are largely related to the maintenance of existing IT-related assets that were previously capitalized and included in rate base. The accuracy of the accounting system's existing rate base functionalization with respect to IT-related costs is questionable and it would take significant effort to confirm accuracy;
- Functionalizing IT costs to a business group may not yield stable results. The functional split may change each year as business focus and priorities change;
- The 'bottom up' analysis described above is high-level at best and relies on judgement to directly functionalize costs. BC Hydro believes the preparation and maintenance of this analysis would be administratively complex and time consuming; and
- BC Hydro estimated the impact of IT functionalization at a 0.4 per cent change in the Residential R/C ratio as part of the F2016 draft COS study model circulated to stakeholders for a thirty day comment period on February 6, 2015 (stakeholder comments relating to the model are found at Appendix C-2C of the Application). IT costs have a smaller impact on F2016 COS study results than

other issues such as Heritage hydro and Distribution classifications discussed respectively in sections 3.7.1 and 3.7.7.

For these reasons BC Hydro believes that a more transparent approach is to treat IT costs the same way as other corporate costs.

3.6.5.2 Transmission and Distribution Costs

As part of the RRA process, T&D operating costs are already split between Transmission and Distribution using a methodology that originated in BC Hydro's 1997 Wholesale Transmission Service proceeding and involves a detailed review of all operating costs within T&D. For example, Line 23 on Schedule 5.4 of the RRA shows that 53.4 per cent of F2016 T&D operating cost is functionalized as Transmission while the remaining 46.6 per cent is functionalized as Distribution; refer to the F2016 COS model at Appendix E of the Application. BC Hydro relies on this information for F2016 COS purposes.

3.6.6 Demand Side Management

At Workshop 2 BC Hydro identified DSM as a functionalization issue, and proposed a departure from the Commission's 2007 RDA Decision Direction 6 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.

At the request of some stakeholders, BC Hydro explored directly assigning DSM costs to rate classes that receive DSM incentives or direct financial benefits from DSM measures. BC Hydro understands that Manitoba Hydro directly assigns DSM costs.[133] BC Hydro examined the costs and benefits of different DSM initiatives (rate structures, codes and standards, and DSM programs) over the F2008 to F2016 period.[134] As illustrated in section 2.3 of the Workshop 2 consideration memo at

[133] Manitoba Hydro recovers approximately $30 million in DSM costs each year as compared to approximately $100 million recovered by BC Hydro.

[134] A multi-year period was selected to smooth out the year over year fluctuations in DSM expenditures.

Appendix C-2A, there is not a direct correlation between the benefits and costs of different DSM initiatives. Accordingly, BC Hydro did not pursue direct assignment of DSM costs for the F2016 COS study.

Refer to for section 2.3 of the Workshop 2 consideration memo (at Appendix C-2A) and section 1.1 of the Workshop 4 consideration memo (at Appendix C-2B) for further detail.

3.6.7 Regulatory Accounts

Regulatory accounts emerged as a functionalization issue as a result of stakeholder feedback at Workshops 2 and 4. Deferral and regulatory account balances represent costs from prior years that have been approved to be capitalized and amortized for recovery over a future period.

The amortized amounts in the current year's revenue requirement have been reviewed to ensure the recovery aligns with the functionalization and classification of the underlying asset. The functionalization for several regulatory account amounts[135] was adjusted, each with a small impact to total costs assigned by function. The largest of these in F2016 was a change in the functionalization of the Rate Smoothing regulatory account, an amount of $122.4 million in the F2016 RRA. This amount was previously assigned to each function proportionate with functionalized O&M. The COS Consultants recommended that this amount be functionalized proportionate to the functionalization of the total revenue requirement. The proportions for the two methods are shown in Table 3-3.

[135] In addition to the Rate Smoothing and Interest on Regulatory and Deferral Accounts amounts, the functionalization of the First Nations and PCB Remediation regulatory accounts were also refined.

Table 3-3 Functionalization of Rate Smoothing Account

Rate Smoothing Account Functionalization	Generation (%)	Transmission (%)	Distribution (%)	Customer Care (%)
Previous O&M Method	35.5	27.0	25.3	13.2
F2016 COS Total Revenue Requirement Method	58.7	16.9	21.5	3.0

The functionalization of the interest on regulatory and deferral accounts was also adjusted to align the interest amount with the functionalization of the underlying regulatory asset. Previously, the interest on these amounts was included with total financing charges for BC Hydro and functionalized by total rate base. In F2016, the Interest on Regulatory and Deferral Accounts is $61.7 million. Refer to Table 3-4.

Table 3-4 Functionalization of Interest on Regulatory and Deferral Accounts

	Generation (%)	Transmission (%)	Distribution (%)	Customer Care (%)
Previous Finance Charges Method	42.3	32.1	25.7	0.0
F2016 COS Regulatory & Deferral Accounts Method	71.9	7.0	20.9	0.3

The classification of the interest on the deferral accounts was also updated to be consistent with that used for Cost of Energy. This amount was previously classified using the classification ratio applied to all of the Generation function. In F2016, this change is applicable to an amount of $23.8 million.

More information on BC Hydro's treatment of regulatory accounts in the F2016 COS study is found in section 3 of the Discussion Guide to Workshop 4 (at Appendix C-2B) and in the F2016 COS study Excel model (at Appendix E; Sheet 1.0 lists each regulatory account separately so stakeholders can understand how each is being functionalized). In past COS studies, regulatory accounts were not functionalized individually and only total additions and total recoveries, across all the accounts, were shown. As noted above in section 3.6.5.1, a description of the draft

F2016 COS study model was circulated to stakeholders for a thirty day comment period on February 6, 2015.

3.7 Classification

Step 2 of the embedded COS approach is classification: what causes the cost to be incurred? In embedded COS analyses, utilities divide costs according to causality into three components: (1) energy (variable costs that vary with the kWh); (2) demand (fixed costs that vary with kW demand); and (3) customer (costs directly related to the number of customers).

Based on the jurisdictional assessments described in section 3.5 above, Generation costs are generally split between energy and demand; Transmission costs are generally classified as demand-related; Distribution costs are generally split between demand-related and customer-related components or directly assigned to a specific rate class; and customer costs are classified as 100 per cent customer-related. Cost classification assumptions that result in more costs being assigned to demand and less to energy tend to benefit higher load factor customers and result in more costs being assigned to low load factor customers. This outcome follows from the fact that high load factor customers use a higher proportion of energy (kWh) in relation to their capacity demands (kW), whereas low load factor customers generally require more capacity relative to their energy needs. Cost allocation methods that attribute more costs to the customer classification and less to demand and energy generally result in relatively lower total costs assigned to larger customers and higher total costs assigned to smaller customers.

BC Hydro believes there is a fair degree of consensus through the 2015 RDA stakeholder engagement process on the following classification issues (refer to section 1 of Workshop 4 consideration memo at Appendix C-2B):

- IPP EPA classification;
- Transmission classification; and

- Customer classification.

Accordingly, this section focuses on the three classification issues which do not have a fair degree of stakeholder consensus: Heritage hydro, Distribution and SMI. In addition, BC Hydro provides discussion on DSM classification as this topic was not canvassed extensively during stakeholder engagement.

3.7.1 Generation: Heritage Hydro

BC Hydro prefers a system load factor approach to classify Generation, resulting in a 55 per cent energy/45 per cent demand split. However, BC Hydro has brought forward two F2016 COS study sensitivities as discussed below and does not oppose adoption of any of the three Generation classification options.

Costs related to the Heritage hydro system exceed about $1 billion and account for the largest share BC Hydro's F2016 revenue requirement (about 25 per cent). In the 2007 RDA, BC Hydro proposed a 50 per cent energy/50 per cent demand Generation classification. 2007 RDA Direction 5 provided for a 45 per cent energy/55 per cent demand Generation classification on the basis that at the time, future Resource Smart additions were predominantly capacity-related.[136]

The COS Consultants recommended that BC Hydro consider either a system load factor or a plant capacity factor method to classify Heritage hydro costs:

- Using a load factor method, the energy portion of Generation cost would be equal to the system load factor while the Generation demand portion would equal one minus the system load factor. BC Hydro would estimate the system load factor for F2016 based on the most recent load forecast; and
- A plant capacity factor approach (i.e., ratio of average plant load to nameplate plant capacity) that sub-functionalizes hydro generating facilities in service and O&M costs by individual plant or groups of plants and then uses the

[136] 2007 RDA Decision, page 91.

corresponding plant capacity factors to classify hydro plant and O&M costs, excluding water costs.

BC Hydro described the pros and cons of each approach in Table 2 of the Workshop 2 Discussion Guide (copy at Appendix C-2A). After engaging with stakeholders at Workshop 2 and Workshop 4, in the F2016 COS study BC Hydro uses a system load factor approach[137] to classify Generation, resulting in a 55 per cent energy/45 per cent demand split. The use of system load factor is based on the advice of the COS Consultants subsequent to Workshop 2 and jurisdictional support (Avista, Newfoundland Power, Idaho Power and PacifiCorp). Refer to section 4 of the Workshop 4 Discussion Guide at Appendix C-2B for a summary of the reasons for selecting a system load factor.

However, as stated in section 2.1.2 of the Workshop 4 consideration memo, BC Hydro believes that both the load factor and capacity factor approaches have merit. As a result, and to respond to AMPC, Transmission Service customer and CEC concerns with the system load factor approach, BC Hydro brought forward two F2016 COS study sensitivities:

1. Forty-five per cent energy/55 per cent demand split resulting from a capacity factor approach (Sensitivity Number 1); and
2. Fifty per cent energy/50 per cent demand split based on BC Hydro's historic classification of Heritage hydroelectric facilities (Sensitivity Number 2). A 50 per cent energy/50 per cent demand split is a compromise approach that recognizes the limitations of and roughly represents an average of the system load factor and capacity factor approaches.

[137] The energy portion of Generation cost is equal to the system load factor while the Generation demand portion is equal: one minus the system load factor. Given that BC Hydro proposes to classify IPPs separately from Heritage hydroelectric (see section 3.7.3 of the Application), it is appropriate to adjust the load factor calculation to remove the impact of IPPs serving load. System load factor is calculated based on loads almost entirely served by Heritage hydroelectric supply.

BC Hydro does not oppose adoption of any of the three Generation classification options. Table 5 of the Discussion Guide for Workshop 4 demonstrated that there is about a 0.5 per cent change in the Residential R/C ratio if the classification of these costs is switched from a 55 per cent energy /45 per cent demand classification (BC Hydro's preferred method) to Sensitivity Number 1.

3.7.2 Generation: Heritage Thermal

There are three BC Hydro-owned thermal generating stations: Fort Nelson Generating Station (**FNG**), Prince Rupert Generating Station (**PRG**) and Burrard Generating Station (**Burrard**). FNG has the most significant impact on BC Hydro's rates with a F2016 forecast of approximately $150 million, compared to about $9 million at PRG and $50 million at Burrard. BC Hydro proposes the following:[138]

- FNG – use a load factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generation costs. This results in a 74 per cent energy and 26 per cent demand classification. Fuel costs are classified as 100 per cent energy;
- PRG – For simplicity, use the system load factor with no adjustment for IPP supply to classify PRG's O&M and capital generation costs. This results in a 60 per cent energy and 40 per cent demand classification. Fuel costs are classified as 100 per cent energy; and
- Burrard – classify Burrard O&M and capital costs as 100 per cent demand with associated fuel costs treated as 100 per cent energy.

The reasons supporting this classification are set out in section 5 of the Workshop 4 Discussion Guide found at Appendix C-2B. As described in section 2.2 of the Workshop 4 consideration memo, while there was not a fair degree of stakeholder consensus regarding BC Hydro's proposal, the classification method selected for the

[138] In the 2007 RDA, BC Hydro classified the three Heritage thermal generating stations as 100 per cent demand.

three Heritage thermal generating stations does not change R/C ratios when reported to one decimal place.

3.7.3 Generation: Independent Power Producers

BC Hydro's preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification.

In the 2007 RDA BC Hydro classified IPPs as 100 per cent energy-related on the basis that the primary purpose of entering into IPP EPAs is procurement of additional energy. The Commission accepted IPP classification as 100 per cent energy-related but 2007 RDA Decision Direction 8 required BC Hydro to prepare a study examining and quantifying the capacity benefits associated with IPP EPAs. In response to Direction 8 and stakeholder feedback at Workshop 2, BC Hydro engaged the appropriate business units, developed five IPP classification options and undertook an EPA-by-EPA analysis (this analysis is found at Attachment 4 of the Workshop 2 consideration memo at Appendix C-2A).

At Workshop 4 BC Hydro identified the 'Value of Capacity' option, in which the relative portion of IPP costs allocated to demand is based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes. There was a fair degree of stakeholder consensus for this IPP classification option. Refer to section 4 of the Workshop 2 and section 1.2 of the Workshop 4 consideration memos for additional detail.

3.7.4 Generation: Demand Side Management

BC Hydro proposes to continue classifying the 90 per cent portion of DSM that has been functionalized as Generation-related, in the same way as overall Generation costs. As described in section 3.6.6, BC Hydro's rationale for functionalizing 90 per cent of DSM to Generation is that DSM expenditures are primarily incurred to avoid generation-related costs, which also avoids the classification of those same costs into energy and demand. Therefore, to be consistent with the rationale for functionalizing DSM costs to Generation, BC Hydro believes that the classification of Generation-related DSM costs should mirror the classification of overall Generation costs in the revenue requirement.

3.7.5 Powerex Net Income

BC Hydro proposes continuing with the 2007 RDA Direction 7 classification of Powerex net income following overall Generation classification. Virtually all stakeholders who commented on this topic at Workshop 2 agreed with this proposed approach; the only exception was COPE 378.

3.7.6 Transmission

BC Hydro's proposes to continue with the 2007 RDA Decision approach that Transmission should be classified as 100 per cent demand related. With the exception of COPE 378, all stakeholders providing Workshop 2 and/or Workshop 4-related written comments on this topic thought reasonable BC Hydro's proposal to continue with the classification of Transmission as 100 per cent demand-related because serving peak loads remains the primary planning consideration for capital expenditures on the transmission system. Refer to section 7 of the Workshop 2 consideration memo at Appendix C-2A. The majority of utilities with similar characteristics to BC Hydro, including Manitoba Hydro, classify Transmission as 100 per cent demand-related.

3.7.7 Distribution

BC Hydro proposes to classify Distribution costs based on Table 1 of the Workshop 4 Discussion Guide (copy at Appendix C-2B) as follows:

- Substations and primary system classified 100 per cent demand;
- Transformers classified 50 per cent demand and 50 per cent customer;
- Secondary/services asset category split 50 per cent secondary and 50 per cent services:

- ▶ Secondary portion classified 100 per cent demand;
- ▶ Service portion classified 100 per cent customer; and
- Meters classified 100 per cent customer.

As part of the 2007 RDA BC Hydro proposed a 75 per cent demand/25 per cent customer classification for Distribution. 2007 RDA Decision Direction 4 mandated a 65 per cent demand/35 per cent customer Distribution classification, and required BC Hydro to conduct minimum system and zero-intercept analysis. The 2010 study entitled *Electric Distribution System, Cost of Service Study* (copy at Appendix B-2A), circulated to stakeholders as part of Workshop 2, addresses this part of Direction 4.

Generally, there are three approaches to classifying distribution costs: (1) minimum system; (2) zero-intercept; and (3) use of professional judgment to separate demand-related and customer-related distribution costs. Classifying distribution plant with the minimum system method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of a customer. The minimum system method involves determining the minimum size pole, conductor, cable, transformer and service that is currently installed by the utility. The resulting minimum distribution system costs are classified as customer costs, with remaining distribution costs classified as demand. The zero-intercept method uses regression analysis to statistically extrapolate what the cost of the facility might be if it did not have any load carrying capability; the no-load intercept is the customer component. This requires considerably more data and calculation than the minimum system method.

The COS Consultants recommended approach (3) on the basis that: the minimum system/zero-intercept methods are labour intensive but produce inaccurate results; and most utilities surveyed (and their regulators) use professional judgment to separate demand-related and customer-related distribution costs rather than relying on minimum system or zero-intercept analyses. For example, the Washington Utilities and Transportation Commission has repeatedly rejected the minimum system and zero-intercept methods as unreasonable because they are likely to lead to double allocation of costs to residential customers and over-allocation of costs to low use customers.[139] Zero-intercept methods are also critiqued because of their lack of realism. Bonbright rejects the minimum system and zero intercept methods.[140] No stakeholder supported using either the minimum system or zero-intercept methodologies.

BC Hydro proposes to classify Distribution costs based on Table 1 of the Workshop 4 Discussion Guide (copy at Appendix C-2B). BC Hydro spent considerable time on Distribution classification issues as part of the review of the F2016 COS study and concludes that methods outlined in Table 1 of the Discussion Guide are most appropriate. The Workshop 4 consideration memo responds to a number of stakeholder comments on Distribution classification methods and provides further detail on BC Hydro's preferred approach (copy at Appendix C2-B). In addition, stakeholder feedback from both Workshop 2 and Workshop 4 indicates that stakeholders recognize that Distribution classification is a challenging topic. Participants generally supported BC Hydro's proposals for the classification of substations, primary system, transformers, secondary system, services and meters.

3.7.8 Smart Meter Infrastructure

BC Hydro proposes to classify SMI-related costs as 100 per cent customer-related.

The classification of SMI was a significant topic during the RDA's stakeholder engagement process. BC Hydro identified five options for classifying SMI costs

[139] Jim Lazar, "Cost of Service Analysis for the Electric and Natural Gas Industries: A Historic Review of Decisions by the Washington Utilities and Transportation Board, 1978-2005", prepared for Public Counsel Section, Office of Attorney General (August 2005), page 10; http://www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/ca2133165b2213418825706c005e81bc!OpenDocument.These issues have been raised in Canadian utility proceedings - for example, in a 2002 Nova Scotia Power proceeding: "The minimum-sized method assigns to all customers a share of the cost of a hypothetical distribution system that has real load-carrying capacity. It also assigns demand costs based on every kW of customer demand. The effect is to 'double count' the demand which could be met by the minimum-sized system"; refer to the evidence of John Stulz submitted on behalf of Nova Scotia Utility and Review Board staff, pages 20 to 21; http://www.regie-energie.qc.ca/audiences/3492-02/RepDemINTERV3492/RepDem_UC_vsHQ-1_PubNS-URB_5fev03.pdf.

[140] Bonbright, *Principles of Public Utility Rates* (1961), *supra*, note 20 in Chapter 1, page 347.

which are described on page 16 of the Workshop 4 consideration memo. These options ranged from classifying SMI costs as 100 per cent customer (Option 1, BC Hydro's preferred approach) to classifying such costs as 100 per cent energy (Option 2, rejected by BC Hydro) with blended classifications between customer and energy forming the basis of options 3, 4, and 5.

BC Hydro used Option 1 with a 100 per cent customer classification for the F2016 COS study. It is simple, defendable from a historical cost allocation perspective and has overwhelming jurisdictional support. As noted in Table 1 of the Workshop 4 consideration memo, classification of SMI does not significantly impact R/C ratios. BC Hydro can revisit this issue in the F2019 COS once the Distribution system has feeder-by-feeder metering, which is expected to be rolled out as part of the SMI analytics system sometime in 2016.

3.7.9 Customer Care

BC Hydro proposes to classify Customer Care-related costs as 100 per cent customer related.

With the exception of COPE 378, all stakeholders providing Workshop 2 and/or Workshop 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 2007 RDA Direction 4; refer to section 10 of the Workshop 2 consideration memo at Appendix C-2A. 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.

3.8 Allocation

The third step in completing the F2016 COS study is the allocation of BC Hydro's total functionalized and classified revenue requirement to the rate classes. This is achieved through the use of an appropriate allocation methodology.

3.8.1 Direct Assignment

Costs incurred to provide unique service to one rate class are assigned directly to that rate class:

- Costs of operating and maintaining street lights and pole attachments are unique to the Street Lighting rate class. Section 3.2 of the F2016 COS study model at Appendix E shows the removal of Distribution costs associated with Street Lighting prior to the classification of Distribution costs; $4.6 million of costs are removed from the functionalized Distribution cost and directly assigned to Street Lighting; and
- BC Hydro proposes to direct assign BC Hydro owned Distribution transformer costs to the rate classes using the method described in the Workshop 4 presentation (slides 45 to 52) and section 2.4.2 of the Workshop 4 consideration memo to the October workshop (copies at Appendix C-2B).

3.8.2 Generation Energy

Energy costs are allocated based on each rate class's pro rata share of energy consumption. Therefore the cents/kWh Generation costs of serving each rate class are identical under the F2016 COS study embedded cost methodology. As described in the Workshop 2 consideration memo, the vast majority of other utilities use this approach to allocate generation energy costs.

Note that Generation energy is adjusted for losses prior to allocation. Before the pro rata calculations are done, transmission and distribution losses of 6 per cent and 6 per cent respectively are added to the energy consumption of distribution customers while transmission losses of 6 per cent are added to the energy consumption of transmission voltage customers. These loss assumptions were reviewed as part of the 2007 RDA and BC Hydro continues to believe they are valid as discussed in section 3.8.2.1.

3.8.2.1 Distribution losses

Combined distribution losses through primary lines, transformer cores, secondary wires and theft is currently estimated at 6 per cent. The source of distribution loss information is engineering studies that have been verified using a load research model called the Distribution Load Shape Estimation that estimates hourly distribution loads and applies loss factors for each distribution circuit for each hour of the year. Within the next 12 to 24 months BC Hydro plans to have metering in place on every distribution feeder, which is expected to improve the accuracy of loss estimates on the distribution system.

3.8.2.2 Transmission losses

Transmission losses vary year to year depending on the volumes of energy imported and exported into the BC Hydro system. In recent years BC Hydro estimates that transmission losses ranged between 5 per cent and 6 per cent. BC Hydro has the ability to measure transmission system losses on an hourly basis using metering on the U.S. and Alberta interties, generators within BC Hydro's service area, and at certain points on the transmission system. BC Hydro believes the current 6 per cent assumption remains valid for the F2016 COS study.

3.8.3 Generation Demand and Transmission

Generation demand-related and Transmission costs are typically allocated on the basis of the system's CP demand because it is combined system demand at peak times that drives Generation capacity and Transmission needs. A rate class's 4CP allocation is calculated as a five-year average of the sum of that rate class's demand at each winter month's peak hour divided by the sum of all rate classes' demand during those same hours. Stakeholders providing Workshop 4-related written comments generally agreed with BC Hydro's proposal to continue with 2007 RDA Decision Direction 3, which mandates a 4CP 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 4 (3CP, variations on 4CP), the results indicate little change from the current 4CP approach. Refer to sections 7 and 8 of the Workshop 2 Discussion Guide and section 11 of the Workshop 2 Consideration Memo (both at Appendix C-2A) and the Workshop 4 slide deck, slides 26 to 31 (at Appendix C-2B) for additional detail.

3.8.4 Distribution

The conventional approach is to allocate Distribution demand-related costs on the basis of NCP (excluding transformer costs which are directly assigned to the rate classes), which are the sum of individual class peak demands regardless of the time of occurrence. The reason for use of NCP is that Distribution demand costs are driven by local network requirements, which do not necessarily coincide with the BC Hydro integrated system CP demand.

BC Hydro's proposed methodology for assigning Distribution demand-related costs is based on average rate class load profiles for five years. For each year of data, each rate class is assigned a 1NCP percentage allocator based on its annual peak load as a proportion of the sum of all the rate classes' annual peak load, which is in line with industry practice. In response to BCOAPO's inquiry at Workshop 4 regarding consideration of possible modifications of the NCP allocator, BC Hydro calculated 3NCP[141] and 12NCP allocators. BC Hydro prefers 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 1NCP approach produces results reasonably close to the bottom up analysis conducted across the ~1500 distribution

[141] 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.

feeders. Refer to section 2.4.2 of the Workshop 4 consideration memo (Appendix C-2B) for additional detail.

3.8.5 Customer Care

Currently, Customer Care costs are allocated to rate classes using a 90 per cent/10 per cent weighted allocator between number of customers and revenue by rate class. This allocation method remains appropriate for the reasons discussed in section 9 of the Discussion Guide[142] for Workshop 4. Figure 1 of the Workshop 4 Discussion Guide demonstrates that the existing 90 per cent/10 per cent allocator aligns well with a direct allocation of Customer Care costs to rate classes.

3.9 Summary of F2016 Cost of Study Methodology Changes, Rate Class Revenue to Cost Ratios and Rate Class Cost Classification

Table 3-5 summarizes the methodology changes arising between the time the draft F2016 COS study circulated to stakeholder on February 6, 2015, and the final F2016 COS study.

[142] See pages 14 to 15; copy found at Appendix C-2B.

Table 3-5 Summary of F2016 COS Study Methodology Changes

Change	Impact on F2016 Residential R/C ratio
IPP Capital Leases The 93 per cent/7per cent IPP classification was originally calculated using IPPs categorized under Cost of Energy. BC Hydro has incorporated the capital lease IPPs into the classification calculation and determined the impact on classification is negligible.[143]	None
NCP Allocator Separate NCP allocators are used to allocate distribution demand related costs to primary and secondary distribution customers. The draft model used a single allocator covering all distribution customers.	None
Street Lighting BC Hydro proposes separating the existing Street Lighting rate class into BC Hydro-owned and customer-owned street lighting as described in section 4.6 of the Application	None

The resulting R/C ratios for BC Hydro's existing rate classes are set out in Table 3-6. For reference, the draft F2016 R/C ratios, prepared in January 2015 and posted to the RDA website for stakeholder comment in February 2016, are also shown.

[143] See Attachment 3 of the Workshop 4 consideration memo at Appendix C-2B for more information.

Table 3-6 R/C Ratios

	R/C Ratios		
	Final F2016 COS Study results		**F2013 Fully Allocated COS**
Rate Class	**Final Study filed in the RDA (%)**	**Draft F2016 COS study posted to RDA website in February 2015 (%)**	**Filed on February 8, 2014 with the Commission (using 2007 RDA decision) (%)**
COLUMN	**A**	**B**	**C**
Residential	93.9	93.9	89.8
SGS	112.0	112.0	126.7
MGS	117.1	120.5	120.8
LGS	100.9	99.7	102.1
Irrigation	85.1	85.2	86.6
Street Lighting	134.1[144]	134.1	115.7
Transmission	101.4	101.5	104.4
Total Classes	**100.0**	**100.0**	

The F2016 COS study cost allocation was presented at Workshop 12[145] and is reproduced in Table 3-7 as it informs RIB rate and SGS rate basic charge cost recovery of customer-related costs (sections 5.2.5.2 and 6.2.3.2 respectively of the Application), and MGS and LGS demand charge recovery of demand-related costs (sections 6.3.4 and 6.4.4 respectively of the Application).

[144] BC Hydro is preparing to segment the Street Lighting rate class. See section 4.6 of the Application.
[145] Slide 18 of the Workshop 12 presentation slide deck found at Appendix C-1B of the Application.

Table 3-7 F2016 Cost of Service Study Cost Classification

Rate Class	Energy (%)	Demand (%)	Customer (%)
Residential	35	52	13
SGS	38	50	12
MGS	42	53	5
LGS	50	49	1
Transmission	65	35	0
Irrigation	42	45	13
Street Lighting	30	47	23

2015 Rate Design Application

Chapter 4

Rate Class Determination

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4.1 Introduction and Chapter Structure

As noted in section 1.4 of the Application, BC Hydro currently has seven rate classes: Residential, SGS, MGS, LGS, Transmission, Irrigation and Street Lighting.

In the 2007 RDA proceeding, BC Hydro stated that rate classes are used to group customers with similar load profiles and similar interconnection characteristics on the basis that such customers will generally cause the utility to incur similar costs.[146] The COS Consultants advised that two main criteria can be used to inform a COS-based determination of appropriate rate classes. As listed at page 14 of the Workshop 8a/8b consideration memo at Appendix C-4A and in section 3.2 of the Workshop 5 consideration memo at Appendix C-5A, these two criteria are:

- Load characteristics (peak demand, annual energy, coincident- and non-coincident demand); and
- Service characteristics (voltage, single or three phase, transformer ownership).[147]

E3 advised that customers should be segmented using readily observable variables that can be easily understood (which are described below), and noted that in addition to load characteristics and service characteristics, other criteria can be considered such as customer understanding (simplicity) and practicality of tariff administration.[148]

BC Hydro uses the expression 'segmentation' to refer to the creation of sub-classes of customers defined by certain characteristics. Potential segmentation falls into two categories: that which may be justifiable on a cost of service basis and that which

[146] Refer to BC Hydro's response to BCUC IR 2.75.1, Exhibit B-7 in the 2007 RDA proceeding; http://www.bcuc.com/Documents/Proceedings/2007/DOC_15416_B-7_BCH-Resp-to-IR-2-final.pdf.
[147] Slides 24 to 26 of the Workshop 12 presentation (at Appendix C-1B) contain additional details concerning load characteristics and service characteristics.
[148] Refer to the Direct Testimony of Dr. Ren Orans, Appendix J of the BC Hydro 2009 LGS Application; copy available at http://www.bcuc.com/Documents/Proceedings/2009/DOC_23224_2009_10_16%20APPL_09LGS.pdf.

cannot. Additional segmentation based on cost of service can lead to increased transparency and better matching of costs and revenues.

Possible ways customers can be segmented arose during the 2015 RDA stakeholder engagement process. This Chapter is organized around this stakeholder input as follows:

- Section 4.2 – Residential rate class. BC Hydro proposes no change to the existing Residential rate class for Module 1 purposes. COPE 378 asked BC Hydro to explore segmenting the Residential rate class on the basis of dwelling type, heating type and/or number of occupants. After meeting with COPE 378 on June 29, 2015, COPE 378 agreed with BC Hydro's analysis that there is no cost of service basis for segmentation by heating type, dwelling type or the number of occupants. No stakeholder challenged the composition of the existing Residential rate class. As part of Module 2, BC Hydro will explore whether it remains appropriate for certain farm service activities to be served pursuant to Residential rates;
- Section 4.3 – General Service rate classes. BC Hydro proposes no changes to the existing LGS, MGS and SGS rate classes for Module 1 purposes. No stakeholder challenged the existing breakpoint defining the SGS rate class. Several stakeholders asked BC Hydro to review: (i) the existing breakpoint between MGS and LGS; and (ii) creating a new class of large LGS customers (referred to as **XLGS** with demand greater than 2,000 kW). BC Hydro commits to re-examining a potential XLGS rate class as part of its assessment of a RS 1823-like rate (LGS TSR-Like rate) for such a class as a RDA Module 2 topic. COPE 378 asked BC Hydro to explore: (iii) re-merging the LGS and MGS rate classes at this time; and (iv) creating a rate class of General Service customers consisting of municipalities, universities, school boards and hospitals (referred to as the **MUSH** sector); and
- Section 4.4 – Transmission Service rate class. BC Hydro proposes no changes to the existing Transmission Service rate class for Module 1 purposes. AMPC

asked BC Hydro to consider creating rate class(es) for New Westminster and FortisBC. While BC Hydro assessed New Westminster and FortisBC load characteristics, BC Hydro proposes to address the issue of potentially separating New Westminster and FortisBC from the remainder of the Transmission Service rate class as part of the F2019 COS when the ramifications will be better understood (e.g., the potential for rate rebalancing from F2020 onward).

In addition, BC Hydro assessed the existing Irrigation and Street Lighting rate classes, and proposes to divide the Street Lighting rate class into two classes: BC Hydro-owned street lighting and customer-owned street lighting. Refer respectively to sections 4.5 and 4.6 of this Chapter. BC Hydro will be exploring the suitability of RS 1401 (Irrigation) for municipal and hotel/golf course customers in RDA Module 2.

4.2 Residential Rate Class

BC Hydro proposes no change to the existing Residential rate class for Module 1 purposes. Consequently, BC Hydro is not proposing any changes to the definition of "Residential Service" in section 1 of the Electric Tariff. As noted in section 1.5.2 of the Application and above, the issue of farm service and the availability of Residential rates to farms will be addressed as part of RDA Module 2. Thus RDA Module 2 will consider aspects of the current scope of Residential service.

4.2.1 Dwelling Type and Heating Type

At Workshop 9a/9b COPE 378 asked BC Hydro to examine segmenting by type of dwelling and/or number of occupants and/or end use (space heating) to determine if it made sense. No other stakeholders raised Residential rate class segmentation issues during the 2015 RDA stakeholder engagement process. BCOAPO asked questions concerning potential differentiated Residential low income rates based on primary heating type as part of its Workshop 12 written feedback,[149] but this is a rate

[149] Copy found at Appendix C-1B of the Application.

design and pricing issue. Refer to section 5.4 of the Application for an overview of 2015 RDA stakeholder engagement discussion concerning low income rates.

BC Hydro responded to COPE 378's request that BC Hydro explore Residential rate class segmentation in the Workshop 9a summary notes,[150] during a meeting held with COPE 378 on June 29, 2015,[151] and at Workshop 12.[152] BC Hydro concludes:

- Segmenting by dwelling type – there is less of a correlation between dwelling type and cost to serve Residential customers as compared to other factors. Differences in BC Hydro's cost of serving Residential customers are driven generally by the time of their energy consumption and more specifically by coincidence of customer load profiles with the system peak. The coincidence of load is much more driven by heating type than dwelling type. There would also be significant tariff administration and customer understanding issues associated with developing and defining the categories of dwelling types (e.g., apartment/condominium; mobile; duplex/row house/townhouse; SFD, etc.);
- Segmenting by number of occupants – there is no cost basis for segmentation on the basis of personal characteristics such as the number of occupants. There would also be significant tariff administration and customer understanding issues associated with the variability of the number of occupants and the challenges with tracking and verifying such information;
- Segmenting by heating type – there are significant tariff administration and customer understanding issues because there is a continuum of heating sources (e.g., with various mixed uses of natural gas and electric space heating somewhere in the middle of the spectrum). The 2014 REUS confirms that a wide variability exists.[153] The assorted end-use mix creates a single continuous distribution of consumption where separating customers legitimately by any

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[150] See the response to Part 3 question 12 on page 17, Attachment 1 to the Workshop 9a/9b consideration memo at Appendix C-3B.
[151] A copy of the summary notes for this meeting is found at Appendix C-3D.
[152] Refer to slides 27 to 30 of the Workshop 12 presentation slide deck at Appendix C-1B.
[153] Refer to Tables 8-7a, 8-7b, 8-8a and 8-8b at pages 69 to 72 of the 2014 REUS, a copy of which is found at Appendix C-3F.

single end use is difficult to accomplish without being subject to some form of non-cost based discrimination;[154] and

- This last observation is consistent with the finding that all surveyed Canadian electric utilities have a single uniform residential class of customers with no end-use segmentation.

4.2.2 Residential E-Plus Customers

BC Hydro also considered whether Residential E-Plus customers should be a separate rate class but concluded that the impact was too insignificant to justify such a change. Residential E-Plus customers account for approximately 0.3 per cent of revenue from the Residential rate class in F2016 and their removal from the Residential rate class would lead to about a 0.2 per cent increase in the R/C ratio of remaining Residential customers. Residential E-Plus R/C ratios are discussed in section 5.3.2 of the Application.

4.3 General Service Rate Classes

BC Hydro proposes no change to three existing General Service rate classes for Module 1 purposes, which are:

- SGS – General Service customers whose billing demand is less than 35 kW. The SGS 35 kW breakpoint has existed since at least 1974;
- MGS – General Service customers whose billing demand is equal to or greater than 35 kW but less than 150 kW and whose energy consumption in any 12-month consecutive period is equal to or less than 550,000 kWh. The existing MGS rate class was created as part of Commission Order No. G-110-10 approving the 2009 LGS Application NSA; and

[154] BC Hydro estimates the primary heating fuel type (electric or non-electric) by account using statistical modeling techniques. The fuel type classification is used *in aggregate* analysis of the Residential rate class for load forecasting, DSM planning and DSM evaluation. The fuel type classification does not reflect the full continuum of heating fuels, including secondary heating fuels, used by customers. As with all statistical modeling efforts, there is uncertainty in the results.

- LGS – General Service customers whose billing demand is equal to or greater than 150 kW or whose energy consumption in any 12-month period is greater than 550,000 kWh. The existing LGS rate class was created as part of Commission Order No. G-110-10 approving the 2009 LGS Application NSA.

The central issue with respect to the LGS, MGS and SGS rate classes is their within class diversity:

- There are a wide range of facility types such as hospitals, sawmills, manufacturing facilities, office building, retail stores and common areas of multi-unit residential buildings; and
- There are a wide range of consumption levels and load factors.[155] For example, within the LGS rate class, there is a 1 GWh (200 per cent of the average annual consumption in the class) energy consumption difference between the 75th and 25th percentile customers.

Figures 6-3, 6-5 and 6-9 and accompanying text in Chapter 6 provide additional detail on this topic.

In response to feedback from stakeholders following Workshop 8a/8b, BC Hydro undertook an analysis of the COS, primarily associated with the load characteristics of its SGS, MGS, and LGS rate classes, together with a jurisdictional assessment. The purpose of the analysis was to answer questions concerning load and cost diversity within the three existing General Service rate classes at different class segmentation breakpoints other than the existing breakpoints. BC Hydro presented the results of its analysis at Workshop 11a and Workshop 12.

4.3.1 Small General Service

The existing 35 kW breakpoint is appropriate for BC Hydro's smallest commercial customers served pursuant to RS 1300/1301/1310/1311:

[155] Refer to the Workshop 11a/11b Appendix found at Appendix C-4B of the Application, slides 7 to 12.

- BC Hydro's jurisdictional review, summarized in Table 4-1 below,[156] revealed that surveyed Canadian electric utilities have small general service classes which do not have demand charges, and that the current SGS 35 kW breakpoint is in the middle of the range of other Canadian electric utility breakpoints used for smaller general service (10 kW to 75 kW);[157]

Table 4-1 Expanded Canadian Jurisdictional Review of General Service Segmentation

Utility/Number of General Service Customers	Small	Medium	Large	Extra Large
BC Hydro ~183,000 customers	<35 kW (160,000 customers) No demand charge	35 - 150 kW (16,000 customers)	>150 kW (7,000 customers)	
FortisBC ~14,600 customers	<40 kW (12,700 customers) No demand charge	40 - 500 kW (1,800 customers)	>500 kVA (50 customers)	
FortisAlberta ~59,000 customers	<75 kW (51,000 customers)	75 kW - 2 MW (8,000 customers)	>2 MW (170 customers)	
Enmax ~35,000 customers	<5000 kWh /month (24,000 customers) No demand charge	<150 kVA (9,000 customers)	>150 kVA (2,000 customers + 252 primary)	
Epcor ~34,000 customers	<50 kVA (28,000 customers) No demand charge	50 - 150 kVA (4,000 customers)	150 kVA - 5 MVA (2,000 customers + 110 primary)	>5 MVA (20 customers: site-specific rates)
SaskPower ~60,000 customers	<75 kVA	75 - 2 MVA	>2 MVA	
Manitoba Hydro ~69,000 customers	<200 kVA	>200 kVA (31 customers)		
Hydro One ~119,000 customers	<50 kW (111,000 customers) No demand charge	>50 kW (8,000 customers)		
Hydro Ottawa	<50 kW	50 - 1500 kW	1500 kW - 5 MW	>5 MW

156 Table 4-1 was presented as Table 1 in section 1 of BC Hydro's Workshop 8a/8b consideration memo (Appendix C-4A). Note the following:

- Table 4-1 has been corrected to remove the reference under Manitoba Hydro that defines a small general service class as 50 kVa. The Manitoba Hydro small general service class is defined by demand ≤ 200 kVa. Customers within that class face an inclining block demand charge, but for demand less than 50 kVa there is no charge under that structure; and
- Table 4-1 has also been corrected to remove the reference under Newfoundland Power that the small general service class does not pay a demand charge; rather, customers face a seasonal demand charge as reported in Table 1 of the Workshop 8a/8b consideration memo.

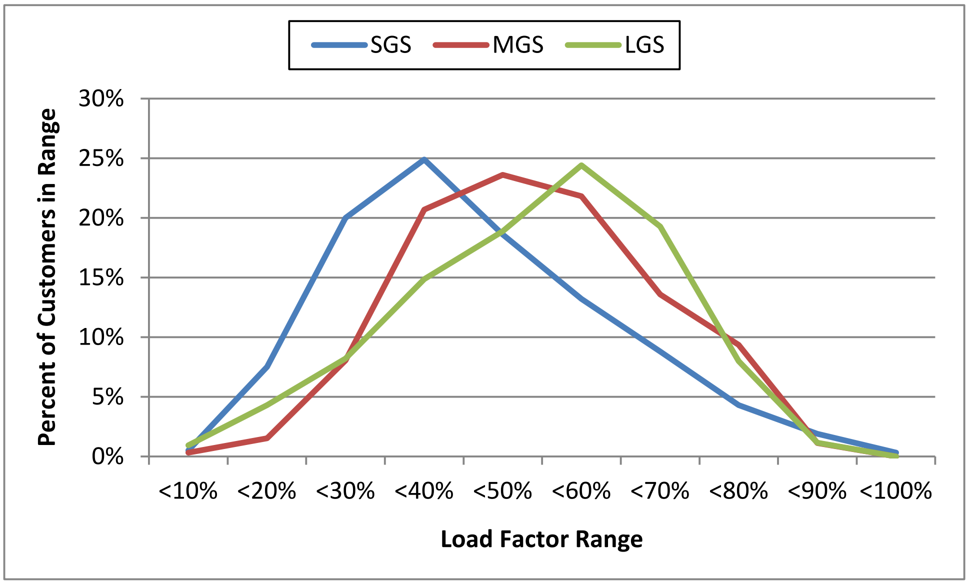
157 As noted in footnote 11, Manitoba Hydro defines its small general class as demand ≤ 200 kVa, but for demand less than 50 kVa there is no demand charge.

Utility/Number of General Service Customers	Small	Medium	Large	Extra Large
~27,000 customers	(24,000 customers) No demand charge	(3,000 customers)	(76 customers)	(11 customers)
Toronto Hydro ~81,000 customers	<50 kW (69,000 customers) No demand charge	50 - 1000 kW (12,000 customers)	1 - 5 MW (440 customers)	>5 MW (49 customers)
Hydro Quebec ~311,000 customers	<65 kW (287,000 customers)	>50 kW (24,000 customers)	>5 MW (100 customers)	
Newfoundland Power ~22,000 customers	<10 kW (12,000 customers)	<100 kW (9,000 customers)	110 - 1000 kVA (1,000 customers)	>1000 kVA (65 customers)

- As described in section 1.2 of the Workshop 8a/8b consideration memo at Appendix C-4A, no stakeholder questioned the existing 35 kW breakpoint for the SGS rate class; and
- The smallest general service customers tend to have lower load factors than MGS and LGS customers, as shown in Figure 4-1 below. Load factor is a customer's average demand divided by their peak demand. Low load factors are indicative of customers that are relatively more costly to serve, and load factor is therefore a consideration when evaluating rate class segmentation.[158] Cumulatively, more than 50 per cent of SGS customers have a load factor under 40 per cent, while that same load factor range applies to only around 30 per cent of MGS and LGS customers.

[158] Refer to page 14 of the Workshop 8a/8b Consideration memo at Appendix C-4A.

Figure 4-1 Load Factor Ranges for General Service Customers



4.3.2 Medium General Service/Large General Service

4.3.2.1 Existing LGS/MSG Breakpoint

The history of the existing LGS/MGS breakpoint is canvassed in section 1 of the Workshop 8a/8b consideration memo and summarized here. E3 recommended in 2009 that BC Hydro continue to use kW demand intervals (e.g., below 35 kW, above 35 kW) as the basis for General Service rate class segmentation. E3 found that 118 of 123 General Service rate schedules reviewed across Canada and the U.S. use kW demand to determine a General Service rate schedule's applicability. E3 also found that statistical clustering of cost data indicated there are two potential segmentation breakpoints: 100 kW and 150 kW. The 2009 LGS Application, discussed in section 2.3.1.7 of the Application, used the 150 kW breakpoint.[159]

As described in Workshop 11A, BC Hydro determines the majority of its costs to be driven by the three primary customer load characteristics set out in Table 4-2.

[159] The additional energy basis for segmenting between LGS and MGS arose from the 2009 LGS Application NSA; refer to sections 3 and 4 of Appendix B to Commission Order No. G-110-10.

Table 4-2 Customer Load Characteristics

Cost Classification	Allocator	Percentage of Costs for General Service Rate Classes (%)
Generation Energy	kWh	45.5
Generation & Transmission Demand	4CP	30.1
Distribution Demand	NCP	18.2

BC Hydro's COS methodology allocates Generation energy costs to rate classes on a per kWh basis which does not vary by time period or customer size. Since all customers have the same generation energy cost of service (on a dollar per kWh basis), energy costs are not a driver for rate class segmentation.

Generation and Transmission demand costs are allocated to rate classes by each rate class's peak demand during the four winter months (coincident peak demand). Based on the F2016 COS, more than 30 per cent of BC Hydro's total costs and 66 per cent of demand-related costs are allocated based on coincident peak demand. Other things being equal, customers with higher coincident peak demands will have a higher cost of service. Therefore, a customer's coincident peak demand is a major consideration in segmenting rate classes.

Distribution demand costs are allocated to rate classes by each rate class's annual NCP. For the segmentation study, BC Hydro used each customer's or subgroup's contribution to the NCP of their respective existing class (SGS, MGS, or LGS). Like coincident peak demand, customers with higher NCP demand will have a higher cost of service. However, since Distribution costs are assigned proportionate to NCP, the cost per NCP kW does not vary and a $/kW analysis cannot be used to identify cost differences between segments.

The jurisdictional review revealed that most Canadian jurisdictions segment general service customers into larger and smaller general service categories, with three general service rate classes appearing to be most common.

BC Hydro undertook two COS-based analyses for purposes of examining whether the existing MGS/LGS breakpoint remains appropriate:[160]

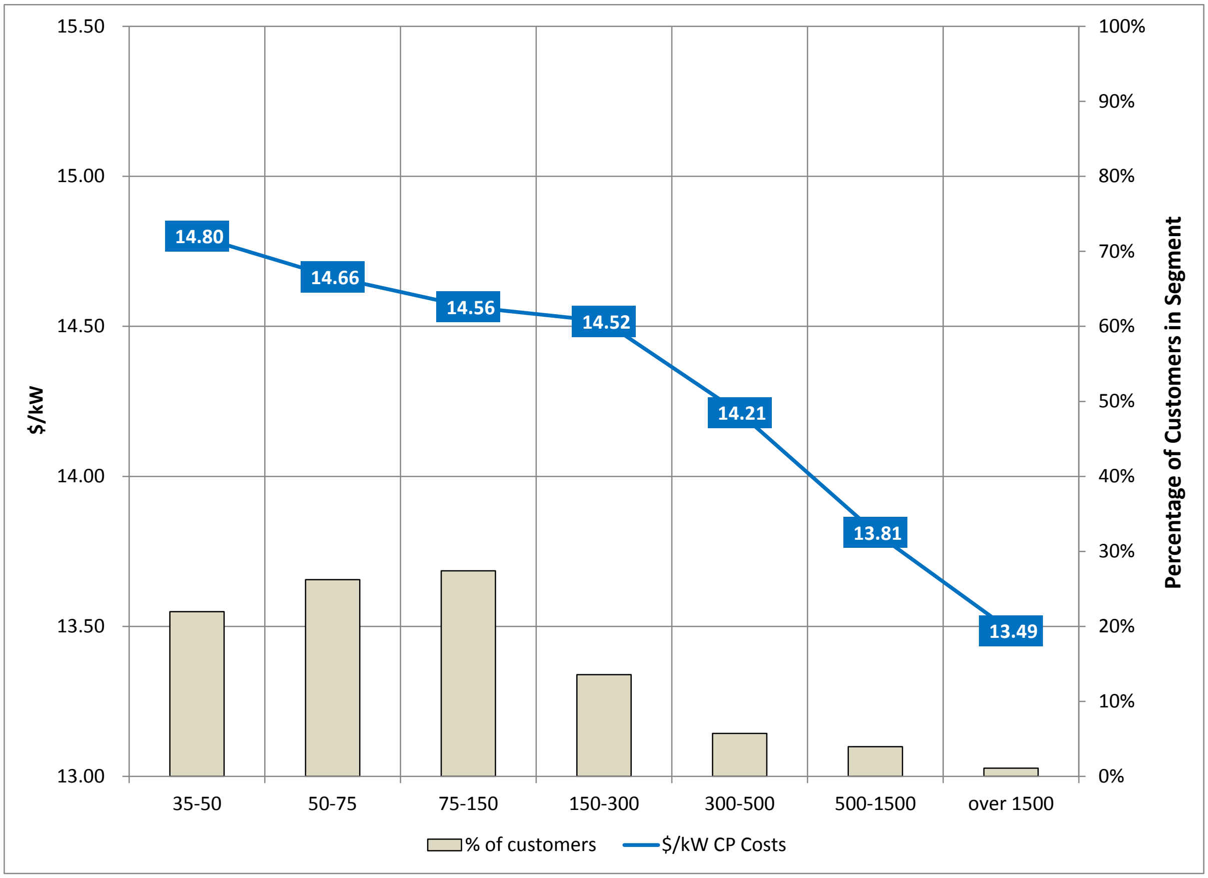
- Individual customer by sampling (**Method 1**) – As described in section 1.2 of the Workshop 8a/8b consideration memo (Appendix C-4A), BC Hydro analyzed a random sample of 1,000 customers from each of its SGS, MGS, and LGS rate classes. The results of Method 1 were not conclusive;[161] and
- Customer Clustered by Size (**Method 2**) – As presented at Workshop 12, this consisted of cost analyses for clusters of customers based on the size of their annual peaks. The Method 2 cost analysis showed no compelling reason to deviate from the 150 kW breakpoint.

As discussed earlier, customer demand at the time of the 4CP coincident peaks is a major driver of differences in customer cost of service. Figure 4-2 below shows the total coincident peak demand costs for each customer group divided by the NCP demand of the group. The coincident demand costs, associated with the Generation or Transmission functions, were found to generally decline with customer size on a dollar per kW basis for LGS and MGS customers. However, it is difficult to pinpoint a clear breakpoint in the downward trend of unit costs on a dollar per kW coincident peak basis that would justify additional segmentation within these classes.

[160] Refer to slides 33 to 38 of the Workshop 12 presentation at Appendix C-1B for details concerning the analysis methodology.

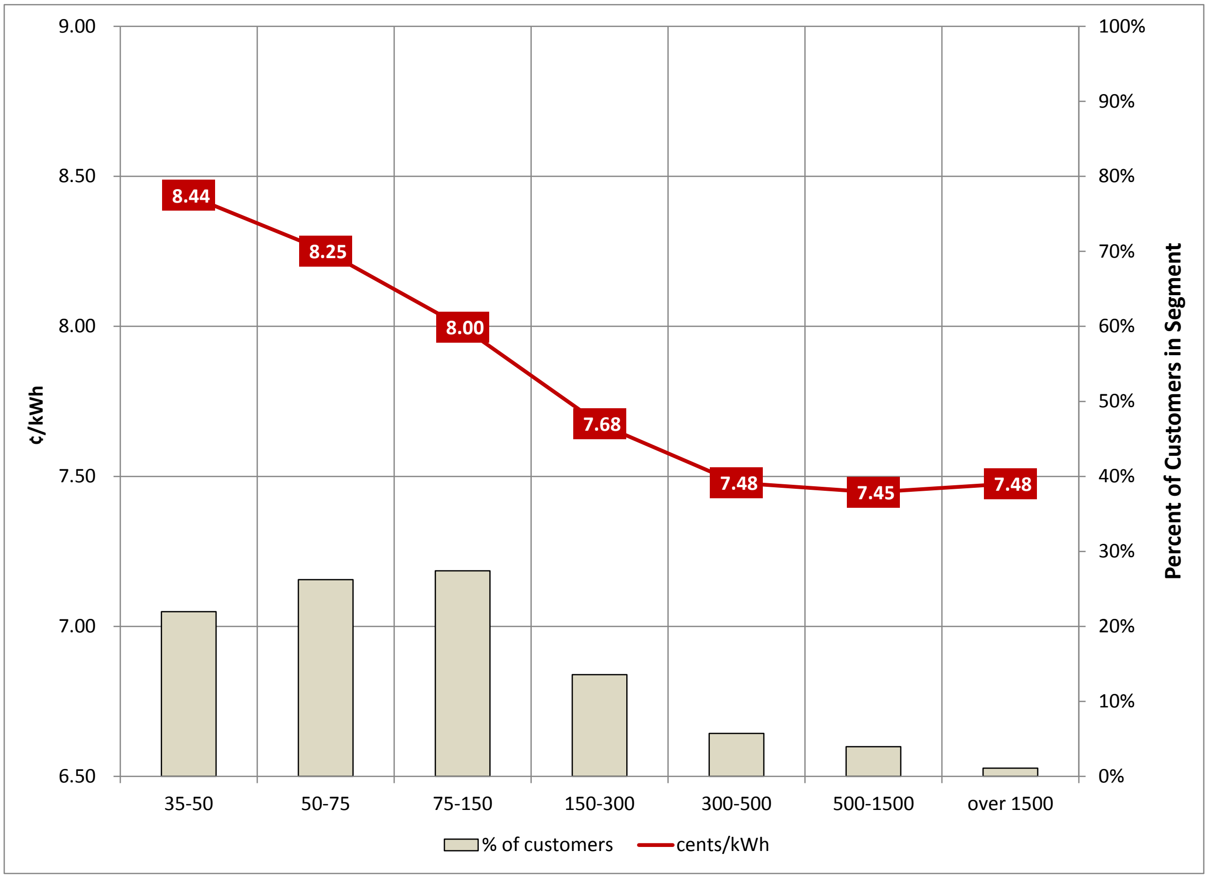
[161] Refer to page 18 of the Workshop 8a/8b Consideration memo at Appendix C-4A.

Figure 4-2 Coincident Peak $/kW Cost by Segment



In Figure 4-3 below, BC Hydro supplements the analysis presented at Workshops 8a/8b and 12 with analysis of the full COS (energy, demand and customer costs) allocated to the same segments on a dollar per kWh basis. Because the MGS and LGS customers tend to have higher load factors as size increases, the average COS of each group declines with size. Because of the smooth nature of the decline, there is no compelling reason to deviate from the current 150 MW breakpoint, which is consistent with the conclusion from Figure 4-2 above.

Figure 4-3 Cents per kWh Cost by Segment



For these reasons, and based on stakeholder input discussed below, BC Hydro proposes to maintain the existing breakpoint between the MGS and LGS rate classes.

As described in section 2.2.3.2 of the Application, while BC Hydro considered all input it received, where it conflicts BC Hydro gave more weight to the views of customers in the rate class who take service under the particular rates being assessed except on issues where there could be cost implications to other rate classes. Given that forecast revenue neutrality is used for the SGS, MGS and LGS rates, and given the Rate Rebalancing Amendment discussed in section 2.2.1.3 of the Application, there are no cost implications to other rate classes with respect to General Service segmentation issues. Accordingly, BC Hydro gave weight to the views of AMPC who represents some LGS customers, CEC, and individual LGS and

MGS customers. In its Workshop 11a/11b feedback, CEC states that there appears to be no evidentiary basis to improve upon the status quo, and therefore CEC concludes that status quo segmentation of the General Service rate classes should be maintained. AMPC does not contest the existing MGS/LGS breakpoint, and no LGS or MGS customer suggested the existing breakpoint is inappropriate.

4.3.2.2 Potential Extra Large General Service Class

For RDA Module 2 purposes, BC Hydro committed to further explore the appropriateness of segmenting some of the largest LGS customers, perhaps those greater than 2 MW, into a separate rate class.

AMPC and a LGS customer, Viterra, suggested at Workshop 8b that BC Hydro consider proposing a separate large LGS segment with the ability to define and adjust baselines annually, similar to RS 1823. There is jurisdictional support for a XLGS rate class; for example, FortisAlberta has a 2,000 kW General Service breakpoint; Epcor has a 5,000 kW breakpoint; SaskPower has a 2,000 kW breakpoint; Toronto Hydro has a 5,000 kW breakpoint; and Hydro Quebec has a 5,000 kW breakpoint.[162]

BC Hydro assessed the cost basis for the creation of a XLGS rate class with demand greater than 2,000 kW. As described above in section 4.3.2.1, it is difficult to pinpoint a clear breakpoint where the downward trend in the per unit COS begins.

A 2,000 kW breakpoint would encompass 172 LGS accounts.[163] The XLGS segmentation issue is connected to the feasibility of administering a LGS TSR-Like rate for 172 or so accounts; this is described in section 6.4.4.2 of the Application. BC Hydro commits to undertaking additional engagement with AMPC and LGS customers who potentially would take service under a LGS TSR-Like Rate, and bringing forward its analysis and proposal as part of RDA Module 2.

[162] Refer to slide 15 of the Workshop 11a presentation slide deck at Appendix C-4A of the Application.
[163] This data is based on LGS account peak demand in calendar year 2014.

4.3.2.3 Re-Merging the Medium General Service and Large General Service Rate Classes

The majority of stakeholders at Workshops 8a/8b and Workshop 11 commented that it was premature to consider re-merging the LGS and MGS rate classes given the uncertainty as to the respective default rate structures to be set by the Commission through its RDA Module 1 decision, and in particular whether the Commission-approved rate structures for LGS and MGS differ. As part of its Workshop 8a/8b feedback, Loblaws Companies Limited (**Loblaws**), with LGS and MGS accounts, commented that re-merging the LGS and MGS rate classes is not necessary at this time. TransLink, with LGS and MGS accounts, stated that re-merging the two rate classes should only be considered if the same rate design is approved by the Commission for both classes. BC Hydro agrees with these comments and opposes re-merging the LGS and MGS rate classes at this time.

In addition, as noted in the Workshop 11a/11b consideration memo at Appendix C-4B, eliminating the existing MGS/LGS split would lead to significant bill impacts for LGS customers. Figure 4-4 and Figure 4-5 below illustrate the bill impacts to MGS and LGS customers respectively.[164] As noted in section 2.4.1.1 of the Application, BC Hydro uses the 10 per cent bill impact test as an 'amber signal'.

- MGS customers: Other than the extremely low load factor, low consumption customers, all other MGS customers have a bill impact less than the RRA rate increase, or a much lower bill than otherwise. About 4,000 MGS accounts (20 per cent of MGS accounts) have F2017 bill impacts of 10 per cent or greater.

[164] F2017 estimated rates for the merged MGS-LGS class are: Demand charge: $9.24/kW; Energy rate: 6.08 cents/kWh; Basic charge: $0.2347/day (same as F2016 status quo MGS and LGS rates). The rates are computed assuming BC Hydro's preferred demand charge cost recovery of 35 per cent for MGS and 65 per cent and demand charge cost recovery for LGS.

Figure 4-4 Re-Merged MGS Bill Impacts

Annual Consumption (kWh)

Load Factor (%)

	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	82.9%	87.2%	37.7%	26.0%	20.8%	11.9%	4.3%	1.6%	-0.4%	-1.9%	-3.0%	-3.9%	-4.7%	-5.3%	-5.8%	-6.3%	-6.7%
20%	23.8%	24.9%	25.2%	11.8%	5.8%	2.4%	0.6%	2.6%	4.1%	4.5%	2.6%	1.0%	-0.2%	-1.2%	-2.1%	-2.8%	-3.5%
30%	4.1%	4.1%	4.1%	4.1%	-1.7%	-5.1%	-7.0%	-5.0%	-3.4%	-2.1%	-1.1%	-0.2%	0.5%	1.2%	0.3%	-0.6%	-1.4%
40%	-5.7%	-6.2%	-6.4%	-6.4%	-6.5%	-9.6%	-11.5%	-9.4%	-7.8%	-6.5%	-5.5%	-4.6%	-3.9%	-3.2%	-2.7%	-2.2%	-1.7%
50%	-11.6%	-12.5%	-12.7%	-12.8%	-12.8%	-12.8%	-14.4%	-12.4%	-10.8%	-9.5%	-8.4%	-7.5%	-6.8%	-6.1%	-5.6%	-5.1%	-4.6%
60%	-15.6%	-16.6%	-16.9%	-17.0%	-17.0%	-17.1%	-16.8%	-14.5%	-12.9%	-11.6%	-10.5%	-9.6%	-8.9%	-8.2%	-7.6%	-7.1%	-6.7%
70%	-18.4%	-19.6%	-19.9%	-20.0%	-20.1%	-20.1%	-19.8%	-16.3%	-14.4%	-13.1%	-12.1%	-11.2%	-10.4%	-9.8%	-9.2%	-8.7%	-8.3%
80%	-20.5%	-21.8%	-22.2%	-22.3%	-22.3%	-22.4%	-22.1%	-18.6%	-15.8%	-14.4%	-13.3%	-12.4%	-11.6%	-11.0%	-10.4%	-9.9%	-9.5%
90%	-22.1%	-23.5%	-23.9%	-24.0%	-24.1%	-24.1%	-23.9%	-20.5%	-17.8%	-15.5%	-14.3%	-13.4%	-12.6%	-12.0%	-11.4%	-10.9%	-10.4%

- LGS - Most customers see a substantial increase in their bills. About 1,400 LGS accounts (20 per cent of LGS accounts) have F2017 bill impacts of 10 per cent or greater.

Figure 4-5 Re-Merged LGS Bill Impacts

Annual Consumption (kWh)

Load Factor (%)

	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	-0.3%	-2.3%	-3.0%	-3.3%	-3.5%	-3.7%	-3.8%	-3.8%	-3.9%	-3.9%	-4.0%	-4.0%	-4.0%	-4.0%	-4.1%	-4.1%	-4.1%
20%	-1.9%	3.7%	2.6%	2.1%	1.7%	1.5%	1.4%	1.2%	1.1%	1.1%	1.0%	1.0%	0.9%	0.9%	0.9%	0.8%	0.8%
30%	-9.6%	7.8%	6.3%	5.6%	5.2%	4.9%	4.7%	4.6%	4.5%	4.4%	4.3%	4.2%	4.2%	4.1%	4.1%	4.1%	4.0%
40%	-14.1%	4.0%	9.0%	8.2%	7.7%	7.3%	7.1%	6.9%	6.8%	6.7%	6.6%	6.5%	6.5%	6.4%	6.4%	6.3%	6.3%
50%	-17.1%	1.1%	9.2%	10.1%	9.5%	9.2%	8.9%	8.7%	8.6%	8.4%	8.3%	8.3%	8.2%	8.1%	8.1%	8.0%	8.0%
60%	-19.2%	-0.9%	7.2%	11.5%	11.0%	10.6%	10.3%	10.1%	9.9%	9.8%	9.7%	9.6%	9.5%	9.5%	9.4%	9.3%	9.3%
70%	-21.3%	-2.4%	5.8%	10.4%	12.1%	11.7%	11.4%	11.2%	11.0%	10.9%	10.7%	10.6%	10.6%	10.5%	10.4%	10.4%	10.4%
80%	-23.6%	-3.6%	4.6%	9.3%	12.3%	12.6%	12.3%	12.0%	11.9%	11.7%	11.6%	11.5%	11.4%	11.4%	11.3%	11.3%	11.2%
90%	-25.3%	-4.5%	3.7%	8.4%	11.4%	13.3%	13.0%	12.8%	12.6%	12.5%	12.3%	12.2%	12.2%	12.1%	12.0%	12.0%	11.9%

4.3.2.4 Segmenting Municipalities, Universities, School Boards and Hospitals

As noted in section 1.2 of the Workshop 11a/11b consideration memo, BC Hydro undertook both a COS analysis and a jurisdictional review to respond to COPE 378's request that BC Hydro assess the merits of creating a new MUSH sector rate class:

- BC Hydro compared a sample of 353 MUSH customers[165] to a sample of 3,000 General Service customers. BC Hydro concludes that while MUSH entities tend to have lower load factors, they have similar levels for coincidence factor (which drives demand cost allocation), as compared to the General

[165] BC Hydro used the North American Industry Classification System codes for Educational Services, Health Services, Municipal Pumping, Public Hospital, Public School and University/College.

Service sample.[166] Given the comparison, BC Hydro concludes there is not a cost basis to segment MUSH customers;

- No surveyed Canadian electric utility separates the MUSH sector for COS and rate class purposes. Yukon Electrical Company Limited (**YECL**) has separate rate schedules for municipal and federal/territorial governments,[167] and rates are typically equivalent or higher than the corresponding non-government General Service rates.

4.4 Transmission Service Rate Class

BC Hydro proposes no changes to the existing Transmission Service rate class for Module 1 purposes.

The sole issue concerning the existing Transmission Service rate class arising from the 2015 RDA stakeholder engagement processes concerned whether FortisBC and New Westminster should be separated out as unique rate class(es) within the COS. The treatment of FortisBC and New Westminster for rate class purposes was not raised as an issue in the 2007 RDA proceeding. The load profiles from both FortisBC and New Westminster were not separately taken into account as part of the allocation of Generation and Transmission demand-related costs as part of the 2007 RDA COS study. Rather, individual load profiles for all industrial and commercial Transmission Service customers were summed and then scaled to match the energy sales from industrial Transmission Service, commercial Transmission Service, and sales to other utilities including New Westminster and FortisBC. BC Hydro is now using specific load profile information for New Westminster and FortisBC in the F2016 COS study.

4.4.1 BC Hydro Assessment and Stakeholder Comment

The following inputs informed BC Hydro’s assessment of whether Fortis BC and New Westminster should be separated out as rate class(es) within the COS:

[166] Refer to Figure 6 in the Workshop 11a/11b consideration memo at Appendix C-4B.
[167] https://www.yukonenergy.ca/customer-centre/commercial-wholesale/rate-schedules/.

- Prior BC Hydro COS treatment. As reported at Workshop 12 and in section 3.2 of the Workshop 10 consideration memo (found at Appendix C-5B), in the 1991 COS there was a separate rate class for West Kootenay Power and Light Company (now FortisBC). This class continued to be identified separately in BC Hydro's COS study submitted to the Commission on June 19, 1998. For the 2007 RDA, BC Hydro's COS study used a single Transmission voltage rate class capturing all customers served at transmission voltage whether they are industrial (forestry, chemical plants), commercial (universities, pipelines) or other utilities purchasing power from BC Hydro (FortisBC and New Westminster);
- Jurisdictional assessment. BC Hydro undertook review of other Canadian electric utilities to determine how they treat sales to other utilities for COS/rate class purposes. FortisBC resells power to municipal utilities within its service territory and FortisBC identifies these utilities as a separate rate class within its 2009 COS study.[168] Other surveyed utilities have separate rate classes for "other utility sales" in their COS studies. An example is SaskPower's 2013 COS study and related 2014-2015-2016 Rate Application, which considers sales to the cities of Saskatoon and Swift Current as part of a separate Reseller rate class;[169]
- Analysis of the load profiles of FortisBC, New Westminster and the remaining Transmission Service customers. For the Workshop 5 consideration memo found at Appendix C-5A, BC Hydro developed a graph[170] showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service

[168] Refer to Appendix A, page 12 of FortisBC's 2009 RDA; http://www.bcuc.com/Documents/Proceedings/2009/DOC_23627_B-1_FortisBC%202009%20Rate%20Design%20Application.pdf. The Commission decided that all of FortisBC's wholesale customers should be a single rate class for COS purposes; refer to the 2009 FBC RDA Decision, page 18.

[169] Section 4.0 of SaskPower 2014-2015-2016 Rate Application (October 2013); http://www.saskpower.com/wp-content/uploads/2014-15-16_rate_application.pdf.

[170] Refer to Figure 7 on page 61 of the Workshop 5 Consideration Memo at Appendix C-5A.

customers.[171] FortisBC and New Westminster have much lower load factors (e.g., FortisBC has a load factor around 35 per cent and New Westminster has a load factor of about 55 per cent) and have load shapes that are highly coincident to BC Hydro's system peak. BC Hydro notes that a few other Transmission Service customers have either load factors or coincident factors comparable with New Westminster and FortisBC; however, these customers are relatively small with the largest purchasing about 30 GWh per year as opposed to annual consumption between 450 GWh and 500 GWh from the two utilities;

- Individual Customer R/C ratio analysis. In an effort to assess intra-class variability within the Transmission Service rate class, BC Hydro used F2014 hourly load data for each Transmission customer to assign F2016 costs to individual customers on a pro rata basis using common allocators from the F2016 COS study. More than 100 Transmission Service customers were included in the analysis. The table found at slide 40 of the Workshop 12 presentation (found at Appendix C-1B) showed there is a variation in R/C ratios by industry within the Transmission Service class. The differences are primarily attributable to differences in coincidence factor, customer load factor, and whether the customer has displaced Tier 2 purchases if they are on RS 1823; and
- The stakeholder input described below.

Table 4-3 below summarizes the differences between New Westminster, FortisBC and the remaining Transmission Service customers using forecast energy sales and revenue for F2016 and averaged actual load profile information from the five year period between F2010 and F2014 to calculate load factor and coincidence factors.

[171] Figure 7 of the Workshop 5 Consideration Memo compared the winter peak loads against load factor and showed that three of the exempt customers – UBC, SFU and YVR – are not that different from other Transmission voltage customers.

Table 4-3 Summary of FortisBC/New Westminster Characteristics and R/C Ratios

	FortisBC	New Westminster	Remaining Transmission Service Customers
Energy sales (GWh)	541	475	13,995
Revenue ($ million)	35.8	27.3	654
Coincidence Factor (%)	86	90	90
Load Factor (%)	37	57	86
Individual R/C Ratios (%)	86.6	89.7	102.7
Combined Transmission Service R/C Ratio (%)	101.5		

As noted in section 3.2 of the Workshop 10 consideration memo, BC Hydro communicated the possibility of separate rate class treatment to New Westminster and FortisBC before Workshop 12:

- New Westminster was notified on July 15, 2015. BC Hydro also met with New Westminster on July 29, 2015 to discuss among other things separate rate class treatment; and
- FortisBC was notified on July 3, 2015.

BC Hydro consulted on the issue of segmenting the Transmission Service rate class during Workshop 12 and distributed the following table for stakeholder comment:

Table 4-4 Summary of New Westminster/FortisBC Segmentation Pros and Cons

	DESCRIPTION	DISCUSSION
Alternative 1: Preferred at time of Workshop 12	Create separate rate classes for both FortisBC and New Westminster in the COS study	It is common for other utility sales to be placed in a separate rate class in COS studies; Previous BC Hydro COS studies considered other utility sales as a separate rate class; The load factors of both of these utilities more resemble a residential customer rather than an industrial customer; Both customers are large relative to the Transmission Service rate class average; Enhances transparency; Two separate rate classes would be more appropriate than one separate rate class because FortisBC has generation and market access, and a hybrid utility/customer relationship with BC Hydro (confirmed in Commission's RS 3808 Decision and discussed in section 2.5 of the Application) while New Westminster has no generation assets and a customer relationship with BC Hydro (New Westminster purchases all of its power from BC Hydro)

	DESCRIPTION	DISCUSSION
Alternative 2	Create a combined "Other utility sales" rate class for these two utilities	Simpler than Alternative 1
Alternative 3	Status quo – FortisBC and New Westminster remain in the Transmission Service rate class	Simpler than Alternatives 1 and 2 Removing FortisBC and New Westminster from the Transmission Service rate class results in a small 1.2 percentage point increase in the R/C ratio of the remaining Transmission Service customers relative to the combined rate class (102.7% vs. 101.5%); The analysis on slide 40 of the Workshop 12 presentation showed that the differential between an individual customer's R/C ratio and the Transmission Service rate class average is greater for some customers (#12 and #13 on Slide 40) than it is for these two utilities; however #12 and #13 are smaller than the two utilities.

BC Hydro also sought feedback on whether it is more appropriate to wait for the F2019 COS filing, as it proposed at Workshop 12, since the potential impacts of creating separate rate classes for FortisBC and New Westminster (such as possible rate rebalancing from F2020 onward if appropriate) will be better understood at that time. The following participants submitted written comments on this topic (copies at Appendix C-1B):

Transmission Service Rate Class Customers/Customer Organizations

- New Westminster submits that the status quo should be maintained until the F2019 COS, at which time the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood. New Westminster further comments that given the Rate Rebalancing Amendment, taking steps to change the rate class status of New Westminster at this time adds no particular value. New Westminster also states that there are no benefits associated with creating two new rate classes, each consisting of one customer; the result would be administrative costs and burdens and unnecessary complexity. Finally, New Westminster questions the R/C ratio analysis provided at Workshop 12;
- FortisBC states that any consideration of separate rate class treatment for FortisBC and New Westminster should be deferred to the F2019 COS so that

potential impacts can be better understood. FortisBC agrees with New Westminster that given the Rate Rebalancing Amendment, expending resources on this topic at this time is of little value; and

- AMPC continues to be of the view that New Westminster and FortisBC should be separated from the remainder of the Transmission Service rate class on the basis that these two utilities have lower load factors and higher coincidence factors than the ‘typical’ Transmission Service customer, and higher costs to serve as shown in Table 4-3 above. AMPC states that BC Hydro is unusual in not having a wholesale rate class to serve large municipalities outside its service area. Finally, AMPC echoes Commission staff’s point below that there has effectively been recognition of the differences between New Westminster and FortisBC and the remainder of the Transmission Service rate class through the setting of different rates for these two utilities while most of the remainder of the Transmission Service rate is served on RS 1823.

Other Participants

- Neither BCSEA nor BCOAPO take a position on this issue at this time; and
- Commission staff commented that New Westminster and FortisBC are already effectively segmented from the rest of the Transmission Service rate class given that they take service under RS 1827 and RS 3808, respectively, and the inability of the Commission to order that New Westminster take service on RS 1823 or a stepped rate. Commission staff asked that BC Hydro outline the pros and cons of the potential segmentation. This BC Hydro has done in Table 4-4 above.

4.4.2 BC Hydro Proposal

BC Hydro proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS. BC Hydro agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the

F2019 COS. BC Hydro will provide the individual R/C ratios for New Westminster and FortisBC, its recommended treatment of them and further analysis supporting its position as part of the F2019 COS Study.

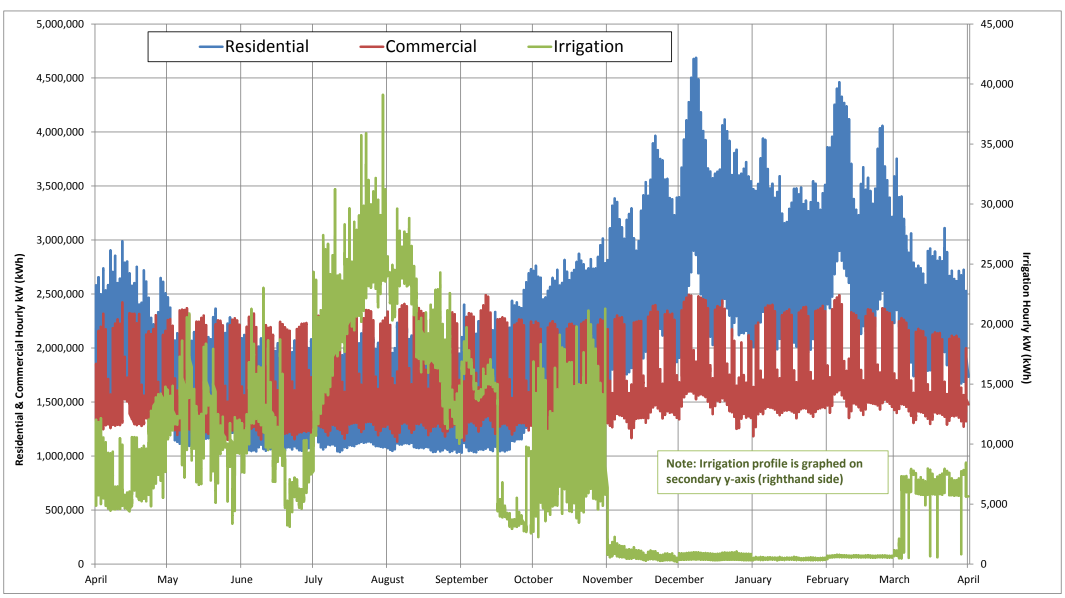
4.5 Irrigation Rate Class

BC Hydro has had an Irrigation rate class since at least the 1989 COS study.

BC Hydro proposes no changes to the existing Irrigation rate class for Module 1 purposes:

- No segmentation issues with the Irrigation rate class were identified during the 2015 RDA stakeholder engagement processes; and
- Customers in the Irrigation rate class have summer peaking load profiles and no allocation of 4CP-related costs in the F2016 COS study, which differentiates this class from the Residential and General Service rate classes. Refer to Figure 4-6 below:

Figure 4-6 Irrigation Rate Class Peak Profile



- BC Hydro's proposal aligns with the Commission's 2009 FBC RDA Decision, which approved continued treatment of FortisBC's irrigation customers as a separate rate class for COS purposes on the basis that FortisBC irrigation and General Service customers have different characteristics with respect to their power supply and infrastructure requirements that cause them to drive costs on FortisBC's system differently.[172] Both ATCO Electric[173] and FortisAlberta,[174] which serve the majority of the rural areas in Alberta, offer a seasonal irrigation rate, as does SaskPower.[175]

The Irrigation rate, RS 1401, is available to customers with motor loads of 746 watts or more used for irrigation and outdoor sprinkling where electricity will be used primarily during the Irrigation Season, defined as the period between March 1 and October 31 (BC Hydro has the discretion to extent the season to a date not later than November 30). In the 2007 RDA Decision,[176] the Commission urged BC Hydro to consider the suitability of RS 1401 for municipal and hotel/golf course customers. As part of RDA Module 2, BC Hydro will review RS 1401 customer availability.

4.6 Street Lighting

As part of Module 1, BC Hydro proposes to divide the Street Lighting class into two rate classes: BC Hydro-owned Street Lighting and Customer-owned Street Lighting. BC Hydro will examine street lighting rate design as part of RDA Module 2.

Currently BC Hydro has a single Street Lighting rate class for customer-owned and BC Hydro-owned street lights. Depending on who owns and maintains the assets, BC Hydro offers customers different street lighting rates and services as part of a single Street Lighting rate class as shown in Table 4-5 below.

[172] At page 18 of the 2009 FBC RDA Decision.
[173] Refer to Price Schedule D25; http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Documents/Electricity/ATCO%20Electric/Appendix%204%20-%202015%20rate%20schedules.pdf.
[174] Refer to Rate 29; http://www.fortisalberta.com/residential/customerservice/rates/Pages/Rates.aspx.
[175] Refer to Rate E-19 at http://www.saskpower.com/wp-content/uploads/farm_rates_2015.pdf.
[176] 2007 RDA Decision, page 202.

Table 4-5 Street Lighting Rate Schedules and Ownership

Rate Schedule	Description	Ownership	F2014 Revenue ($million)
RS 1701	Overhead Street Lighting	BC Hydro owns poles and street lights	17.5
RS 1702	Public Area Ornamental Street Lighting	Customer owns poles and street lights	14.0
RS 1703	Street Lighting Service	Customer owns street lights BC Hydro owns poles	1.0
RS 1704	Traffic Control Equipment	Customer owns poles and all traffic related devices	1.0
RS 1755	Private Outdoor Lighting (Closed)	BC Hydro or Customer owns poles BC Hydro owns fixtures	1.1

Differences in ownership and maintenance of street lighting assets drive variation in the cost of serving street lighting customers. Significant differences in the nature of service to a particular customer are often justification for the creation of separate rate classes. The Commission determined at page 203 of the 2007 RDA decision that:

> Given the difference in connection requirements (cost of fixtures) between the two groups, the significant difference in R/C ratios, and the lack of evidence as to how the cost differences were taken into account in rates design, the Commission Panel requests BC Hydro to separate street lighting into two or more classes and to calculate R/C ratios for each class in its next [Fully Allocated COS] or rate design filing.

The draft F2016 COS study identified an overall Street Lighting rate class R/C ratio of 135 per cent. This is higher than values reported in past COS studies for three main reasons:

1. As part of managing its costs BC Hydro replaced its group re-lamping program, which previously changed out all BC Hydro-owned street lights on a five-year

cycle, with a spot repair program that replaces individual street lights at end of life. As a result, annual O&M spending is likely to be lower in the short term;[177]

2. Street lighting is one of the most significant unmetered loads on the BC Hydro system. The class' share of system energy sales and demand-related costs is estimated using aggregate billing information and high level load research profiles. Given the unmetered nature of the service, there is more uncertainty surrounding the allocation of energy and demand costs to this class of customers than to other rate classes in the COS study; and

3. In recent years the rate base for BC Hydro-owned street lights remained relatively constant while revenues have risen primarily because of rate increases. The F2016 COS study uses this rate base to assign customer owned lights a proportionate share of capital costs (taxes, financing, depreciation and RoE) related to these distribution assets.

Together these factors result in a declining allocation of costs to the Street Lighting rate class in F2016 despite consistently rising revenue due to annual rate increases. The net result is a rising R/C ratio.

BC Hydro explored this issue in more detail and separately calculated the costs of serving RS 1701 and RS 1755 lights from the rest of the Street Lighting rate class. This includes a direct allocation of costs associated with the ownership and maintenance of BC Hydro-owned fixtures. BC Hydro has not calculated separate R/C calculations for each of the remaining street lighting rates as the nature of the service is similar between RS 1702/RS 1703/RS 1704 (i.e., customers own and maintain the street lighting fixture assets). The results of this analysis were presented on slide 41 of the Workshop 12 presentation found at Appendix C-1B. As shown in Table 4-6, BC Hydro currently estimates R/C ratios of 175 per cent for BC Hydro-owned lighting and 105 per cent for customer-owned street lighting.

[177] Short term refers to the five years after implementation. The cost of serving BC Hydro owned street lighting is about $11.5 million dollars. Even a $1 million change in O&M costs can cause up to a 10 percentage point swing in the R/C ratio for this group of customers.

Table 4-6 Street Lighting R/C Ratios

Rate Class	R/C Ratios (%)
Street Lighting – BC Hydro-owned	175
Street Lighting – Customer-owned	105

Given the significant differences in these R/C ratio estimates, the fact that BC Hydro-owned street lights account for 50 per cent of revenue from the Street Lighting class, and the Commission's 2007 RDA request noted above, BC Hydro believes there is a strong basis for creating a separate rate class for BC Hydro-owned street lighting.

BC Hydro will examine street lighting rate design as part of RDA Module 2. BC Hydro notes that it is actively exploring high efficiency Light Emitting Diodes technology through a DSM pilot program, which is expected to run from fall 2015 to fall 2016, to determine if additional options can be offered to BC Hydro-owned street lighting customers to lower their costs.

BC hydro

2015 Rate Design Application

Chapter 5

Residential Rate Design

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5.1 Introduction and Chapter Structure

This chapter consists of two parts.

Part 1 contains BC Hydro's proposals for the Residential default rate, which is currently the RIB rate (RS 1101/RS 1121), and the Residential E-Plus rate (RS 1105). As identified in section 1.5.2 of the Application, RDA Module 2 will address: (1) RS 1151/RS 1161 (Exempt Residential Service) as it is used in part for farm service; (2) RS 1107/RS 1127 (Residential Service – Zone II) and RS 1148 (Residential Service – Zone II (Closed)), which are the Residential Zone II rates (NIA); and (3) potential Residential rate options.

Part 1 is organized as follows:

- Section 5.2 – Default Residential rate. Section 5.2.1 identifies the RIB rate as BC Hydro's preferred default Residential rate. Section 5.2.2 provides background to the current RIB rate, while section 5.2.3 summarizes the results of *Evaluation of the Residential Inclining Block Rate: F2009-F2012* (**2013 RIB Evaluation Report**).[178] Section 5.2.4 sets out the reasons why the RIB rate is BC Hydro's preferred default Residential rate. BC Hydro's proposal is based on the three prior Commission decisions concerning the RIB rate described in section 2.3.1.6 of the Application; stakeholder input (Workshop 3 and Workshop 9a/9b, the February 2015 residential focus group sessions and face-to-face meetings with BCOAPO and COPE 378); BC Hydro's Bonbright assessment including the residential rate jurisdictional review and the 2013 RIB Evaluation Report; and advice from E3. BC Hydro also includes in section 5.2.4 analysis on and discussion of a flat rate and a three step rate as the two viable alternatives to the RIB rate. In section 5.2.5, BC Hydro identifies its proposed RIB Pricing Principles (for RRA rate increases to the RIB rate pricing elements for F2017-F2019);

[178] Revision 2 dated June 2014; copy at Appendix C-3B of the Application.

- Section 5.3 – Residential E-Plus rate. As noted in section 1.1.3 of the Application, BC Hydro proposes to amend RS 1105 Special Condition 1 to provide a practical interruptible option on the basis of E-Plus customer and stakeholder input (including from the E-Plus engagement stream, an overview of which is found in section 2.2.3.5 of the Application with further details in section 5.3), assessment of other BC Hydro interruptible rate provisions, review of prior Commission orders concerning the Residential E-Plus rate and consideration of 2013 IRP Recommended Action 2 (to pursue DSM capacity initiatives such as demand response). As described in section 1.5.2 of the Application, BC Hydro will review the commercial E-Plus rates (RS 1205/1206/1207) as part of RDA Module 2; and
- Section 5.4 contains BC Hydro's legal and jurisdictional assessment of low income rates as communicated through the 2015 RDA stakeholder engagement processes. BC Hydro defines the phrase '**low income rates**' as rates pursuant to which low-income energy customers are charged a different rate for electricity. For purposes of the 2015 RDA, 'low income rates' does not include potential Electric Tariff low income terms and conditions discussed in section 8.6 of the Application, even though the definition of 'rate' in section 1 of the *UCA* includes such low income terms and conditions. BC Hydro understands from BCOAPO that through intervener evidence, BCOAPO will be proposing a specific low income rate that could be overlaid onto the default RIB rate. BC Hydro's consideration of such a low income rate will occur through IRs on such evidence, additional legal submissions and other processes as the regulatory review of RDA Module 1 unfolds.

Part 2 is comprised of the following:

- Section 5.5 - Information on the methodologies BC Hydro is using to gather information and report on the five questions posed in the Minister RIB Report Letter as requested by the Commission RIB Report Methodology Letter. BC Hydro proposes:

  - To define “low income customers” as BC Hydro Residential customers with a before tax annual household income equal to or less than the low-income cut-off established by Statistics Canada (**LICO**). LICO is used in the 2015 RDA engagement modelling and the 2014 REUS;
  - To define “factors” that lead to high energy use such as heating fuel type, dwelling type and region.
- Section 5.6 - Description of BC Hydro’s two existing low income DSM program offers given that one of the Minister’s questions concerns what options there are for additional DSM low income programs within the current regulatory environment, and to provide context for any examination of low income rates.

5.2 Residential Default Rate

5.2.1 BC Hydro’s Preferred Rate: Residential Inclining Block Rate

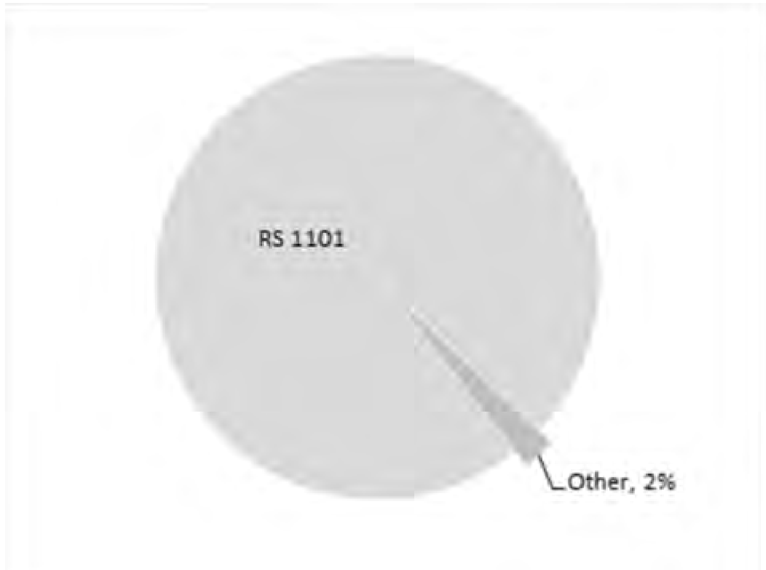
BC Hydro’s preferred default Residential rate is the RIB rate. In accordance with Direction 4 of Commission Order No. G-13-14, BC Hydro reviewed the RIB rate, as well as four alternative means of delivering the RIB rate (refer to section 5.2.5). BC Hydro also reviewed five alternatives to the RIB rate (refer to section 5.2.4) as a result of stakeholder comments at Workshops 1, 3 and 9a. As discussed below in section 5.2.3, the RIB rate encourages relatively higher energy consumers to consume less. The RIB rate is achieving its intended goal of delivering energy conservation through the simple two step rate structure. The RIB is expected to have delivered approximately 480 GWh/year in cumulative conservation over the first ten years of implementation (October 2008 through F2017).

5.2.2 Background

5.2.2.1 RIB Rate Background

The RIB rate (RS 1101/RS 1121) is the default Residential rate. Of the 1.7 million Residential rate class accounts (F2015), 98 per cent are served under RS 1101 as illustrated in Figure 5-1 below.

Figure 5-1 F2015 Residential Accounts



The F2016 RIB rate pricing is set out in Table 5-1.

Table 5-1 Existing RIB Rates (F2016)

Step 1 energy rate (for first 1,350 kWh in an average two-month billing period) (cents/kWh)	7.97
Step 2 energy rate (for all additional consumption) (cents/kWh)	11.95
Basic charge (cents/day)	17.64

As described in section 2.3.1.6 of the Application, the RIB rate was approved by Commission Order No. G-124-08[179] and made effective on October 1, 2008. The RIB rate is a two-step inclining block rate, with the first lower rate called the Step 1 energy rate and the second higher rate called the Step 2 energy rate:

- The Commission found that the RIB rate is a 'conservation rate' intended to show existing Residential customers the cost of new supply and to offer an incentive to reduce consumption. In the 2008 RIB Decision and the 2011 RIB Re-Pricing Decision (described in section 2.3.1.6 of the Application), the

[179] Commission Order No. G-124-08 was issued on August 28, 2008.

Commission determined that BC Hydro's LRMC for new supply is the appropriate referent for the Step 2 energy rate. BC Hydro's energy LRMC range for Distribution service customers is set out in Table 2-6 in Chapter 2. As noted in respect of the capacity LRMC discussion in section 2.3.2.3 of the Application, BC Hydro sets out both the upper end of the energy LRMC range, and the upper end of the energy LRMC range with a generation capacity value (the Rev 6 UCC), in various figures in this Chapter; and

- The Step 1 energy rate and basic charge are to be calculated residually to achieve revenue neutrality for the Residential rate class for the relevant period. The basic charge is a fixed daily charge to recover a portion of customer-related costs allocated to the Residential rate class such as billing and metering costs.

The Commission established the Step 1 energy rate/Step 2 energy rate threshold at 1,350 kWh per two-month billing period (referred to as the **Step 1/Step2 threshold**), being more or less 90 per cent of the median consumption of BC Hydro's Residential customers of about 760 kWh per month.[180] In support of this threshold the Commission cited RS 1823 which sets individual thresholds at 90 per cent of each customer's CBL.

As noted in section 1.1.3 of the Application, the current RIB rate pricing principles expire on March 31, 2016. In addition, the Commission Order No. G-13-14 contains directions relevant to or to be addressed as part of the 2015 RDA, summarized in Table 5-2.

[180] 2008 RIB Decision, *supra*, note 50 in Chapter 2, pages 106 to 107.

Table 5-2 Summary of 2013 RIB Re-Pricing Directions

Direction	Status
3 – BC Hydro is directed to file a report with the Commission, with copies to all interveners, concerning its decision with regard to the RIB control group re-establishment on or before the autumn of 2014	Completed – On October 27, 2014 BC Hydro reported to the Commission by way of letter on its evaluation of RIB control group re-establishment. A copy of this letter is found at Attachment 5 to the Workshop 9a/9b consideration memo at Appendix C-3B to the Application. COPE 378 expressed an interest in the RIB control group issue. At the June 29, 2015 meeting noted in section 2.2.3.4 of the Application, BC Hydro advised COPE 378 of the October 27, 2014 letter findings as follows. BC Hydro examined whether New Westminster, with a flat residential rate, could be an effective control group. New Westminster's climate and residential dwelling mix are different than those of many other regions in BC Hydro's service area (e.g., about 60 per cent of BC Hydro's residential accounts are SFDs versus 25 per cent in New Westminster). There are limitations in the New Westminster electricity billing data (e.g., limited tracking of housing type, no tracking of primary heating fuel type). BC Hydro was unable to obtain a reliable estimate of price elasticity of demand for New Westminster's flat rate. BC Hydro provided COPE 378 with a copy of the October 27, 2014 letter at this meeting (found at Appendix C-3D).
4 – BC Hydro is relieved from certain elements of Directive 4 of Order No. G-45-11 and shall file a rate design application in F2016 that includes the outstanding information required by Directive 4 of Order No. G-45-11: a. A revisit of the setting of the Step 1/Step 2 threshold; b. Evidence that the directives on page 120 of the 2008 RIB Decision: interaction of the basic charge and the RIB rate structure, as well as minimum charge and the cost of remaining attached to the system have been addressed; and c. A recommendation for a pricing principle to apply beyond F2016.	Direction 4a, b and c are addressed in section 5.2.5: • Section 5.2.5.1: BC Hydro's preferred pricing principle for F2017-F2019 is to continue with the Order No. G-13-14 pricing principle of uniformly increasing the Step 1 energy, the Step 2 energy rate and the basic charge by the amount of the approved RRA rate increases effective April 1, 2016, 2017 and 2018; • Sections 5.2.5.2/5.2.5.3: BC Hydro examined the interaction of the basic charge with the RIB rate structure, and rejects an increase in the basic charge recovery of customer-related costs. BC Hydro also considered whether a minimum charge should be implemented, separate from the basic charge, to reflect the cost of remaining attached to the system during periods of very low consumption or dormancy. BC Hydro has decided to not pursue a separate minimum charge; • Section 5.2.5.4: BC Hydro modelled a range of both increases and decreases to the Step 1/Step 2 threshold. BC Hydro sees no compelling reason to change the Step 1/Step 2 threshold.

5.2.2.2 *Residential Class Characteristics*

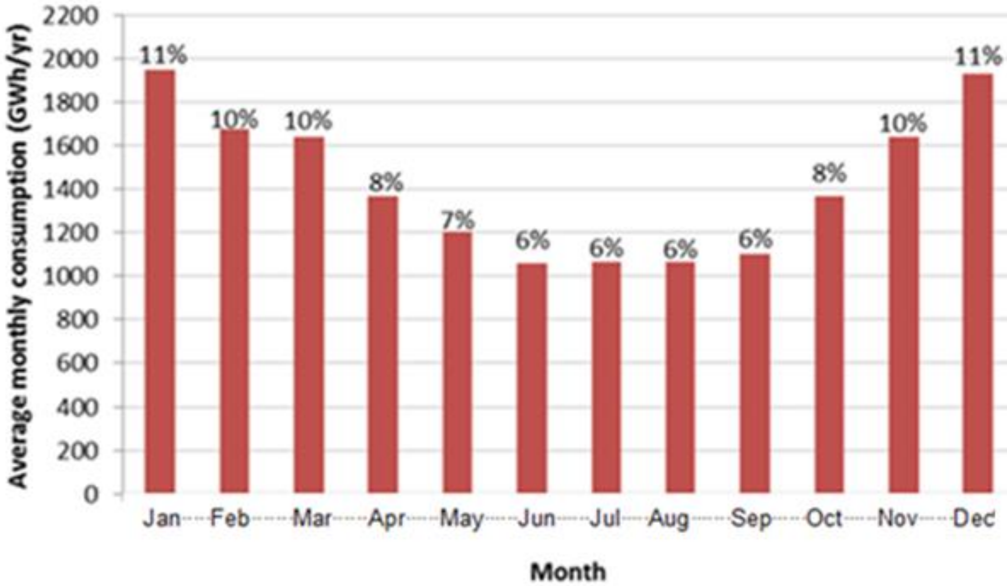
The Residential class served under the RIB rate consists of about 1.7 million accounts and consumed 16,459 GWh in F2015. The following customer characteristics are compiled from a combination of the results of the F2014 REUS and billing data up to F2015, which is the most recent data available at the time of the filing of the Application. The key issues informed by Residential customer characteristics are:

- Aggregate conservation induced by the RIB rate;
- Customer bill impact analysis; and
- Minister RIB Report Letter question 2 (impacts to BC Hydro low income customers of the RIB rate relative to other Residential rate design alternatives) and question 3 (identify factors that drive higher than average annual electricity consumption).

Consumption Distribution by Month

The average Residential rate class consumption by month over the period between F2011-F2015 is illustrated in Figure 5-2 below. Generally, consumption is highest during the winter months (November to February), and lowest during the summer months due to higher lighting and heating demand in the winter.

Figure 5-2 Average Residential Class Consumption by Month, F2011-F2015 (GWh)

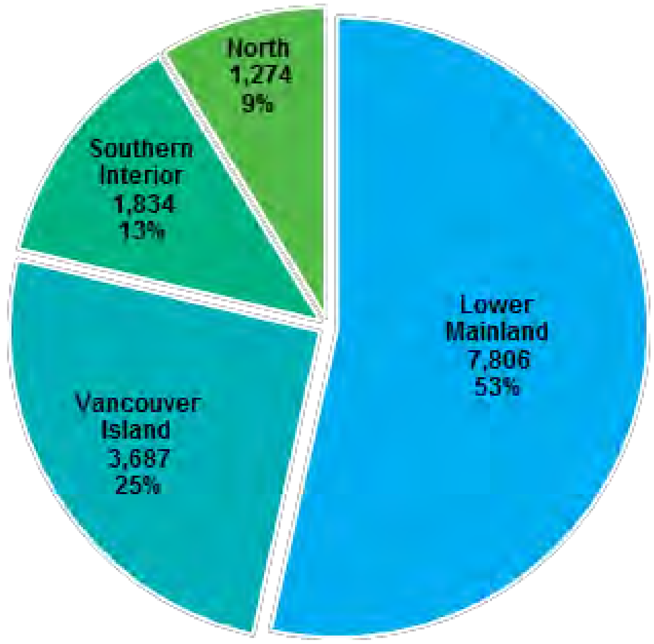


Note: Percentages indicate the average proportion of annual consumption for each month

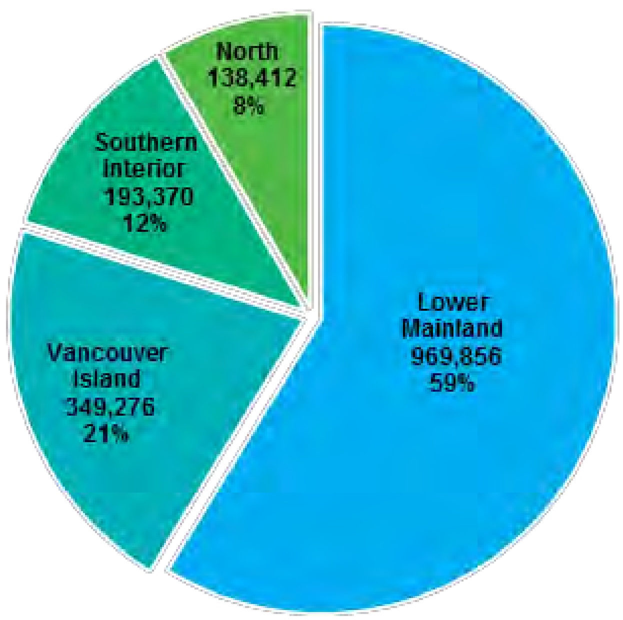
Regional distribution

The regional distribution of consumption and accounts are illustrated in Figure 5-3 and Figure 5-4. The Lower Mainland has the majority of Residential accounts and about half of the total Residential rate class consumption. This is followed by Vancouver Island, Southern Interior and Northern Interior.

1 **Figure 5-3 Total Consumption by Region (GWh)**



2 **Figure 5-4 Customer Accounts by Region**



Dwelling Type

The distribution of consumption and accounts by dwelling type are illustrated in Figure 5-5 and Figure 5-6 below. SFDs make up about half of the customer accounts and have the majority of the total class consumption. This is followed by apartments/condominiums. The consumption per account is generally highest for SFDs with a median consumption of about 9,800 kWh/year and a median F2016 annual electricity bill of about $900. In comparison, apartments and condominiums generally have the lowest consumption per account with a median consumption of about 3,700 kWh/year and a median F2016 annual bill of about $360.

Figure 5-5 Total Consumption by Dwelling Type (GWh)

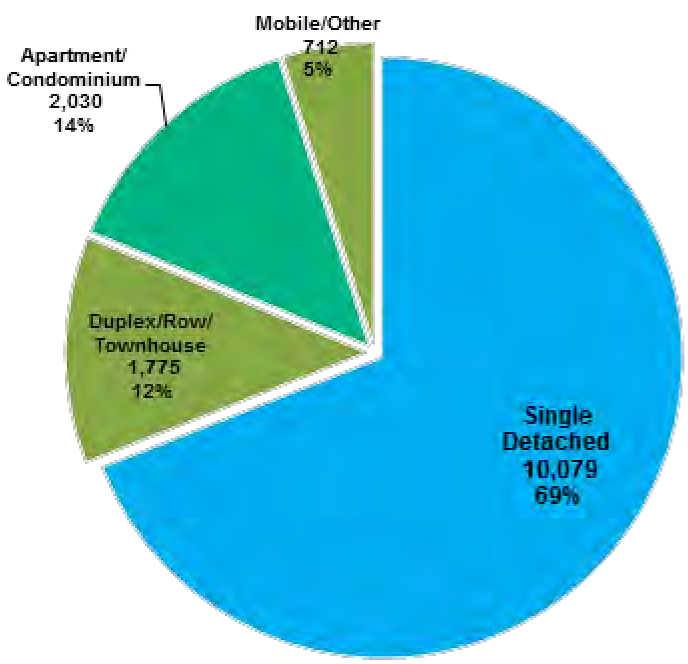
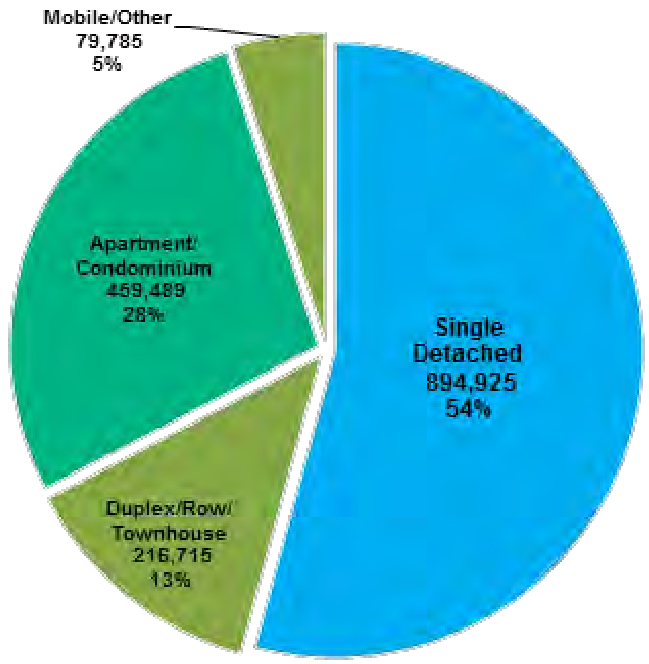


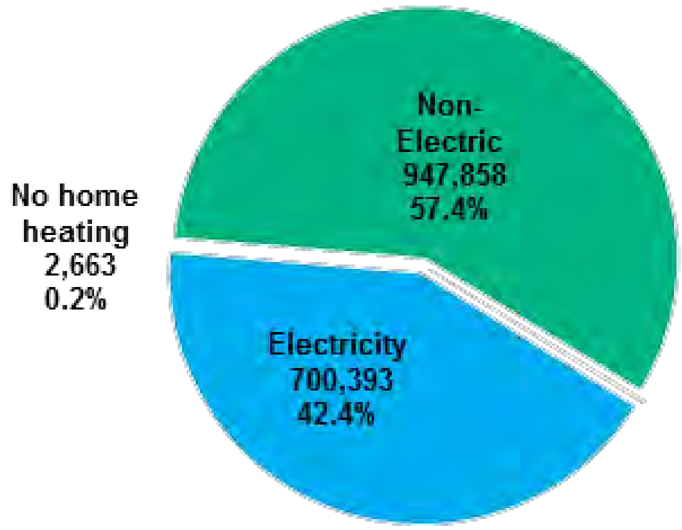
Figure 5-6 Customer Accounts by Dwelling Type



Primary space heating source

Figure 5-7 shows that about 700,400 (42 per cent) of the Residential accounts have electric heat as the primary source of heating in BC Hydro's service area. The consumption per account is generally higher for electric heating than non-electric, with a median consumption of about 8,184 kWh/year and a median F2016 annual bill of about $760. In comparison, accounts with non-electric primary heating sources have a median consumption of about 7,078 kWh/year and an F2016 annual bill of about $640.

Figure 5-7 Customer Accounts by Heating Type



Low Income

Figure 5-8 shows that about 161,287 (10 per cent) of the Residential accounts are indicated as low income using Statistics Canada's LICO, and Figure 5-9 shows that about half of that, 84,250 (5 per cent), have electric heat as the primary heating source. (Refer to section 5.5.1 below for information concerning the definition of low income customers):

- The median consumption of low income accounts is about 5,297 kWh/year and a median F2016 annual bill of about $511; and
- In comparison, low income accounts with electric heat as the primary heating source have a median consumption of about 4,966 kWh/year and a median annual bill of about $503 in F2016. This lower median consumption is likely attributable to the higher proportion of apartments in electrically heated dwellings in the low income segment. (BC Hydro examined the proportion of low income, electrically heated accounts to respond to the Minister RIB Report Letter questions).

Figure 5-8 Proportion of Low Income Customer Accounts

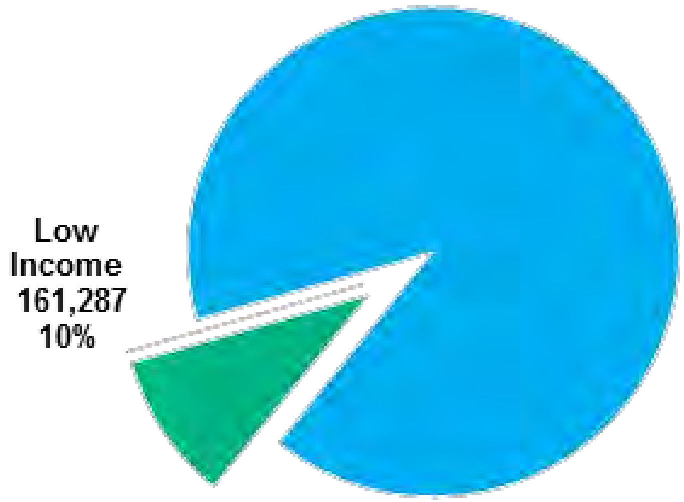
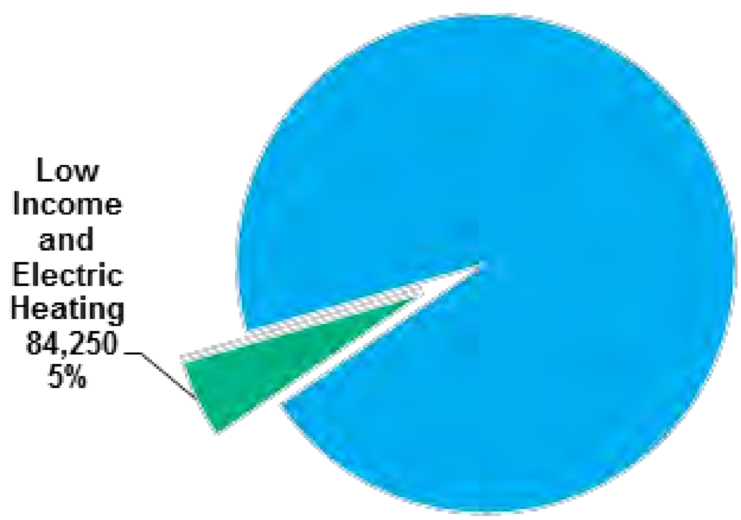


Figure 5-9 Proportion of Low Income, Electrically Heated Customer Accounts



As seen in Figure 5-12 at the end of this section, the low income segment has a slightly lower distribution, mostly due to the higher proportion of apartments/condominiums in that segment.

Household Size

The household size composition of the residential class is illustrated in Figure 5-10 and Figure 5-11. The majority of households are composed of one or two people.

Figure 5-10 Total Consumption by Household Size (GWh)

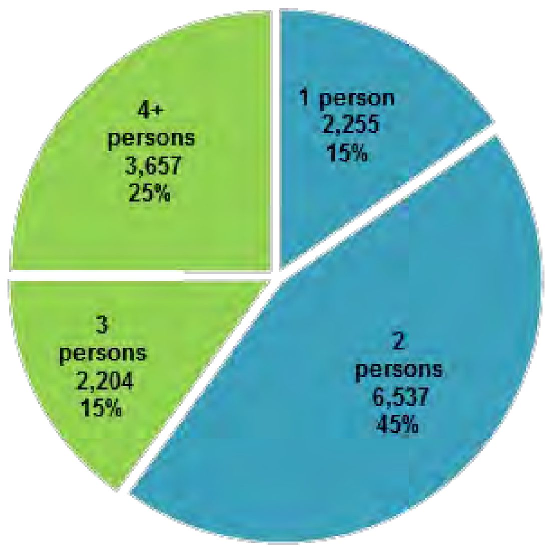
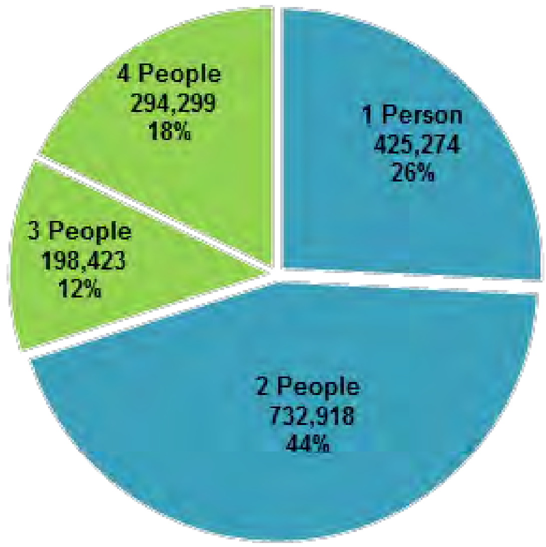


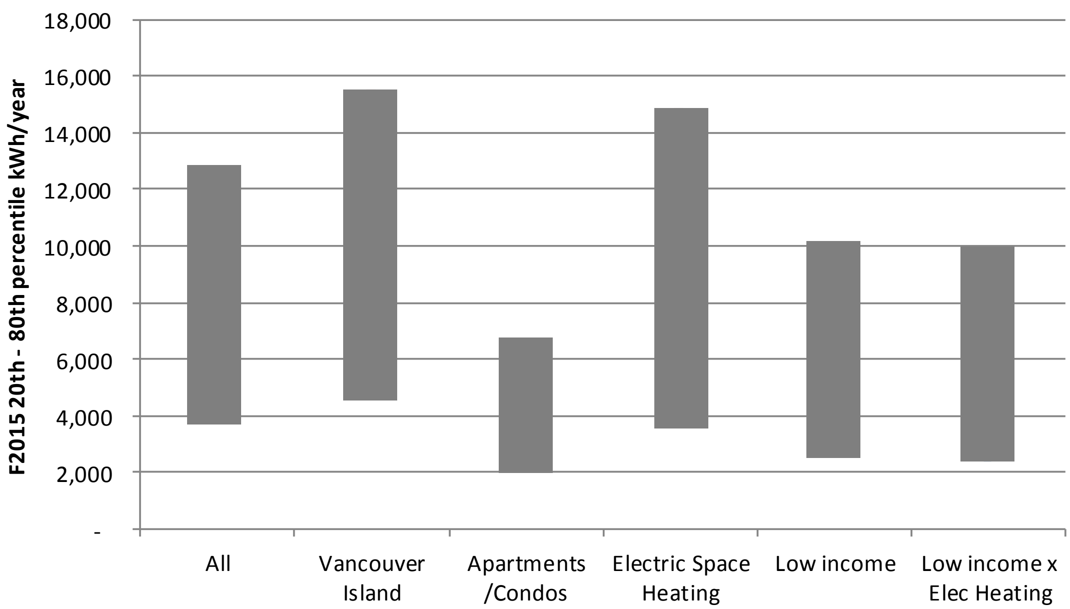
Figure 5-11 Customer Accounts by Household Size



Consumption distribution of select Residential customer segments

The consumption distribution of the Residential class is depicted in Figure 5-12, where the bars show the consumption range of 'typical' Residential customers (the 20th to 80th percentile of annual consumption). The distribution of consumption is quite similar for most segments, with the exception of apartments/condominiums, which is substantially lower. Taking all accounts into consideration, the range of the typical Residential customers is between 4,000 and 13,000 kWh/year. The low income segment has a slightly tighter consumption distribution, mostly due to the higher proportion of apartments/condominiums in that segment. The difference in the distribution between low income and low income with electric heating is very small.

Figure 5-12 Consumption Distribution of Select Residential Customer Segments, 20th to 80th Percentile of Annual Consumption in F2015



Note: Above chart based on 2014 REUS outcomes and F2015 billing data

5.2.3 2013 Residential Inclining Block Rate Evaluation Report

The 2013 RIB Evaluation Report evaluated the impacts and customer response to the RIB rate, net of DSM programs and natural conservation,[181] over the period F2009 through F2012. A copy of the 2013 RIB Evaluation Report is found at Appendix C-3B of the Application. The 2013 RIB Evaluation Report was submitted as Appendix C to BC Hydro's 2013 RIB Rate Re-Pricing Application; the report was the subject of a number of Commission staff IRs in that proceeding.

The 2013 RIB Evaluation Report concluded that the RIB rate appears to be achieving its overall objective of encouraging conservation through Residential customer response to higher marginal prices at the Step 2 energy rate – particularly among customers with the highest consumption. Specific findings germane to the

[181] Natural conservation is conservation induced by RRA rate increases absent any rate structure changes.

2015 RDA stakeholder engagement process and RIB rate analysis are summarized below.

Estimated Price Elasticity

- The estimated range of Step 2 price elasticity (-0.08 to -0.13) encompasses the Step 2 elasticity assumption in the BC Hydro 2008 RIB Application of -0.10 for forecasting RIB rate impacts;
- Price elasticity for BC Hydro's small Residential customers with only Step 1 consumption was not able to be measured with adequate precision due to the limited variation in real prices over the time period covered by the evaluation; and
- The class average elasticity due to RRA rate increases under a flat rate was not able to be estimated using empirical data. The evaluation used the assumption of -0.05 as the class average price elasticity to determine the natural conservation baseline.

Differences in Price Elasticity by Consumption Level

The 2013 RIB Evaluation Report found that large consumers have higher elasticities than smaller consumers. Refer to the following 2013 RIB Evaluation Report findings:

- Large residential users consuming more than 2,400 kWh bi-monthly show a substantially higher than average response to higher prices. The 2013 RIB Evaluation Report indicates that the customer segment above 2,400 kWh of bi-monthly consumption has an estimated price elasticity of -0.16 to -0.18 (RIB Evaluation Report, pages vi, 20);
- Price elasticity is generally larger for customer segments with higher consumption. As discussed in section 5.2.2.2 above, customers living in single family detached homes generally have higher consumption than those living in other dwelling types. The 2013 RIB Evaluation Report finds that customers living in single family detached houses demonstrate higher price

responsiveness than customers living in town houses, apartments or mobile homes (2013 RIB Evaluation Report, pages vi, 19). Section 5.2.2.2 also shows that customers with electric heat tend to have higher consumption than those that use other heating fuels. Price elasticity is higher among households with electric heat than those with non-electric heat (2013 RIB Evaluation Report, pages vi, 20); and

- Higher consumption is correlated with both higher awareness of the RIB rate and higher price elasticity; however, no firm conclusions can be drawn about how RIB awareness is related to customer price response (RIB Evaluation Report, pages vii, 28).

These results are all consistent with the RIB rate design assumptions that customers with a higher level of consumption tend to have a higher responsiveness to price.

Customer Response, Awareness, and Understanding

Using customer survey and billing data, the 2013 RIB Evaluation Report analyzed customer awareness and understanding of the RIB rate. The key findings are summarized below:

- The usage distribution of the sample of customers that were surveyed very closely reflects the actual usage distribution of all RIB accounts;
- A total of 50 per cent of Residential customers appear to be aware of the RIB rate as of February 2012; and
- The total amount of the household electricity bill serves as the greatest incentive to manage electricity consumption among residential customers, followed by electricity prices.

The 2013 RIB Evaluation Report also contains three recommendations for future work. The recommendations are outlined below, along with status updates:

1. Continue to attempt to estimate Step 1 price elasticity and the class average price elasticity: Future evaluations will likely be improved by accumulation of empirical data and price variation over time and the exploration of alternative methods to estimate the class average elasticity. The next RIB evaluation is slated to occur sometime in the F2017-F2020 period, and depends on the Commission's decision concerning the default Residential rate and if the RIB rate is selected, the various RIB rate-related design issues discussed in section 5.2.5 below;

2. Future RIB rate evaluations may benefit from complementary econometric analysis of a select sample of customers. This would require additional data collection on changes (stock turnover) in major household energy end-uses (e.g., appliance replacements, heating system upgrades), changes in economic and demographic circumstances (e.g., occupancy) and participation in DSM programs to attempt to further isolate the effects of electricity prices on consumption. This work may form part of the next RIB evaluation; and

3. Consider ways to increase awareness of the RIB rate, particularly targeted at customer segments that have shown the largest response to price. The evaluation results indicate there are correlations between RIB rate awareness and energy conservation behaviours. While causation is unclear, this could mean that increasing RIB rate awareness will lead to increases in energy conservation behaviours and corresponding energy savings. At Workshop 9a, BC Hydro responded to a BCSEA inquiry as to whether the 50 per cent of Residential customer awareness of the RIB rate could be increased. BC Hydro responded that it may be possible to further increase customer awareness but this would come at a cost. Awareness efforts have continued since the October 2008 initial launch by including RIB rate messaging in other communications where appropriate (e.g., Power Smart residential DSM program materials, email correspondence with billing notices). However, a

broader marketing campaign would be necessary to ensure that RIB-specific messaging was promoted.[182]

5.2.4 Residential Default Rate: Residential Inclining Block Rate and Alternatives Reviewed

BC Hydro used the 2008 RIB Decision for the purpose of advancing alternatives to the RIB rate for modelling and stakeholder consideration at Workshop 3. This resulted in four alternatives: (1) flat rate; (2) three step rate; (3) customer specific baseline rate; and (4) seasonal rate design consisting of a higher winter Step 1/Step 2 threshold to potentially moderate bill impacts to electric space heating customers (seasonal rate alternative 1). BC Hydro used its Residential rate jurisdictional review outlined in section 2.4.2.2 of the Application to identify another seasonal rate (seasonal rate alternative 2) with a higher rate targeted to the four month winter season of November through February (and a lower rate in the other months).

Participants generally agreed that BC Hydro should not continue to consider the customer specific baseline rate, seasonal rate 1 or seasonal rate 2:

- Customer specific baseline rate would be impractical and would impose significant implementation challenges due to the large scale (about 1.7 million Residential accounts), which is the overriding reason that no North American utility offers individual residential customer baseline rates;
- Seasonal rate 1 consists of designs that would increase the Step 1/Step 2 threshold in the winter months. This design would be misaligned with BC Hydro's peak period cost causation and would result in some customers facing lower effective rates in winter; and

[182] The summary of the initial RIB rate engagement plan submitted during the RIB rate proceeding is attached to the Workshop 9a summary notes, found at Attachment 1 to the Workshop 9a/9b consideration memo at Appendix C-3B. All activities were performed with the exception of direct mail letters to high consumption customers. As shown, the communication efforts were substantial. Refer to BC Hydro's response to question 37, Part 3 of the Workshop 9a summary notes (found at Attachment 1 to the Workshop 9a/9b consideration).

- Seasonal rate 2 consists of designs where Residential customers pay a higher rate for electricity during winter months and a lower rate for electricity during non-winter months compared to the existing RIB rate. This would be a blunt instrument to achieve any intended winter peak savings, and would impose higher bill impacts on customers who already claim to have high bill impacts in winter (such as electric heating customers). Newfoundland Power is the only Canadian electric utility surveyed to offer a voluntary residential seasonal rate in this form. Newfoundland Power states that residential customers "most likely NOT to benefit" from the voluntary seasonal rate are "those using more electricity in winter than the non-winter months".[183] Approximately 1 per cent of Newfoundland Power's residential customers have opted for the seasonal rate. A voluntary seasonal rate would confer a benefit to some participating customers that do not change their consumption behaviour and would yield no reliable capacity.

As a result, BC Hydro did not carry forward these three alternatives for additional analysis. Refer to sections 2.2 and 2.3 of the Workshop 3 consideration memo at Appendix C-3A for additional detail.

While no Workshop 3 participant other than CEC favoured BC Hydro carrying forward a flat rate for additional analysis, COPE 378 expressed interest in a flat rate at Workshop 9a and at the June 29, 2015 meeting. Accordingly, BC Hydro put forward additional analysis and its position concerning a flat rate in the Workshop 9a/9b consideration memo and at Workshop 12. Refer to section 5.2.4.1 below. BCOAPO and COPE 378 asked BC Hydro to carry forward the three step rate modelled and discussed at Workshop 3, and BCOAPO requested that BC Hydro model two other versions of a three step rate. Refer to section 5.2.4.2 below.

[183] https://secure.newfoundlandpower.com/customerrelations/seasonalrates.aspx.

5.2.4.1 Flat Rate

BC Hydro modelled a revenue neutral flat energy rate of 10.02 cents/kWh (F2017). The level of the flat rate is coincidently within the energy LRMC range for that year [lower end – 9.46 cents/kWh; upper end – 11.13 cents/kWh]; it was not deliberately set to be within the 2013 IRP energy LRMC range. The basic charge would be the RIB rate basic charge.

No stakeholder supports a flat rate, although as discussed in section 5.2.5.1 COPE 378 favours a RIB rate pricing principle that would not apply any RRA rate increases to the Step 2 rate for the reason, in part, that this would transition the RIB rate to a flat energy rate structure over time. BCOAPO advised BC Hydro at Workshop 12 and in its Workshop 12 written comments that it opposes a flat rate at this time on the basis of bill impacts to low electricity users including low income customers, and a likely loss of conservation. BC Hydro agrees that the flat rate yields the two negative impacts identified by BCOAPO.

The essential trade-off between the RIB rate and a flat rate is greater economic efficiency on the one hand, and loss of conservation and bill impacts on the other hand:

1. The flat rate as modelled by BC Hydro, which would be within the energy LRMC range, is arguably more economically efficient given all Residential customers would see a LRMC price signal, although there is likely to be a loss of conservation as compared to the RIB rate for the reasons set out above in section 5.2.3 concerning the 2013 RIB Evaluation Report (e.g., large consumers have higher elasticities than smaller consumers) and in section 5.2.4.3 below concerning additional work BC Hydro undertook to respond to COPE 378's 2013 RIB Evaluation Report-related comments made at the June 29, 2015 meeting (this work reinforced the 2013 RIB Evaluation Report's finding that large consumers have higher elasticities than smaller consumers);

2. As for conservation savings, a flat rate will likely result in a reduction in conservation because most customers are facing a reduction in their marginal price relative to the RIB rate;

3. Bill impacts are part of the Bonbright customer understanding and acceptance criterion. BC Hydro's primary concern with a Residential flat rate is that it cannot be achieved without imposing significant bill impacts on most customers. As discussed at Workshop 9a, under a flat rate bills would go up for most customers, including low income customers, while bills would go down for larger consuming residential customers. Figure 5-13 and Figure 5-14, and Table 5-3 and Table 5-4, illustrate the estimated bill impact distribution for flattening of the RIB rate in F2017 (relative to BC Hydro's RIB Pricing Principles):

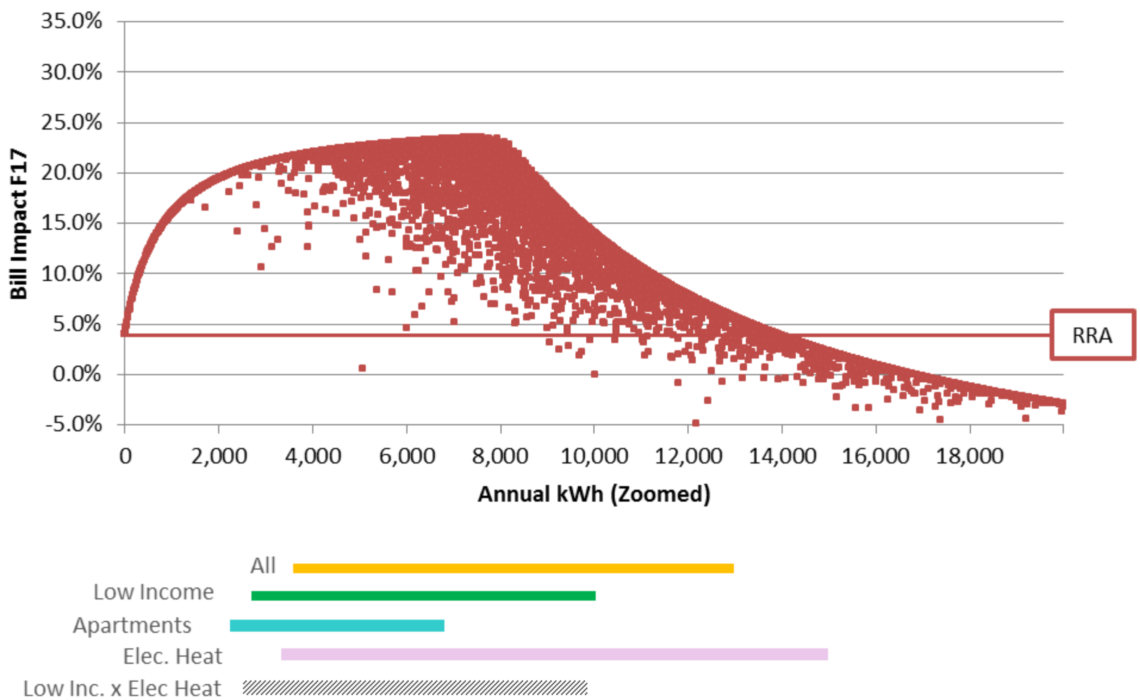
    (a) Figure 5-13 shows that high bill impacts would be experienced by most customers, with the maximum bill impact being experienced by customers near the class median. Most customers are worse-off under the flat rate and experience bill impacts above the RRA rate increase (Figure 5-14). Furthermore, 70 per cent and 41 per cent of customers would experience bill impacts greater than 10 per cent and 20 per cent, respectively (Table 5-3);

    (b) Table 5-4 shows that only 9 per cent of low income customers would be better off under a flat rate as compared to the RIB rate;

    (c) BC Hydro's simulations show that about 18 per cent of customers are better off under the flat rate, composed of the largest customers who benefit from a substantive reduction in the RIB Step 2 rate where a majority of their consumption is billed. For example, about a quarter (26 per cent) of electric space heating customers would be better off on the flat rate;

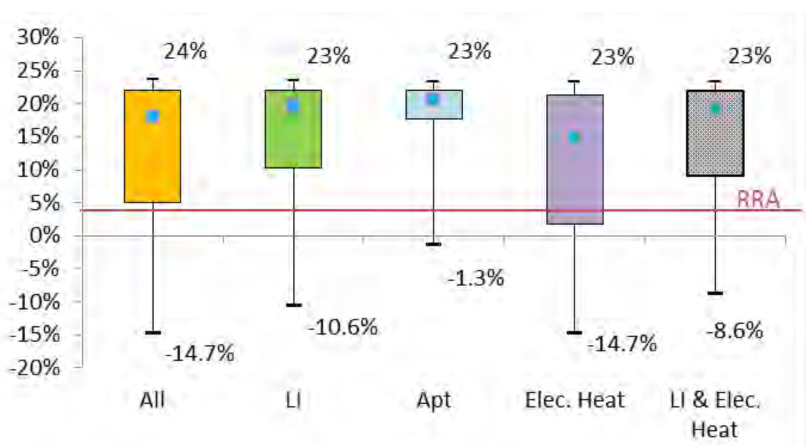
    (d) For typical customers consuming at about the median, the nominal bill increase from the status quo RIB rate is about $100 per year. A similar bill increase is also estimated for the median low income customer and the median low income customers with electric heat (Table 5-4).

Figure 5-13 Bill Impact vs Annual Consumption for Flat Rate in F2017



Note: The chart above is zoomed to show the majority of customers. Color bars indicate the annual consumption range for the middle 60 per cent of each customer segment.

Figure 5-14 Bill Impact Box-Plot for Flat Rate in F2017



Note: Box indicates middle 60 per cent of segment by annual bill impact; blue square indicates median. LI refers to Low Income segment and Apt indicates apartments.

Table 5-3 Bill Impact Distribution by Customer Segment for Flat Rate in F2017

Account Segments	Proportion Higher than 10% BI (%)	Proportion Higher 20% BI (%)
All	70	41
Low Income	80	49
Apartment	95	59
Electric Heat	59	32
Low Income & Electric Heat	79	47

Table 5-4 Bill Characteristics for Flat Rate in F2017

Account Segments	Proportion Better Off than SQ (%)	Median Bill of Segment ($)	Median Bill Difference from SQ ($)
All	18	855	115
Low Income	9	628	96
Apartment	1	460	67
Electric Heat	26	931	98
Low Income & Electric Heat	9	593	90

5.2.4.2 Three Step Rate

As noted above, BC Hydro modelled and assessed three different options for a three step rate as described in Table 5-5.

Table 5-5 Three Step Rate Options

Three Step A – Developed by BC Hydro for Workshop 3; carried forward to Workshop 9a; carried forward to 2015 RDA	Step 1/Step 2 threshold is RIB rate Step 1/Step 2 threshold; Step 1 rate is the RIB Step 1 energy rate; Step 2 is set within the energy LRMC range; and the Step 2/Step 3 threshold and Step 3 rate are derived – refer to Appendix H-1A for additional detail. For F2017 the Step 2/Step 3 derived threshold is about 818 kWh per month.
Three Step B – Modelled at request of BCOAPO; carried forward to Workshop 9a; not carried forward to 2015 RDA	Step 1/Step 2 threshold = 250 kWh per month; Step 2/Step 3 threshold = 675 kWh per month; the Step 2 rate is set within the energy LRMC range; Step 3 rate is 10 per cent higher than the upper end of the energy LRMC range. The Step 1 rate is derived.
Three Step C – Modelled at request of BCOAPO; carried forward to Workshop 9a; not carried forward to 2015 RDA	Step 1/Step 2 threshold = 250 kWh per month; the Step 2/Step 3 threshold is 2000 kWh per month; Step 1 rate is 3 cents/kWh; and the Step 3 rate is equal to the UEC for greenfield IPPs + the LRMC for capacity + T&D losses resulting in a Step 3 energy rate of about 13 cents/kWh. The Step 2 rate is derived.

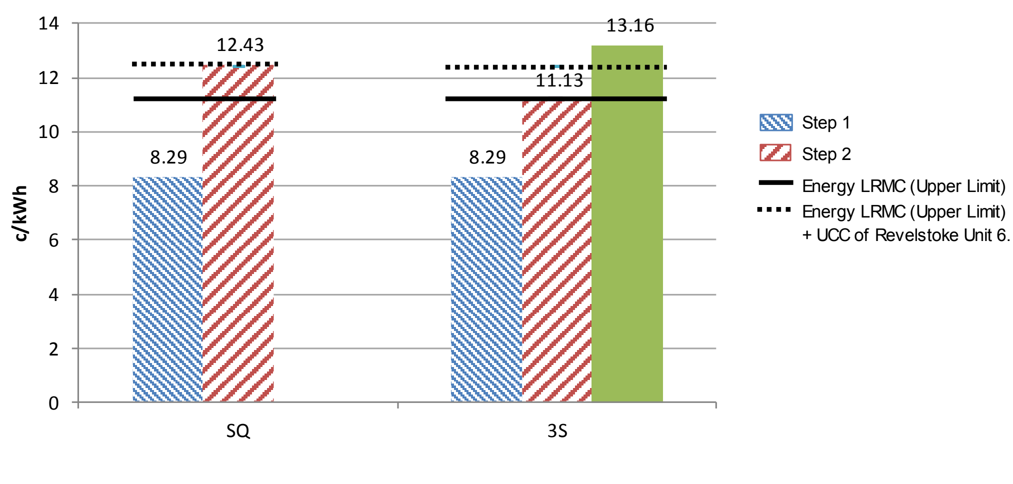
At Workshop 9b, BC Hydro discussed strengths and weaknesses of each of these three step rates. There was no material change in expected energy conservation savings as compared to the RIB rate (ranging from about +30 GWh in F2017 from Three Step A to about -20 GWh in F2017 from Three Step B). Three Step B and C had the highest bill impacts to typical Residential customers in the range of median consumption.

Most participants agreed that only Three Step A should be advanced for the 2015 RDA, and that Three Step A was inferior to the RIB rate. For example, CEC remarks that directionally a three-step rate would complicate rate design. FNEMC acknowledges that the modeling results of the three step rates performed worse than the RIB rate when compared against the Bonbright criteria.[184] BCOAPO noted in its Workshop 9a written comments that ‘attempts to introduce some form of benefit to low income customers as part of a ‘universal’ three part rate were not successful”.[185]

Figure 5-15 compares the RIB rate to Three Step A in F2017 assuming BC Hydro’s preferred pricing principle for the RIB rate.

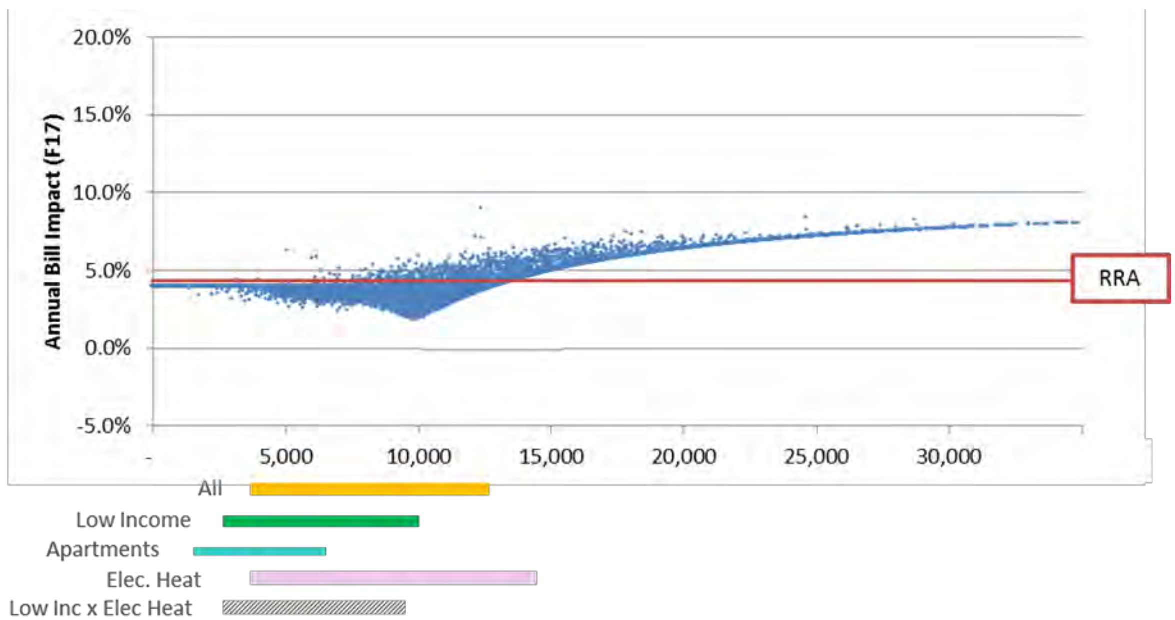
[184] Refer to Workshop 9a presentation slides 50, 53, 55, and 57 to 59 at Appendix C-3B.
[185] Refer to Attachment to the Workshop 9a/9b consideration memo.

Figure 5-15 Comparison of RIB Rate to Three Step A



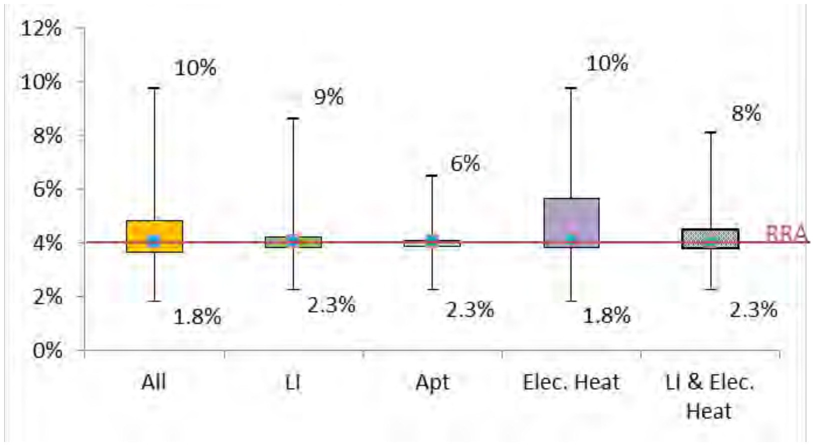
The bill impacts for Three Step A are set out in the Figure 5-16 and Figure 5-17, and Table 5-6 below.

Figure 5-16 Bill Impact vs Annual Consumption for Moving to the Three Step A RIB Rate in F2017



Note: The chart above is zoomed to show the majority of customers. Color bars indicate the annual consumption range for the middle 60 per cent of each customer segment.

Figure 5-17 Bill Impact Box-Plot for Moving to the Three Step A RIB Rate in F2017



Note: Box indicates middle 60 per cent of segment by annual bill impact; blue square indicates median. LI refers to Low Income segment and Apt indicates apartments.

Table 5-6 Bill Characteristics Moving to the Three Step A RIB Rate in F2017

Account Segments	Proportion Better Off than SQ (%)	Median Bill of Segment ($)	Median Bill Difference from SQ ($)
All	58	733	(7)
Low Income	54	531	(0)
Apartment	54	392	(0)
Electric Heat	46	822	(11)
Low Income & Electric Heat	52	503	(0)

The bill impacts of Three Step A are generally low as compared to the RIB rate. Most of the typical customers experience bill impacts that are at about the RRA rate increase (Figure 5-16 and Figure 5-17), although bill impacts generally increase with consumption up to a maximum of 10 per cent as per the constraint in the pricing principle. In terms of bill differences as compared to the status quo RIB rate, about half of the accounts are better off under the Three Step A; however, the nominal amount is small. For the “typical” account that consumes at around the median, the reduction in the annual bill is about $7, or $0.58 per month. The nominal impact on each segment shown also shares the same trend (Table 5-6). For instance, there is no impact on the "typical" low income accounts that consumes at the low income segment's median.

As noted above, BC Hydro does not anticipate much incremental conservation produced by adopting Three Step A in terms of expected energy conservation savings. There would also be a moderate decrease in customer understanding and acceptance as compared to the RIB rate which would probably dampen Three Step A's intended conservation signals. In addition, only one Canadian jurisdiction has a three-step rate, YECL, with energy rates applicable to consumption up to 1,000 kWh; between 1,001 to 2,500 kWh; and in excess of 2,500 kWh.[186] BC Hydro also advised Workshop 9a/9b participants of the outcome of the California Public Utilities Commission's (**CPUC**) June 21, 2015 residential rate reform plan, which will see the current four step residential rates of the three large investor owned utilities - Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric - reduced to two steps.[187]

As a possible three step rate variation, at Workshop 9a BCOAPO and COPE 378 suggested a charge on large energy consumers as a means of funding a low income rate. This raises the legal issue identified in section 5.4 below.

5.2.4.3 BC Hydro Proposal for Residential Default Rate and Stakeholder Engagement

At Workshop 9a BC Hydro presented its Bonbright assessment of the RIB rate,[188] which is reproduced in Table 5-7 below with presentation modifications. Stakeholders generally agree with BC Hydro's assessment and support the RIB rate compared to the alternatives. A few stakeholders raised concerns about impacts on low income customers and certainty of achieved conservation.

[186] YECL Rate Schedules 1180, 1280, 1380 and 1480; https://www.yukonenergy.ca/customer-centre/commercial-wholesale/rate-schedules/.
[187] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K024/153024891.PDF/; refer to section 5.
[188] Refer to slide 47 of the Workshop 9a presentation at Appendix C-3B.

Table 5-7 RIB Rate Bonbright Assessment

Bonbright Criteria	Performance	Remarks
Economic Efficiency - Price signals that encourage efficient use and discourage inefficient growth	Good	The RIB rate is an economically efficient rate that exposes a majority of Residential customers to a price signal set in reference to the energy LRMC; The Step 2 rate exceeds the upper end of the energy LRMC range
Fairness - Fair apportionment of costs among customers; Avoid undue discrimination	Good	The Step 1/Step 2 threshold is generally reflective of typical Residential customer consumption on an on-going, stable basis; The basic charge recovers about 45% of customer-related costs, which is in line with other jurisdictions
Practicality – Customer understanding and acceptance, practical and cost-effective to implement; Freedom from controversies as to proper interpretation	Good	The simple two step RIB rate design sends a clear price signal to consumers that both higher consumption costs more and conservation reduces your bill; As demonstrated in the 2013 RIB Evaluation Report, 50% of Residential customers are aware of the RIB rate and 79% of those customers believe its serves as an incentive to manage electricity consumption (RIB Evaluation Report, Table 3.14); Many Canadian and U.S. jurisdictions have two-step inclining block rates for residential customers
Stability – Recovery of the revenue requirement; revenue stability; rate stability	Good	The RIB rate has been in place since October 2008; The RIB rate is effective in collecting the revenue requirement

BCSEA is of the view that the existing RIB rate structure is the best option at the present time in terms of both conservation and ratepayer interests. BCSEA concludes that the RIB rate meets the Bonbright criteria and has the practical benefit of being relatively well known and understood. FNEMC, BC Non-Profit Housing Association[189] (**BCNPHA**) and CEC identified the RIB rate as the preferred rate design for the Residential sector.

Only one stakeholder expressed a preference for an alternative to the RIB rate. As part of its Workshop 9a feedback, COPE 378 advanced that a flat rate is "arguably more consistent with Bonbright than the RIB rate". BC Hydro does not agree with this statement; the trade-off associated with a flat rate is described above in section 5.2.4.1. In its Workshop 12 feedback COPE 378 stated that it supports the RIB rate if COPE 378's preferred pricing principle for F2017-F2019 is adopted (Option 2 described in section 5.2.5.1 below).

A number of stakeholders asked how the RIB rate performs as compared to the two viable alternatives in terms of bill impacts to low income customers:

- Three Step A results in 54 per cent of low income customers being better off than under the existing RIB rate in terms of bill impacts; and
- In the 2008 RIB Decision, the Commission found that "the vast majority of BC Hydro's low-income customers will be better off under a simple two-step inclining block structure that is revenue neutral for the residential customer class then under the [then current] flat rate".[190] BC Hydro agrees with this finding, and believes it continues to apply as compared to the flat rate modelled in section 5.2.4.1 above. Table 5-4 highlights that only nine per cent of low income customers would be better on a flat rate as compared to the existing RIB rate design. Comparing the annual consumption distribution between the full Residential customer population and the low income segment, the low income segment is slightly lower overall, as indicated by the lower

[189] BCNPHA members are primarily non-profit housing providers.

[190] 2008 RIB Decision, page 33; refer to note 23 in Chapter 2 of the Application. Refer also to BC Hydro's response to BCOAPO IR 1.1.3, Exhibit B-3 in the 2008 RIB Rate proceeding, which sets out BC Hydro's conclusion that 84 per cent of low income customers would be better off under the 2008 RIB rate proposal as compared to the then existing Residential flat rate; http://www.bcuc.com/Documents/Other/2008/DOC_18564_2008_04_18%20BCH%20IRES_1_BCUC_INT.pdf.

median consumption and the distribution of ‘typical’ customers of the segment as shown in Figure 5-12 in section 5.2.2.2. This is likely due to the higher share of apartment dwellers for low income households compared to the general Residential customer population. As a result, a higher proportion of low income customers have a greater share of annual consumption in Step 1 of the RIB rate. This is illustrated in the figures in the Workshop 3 slides.[191]

COPE 378 expressed concern at the June 29, 2015 meeting that the RIB rate’s total impact on conservation is still unknown due to uncertainty surrounding the Step 1 price elasticity. BC Hydro noted that the lack of Step 1 variation during the period of time examined as part of the 2013 RIB Evaluation Report made estimating the price elasticity of smaller customers challenging, and agreed with COPE 378 that this does not necessarily mean that small customers are price-insensitive. It means that the limited data variations did not allow for precise detection of these customers’ price responsiveness.[192] BC Hydro maintained the initial assumption of -0.05 for the price elasticity of low use customers, which is consistent with the default elasticity assumption BC Hydro uses for the entire Residential rate class when BC Hydro forecasts Residential class sales. In BC Hydro’s view it’s unlikely that the actual elasticity of Step 1 can be as large as the elasticity for Step 2:

- As noted in section 5.2.3, the 2013 RIB Evaluation Report found that large consumers have higher elasticities than smaller consumers; and
- Other studies support the 2013 RIB Evaluation Report finding. Refer to E3’s literature review for purposes of informing the issue of the relative elasticities of small and large BC Hydro Residential customers at Appendix D-2 to the Application. E3 states that there is evidence in the fifteen studies and regulatory filings reviewed that large residential customers are more responsive to price than small customers.

[191] Refer, for example, slides 26 to 28 and 50 of the Workshop 3 presentation at Appendix C-3A.

[192] As noted in the article of Michael Li, Ren Orans, Jenya Kahn-Lang and C.K Woo, “Are Residential Customers Price-Responsive to an Inclining Block Rate? Evidence from, British Columbia”, *Electricity Journal*, January/February 2014, Vol. 27, issue 1, pages 87 and 92 (footnote 17).

Even if the elasticities of small and large customers were equal, conventional economic theory shows that the RIB rate would induce conservation, as the RIB rate increases the average of the marginal rates faced by customers.

5.2.5 Alternative Means of Delivering Residential Inclining Block Rate

'Alternative means' refers to the different ways the RIB rate can be delivered (i.e., the method for determining the price levels for the various rate design components). BC Hydro used Direction 4 of Commission Order No. G-13-14 (described above in Table 5-2) and stakeholder engagement to identify and examine four different alternative means of delivering the RIB rate:

- Section 5.2.5.1 – Two pricing principle options for F2017-F2019. As noted in section 1.1.3 of the Application, pricing principle refers to how the RRA rate increases are applied to each of the RIB rate's pricing elements (Step 1 energy rate; Step 2 energy rate; and basic charge);
- Section 5.2.5.2 – Whether to adjust the level of the RIB rate basic charge cost recovery of customer-related costs;
- Section 5.2.5.3 – Whether to implement a separate minimum charge to reflect the cost of customers remaining connected to the system during periods of very low consumption or dormancy; and
- Section 5.2.5.4– Whether to adjust the existing Step 1/Step 2 threshold.

5.2.5.1 F2017-F2019 Pricing Principles

As noted in section 1.1.3 of the Application, BC Hydro proposes pricing principles for the RIB rate for each year, F2017 to F2019, whereby each pricing element of the RIB rate will increase by the RRA rate increases ordered by the Commission in regard to BC Hydro's revenue requirements effective April 1, 2016, 2017 and 2018.

At Workshops 3 and 9b, BC Hydro reviewed and sought feedback on two pricing options for applying RRA rate increases to the RIB rate.

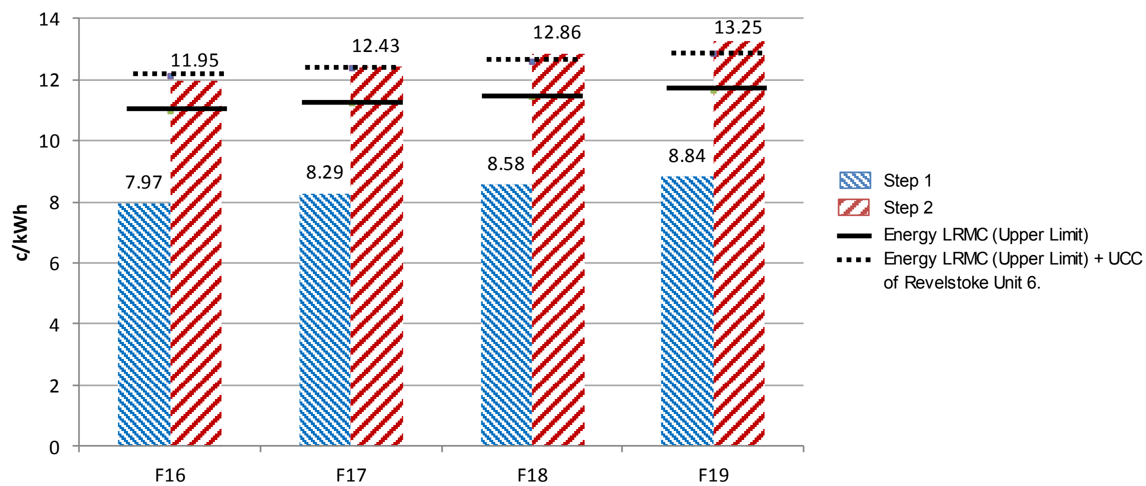
Option 1 (BC Hydro's proposal) would continue the Commission Order No. G-13-14 approach of applying RRA rate increases equally to all three RIB rate pricing elements. The effect of Option 1 would be to maintain the current differential in percentage terms between the Step 1 and Step 2 energy rates, and by extension, a Step 2 energy rate that currently exceeds the upper range of BC Hydro's LRMC. Since all components of the rates go up by the RRA rate while the DARR is forecasted to hold steady at 5 per cent for F2016 to F2019, the bill impacts for all customers is at the RRA rate increase (Direction No. 7 rate caps) in Table 5-8, as follows:

Table 5-8 Bill Impacts under Pricing Principle Option 1, F2017-F2019

F2017 (%)	4
F2018 (%)	3.5
F2019 (%)	3

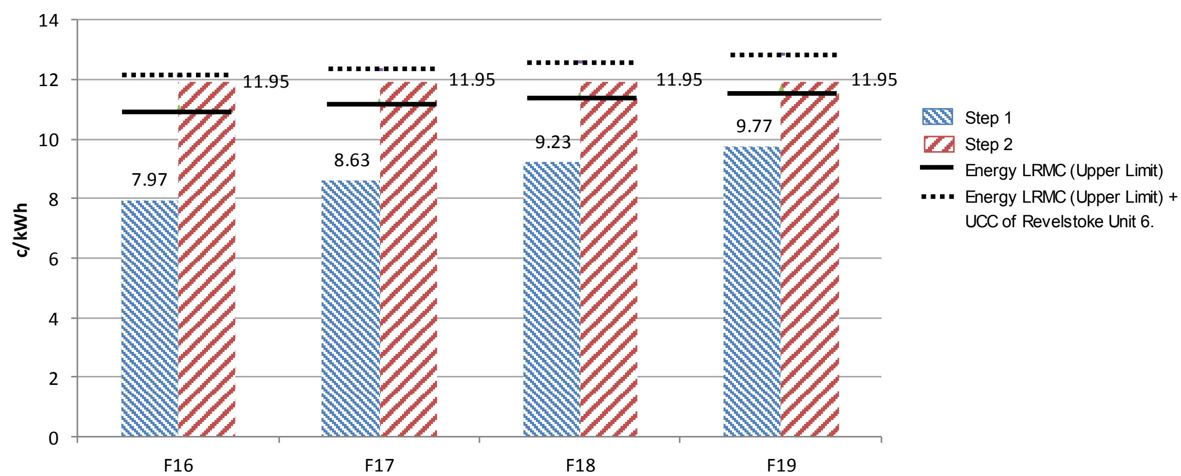
BC Hydro's requested RIB rate pricing principle for F2017-F2018 (Option 1) is depicted in Figure 5-18 below.

Figure 5-18 Requested RIB Rate Pricing Principle (Option 1), F2017-F2019



Option 2 would apply the rate increases to the Step 1 energy rate and basic charge only while holding the Step 2 energy rate at its current level, which results in narrowing the differential between the Step 1 and Step 2 energy rates over time. Under Option 2, the Step 2 energy rate would be approximately equal to the energy LRMC upper limit by F2019, with a forecast loss of conservation in comparison to Option 1. Higher bill impacts for most customers, including low income customers, would also be expected under Option 2. Option 2 is depicted in Figure 5-19.

Figure 5-19 Pricing Principle Option 2, F2017-F2019

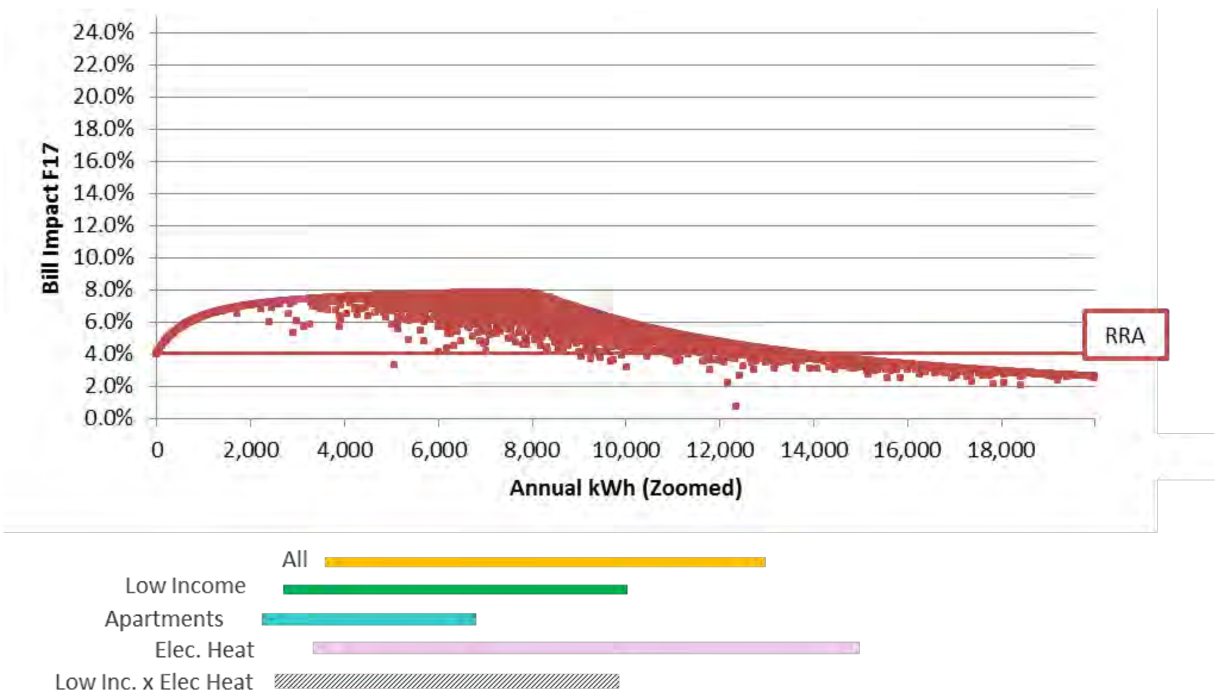


Bill Impact effects

Figure 5-20 to Figure 5-24 below illustrate the estimated bill impact distribution for Option 2 from F2017 to F2019, which increases in magnitude over time (Figure 5-20, Figure 5-21, Figure 5-22) and eventually achieves a bill impact distribution pattern that takes on a similar shape as the flat rate. Bill impacts above the RRA rate increases are experienced by the majority of customers starting in F2017 (Figure 5-23), with the highest bill impacts experienced by customers who consume near the class median. For these customers, the highest impact aggregates over time, starting with 8 per cent in F2017 relative to a RRA rate increase of 4 per cent, and ending with a cumulative bill impact of 21 per cent relative to a cumulative RRA rate increase of 10.9 per cent in F2019 (Figure 5-24). The largest customers experience lower bills relative to Option 1 due to the majority of their consumption being in Step 2, which holds constant rather than increasing by RRA rate increases between F2017 and F2019.

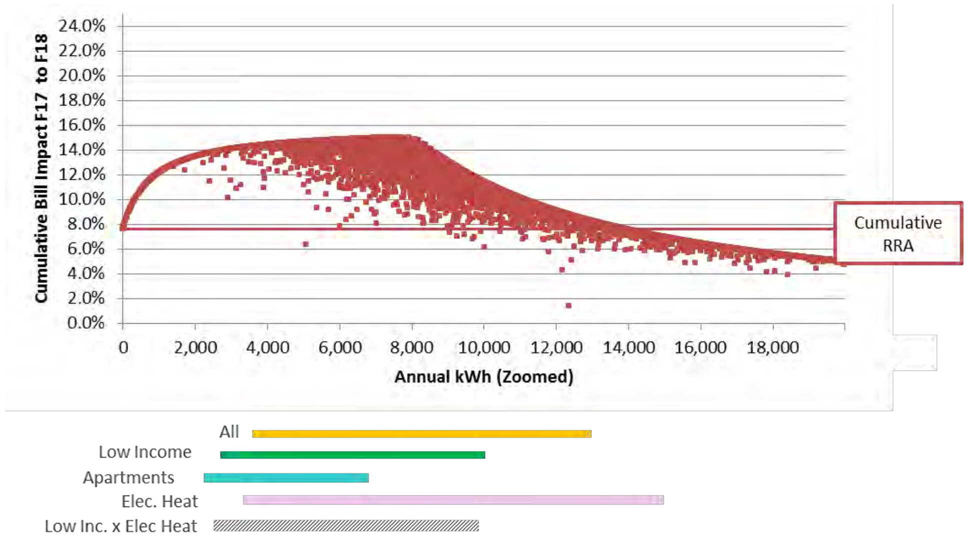
Most customers are worse-off under Option 2 across all segments examined, and that proportion increases over time (Table 5-9 and Table 5-10). For typical customers consuming at about the median, the nominal bill difference from Option 1 is an increase of about $22 per year for F2017 and that difference grows to an increase of $62 for F2019. This substantive increase is expected across all segments examined, including low income.

Figure 5-20 Bill Impact vs Annual Consumption for Option 2 of the RIB Rate in F2017



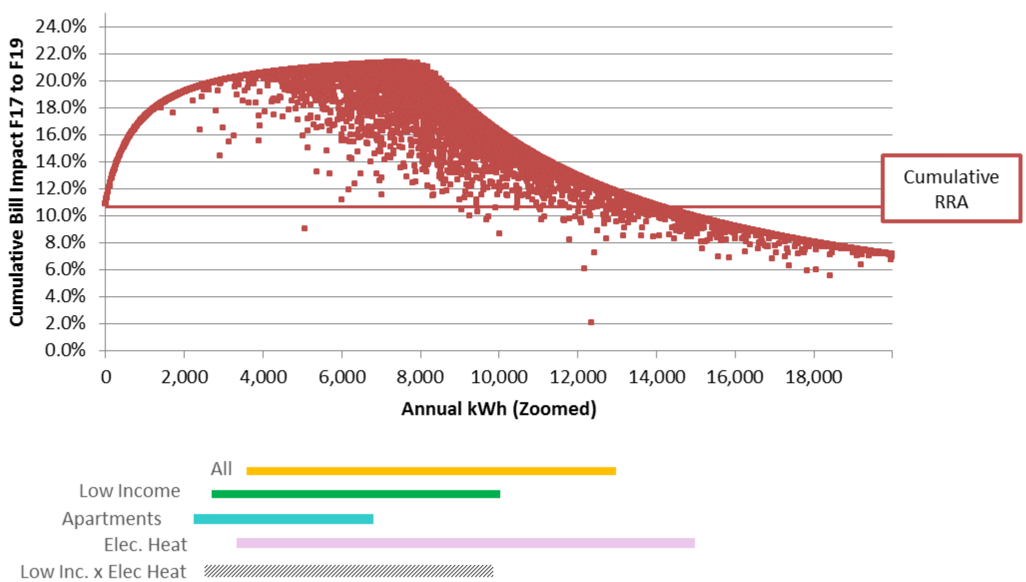
Note: The chart above is zoomed to show the majority of customers. Color bars indicate the annual consumption range for the middle 60 per cent of each customer segment.

Figure 5-21 Cumulative Bill Impact vs Annual Consumption for Option 2 of the RIB Rate in F2018



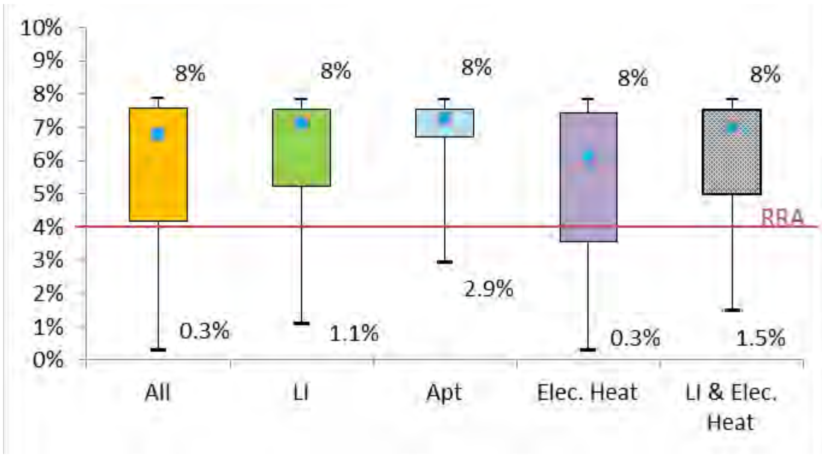
Note: The chart above is zoomed to show the majority of customers. Color bars indicate the annual consumption range for the middle 60 per cent of each customer segment.

Figure 5-22 Cumulative Bill Impact vs Annual Consumption for Option 2 of the RIB Rate in F2019



Note: The chart above is zoomed to show the majority of customers. Color bars indicate the annual consumption range for the middle 60 per cent of each customer segment.

Figure 5-23 Bill Impact Box-Plot for Moving to the Option 2 of the RIB Rate in F2017

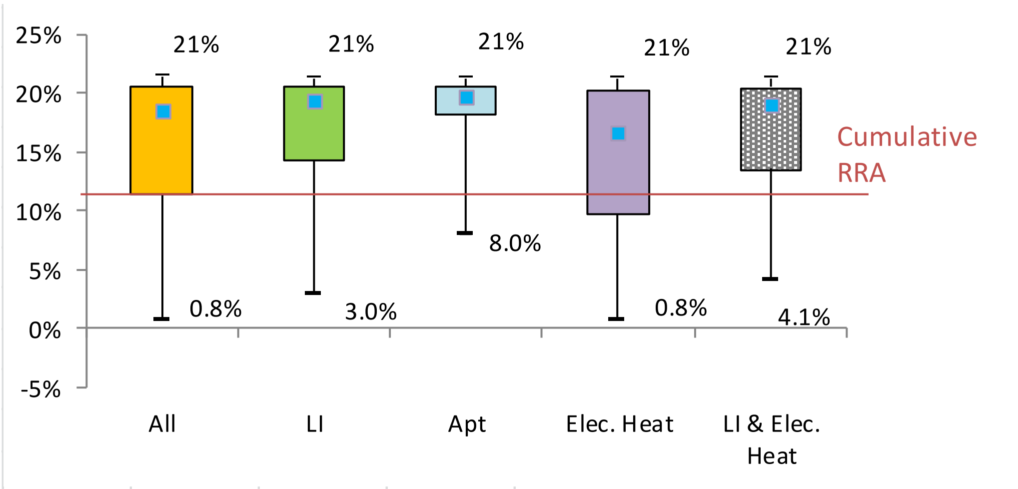


Note: Box indicates middle 60 per cent of segment by annual bill impact; blue square indicates median. LI refers to Low Income segment and Apt indicates apartments.

Table 5-9 Bill Characteristics for Moving to the Option 2 of the RIB Rate in F2017

Account Segments	Proportion Better Off than SQ (%)	Median Bill of Segment ($)	Median Bill Difference from SQ ($)
All	21	763	22
Low Income	13	550	19
Apartment	2	406	13
Electric Heat	30	852	19
LI & Electric Heat	13	520	18

Figure 5-24 Cumulative Bill Impact Box-Plot for Moving to the Option 2 of the RIB Rate in F2019



Note: Box indicates middle 60 per cent of segment by annual bill impact; blue square indicates median. LI refers to Low Income segment and Apt indicates apartments.

Table 5-10 Bill Characteristics for Moving to the Option 2 of the RIB Rate in F2019

Account Segments	Proportion Better Off than SQ (%)	Median Bill of Segment ($)	Median Bill Difference from SQ ($)
All	19	851	62
Low Income	11	618	52
Apartment	1	454	36
Electric Heat	27	941	53
LI & Electric Heat	11	584	49

All Workshop 9b participants commenting on this topic support Option 1 except COPE 378. BCSEA supports Option 1 on the basis of customer understanding and acceptance (Option 1 is easily understood and easily communicated). BCOAPO opposes Option 2 because of the bill impacts to low income customers. COPE 378 favours Option 2 because it believes that what it calls “the greatest price distortion” is with the Step 1 energy rate, not the Step 2 energy rate and because Option 2 would provide BC Hydro with a transition strategy to a flat energy rate structure.

The trade-off is:

- Achieving better economic efficiency, which favours Option 2 as the Step 2 energy rate would be approximately equal to the energy LRMC upper limit by F2019. However, BC Hydro is of the view that Option 1 Step 2 pricing is reflective of the energy LRMC for the F2017-F2019 period. A number of stakeholders, including AMPC and BCSEA, urged BC Hydro to not adopt a 'false precision' with respect to the energy LRMC for purposes of rate design proposals;
- Ascribing greater weight to incremental bill impacts, which favours Option 1. Option 1 is the only pricing option that does not create a bill impact that is greater or lesser than CARC[193] for a portion of the RIB class such as smaller accounts. BC Hydro is concerned with the distribution of the bill impacts under Option 2. The majority of customers experience a greater bill impact than CARC due to the proportionately greater increase in the Step 1 rate. While low income customers have a bill impact distribution that is similar to the distribution of the total RIB class, a greater portion of accounts in the low income sub-segment would have higher bill impacts (i.e., above CARC) under Option 2 than for the class as a whole. This is because low income customers, on average, have a slightly greater portion of their usage in Step 1 than the RIB class, and Option 2 has the price increase allocated to the Step 1 energy rate.

BC Hydro's primary RIB rate pricing principle consideration is customer understanding and acceptance, and in particular bill impacts. BC Hydro defines the Bonbright rate stability criterion as the degree of rate structure changes relative to the status quo rate structure being assessed, and as such its main application is with respect to alternatives to the RIB rate, and not alternative means of delivering

[193] Defined in section 2.3.1.6 of the Application; as noted, CARC can arise from any or all of the following: revenue requirement changes and rate rider changes.

the RIB rate such as pricing principles. Nonetheless, it is the case that Option 1 is a continuation of the pricing principle from F2015-F2016.[194]

5.2.5.2 Basic Charge Cost Recovery Increase

BC Hydro proposes no changes to the basic charge cost recovery of customer-related costs.

The Residential basic charge was introduced in March 1977 and has since been increased by the amount of any RRA rate increase as approved by the Commission. The basic charge is intended to recover a portion of BC Hydro's customer-related costs, which do not vary with usage.

The current RIB rate basic charge recovers 45 per cent of customer-related costs. To respond to Direction 4 of Commission Order No. G-13-14 summarized in Table 5-2 above, BC Hydro assessed and ultimately rejected an increase to basic charge recovery of customer-related costs based on customer bill impacts, including to low income customers. At Workshop 3, BC Hydro outlined:

- Increasing the basic charge so that it recovers more or all of BC Hydro's customer costs to supply the Residential rate class would provide a closer relationship between the fixed cost elements of BC Hydro's cost structure and the rate elements whose purpose is to provide some recovery of those costs, but would have significant bill impacts on low usage customers. BC Hydro modelled a 100 per cent basic charge cost recovery to illustrate this. BC Hydro is opposed to increasing the basic charge to recover 100 per cent of customer-related costs due to the very high bill impacts imposed on some customers. BCSEA opposed any change to the basic charge, noting that the current charge is accepted by customers and any change would produce little or no additional conservation. BCOAPO is of the view that the basic charge is regressive and opposes any proposal to increase the charge. BC Hydro shares

[194] Pursuant to Commission Order No. G-13-14; http://www.bcuc.com/Documents/Orders/2014/DOC_40515_G-13-14-BCH-RIB-Rate-Re-Pricing-Reasons.pdf.

BCOAPO's concern with increasing the amount of cost recovery through the basic charge due to the impact on low consuming customers, including apartments and some low income customers; and

- Decreasing the basic charge would diminish the relationship between the basic charge and fixed costs. BC Hydro opposes eliminating all forms of fixed charges such as the basic charge; as stated by CEC at Workshop 3, utilities generally have a fixed charge in addition to a volume-based energy charge. Nor does BC Hydro support a reduction in the basic charge recovery of customer-related costs. BC Hydro notes its jurisdictional assessment of residential Canadian electric utility residential rate basic charge cost recovery presented at Workshop 9a,[195] which range between a low of 22 per cent (SaskPower) and a high of 100 per cent (New Brunswick Power). The current RIB rate basic charge recovery of 45 per cent is in the range of Canadian electric utility residential rate basic charge cost recovery but at the lower end of the range; for example, reducing RIB rate basic charge recovery of customer costs from 45 per cent to 35 per cent would leave BC Hydro with the second lowest residential basic charge cost recovery of the eight Canadian electric utilities surveyed (SaskPower, Manitoba Hydro, Hydro Quebec, Nova Scotia Power, Newfoundland Power, New Brunswick Power, YECL, FortisBC).

5.2.5.3 Minimum Charge

BC Hydro is not proposing a separate minimum charge.

Minimum charges are intended to recover a minimum contribution toward fixed costs. Direction 4 of the Commission Order No. G-13-14 tied a separate minimum charge to recovering some portion of the cost of customers remaining connected to the system during periods of very low consumption or dormancy. Currently, BC Hydro's basic charge is the minimum charge for Residential service.

[195] Slide 28 of the Workshop 9a presentation found at Appendix C-3B of the Application.

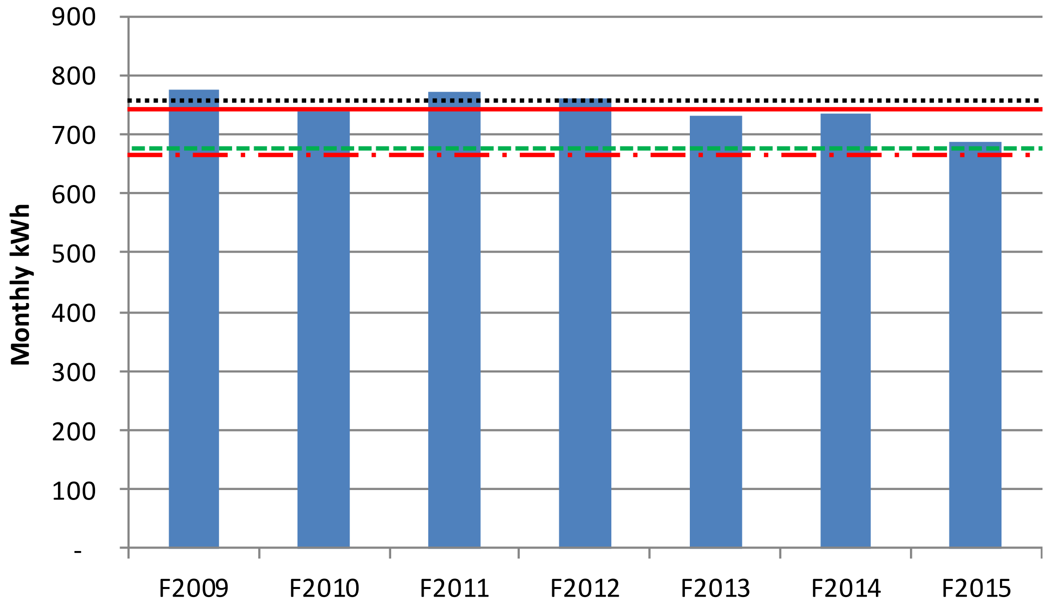
To respond to Direction 4 of the Commission Order No. G-13-14 summarized in Table 5-2 above, BC Hydro considered a separate minimum charge. BC Hydro modeled a $15 per month minimum charge, roughly equivalent to the average fixed Distribution and customer-related cost per month per Residential customer. BC Hydro tested the idea that additional cost recovery through a separate minimum charge may benefit lower consuming customers, including some low income customers, given that the charge would allow for a consequent lowering of the RIB Step 1 rate. In Workshop 9b-related analysis, BC Hydro determined that it would be unable to precisely target a minimum charge to materially improve cost recovery from dormant or low use accounts. BC Hydro noted that a minimum charge would affect about 1.5 per cent of Residential customers, of which about 50 per cent are low income customers.

At Workshop 9b, BC Hydro sought stakeholder comment on whether a minimum charge should be implemented, separate from the basic charge. All stakeholders providing written comments on the topic as part of Workshop 9b feedback except BCNHPA agreed that BC Hydro should not pursue a separate minimum charge at this time. BCOAPO, BCSEA and FNEMC expressed concern that a separate minimum charge would disproportionately impact low income customers, and advanced that potential benefits of a minimum charge are uncertain at best.

5.2.5.4 Step 1/Step 2 Threshold

BC Hydro proposes no change to the existing Step 1/Step 2 threshold. The current threshold of 675 kWh per month reflects typical residential use, as it still represents approximately 90 per cent of the monthly median consumption given seven years of consumption data to date. This is shown by Figure 5-25 and Table 5-11 below.

1 **Figure 5-25 Median Consumption per Month**[196]



Median Consumption (762 kWh/month) at time of 2008 Commission Decision

Average of Median Consumption over the past seven years (744 kWh/month)

Current Threshold (675 kWh/month), as determined by Commission, which is ~90 per cent of median consumption

90 per cent of Average of Median Consumption over the past seven years (669 kWh/month)

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[196] Figure 5-25 is updated from slide 59 of the Workshop 3 presentation found at Appendix C-3A.

Table 5-11 Median Consumption per Month

	Monthly Median (kWh)*	90% of the Monthly Median (kWh)
F2009	777	699
F2010	739	665
F2011	772	695
F2012	762	686
F2013	733	660
F2014	734	661
F2015	689	620
Seven-Year Average	744	669
Threshold set from 2008 Commission Decision, page 107	Based on 762	675

* Computed based on the same methodology as the 2008 RIB Application which includes all customers in RS 1101 with consumption between 1,200 kWh/year and 120,000 kWh/year. The monthly median of each year is computed as the median annual consumption divided by 12.

Under the existing Step 1/Step 2 threshold, BC Hydro estimates that the majority of Residential accounts experience the Step 2 price as their marginal rate (Figure 5-26), which is about 65 per cent for F2015. That proportion is smaller (50 per cent) for low income customers, likely due to the higher proportion of apartment dwellers in that segment. Refer to Figure 5-27.

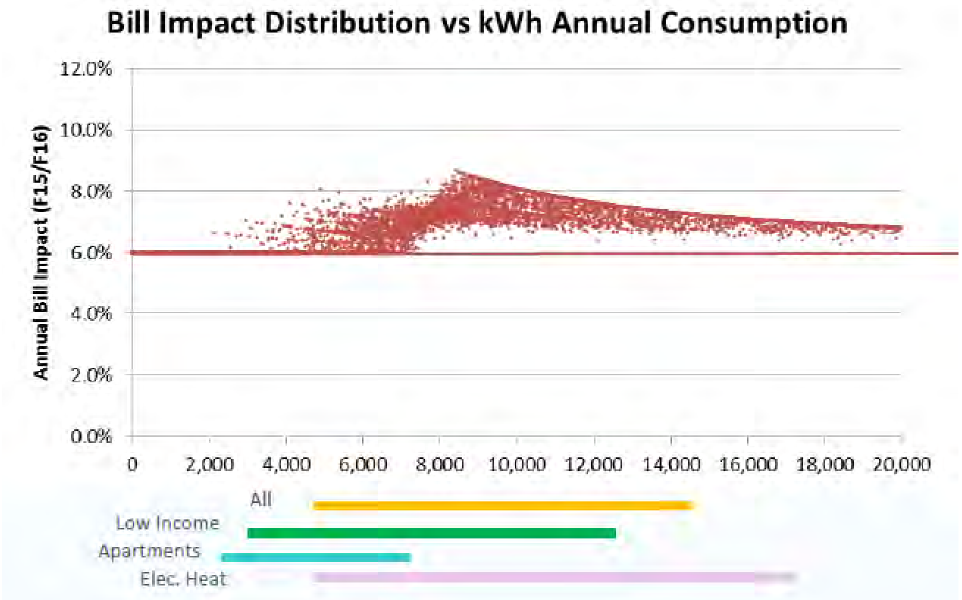
Figure 5-26 Step 2 Exposure, all Accounts

Figure 5-27 Step 2 Exposure, Low Income

BC Hydro concludes that moving the Step 1/Step 2 threshold results in no substantive changes from status quo RIB conservation forecasts within the scope modelled, given a maximum bill impact constraint of 10 per cent. BC Hydro agrees with BCSEA that there is no apparent problem with the current Step 1/Step 2 threshold, and generally that the existing RIB rate design has the advantage of customer understanding and acceptance. BC Hydro modelled a range of both increases and decreases to the Step 1/Step 2 threshold. As reviewed at Workshop 3, the bill and conservation impacts of changing the threshold vary by the exposure of customers to the Step 1 energy rate (which is held constant) and by the consequent increase or decrease to the Step 2 energy rate (to maintain revenue neutrality):

- Exposing more customers to the Step 2 energy rate through even a moderate decrease in the Step 1/Step 2 threshold has the effect of imposing higher bill impacts on nearly all typical customers, with no substantive change in conservation overall. Figure 5-28 below illustrates the bill impacts of reducing the threshold from 675 kWh per month to 635 kWh with a minor reduction to the Step 2 rate to maintain revenue neutrality.

Figure 5-28 635 kWh Step1/Step 2 Bill Impact Distribution[197]

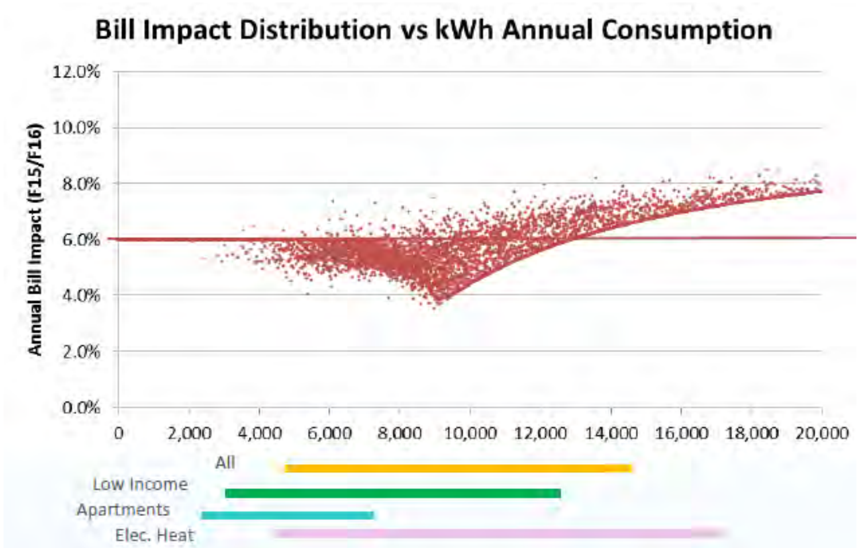


Note: The chart above is zoomed to show the majority of customers. Color bars indicate the annual consumption range for the middle 60 per cent of each customer segment.

- Alternatively, residually calculating the Step 1 energy rate while keeping the Step 2 energy rate constant would subject a number of typical customers to bill impacts higher than the RRA rate increase but with no substantive change in net conservation; and
- Increasing the Step1/Step 2 threshold while maintaining Step 1 at the status quo price would result in an increase in conservation as a result of increasing the Step 2 energy rate to maintain class revenue neutrality. However, this would also impose a wide range of bill impacts across customer types. A moderate increase to the threshold results in lower bill impacts to typical customers and higher bill impacts to higher than average users. Figure 5-29 illustrates the bill impacts of moving from the existing 675 kWh threshold to a 719 kWh threshold.

[197] Figure 5-28 is reproduced from slide 61 of the Workshop 3 presentation found at Appendix C-3A.

Figure 5-29 719 kWh Step1/Step 2 Bill Impact Distribution[198]



Note: The chart above is zoomed to show the majority of customers. Color bars indicate the annual consumption range for the middle 60 per cent of each customer segment.

5.3 Residential Dual Fuel Interruptible (E-Plus) Rate

5.3.1 BC Hydro's Preferred Residential E-Plus Rate Design

As described in section 1.1.3 of the Application, BC Hydro proposes to amend Special Condition 1 of RS 1105 so that Residential E-Plus service will only be provided where BC Hydro has available energy and capacity to do so, as illustrated in Appendix F-1D. The Residential E-Plus Amendment is consistent with the wording found in BC Hydro's other non-firm (interruptible) rates such as the Shore Power Rates recently approved by the Commission and RS 1880, and will enable BC Hydro to practically interrupt the service.

5.3.2 Background

RS 1105, the Residential E-Plus rate, is a non-firm rate closed to new customers in 1990 under which customers pay a discounted rate for space and water heating loads on condition of having an alternative fuel back-up heating system. The

[198] Figure 5-29 is reproduced from slide 62 of the Workshop 3 presentation at Appendix C-3A.

RS 1105 energy rate for F2016 is 5.22 cents/kWh and there is no basic charge. There are approximately 7,500 Residential E-Plus customers. Residential E-Plus customers represent a small portion of the Residential customer revenues (approximately $4.7 million of $1.9 billion (F2014)).

E-Plus rates were introduced in 1987 to residential and commercial customers. The purpose of the rates was to market surplus energy that would have been spilled because at the time consistent access to the spot market was not available. As part of the 2007 RDA Decision,[199] the Commission approved restricting the ability to transfer the E-Plus rate to a new customer by amending the RS 1105 Availability clause to state that the E-Plus rate is available "only in Premises where there has been no change in customer since April 1, 2008".

The 2007 RDA Decision contains Residential E-Plus-related directions relevant to or to be addressed as part of the 2015 RDA, summarized in Table 5-12.

[199] Commission Order No. G-130-07; http://www.bcuc.com/Documents/Orders/2007/DOC_17039_G-130-07_BCH_2007RD%20Phase%201%20Decision.pdf.

Table 5-12 Summary of 2007 RDA Decision Residential E-Plus Directions

Direction	Status
13 – The Commission Panel has also considered the E-Plus Group's submission that the price of [RS 1105] would never exceed two thirds of the "regular rate" and finds that this statement was made to E-Plus customers in the form of a letter from BC Hydro and that such a communication cannot bind the Commission	No BC Hydro action required. Note that BC Hydro's preferred Residential E-Plus rate design does not include energy rate re-pricing other than to continue to increase the RS 1105 energy rate by Commission approved RRA rate increases. Refer to section 5.3.3 and 5.3.4 below
14 – The Commission Panel directs BC Hydro to include the interruptible service to its E-Plus customers as a separate class in its future [Fully Allocated] COS with its next rate design application or rate design filing, and to calculate the costs of providing service as though it has the ability to interrupt the class for the four winter months … The Commission Panel directs BC Hydro to pay more attention to the exercise of its rights under the [E-Plus] Rate Schedules and to invest the necessary time and resources to ensure that its E-Plus customers comply with the Special Conditions of the Rate Schedules, and to work with E-Plus customers who may wish to move back to the firm rate to ensure that information on [DSM] programs are made available to them	As discussed in section 4.2.2 of the Application, BC Hydro has not separated out Residential E-Plus customers as a separate rate class from the Residential rate class. The topic of how to calculate the Residential E-Plus heating load R/C ratio was discussed at Workshop 2 and refined/presented at Workshop 9b. The resulting E-Plus heating load R/C ratio is set out below in Table 5-13. As noted in section 2.2 of the Workshop 9b Discussion Guide found at Appendix C-3B of the Application, BC Hydro acted on the E-Plus compliance portion of the 2007 RDA Decision 14 by requesting E-Plus customers confirm their compliance with the conditions of the rate. Two direct mailings were sent between November 2007 and February 2008 and an additional four were done between December 2011 and May 2014; follow-up phone calls took place in spring 2008 and in October 2012. Non-responsive customers were transferred off the rate as were non-compliant customers.

BC Hydro has never interrupted E-Plus load. Special Condition 1 of RS 1105 restricts BC Hydro's right to interrupt the supply of electricity; there must be a "surplus hydro energy" and "the service cannot be provided economically from other energy sources". This is very different language than the typical interruptible rate provisions whereby BC Hydro will only provide service when it has available energy and capacity to do so.

As a result of stakeholder input gathered at Workshop 2 and at Workshop 9b:

- BC Hydro continues to assign Generation, Transmission and Distribution demand-related costs to Residential E-Plus customer heating load because such E-Plus loads are included in BC Hydro's peak demand load forecast and planning assumptions, as there is no ability to interrupt E-Plus customers for capacity-related reasons given RS 1105 Special Condition 1, which specifically refers to interruptions for energy;[200]

- E-Plus load should not be in the energy load forecast. While there is no definition of the phrase "lack of surplus hydro energy" in Special Condition 1, it is circular to include E-Plus load for purposes of determining whether there is such a surplus. On this basis, BC Hydro would not assign Residential E-Plus heating load any Generation energy-related costs for COS analysis. The R/C ratio of Residential E-Plus Heating load is ~ 65 per cent when Generation costs are not assigned, as shown in row 1A of Table 5-13. The R/C ratio of Residential E-Plus Heating load is ~ 45 per cent when generation costs are assigned, as shown in row 1B of Table 5-13. These figures compare to a R/C ratio for all remaining E-Plus customer load of about 95 per cent, as shown in row 2 of Table 5-13.[201] These are high level estimates developed using actual F2014 billing data for E-Plus customers.

Table 5-13 Residential E-Plus R/C Ratios

Row	F2014	Total Revenue ($ million)	Total Cost ($ million)	Revenue Shortfall ($ million)	R/C Ratio (%)
1A	Residential E-Plus – Heating load, Generation energy costs not assigned	4.7	7.4	2.7	~ 65
1B	Residential E-Plus – Heating load, Generation energy costs assigned	4.7	11.0	6.3	~ 45
2	Residential E-Plus – Remaining load	7.6	8.1	0.4	~ 95

5.3.3 Options Reviewed

In a letter dated February 24, 2015 (found at Attachment 7 to the Workshop 9a/9b consideration memo at Appendix C-3B), BC Hydro sought feedback on the

[200] Refer to section 12 of the Workshop 2 consideration memo at Appendix C-2A.
[201] Refer to pages 14 to 16 of the Workshop 9b Discussion guide at Appendix C-3B of the Application.

Residential E-Plus rate as part of the 2015 RDA customer engagement. In this letter to E-Plus customers, two options for the Residential E-Plus rate were put forward:

- Option 1 – maintain the E-Plus rate under the same terms and conditions; and
- Option 2 - phase out E-Plus rate over a period of time (e.g., five to ten years) after which customers would pay the default rate for their rate class for all consumption.

After considering all feedback (as described below), and in particular, to the issue that the E-Plus rate should serve a useful function, BC Hydro developed a third option - Option 3. At Workshop 9b, BC Hydro set out the three options for Residential E-Plus rates:

1. Status Quo;
2. Phase out the E-Plus rate and transition accounts to the RIB rate; and
3. Amend RS 1105 Special Condition 1 to provide a practical interruptible option.

Under Option 3, Special Condition 1 of RS 1105 would be aligned with the language found in BC Hydro's other interruptible (non-firm) rates.

5.3.4 BC Hydro Proposal and Stakeholder Engagement

As described in section 2.2.3.5 of the Application, BC Hydro engaged E-Plus customers through a letter dated February 24, 2015 seeking feedback on the E-Plus rate as well as holding two open houses held in Nanaimo and Victoria on April 1 and April 2, 2015. BC Hydro received approximately 3,700 Residential E-Plus customer responses to the February 24, 2015 letter (about 45 per cent of the total number of Residential E-Plus customers). The vast majority of respondents support Option 1 for a number of reasons including:

1. The E-Plus rate is a contract between BC Hydro and the customer (37 per cent of comments);

2. Investments in back-up systems were made in good faith (36 per cent of comments);
3. Electricity affordability (36 per cent); and
4. The closed rate will end under attrition given the generally older age of E-Plus customers (21 per cent).

As described in the section 5.1 of the Workshop 9a/9b consideration memo, the E-Plus Homeowners Group (**EPHG**) provided feedback in the form of a letter (found at Attachment 7 to the Workshop 9a/9b consideration memo at Appendix C-3B) expressing why EPHG believes E-Plus service should be maintained under existing terms and conditions. The comments of EPHG largely parallel the feedback from individual Residential E-Plus customers:

- BC Hydro should respect its agreements with E-Plus customers;
- Homeowners have made considerable investments to qualify and remain on E-Plus;
- Ending the E-Plus program would impose considerable financial hardship on users, almost all of whom are seniors;
- E-Plus rates are associated with energy conservation; and
- The small group of households on the E-Plus program do not measurably impact power supply or costs in the province.

EPHG notes also that E-Plus customers were not notified of the additional Option 3 under consideration. Despite this, in its letter EPHG opposes Option 3. EPHG considers that the E-Plus rate has been serving a useful function since it was first introduced. Refer to the copy of EPHG's letter of June 9, 2015 found at Attachment 7 to the Workshop 9a/9b consideration memo at Appendix C-3B of the Application. As noted below in this section, EPHG and a few Residential E-Plus customers provided BC Hydro with feedback on Option 3 in September 2015.

BCOAPO indicated it was neutral on Residential E-plus issues. Other organizations representing some sectors of BC Hydro's residential ratepayers commented as follows. At Workshop 9b COPE 378 suggested an option whereby customers are given a choice between truly interruptible service, if a service can be developed and implemented to provide an appreciable benefit to BC Hydro and the system that justifies the lower rate, and a phase-out of RS 1105 over a reasonable period instead of the attrition program currently in place. As part of its written Workshop 12-related feedback BCSEA questioned whether Option 3 would improve the situation but notes that it had not had a chance to review BC Hydro's response to BCSEA's written questions, which were provided in Attachment 6 to the Workshop 9a/9b consideration memo.

Taking into account the feedback received BC Hydro favours Option 3 for the reasons described in section 5.2 of the Workshop 9a/9b Consideration Memo and Workshop 9b Discussion Guide (found at Appendix C-3B). Some of the reasons include:

- Rejection of Option 2 on the basis of the large bill impacts to E-Plus customers of Option 2. The median expected bill impact to E-Plus customers if E-Plus customers were transferred to the RIB rate is approximately 42 per cent;
- The potential value of capacity and 2013 IRP Recommended Action 2. The 2013 IRP identifies a need for capacity in F2019 assuming BC Hydro continues with its current DSM initiatives and renews IPP contracts as recommended in the 2013 IRP. As canvassed in section 2.3.2.3 of the Application, the system capacity value is based on Rev 6 at $50-55/kW-year if no LNG demand materializes.[202] As part of 2013 IRP Recommended Action 2, BC Hydro is investigating the viability of residential demand response initiatives through a pilot program in Sidney and North Saanich, Vancouver Island aimed at shaving and shifting peak load by focusing on hot water heating and storage. Option 3

[202] If forecasted LNG demand materializes, the next avoided capacity generation resource would be a SCGTs with a UCC of about $88/kW-year; refer to section 2.3.2.3 of the Application.

dovetails with these initiatives. Refer to BC Hydro's response to BCSEA Question 11.2 found at Attachment 6 to the Workshop 9a/9b consideration memo for further details; and

- The proposed changes to Special Condition 1 will allow for the Residential E-Plus rate to be practically interruptible. BC Hydro proposes the following language for Special Condition 1 as shown on the amended RS 1105 in Appendix F-1D: "*BC Hydro will provide electricity under this rate schedule only to the extent that it has energy and capacity to do so. BC Hydro may, at any time and from time to time, interrupt the supply of electricity under this rate schedule where BC Hydro does not have sufficient energy or capacity*". This language aligns with interruption provisions in the recently Commission approved Shore Power Rates.[203] The proposed language is also generally consistent with Commission Order No. G-37-90[204] which approved interruption criteria for E-Plus service as follows: "*BC Hydro may, at any time and from time to time, interrupt the supply of energy under this Rate Schedule*". This point is expanded on in BC Hydro's response to BCSEA written question 1.6 provided in Attachment 6 to the Workshop 9a/9b consideration memo at Appendix C-3B.

In summary, Option 3 ensures that customers who use the E-Plus rate would continue to receive the current discount, while also ensuring that the rate is truly interruptible and serves a useful function as was intended when the discount was offered.

BC Hydro communicated its selection of Option 3 to Residential E-Plus customers by way of a letter dated August 26, 2015, a copy of which is found at

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[203] Refer to Exhibit B-1 in the Approval for Shore Power Rate proceeding, Appendix C-1, Special Condition 1 of RS 1280; http://www.bcuc.com/Documents/Proceedings/2015/DOC_43469_B-1-BCH-Application-ShorePowerRate.pdf. The Commission approved the Shore Power Rate pursuant to Commission Order No. G-111-15; http://www.bcuc.com/Documents/Orders/2015/DOC_43961_G-111-15_BCH_Shore-Power-Order-with-Reasons.pdf.

[204] http://www.bcuc.com/Documents/Orders/1990/DOC_39416_G-37-90_BCH_CloseAvailabilityofResidentialandGeneralDuelFuelInterruptibleService.pdf.

Appendix C-3E. In response, EPHG sent two e-mails on September 4, 2015 and a letter dated September 4, 2015 (copies found at Appendix C-3E) raising two issues with Option 3:

1. Requesting that BC Hydro include in RS 1105 a statement that BC Hydro will not sell power outside of B.C. for six months prior to interrupting Residential E-Plus customers. BC Hydro rejects this potential condition given that it would mean BC Hydro would never be able to interrupt Residential E-Plus customers as BC Hydro buys and sells electricity every day through trade; and
2. Asking BC Hydro to confirm the notice period for interruptions. Since its inception, RS 1105 has not contained a notice period provision. As part of developing its response, BC Hydro reviewed its other interruptible rates. There is no notice provision in RS 1280 (the Distribution Service Shore Power Rate) or RS 1891 (the Transmission Service Shore Power Rate). There is a requirement in RS 1880 for customers to give 30 minutes' notice prior to taking energy under RS 1880 but this is not analogous to the Residential E-Plus situation. BC Hydro concluded that RS 1852 (Modified Demand) is the most relevant of its existing interruptible rates. There is no notice provision in RS 1852 itself. However, section 5.1 of the accompanying TS 54 provides that "BC Hydro will make reasonable efforts to alert the Customer by telephone of the potential of making an Offer for Demand Reduction in the days or hours ahead" (refer to section 7.3.2 of the Application for additional detail). BC Hydro proposes the following as business practices: (i) the issuance of a 'seasonal notice' each year prior to the November-February winter months reminding Residential E-Plus customers that they are served on an interruptible rate. This seasonal notice would be given to all Residential E-Plus customers through auto-dialer, e-mail or letter; (ii) up to one week's notice that an interruption event is likely to occur. This notice would happen through auto-dialer, e-mail or letter. The interruption itself would occur by manual or automatic means or by written notice as set in Special Condition 3 of RS 1105.

5.4 Low Income Rate

As noted above in section 5.1, consideration of any intervener low income rate proposal will occur through IRs on intervener evidence, additional legal submissions and other processes as the regulatory review of RDA Module 1 unfolds. This section provides BC Hydro's low income rate legal and jurisdictional assessment as communicated through the 2015 RDA stakeholder engagement processes.

As described in section 2.2.1.1 of the Application, BC Hydro's proposed rates in the 2015 RDA, and the rates to be set by the Commission, must be 'fair, just and not unduly discriminatory'. Pursuant to subsections 59(1) and 59(2) of the *UCA*, public utilities must not make, demand or receive "an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service by it" in B.C. While the Commission has considerable discretion in designing rates pursuant to section 60 of the *UCA*, subsection 60(1)(b) provides that the Commission "must have due regard in the setting of a rate that: (i) it is not unjust and unreasonable within the meaning of section 59 …". As noted in Table 2-7 in Chapter 2, generally speaking, BC Hydro accepts Bonbright's view that rates are unduly discriminatory when they have a serious distortion effect on the relative use of the service. This means rate structures must not be divorced from the nature and quality of the associated service, including cost of service.

The issue of the Commission's jurisdiction to approve a differentiated rate for BC Hydro's low income customers arose in 2008 as part of the review of BC Hydro's RIB rate. BC Hydro's and intervener submissions concerning this topic are found at the Commission website.[205] In the 2008 RIB Decision the Commission stated that it was unnecessary to decide the issue of its jurisdiction to set low income rates because the Commission concluded that even if it had the jurisdiction to do so, it would not exercise that discretion as "the vast majority of BC Hydro's low income

205 http://www.bcuc.com/ApplicationView.aspx?ApplicationId=187.

customers will be better off under the [the approved RIB rate as compared to] a flat rate".[206] Refer to section 5.2.4.3 above for further discussion on this topic.

In the context of *UCA* sections 58 to 61 rate setting, low income rates are likely to be seen as unduly preferential to low-income customers or unduly discriminatory to the remaining customers who subsidize those rates because the low income rate would be based on the personal characteristics of the customer, divorced from the cost to deliver electricity to the premises. BC Hydro outlined this position at Workshops 1, 3 and 9a, and section 2.1.2 of the Workshop 3 consideration memo (found at Appendix C3-A).

This position accords with the majority of Canadian electric utilities and utility commissions, where cost-based ratemaking is the most widely-used standard for evaluating whether rates are 'fair, just and not unduly discriminatory'. Canadian electric utilities typically offer targeted low income DSM programs, as opposed to low income rates:

- Each of the Nova Scotia Public Utility and Review Board (**NSRUB**),[207] the New Brunswick Energy and Utilities Board[208] and the Alberta Energy and Utilities Board[209] decided that in the absence of express language authorizing the particular utility board to set rates according to customer's ability to pay rather than according to the cost of serving those customers, low income rates are unduly preferential and/or unjustly discriminatory;
- Ontario is the exception. In 2008, a majority of the Ontario Superior Court of Justice, Divisional Court in *Advocacy Centre for Tenants-Ontario v. Ontario*

[206] 2008 RIB Decision, pages 32 to 33; refer to note 50 in Chapter 2 for citation.
[207] In 2006, the Nova Scotia Court of Appeal (**NSCA**) in *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.* (2006 NSCA 74) upheld that the NSURB does not have jurisdiction to set a rate featuring credits for low income customers as Nova Scotia's *Public Utilities Act* (R.S.N.S 1989, c.380) (***NSPUA***) did not authorize NSURB to set rates based on customer income level. The NSCA agreed with NSURB that low income rate relief is a social and public policy question for the Nova Scotia legislature.
[208] *In the Matter of a Review of New Brunswick Power Distribution and Customer Care Corporation's Customer Care Policies*, 29 January 2007, pages 12 to 13; http://142.166.3.251/Documents/Decisions/Electricity/E/2007%2001%2029%20Disco%20Decision%20final%20E.pdf.
[209] Decision 2004-066, section 9.2.6; http://www.auc.ab.ca/applications/decisions/Decisions/2004/2004-066.pdf.

Energy Board[210] found that the Ontario Energy Board (**OEB**) is granted authority to use "any method or technique it considers appropriate" in approving "just and reasonable rates" under Part III (Gas Regulation), section 36 of the *Ontario Energy Board Act*[211] (***OEB Act***). Subsequently, the OEB introduced the Low Income Energy Assistance Program[212] (**LEAP**) and the related Low Income Customer Rules. All regulated utilities are required to offer LEAP, which among other things consists of specific low income rules such as: security deposit waiver; equalized billing payments (spread evenly over 12 months); suspension of disconnection process for 21 days; and more time to pay outstanding balances. LEAP is described in more detail in section 8.6.1.1 of the Application as it pertains to BC Hydro's assessment of the potential low income terms and conditions, and is also the subject of BC Hydro's jurisdictional review of low income rates/low income terms and conditions/low income DSM programs found at Appendix C-3D. In a letter dated April 23, 2014 the Ontario Minister of Energy invoked section 35 of *OEB Act* to request OEB recommendations on rate relief consisting of credits applied against low income electricity bills.[213] The OEB in its December recommendations report stated that it believed legislative change would be necessary as the OEB indicated that it did not have the authority to either set a charge on ratepayers for this type of program or to establish the rules for the funds to be disbursed to the utility distributors.[214] In February 2015 the Ontario Minister of Energy announced

[210] [2008] OJ No. 1970. In this regard, the Ontario court contrasted section 36 of the *OEB Act* with section 67 of the *NSPUA*, which provides that rates must "under substantially similar circumstances and conditions in respect of service of the same description be charged equally to all persons and at the same rate".

[211] S.O. 1998, c.15, Sch. B; copy available at http://www.canlii.org/en/on/laws/stat/so-1998-c-15-sch-b/latest/so-1998-c-15-sch-b.html.

[212] http://www.ontarioenergyboard.ca/OEB/Consumers/Consumer+Protection/Help+for+Low-Income+Energy+Consumers.

[213] Copy at http://www.ontarioenergyboard.ca/oeb/_Documents/Documents/letter_low-income_affordability_20140423.pdf.

[214] OEB, *Report of the Board: Developing an Ontario Electricity Support Program*, December 22, 2014, page 25; http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2014-0227/Report_of_the_Board_Developing_an_OESP_20141222.pdf.

such rate relief would proceed, with costs to be recovered from all regulated utility ratepayers.[215]

As part of the Manitoba Public Utilities Board (**MPUB**) decision (**MPUB Order 73/15**,[216]concerning Manitoba Hydro's 2015/16 and 2016/17 General Rate Application (**Manitoba Hydro 2015-2017 Rate Application**)), the MPUB ordered Manitoba Hydro to initiate a collaborative process to develop a 'bill affordability program'. The MPUB concluded it had jurisdiction to make Order 73/15 through subsection 26(4) of the Manitoba *Crown Corporations Public Review and Accountability Act*,[217] which authorizes the MPUB to consider "any compelling policy considerations that [MPUB] considers relevant to the matter", and that this language is broadly worded similar to the *OEB Act*. The MPUB ordered a collaborative process to examine a number of different bill affordability program models, including capping a customer's bill or providing a fixed credit on the bill (all based on household income), and an inclining block rate similar to the RIB rate on the basis that such a rate is more progressive that Manitoba Hydro's flat residential rate.

Refer to Appendix C-3D for BC Hydro's jurisdictional review of low income rates/low income terms and conditions/low income DSM programs. The common element is that legislation has been used in those jurisdictions in which low income rates have been introduced or in which the utility commission may consider such rates:

- An example of the former is California, where the California legislature mandated with the 1975 *Warren-Miller Energy Lifeline Act*[218] that each California residential electricity customer should receive a minimal supply of electricity at a discounted price while paying a higher price for electricity taken in excess of that minimum. The California legislature tasked the CPUC with

215 Copies of the Ontario Minister of Energy's letters and details concerning the announced rate relief are found at http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Low-Income%20Assistance%20Review%20%28EB-2014-0227%29.

216 Section 4.0 of MPUB Order No. 73/15 concerning Manitoba Hydro's 2015/16 and 2016/17 General Rate Application; http://www.pub.gov.mb.ca/pdf/15hydro/73-15.pdf.

217 C.C.S.M. c.C336; copy at https://web2.gov.mb.ca/laws/statutes/ccsm/c336e.php.

218 California Stats 1975, Ch. 1010, section 1(a).

designating a baseline quantity "which is necessary to supply a significant portion of the reasonable energy needs of the average residential customer"; the result is the 'baseline allowance'.[219] The CPUC by statute is tasked with not only ensuring utility rates are just and reasonable. The *California Public Utilities Code* also states that "electricity is a basic necessity" and that "all residents of the state should be able to afford essential electricity", directs the CPUC to ensure that low income ratepayers are not "[j]eopardized or overburdened by monthly energy expenditures" and addresses the lifeline program[220] established by the *Miller-Warren Energy Act*;

- Quebec is an example of the latter. The legislature passed *An Act Respecting the Régie de l'Énergie*;[221] section 49 allows the Régie de l'Énergie to consider rates that are 'fair and reasonable', and 'consider such economic, social and environmental concerns as have been identified by order by the Government'. To date Quebec has not introduced low income rates.

5.5 Methodologies for Minister Residential Inclining Block Rate Letter

This section is organized to respond to the Commission RIB Report Methodology Letter as follows. The Commission RIB Report Methodology Letter asks BC Hydro for "a detailed outline of the methodologies for the report [BC Hydro] will submit to the Commission on the five questions posed by the [Minister RIB Report Letter] including":

- How BC Hydro intends to define "low income customers" – refer to section 5.5.1;

[219] The definition of baseline allowance under California statute and under CPUC orders has evolved over time. BC Hydro understands that electric utilities presently calculate the baseline using between 50 to 55 per cent of the average residential usage for a number of California climactic zones.

[220] California Public Utilities Code, sections 382(b) and 739; http://www.leginfo.ca.gov/cgi-bin/calawquery?codesection=puc.

[221] CQLR c. R-6.01.

- How BC Hydro intends to define “factors” that lead to high energy use – refer to section 5.5.2;
- For each of the five questions, the general approach BC Hydro intends to take to answer the question – this is set out in section 5.5.3;
- Any other relevant method(s) BC Hydro will use to gather information or answer the questions posed in the Minister RIB Report Letter – this consists of providing a summary of BC Hydro’s existing Residential DSM programs and detailed information concerning BC Hydro’s two low income DSM program offers. Refer to section 5.6;
- Any other relevant issues with the RIB rate that BC Hydro has not previously addressed but should be included in BC Hydro’s report to the Commission and the Commission’s report to the B.C. Government. Given that BC Hydro is reviewing the RIB rate as part of RDA Module 1, BC Hydro is of the view that the RDA and in particular this Chapter address this issue; and
- Comments on the Commission’s proposed process and suggested timing. BC Hydro urges the Commission to adhere to the Minister RIB Report Letter’s statement that the Commission should use the RDA Module 1 review process to collect information for its report to the B.C. Government. Accordingly, BC Hydro is of the view that the Commission should use the RDA regulatory timetable for the issuance of Round 1 IRs to ask any follow up questions concerning BC Hydro’s proposals and the information provided in sections 5.5 and 5.6 of this Chapter, and to use the proposed December 2015 procedural conference described in section 1.6.1 of the Application to seek input on the timing for BC Hydro’s report to the Commission after BC Hydro submits its responses to any Commission follow up questions in accordance with the timetable for BC Hydro to file its responses to Round 1 IRs.

BC Hydro shared the contents of sections 5.5 and 5.6 of the Application with FortisBC on September 17, 2015. FortisBC advised BC Hydro on

September 18, 2015 that the two utilities are generally aligned with respect the methodological approach to address the Minister RIB Report Letter. There may be some differences in available data.

5.5.1 Definition of Low Income Customers

BC Hydro proposes to use Statistics Canada's LICO as the method for defining low income customers. LICO is an income threshold below which a family will likely devote a larger share of its income on the necessities of food, shelter and clothing than the average family. The approach is essentially to estimate an income threshold at which families are expected to spend 20 percentage points more than the average family on food, shelter and clothing. The reasons for using LICO are:

- Statistics Canada releases LICO updates annually using CPI;
- LICO includes required spending on a comprehensive set of basic necessities and not just on one specific component such as housing or energy costs;
- LICO is sensitive to family and community size as cut-offs vary by seven family sizes and five different populations of the area of residence.[222] Thus LICO reflects different regional costs of living between rural and urban areas and between urban areas of different sizes; and
- LICO is the basis for all 2015 RDA residential rate modelling, as elaborated upon below.

BC Hydro proposes to use pre-tax rather than after-tax income levels. Pre-tax levels are easier for customers and survey respondents to think about and report, and are therefore used in the REUS.

[222] The five different population groupings are: (1) Rural areas, which includes communities with a population of less than 1,000 or with a population density less than 400 persons per square kilometer that are located outside Census Metropolitan Areas (**CMAs**) or Census Agglomerations (**CAs**); (2) Population under 30,000: CAs below 30,000 and population centres below 10,000 persons; (3) Population 30,000 to 99,999: CAs between 30,000 and 99,999 persons; (4) Population 100,000 to 499,999: CMAs between 100,000 and 499,999; and (5) Population 500,000 and over: CMAs with 500,000 or more persons.

5.5.1.1 Leveraging BC Hydro's Residential End-Use Study to Inform Low Income Analytics

BC Hydro has undertaken bi-annual quantitative end-use studies with its Residential customers over the past thirteen years to help facilitate and inform the load forecast and DSM program, rate design and codes and standards development. The most recent REUS is the 2014 REUS, a copy of which is found at Appendix C-3F of the Application.

The specific objectives of the REUS are to collect – and track over time – detailed information about the characteristics and features of Residential customers' homes, as well as the saturation of electrical end-uses. Areas of interest include:

- Customer household demographics;
- Home structure basics such as housing type, year home built, size of home, etc.;
- Doors, windows and insulation;
- Space heating;
- Heating controls and home temperatures; and
- Water Heating.

In addition to collecting end-use information, the REUS solicits customer opinions, attitudes and behaviours relating to electricity and conservation.

Aside from any 'proof of' documentation required by Residential customers when participating in BC Hydro's low income DSM programs, BC Hydro estimates the incidence of low income customer accounts in its service area and profiles them using its REUS – first by the individual flagging of customer households in the survey sample, followed by sample expansion to the overall population.

Step 1: Flagging REUS Households as Low Income Customers

The REUS provides two of the three parameters necessary to flag a given customer household as low income using LICOs: 1) the household's total pre-tax annual income; and 2) its total number of occupants. The household's service town and postal code are then used to link in the third parameter – 3) the population of the household's CMA via Statistics Canada census data. In addition to the community size, parameters relating to the mean and median household income as well as the incidence of low income for the household's postal code area are linked in as reference parameters.

For every one of the 7,451 households (i.e., survey records) in the 2014 REUS survey, the process was as follows:

- Match in the population of its CMA based on its postal code;
- To serve as a surrogate in the event of missing values, also match in the neighborhood's mean and median household income levels;
- Flag the customer account as low income if reported total pre-tax income is below the LICO cut-point corresponding to its household size and its CMA area;
- Consider neighborhood level information should the survey record be missing income and/or household size; and
- Consider neighborhood level information should the LICO cut-point be within the household's income bracket.

Note that every survey record must be flagged as LICO or not-LICO due to the fact that missing values (i.e., missing flags) will bias the estimation of the overall incidence of low income households.

For a given customer household, the accuracy of BC Hydro's low income classification procedure is dependent and challenged by several factors: 1) the disclosure or completeness of the survey respondent's total household income, 2) the accuracy of the survey respondent's reporting of total household income, 3) the use of bracketed household income levels in the end-use survey and 4) the disclosure or completeness of the survey respondent's total number of household occupants. These factors are discussed below.

Disclosure of Total Household Income - Total household income is the most essential parameter needed to classify a customer household in the REUS as possibly being low income. When a missing value occurs on this parameter, the customer household has to be either left as unclassified in their low income status or other secondary information has to be leveraged to make an informed classification. In this case, the mean and median household income levels for the household's postal code area together with the area's incidence of low income are taken into account to inform the decision on the low income status. For example, if the mean and median income levels for the postal code area are $65,000, and the incidence of low income in that neighbourhood is say 2 per cent, then the household in question has a very low probability of actually being of low income status. Note that in this case, $65,000 is greater than even the largest of the LICO thresholds.

Not unlike most other market research studies, a total of 25 per cent of responding customers in the 2014 REUS chose not to disclose their total household income. Analysis of the survey data indicates that these missing values are more or less evenly dispersed among other disclosed demographics such as region, dwelling type, household size as well as respondents' gender, age and education. This suggests that 'item' response bias is likely minimal. Instead of discarding these households from any low income analysis, BC Hydro incorporated their neighbourhood income information to serve as a proxy during classification.

Accuracy of Reporting of Household Income - Income levels in the REUS are at the combined household level and as such, the accuracy of total reporting is dependent on a survey respondent's estimation or solicitation of all other working members in the home of their individual earnings. For a household with two working adults, as an example, slightly inaccurate reporting of total income – say, off by just $5,000 – can potentially qualify or disqualify a household of low income status. The mitigating factor is that the study is self-administered, thereby giving the survey respondent essentially an unlimited amount of time to make a considered estimate of the total household pre-tax income level.

Step 2: Sample Expansion (Data Weighting)

As with most other analytics facilitated by the 2014 REUS, the sample of 7,451 survey records is statistically weighted by four housing types within four regions to precisely reflect the known distributions among all Residential accounts in BC Hydro's billing system. This ensures that the sample, analytics and related findings – including those that pertain to low income households – are generalizable to the entire population of Residential customers in BC Hydro's service area.

5.5.1.2 Estimated Incidence of Low Income BC Hydro Customer Households

The estimated incidence of low income BC Hydro customer households based on Statistics Canada pre-tax LICO cut-off measures 10 per cent in regards to the 2013 tax year. Regionally, this incidence measures highest at 11 per cent among customer households in the Lower Mainland. By housing type, the incidence measures highest at 17 per cent among customer households in apartments/condominiums and lowest at 6 per cent among customer households in single detached houses. Refer to Table 5-14 and Table 5-15.

Table 5-14 Low Income Status for the 2013 Tax Year by Region

	Total (%)	Lower Mainland (%)	Vancouver Island (%)	Southern Interior (%)	North (%)
Yes – Low Income Household	10	11	8	7	9
No	90	89	92	93	91

Table 5-15 Low Income Status for the 2013 Tax Year by Housing Type

	Total (%)	Single Detached House (%)	Duplex/Row/ Townhouse (%)	Apartment/ Condominium (%)	Mobile Home/Other (%)
Yes – Low Income Household	10	6	10	17	11
No	90	94	90	83	89

5.5.1.3 Other LICO Definitions considered

BC Hydro reviewed the possibility of using the LICO multiplied by 1.3 measure forming part of the definition of "low-income household" in section 1 of the Demand-Side Measures Regulation[223] (**DSM Regulation**) but is concerned that this would have a distorting effect on analysis undertaken with respect to the RIB rate. Use of LICO results in the categorization of 10 per cent of BC Hydro's Residential customers as low income customers, while use of the DSM Regulation's LICO multiplied by 1.3 would more than double this to about 24 per cent of BC Hydro's Residential customers.[224] All of the RDA modelling for the RDA stakeholder engagement process and for the RDA itself (refer to sections 5.2.4 and 5.2.5 above) used LICO. Re-modelling and related analysis on the basis of the DSM Regulation's LICO multiplied by 1.3 would take months. BC Hydro engaged with BCOAPO on this issue at a meeting on August 18, 2015 and understands that BCOAPO agrees with BC Hydro that Statistics Canada's LICO should be used for purposes of responding to the Minister RIB Report Letter. BCOAPO supports the continued use of the DSM Regulation's definition of low-income households as being LICO multiplied by 1.3 for low income DSM programs.

5.5.1.4 BC Hydro Residential Rate Modelling for Stakeholder Engagement

BC Hydro undertook extensive Residential rate design modelling for the RDA stakeholder engagement process which will be relied on for purposes of

[223] B.C. Reg. 326/2008; https://www.canlii.org/en/bc/laws/regu/bc-reg-326-2008/latest/bc-reg-326-2008.html.
[224] Based on the Vancouver CMA LICO.

questions 1, 2 and 3 in the Minister RIB Rate Report Letter. As noted in section 2.4.3 of the Application, for the residential sector, BC Hydro used a representative sample of 10,000 to illustrate the overall population impact. This is followed by using the representative sample from the REUS to assess impacts by customer segments, such as low income, electrical heating and housing types. Refer to sections 5.2.4 and 5.2.5 above.

5.5.2 Defining Factors Leading to High Energy Use

BC Hydro defines the phrase "high energy use" as including both energy consumption and peak demand. Based on the 2014 REUS and the Residential rate class segmentation analysis in section 4.2.1 of the Application, BC Hydro identifies the following factors as driving higher than average annual electricity consumption:

- Electricity consumption by heating fuel. The 2014 REUS found that single detached houses which rely on electricity for their home heating emerge as having had the highest annual consumption at 17,758 kWh (2014 REUS, page 234); and
- Electricity consumption by housing type within region. Due primarily to the fact that they rely on electricity for space heating, residential customers on Vancouver Island lead all four regions in average annual consumption at 11,776 kWh. Average household consumption was higher in the Southern Interior (10,211 kWh) and the North (9,894 kWh) than it was in the Lower Mainland (8,634 kWh), most likely due to the relatively heavier electrical demand for space heating and space cooling in those regions (2014 REUS, page 233).

BC Hydro considered but rejected number of occupants as a factor. As noted in the 2014 REUS, while the average annual household consumption of electricity generally steps up with the number of individuals in the home, the number of household occupants is correlated with the physical size of the home in terms of floor area.

5.5.3 Approach to Address Minister Residential Inclining Block Rate Letter

Minister RIB Report Letter Question 1

BC Hydro will assess the possibility of the RIB rate causing a "cross-subsidy between customers with and without access to natural gas service" posed by Minister RIB Report Letter question 1 using cost of service information.

Responding to this question requires a practical definition of "access to natural gas". BC Hydro proposes adopting a community approach to define access to natural gas. As noted in the Workshop 12 summary notes found at Appendix C-1B,[225] pages D8 to D10 of Fortis Gas' tariff[226] list communities that have access to natural gas. Examples of B.C. communities in BC Hydro's service area without natural gas include: Clearwater, Golden, Invermere, Port Hardy and Valemount. According to the 2014 REUS about 50 per cent of households in these communities use electricity for primary heating, which is higher than the provincial average. This is supported by billing data that shows F2014 average residential consumption of 14,000 kWh per year in these areas, which is higher than median consumption for electric or non-electric residential customers of about 10,000 kWh and 8,500 kWh per year respectively as reported on slide 24 of the Workshop 3 slide deck presentation at Appendix C-3A.

Minister RIB Report Letter Question 2

Question 2 asks "[w]hat evidence is available about high bill impacts [greater than 10 per cent as a result of the adoption of the [BC Hydro RIB rate] on low income customers?". As noted in section 5.2.2 above, the RIB rate was implemented on

[225] BC Hydro response to question 7 in Part 2 of the summary notes.

[226] http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasTariffs/Documents/FortisBC_GeneralTermsAndConditions.pdf.

October 1, 2008, almost seven years ago. Accordingly, to respond to question 2, BC Hydro proposes:

- To highlight the Commission's findings of the RIB rate impacts on low income customers in the 2008 RIB Decision. As noted in section 5.2.4.3 above, the Commission found "the vast majority of BC Hydro's low-income customers will be better off under a simple two-step inclining block structure that is revenue neutral for the residential customer class then under the [then current] flat rate";
- To assess the two F2017-F2019 pricing principle options for the RIB rate discussed in section 5.2.5.1 above. BC Hydro's preferred pricing principle Option 1 results in bill impacts set out in Table 5-8 above (F2017 – 4 per cent; F2018 – 3.5 per cent; and F2019 – 3 per cent). No low income customer will have a bill impact greater than 10 per cent under RIB rate pricing principle Option 1;
- As the RIB rate has been in place for almost seven years, the only sound method to gauge bill impacts to low income customers is to compare the RIB rate to an alternative had the RIB rate not been in place. BC Hydro proposes that the flat energy rate modelled for the 2015 stakeholder engagement process and described in section 5.2.4.1 above serve as the counter-factual. As noted in Table 5-3 above, BC Hydro estimates that with a flat rate, in F2017 80 per cent of low income accounts will experience bill impacts greater than 10 per cent, and 47 per cent greater than 20 per cent.

Minister RIB Report Letter Question 3

As illustrated in section 5.2.4.1 above, BC Hydro modelled the bill impacts of moving from the RIB rate to a flat rate by dwelling type (apartments) and for customers using electric space heating. BC Hydro also proposes to model the bill impacts of moving from the RIB rate to a flat rate for customers in communities that do not have access to natural gas.

Minister RIB Report Letter Questions 4 and 5

The Commission RIB Report Methodology Letter at page 3 asks BC Hydro to provide:

> d. Any other relevant method [BC Hydro] will use to gather information or to answer the questions posed in the [Minister RIB Letter].

The Minister RIB Report Letter question 4 asks what the potential is for existing DSM programs to mitigate any RIB rate-related high bill impacts on low income customers, if there are such impacts; and question 5 asks what options there are for additional residential DSM programs, including low income programs, within the current regulatory environment. Section 5.6.1 below provides a summary of BC Hydro's existing Residential DSM programs, while section 5.6.2 contains detailed information on BC Hydro's two existing low income DSM program offers. As set out in section 5.2.4.3 above, BC Hydro's assessment is that in comparison to the RIB rate, a move to a flat rate will result in high bill impacts to the majority of BC Hydro's low income customers. In addition, no low income customer will have a bill impact greater than 10 per cent under RIB rate pricing principle Option 1. Nevertheless, BC Hydro provides information on its existing low income DSM programs as part of responding to Minister RIB Report Letter questions 4 and 5, and to fulfil the commitment made to BCOAPO and other stakeholders at Workshop 12 that BC Hydro would provide such information in the RDA Module 1 filing.

5.6 BC Hydro Residential Demand Side Management Programs

Minister RIB Report Letter question 5 states "[w]ithin the current regulatory environment, what options are there for additional [DSM] programs, including low income programs". The phrase "within the current regulatory environment" raises two issues:

- At Workshop 12, BC Hydro set out its view that the Commission cannot accept or reject expenditures associated with BC Hydro's existing low income or other Residential DSM programs as part of the 2015 RDA decision because low income DSM programs are not rates. The proper venue for such a Commission decision would be a section 44.2 *UCA* DSM expenditure determination filing;[227] and
- The F2017-F2019 rate caps set out in section 9 of Direction No. 7 (discussed in section 2.2.1.3 of the Application) must inform any response to Minister RIB Report Letter questions 4 and 5.

5.6.1 BC Hydro's Existing Residential Demand Side Management Programs

BC Hydro's existing Residential DSM programs are summarized in Table 5-16.

Table 5-16 Existing BC Hydro Residential DSM Programs

Program Name	Description
Retail Rebate	Provides a rebate offer for lighting, appliances, consumer electronics and other energy efficient products.
Behaviour	Provides an incentive for Residential customers who are successful in reducing their electricity consumption by 10% over one year.
Refrigerator Buy Back	Provides an incentive for the removal of secondary, inefficient fridges.
New Home	Provides incentives to owners of qualified Energy Star new homes. Features of Energy Star new homes include efficient heating and cooling systems, Energy Star appliances, heat recovery ventilation systems, insulation and Energy Star windows and doors.
Home Energy Rebate Offer	Provides rebates to owners of existing homes for improving the energy efficiency of their home. Rebates are provided for insulation, draft proofing, ductless heat pumps, Energy Star water heater, Energy Star bathroom fans, Energy Star windows and doors, Energy Star high efficiency heating systems and Energy Star heat recovery ventilators.
Low Income	Provides energy savings kits and financing for deeper energy efficiency retrofits for low income customers. Refer to section 5.6.2 below.

[227] Refer to Part 2, response to question 6 of the Workshop 12 summary notes at Appendix C-1B of the Application.

5.6.2 BC Hydro's Existing Residential Low Income Demand Side Management Programs

BC Hydro has two existing low income DSM program offers:

- Energy Savings Kits (**ESKs**): The ESK is a package of basic energy saving measures provided at no charge that can be installed by most homeowners or tenants with limited or basic tools. ESKs contain lighting-related products (such as CFLs, light switch stickers and a nightlight), water saving products (such as faucet aerators and a low flow showerhead), heat-loss products (such as water heater pipe wrap, draft proofing material, and window film) and general energy savings tips and brochures. As of August 31, 2015, almost 85,000 low-income houses have received energy savings kits from BC Hydro since the ESK program launched in April 2008; and
- Energy Conservation Assistance Program (**ECAP**): ECAP provides eligible BC Hydro low income Residential customers at no charge with a home evaluation, installation of energy saving products and education on what customers can do around their homes to save energy. Some of the energy saving products that may be installed include energy saving light bulbs (compact fluorescent lamps), low-flow showerheads and faucet aerators, a water heater blanket and pipe wrap, advanced draft proofing (such as caulking and door sweepers), an Energy Star refrigerator, a high-efficiency gas furnace, and insulation for attics, walls and crawlspaces. As part of the December 2012 DSM Milestone Evaluation Summary, BC Hydro estimated eligible low income households, about 47 per cent own and inhabit electrically heated SFDs eligible for further retrofits under the basic or advanced stream of ECAP. The advanced stream includes basic offerings but adds a comprehensive home insulation offer. Both electric and natural gas heated SFDs are eligible for the insulation upgrades offer due to BC Hydro's partnership with FortisBC. ECAP commenced in May 2009. As of August 31, 2015, over 11,400 of BC Hydro's Residential customers have participated in the program (with over 2,500

receiving Energy Star fridges). The energy savings kits referred to above can help recipients save up to $100/year on utility bills, while a low income customer receiving basic measures and a fridge could save up to $150/year and a low income customer receiving insulation upgrades up to $300/year (approximately 25 per cent of the annual bill for a typical electrically-heated single-family home for a low-income customer in BC Hydro's service area).

These two DSM program offers have delivered nearly half a million dollars in electricity cost savings to participants to date. Similarly defined programs are available in many other North American jurisdictions; refer to the low income rate/low income DSM program jurisdictional review at Appendix C-3D.

Low income customers face barriers to participation in BC Hydro's conventional Residential DSM programs. Factors affecting participation include low disposable income and sub-optimal access to program information and financing. Program activities to reach qualified low income participants include marketing bill inserts, direct mail campaigns, advertising through non-profits, print materials, as well as contractor training, quality assurance services and technical consulting services. BC Hydro strives to reach customers by partnering with existing agencies that are already working within this community. Partnerships to date include FortisBC, the B.C. Ministry of Social Development and Social Innovation (**MSDSI**), BC Housing, food banks and Better At Home (managed by the United Way, one of the largest social service agencies in B.C.). BC Hydro also provides capacity funding to non-profit housing providers and aboriginal units to assist them to hire someone locally to help promote the ESK and ECAP programs and collect application forms from tenants and/or members of the community on behalf to the two programs.

These two DSM program offers identified above were originally designed for Residential low-income customer identified under Statistics Canada's before-tax LICO. On July 10, 2014 amendments to the DSM Regulation came into effect. The following is relevant to BC Hydro's low income DSM programs:

- The low income program eligibility LICO threshold is raised to 1.3 times the LICO; and
- There is a list of pre-qualified recipients of various government income and housing assistance programs.

Table 5-17 sets out the low income household income levels for ESK and ECAP eligibility.

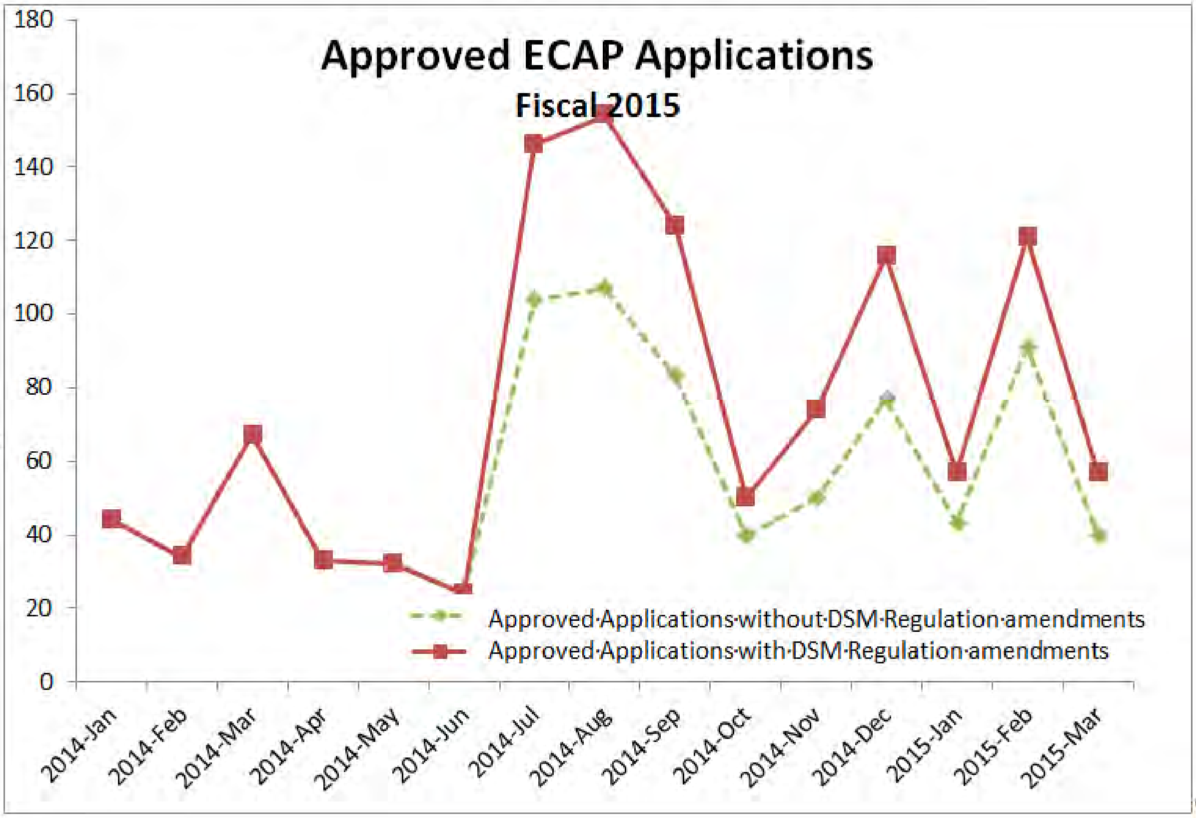
Table 5-17 ESK and ECAP Eligibility Household Incomes

Household Size (Number of Persons)	Household Income ($)
1	31,700
2	39,400
3	48,500
4	58,800
5	66,700
6	75,200
7 or more	83,700

At Workshop 9a, BC Hydro stated that it anticipates that these DSM Regulation changes will increase eligibility for its two low income DSM programs from 11 per cent to 21 per cent of BC Hydro residential customers. Figure 5-30 below sets out ECAP applications for F2015. The dashed line shows the applications that would have been approved prior to the changes to the DSM Regulation, while the solid line shows the applications under the DSM Regulation changes. As a result of the DSM Regulation amendments relating to the definition of "low income household", 260 additional households were approved for ECAP, representing a 42 per cent increase in individual applications.[228]

[228] Based on individual applicants; excludes bulk applications from non-profit housing providers and aboriginal communities where individual income levels are not collected.

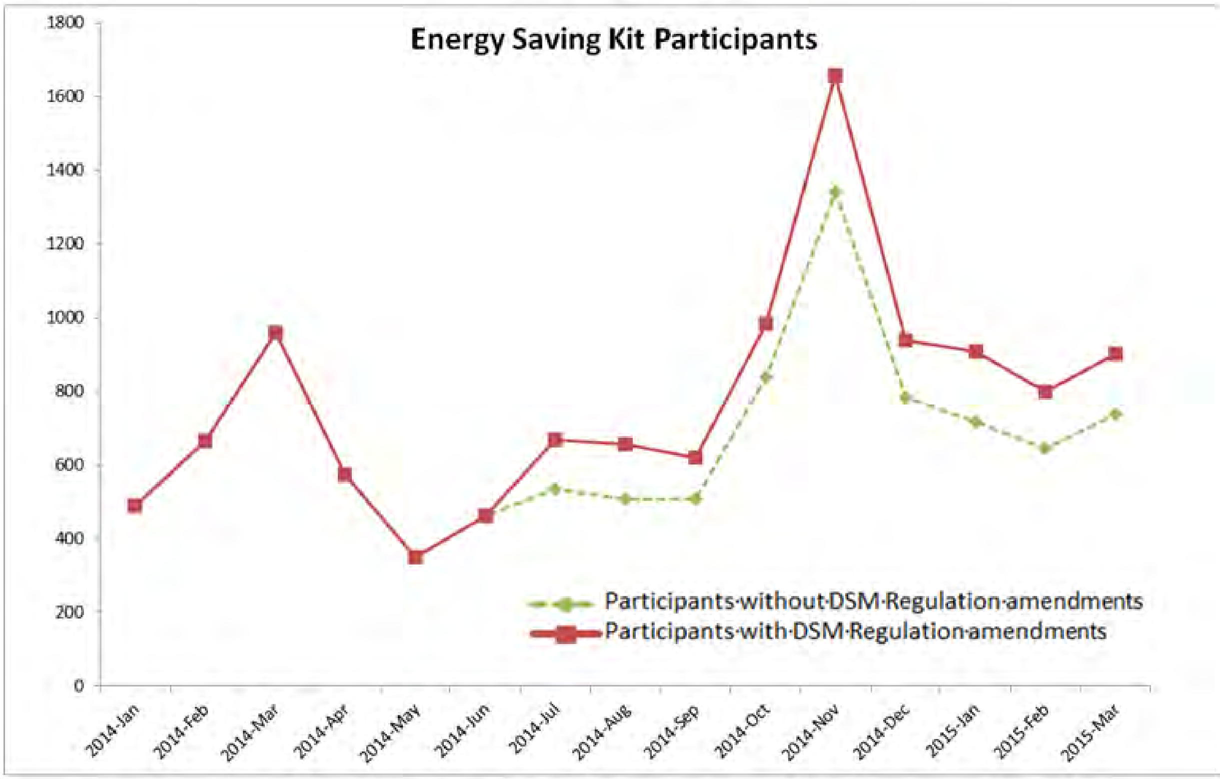
Figure 5-30 DSM Regulation Amendments and ECAP Participants



In F2015, the DSM Regulation amendments resulted in 1,500 additional households[229] receiving ESKs, representing a 23 per cent increase in participation. Refer to Figure 5-31.

[229] Refers to households who would not have qualified under the previous DSM Regulation low income rules.

1 **Figure 5-31 DSM Regulation Amendments and ECAP**
2 **Participants**



2015 Rate Design Application

Chapter 6

General Service Rate Design

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6.1 Introduction and Chapter Structure

This Chapter outlines BC Hydro's proposals for SGS, MGS and LGS rates. As described in section 1.4 of the Application, General Service customers collectively can be thought of as BC Hydro's commercial and small industrial customers.

The existing General Service rate structures are:

- The SGS rate class which consists of General Service customers whose billing demand is less than 35 kW. The SGS rate class is served under RS 1300/1301/1310/1311 (collectively referred to at times as RS 13xx). The current default rate structure for SGS customers consists of a flat energy rate and a basic charge;
- The MGS rate class which consists of General Service customers whose billing demand is equal to or greater than 35 kW but less than 150 kW and whose energy consumption in any 12-month consecutive period is equal to or less than 550,000 kWh. The MGS rate class is served under RS1500/1501/1510/1511 (collectively referred to at times as RS 15xx). The existing default rate structures for MGS customers consists of a two-part energy rate (sometimes referred to as a '**baseline-based rate**'), a three-step inclining block demand charge, a basic charge and a monthly minimum charge (referred to at times as the '**demand ratchet**'); and
- The LGS rate class which consists of General Service customers whose billing demand is equal to or greater than 150 kW or whose energy consumption in any 12-month period is greater than 550,000 kWh. The LGS rate class is served under RS1600/1601/1610/1611 (collectively referred to at times as RS 16xx). The existing default rate structures for LGS customers consists of a two-part energy rate, a three-step inclining block demand charge, a basic charge and a monthly minimum charge.

Figure 6-1 and Figure 6-2 illustrate the breakdown between the three General Service rate classes by GWh sales and number of accounts (F2015).

Figure 6-1 F2015 General Service – Energy Sales (GWh)

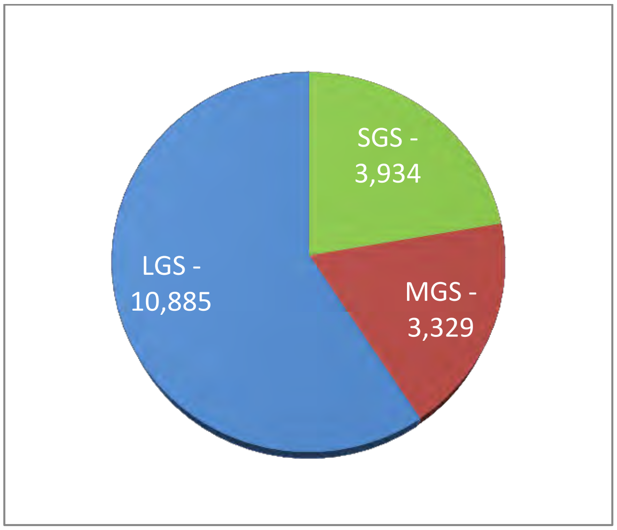
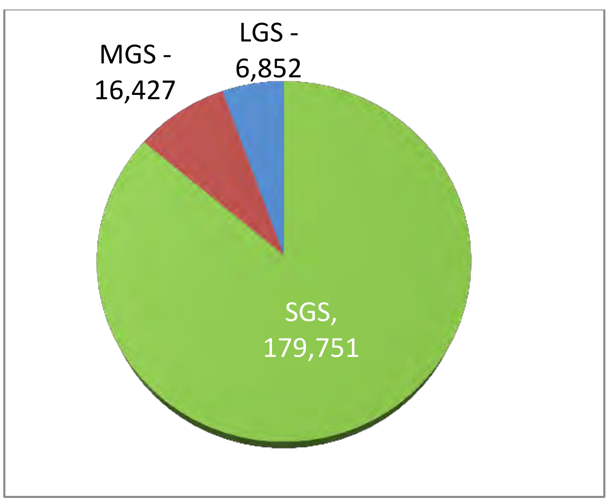


Figure 6-2 Number of General Service Accounts (Ending number, F2015)



As identified in section 1.5.2 of the Application, RDA Module 2 will address:

- NIA (Zone II) and Bella Bella (Zone IB) rate design issues, including: RS 1234 (Small General Service (Under 35 kW) – Zone II) and RS 1255/1256/1265/1266

(General Service (35 kW and Over) – Zone II); and RS 1200/1201/1210/1211 (collectively referred to at times as 12xx) as Zone IB customers are served on these rate schedules; and

- Commercial E-Plus rates (RS 1205/1206/1207).

This Chapter does not address the following rate schedules because they were the subject of recent Commission decisions (as discussed in section 2.5 of the Application):

- RS 1280 (Shore Power Service – Distribution); and
- RS 1289 (Net Metering Service).

Finally, this Chapter does not address:

- RS 1268 (Distribution Service – IPP Distribution Transportation Access) as this rate schedule relates to BC Hydro's Open Access Transmission Tariff (**OATT**) and accordingly is more appropriately addressed in an OATT proceeding; and
- RS 1278 (Power Service – (Closed)). RS 1278 originated with one of BC Hydro's predecessor companies, BC Electric, in the 1920s. RS 1278 is designed to encourage industrial developments, specifically electric arc furnaces. RS 1278 was closed in the 1970s and was reviewed by the Commission in the 1991 RDA. The 1991 RDA Decision determined that BC Hydro may terminate rate availability when there is a change in ownership or use. There is currently one customer receiving service under RS 1278. This rate was not reviewed in the 2015 RDA stakeholder engagement process and therefore specific engagement with the customer did not occur. Accordingly, BC Hydro believes it would be inappropriate to eliminate RS 1278 at this time.

6.1.1 Summary of BC Hydro Proposals

Based on the inputs summarized in section 6.1.2, BC Hydro proposes the following, to be effective April 1, 2017:

SGS Rates

- Retaining the existing flat energy rate; and
- Increasing the SGS basic charge recovery of customer-related costs from approximately 33 per cent to 45 per cent.

MGS Rates

- Replacing the existing MGS two-part energy rate with a flat energy rate;
- Replacing the existing MGS three-step inclining block demand charge with a flat demand charge; and
- Increasing the demand charge recovery of demand-related costs from approximately 15 per cent to 35 per cent.

LGS Rates

- Replacing the existing LGS two-part energy rate with a flat energy rate;
- Replacing the existing LGS three-step inclining block demand charge with a flat demand charge; and
- Increasing the demand charge recovery of demand-related costs from approximately 50 per cent to 65 per cent.

6.1.2 Summary of Stakeholder Engagement and Other Inputs

Stakeholder input into BC Hydro's General Service rate proposals included:

- Five workshops on General Service rates:
  - Workshop 8a outlining the regulatory history of and issues associated with the MGS and LGS rate structures, and discussing the existing SGS rate structure;
  - Workshop 8b setting out potential alternatives to the SGS, MGS and LGS rate structures;

- ▶ Workshop 11a identifying BC Hydro's preferred SGS rate structure and SGS basic charge cost recovery, and preferred MGS energy rate structure, and canvassing alternative MGS demand charge structures and cost recovery levels;
- ▶ Workshop 11b addressing alternative LGS energy rate structures and demand charge structures, the MGS/LGS demand ratchets, and potential General Service voluntary rate options for RDA Module 2; and
- ▶ Workshop 12 identifying BC Hydro's preferred MGS demand structure and cost recovery level, and BC Hydro's leaning at that time toward a LGS flat energy rate, flat demand charge and increased demand charge cost recovery.

- Face-to-face meetings with CEC on November 10, 2014 and April 22, 2015 to discuss potential LGS/MGS voluntary rate options for RDA Module 2;
- Face-to-face meetings focused on MGS and LGS energy charge structure alternatives with the following organizations whose members are comprised of LGS and MGS customers:
  - ▶ May 7, 2015 with BOMA, and 14 LGS and MGS customer attendees; and
  - ▶ May 22, 2015 with BCFPA, CME and 20 LGS and MGS customer attendees. Refer to the Workshop 8a/8b consideration memo found at Appendix C-4A for additional detail.

Other inputs included:

- Review of prior Commission decisions, including the 2007 RDA Decision and Commission Order No. G-110-10 approving the 2009 LGS Application NSA;
- Review of LGS, MGS and SGS customer characteristics;
- Two evaluation reports: 1) the F2014 LGS and MGS Evaluation Report referenced in section 2.2.3.3 of the Application and circulated to stakeholders

prior to Workshops 8a/8b; and 2) the *Evaluation of the LGS and MGS Conservation Rates – Calendar Years 2011 and 2012* report (**2011-2012 LGS and MGS Evaluation Report**) contained in the *LGS and MGS Three-Year Report* dated January 1, 2014 (**Three-Year Evaluation Report**). Copies are found at Appendix C-4A, and are discussed in sections 6.3 and 6.4;

- Advice from E3;
- Jurisdictional review of Canadian electric utilities with market structures similar to BC Hydro (vertically integrated monopolies). Refer to Attachment 3 to the Workshop 11a/11b consideration memo at Appendix C-4B of the Application; and
- Internal review of customer-related issues and complaints and rate administration issues as further described in this Chapter and Appendix C-4D.

6.1.3 Chapter Structure

The remainder of this Chapter is structured as follows:

- Section 6.2 – Default SGS rate. Section 6.2.1 identifies the SGS Proposal. Section 6.2.2 provides background to the existing SGS rate, including discussion of SGS customer characteristics. Section 6.2.3 contains the reasons for the SGS Proposal, together with a discussion of why an inclining block rate and a baseline-based energy rate are not viable alternatives. Section 6.2.3 also provides BC Hydro's rationale for proposing an increase in the SGS basic charge cost recovery;
- Section 6.3 – Default MGS rate. Section 6.3.1 identifies the MGS Proposal. Section 6.3.2 provides background to the existing MGS rates, including a summary of the relevant Commission direction and review of MGS customer characteristics. Section 6.3.3 canvasses the two evaluation report findings concerning MGS, while section 6.3.4 outlines the alternatives to the existing MGS rates analyzed with stakeholders. Section 6.3.5 concludes this section

with a discussion of BC Hydro's proposal to substantially simplify the existing MGS rate structure;

- Section 6.4 – Default LGS rate. Section 6.4 is structured in the same way as section 6.3. Section 6.4.1 identifies the LGS Proposal. Section 6.4.2 provides background to the existing LGS rates, including review of LGS customer characteristics. Section 6.4.3 canvasses the two evaluation report findings concerning LGS, while section 6.3.4 outlines the alternatives to the existing LGS rates analyzed with stakeholders, which differed from the MGS alternatives. Section 6.4.5 concludes this section with a discussion of BC Hydro's proposal to substantially simplify the existing LGS rate structure;
- Section 6.5 provides BC Hydro's phase-in analysis for the proposed MGS and LGS rates. BC Hydro concludes that: (1) a three year phase-in period for BC Hydro's preferred MGS rate may have minor mitigation of bill impacts but the trade-off is a complex transition that will not give MGS customers certainty; and (2) a phase-in period for the preferred LGS rate is not an effective bill impact mitigation strategy;
- Section 6.6 contains the rationale for BC Hydro's request for a final order effective January 1, 2016 approving a change in the pricing for new accounts that do not have a Historical Baseline (**HBL**) on RS 15xx or RS 16xx from 85/15 Pricing to 100 per cent Part 1 Pricing;
- Section 6.7 discusses three requests related to assumed Commission approval of BC Hydro's MGS and LGS rate proposals: (1) terminating TS 82, the rules for prospective growth applications for modified LGS pricing, and transfer of any remaining LGS customers on TS 82 modified pricing to RS 16xx effective April 1, 2017; (2) dissolving the LGS and MGS control groups and related amendments to RS 12xx; and (3) terminating RS 2600/2601/2610/2611 (collectively referred to at times as RS 26xx) and transferring Corix Multi-Utility

Services Inc. (**Corix**), the sole customer talking service under RS 26xx, to the LGS rate on April 1, 2017;

- Section 6.8 summarizes the reasons why BC Hydro is proposing no changes to RS 1253 (Distribution Service – IPP Station Service) at this time.

6.2 Small General Service

6.2.1 BC Hydro's Small General Service Proposal

BC Hydro proposes maintaining the existing SGS rate structure of a flat energy rate and a basic charge. BC Hydro seeks approval of a one-time increase to the RS 13xx basic charge to 45 per cent recovery of customer-related costs attributable to the SGS class in the F2016 COS study, and a one-time offsetting reduction of the energy rate, to maintain forecast revenue neutrality based on the SGS revenue target calculated using any applicable rate increases arising from the F2017 RRA. The proposal results in the following illustrative SGS pricing assuming the F2018 rate cap increase of 3.5 per cent: a flat energy rate for all kWh of approximately 11.39 cents/kWh and a basic charge of approximately 33.12 cents/day (F2018).

6.2.2 Background

The pricing elements of the existing SGS default rate structure are set out in Table 6-1:

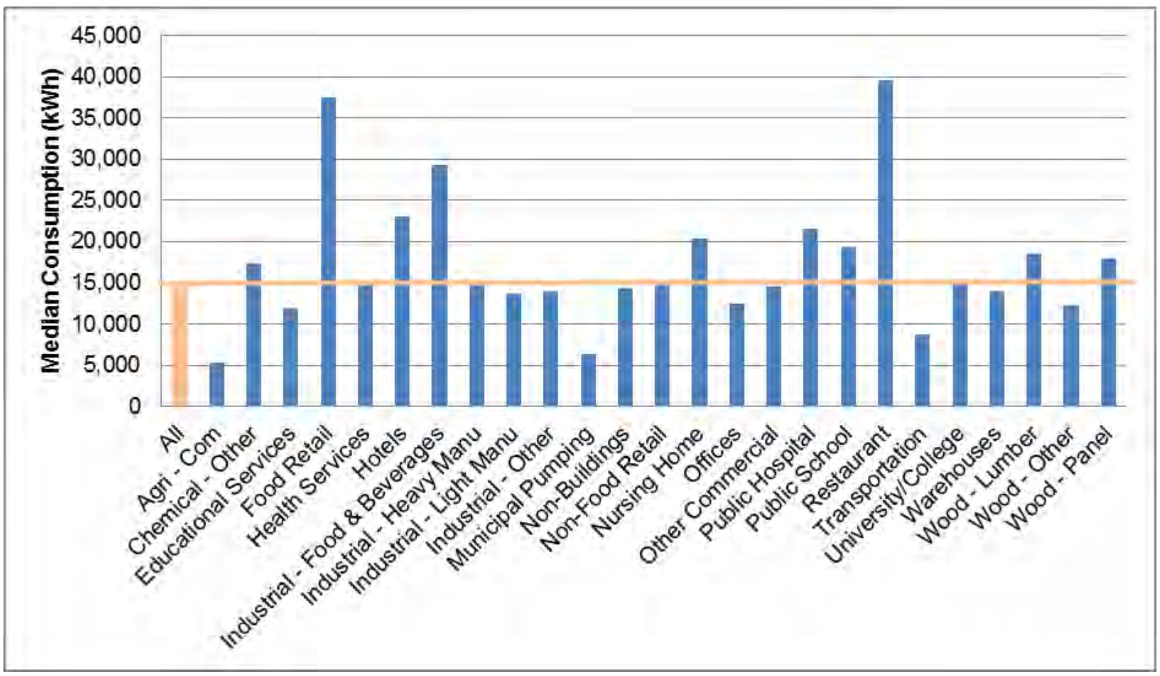
Table 6-1 Existing SGS Rates (F2016)

Energy Rate (cents/kWh)	Basic Charge (cents/day)
10.73	22.57

The flat energy rate structure has been in place since 1996; prior to that a declining block energy rate was in effect. There has been no demand charge since at least 1973. As noted at Workshop 8a, about 45 per cent of SGS customers have residential-type meters and these meters do not have Measurement Canada approved demand functions.[230] The SGS basic charge currently recovers about 33 per cent of customer-related costs allocated to the SGS rate class. There were no SGS restructuring proposals in the 2007 RDA, nor was SGS rate design the subject of the 2009 LGS Application. As a result there are no relevant Commission directions pertaining to the SGS rate.

The SGS class consists of 179,751 accounts with total consumption of about 3,934 GWh (F2015). There is a high degree of diversity within the SGS rate class; 'typical' customers in the 20th to 80th percentile of class consumption ranges from about 5,000 to 35,000 kWh/year. As Figure 6-3 highlights, there are a variety of SGS site types and median SGS consumption varies widely by site type.

Figure 6-3 Median SGS Consumption by Site Type



230 Per the Electricity and Gas Inspection Regulations, SOR/86-131; copy available at http://laws-lois.justice.gc.ca/eng/regulations/SOR-86-131/. Although demand could be calculated using meter interval data, it cannot be used for billing as it is not recognized as demand processed legal unit of measurement. Refer also to slide 70 of the Workshop 8a presentation at Appendix C-4A to the Application.

6.2.3 Small General Service Rate and Options Reviewed

There is no better alternative to the existing SGS rate. It is easy to understand and simple to administer, and generally reflects LRMC in its flat energy structure. The sole issue identified through stakeholder engagement is whether BC Hydro should increase the SGS basic charge recovery of customer-related costs from about 33 per cent to 45 per cent. The alternatives brought forward in the 2015 RDA are summarized in Table 6-2.

Table 6-2 Alternative SGS Pricing

Pricing Element (F2017)	BC Hydro Proposal (Increase basic charge to 45% of customer-related costs)	Status Quo
Energy rate (cents/kWh)	11.01	11.16
Basic charge (cents/day)	32.00	23.47

6.2.3.1 SGS Rate Structure

At Workshop 8a BC Hydro stated that it saw no strong basis to depart from the existing SGS rate structure. The flat energy rate of 11.01 cents/kWh (F2017) is within BC Hydro's energy LRMC range (upper bound is 11.13 cents/kWh (F2017)).

BC Hydro rejects a demand charge for the SGS rates. As noted in section 4.3.1 of the Application, almost all surveyed Canadian electric utilities do not bill smaller general service customers separately for demand. The main distinguishing rate design feature between larger general service rates and rates for the smallest class is that the smaller class is typically considered too small to justify the expense and added complexity of demand meters and rate structures. Refer to Attachment 3 to the Workshop 11a/11b consideration memo (found at Appendix C-4B) for BC Hydro's Canadian jurisdictional review of general service rates. No stakeholder suggested that the SGS rate structure should have a demand charge. As indicated in section 1.5.1 of the Application, customer understanding and acceptance/practical and cost-effective to administer is one of BC Hydro's three prioritized rate design criteria. A demand charge would make the SGS rate more complex to understand. A

SGS demand charge would also require a demand meter which not all SGS customers have. The requirement for a demand meter on all SGS customers makes the demand charge less practical and cost-effective to administer.

A flat energy rate is common across comparable small general service rate classes of surveyed Canadian electric utilities; declining block energy rates are also common. BC Hydro identified two potential energy rate alternatives to the existing SGS flat energy rate. Neither alternative is viable:

- An inclining block rate would not be easy to implement in a fair and reasonable manner given the overall heterogeneity of the SGS rate class, as highlighted in Figure 6-3. Absent an individual customer baseline-based rate structure, there are no criteria to support a one-size fits all threshold for a SGS inclining block rate that would be a fair reflection of typical SGS customer consumption. There is no jurisdictional support for an inclining block rate for smaller general service customers.[231] CEC opposes an inclining block rate for the SGS rate class for the reasons set out by BC Hydro;
- A baseline-based energy rate for SGS customers is too complex and not appropriate as a SGS default rate structure at this time, given the identified problems with the baseline-based MGS and LGS rate structures discussed in sections 6.3 and 6.4. No other surveyed North American electric utility has implemented baseline-based rates for general service customers.

At Workshop 11a, BC Hydro indicated that no SGS rate structure issues had been identified through the 2015 RDA stakeholder engagement process. There was general agreement among stakeholders that there is not a strong basis to depart from the existing SGS rate structure.

[231] As noted in section 2.4.2.2 of the Application, Ontario has a different market structure than B.C. Nevertheless, as suggested by Commission staff, BC Hydro surveyed Ontario for residential and general service rate purposes. Ontario implemented an inclining block rate for smaller general service customers but is in the process of phasing out the inclining block rate.

6.2.3.2 SGS Basic Charge Cost Recovery

In response to Workshop 8a-related stakeholder feedback, at Workshop 11a BC Hydro reviewed the impacts of increasing the basic charge recovery of customer-related costs from about 33 per cent to a level comparable to the RIB rate basic charge customer-related cost recovery of about 45 per cent (F2016 COS). As set out in Table 3-7 in Chapter 3, Residential and SGS customer cost allocation is similar, as are energy and demand cost allocations. BC Hydro concluded that the RIB rate basic charge customer-related cost recovery level is the appropriate reference.

To inform stakeholder comment on this topic at Workshop 11a, BC Hydro assessed bill impacts. Forecast F2017 bill impacts resulting from increasing the SGS basic charge cost recovery to 45 per cent and the offsetting reduction in the energy rate (as a result of forecast revenue neutrality) are set out in Table 6-3 in section 6.2.4.

6.2.4 BC Hydro Proposal and Stakeholder Engagement

CEC, which represents customers taking service under SGS rates, acknowledges that the increase in basic charge recovery of customer-related costs will improve fairness. AMPC, BCOAPO and FNEMC also support this position. Only COPE 378 does not support an increase to the SGS basic charge cost recovery. COPE 378 maintains that the reduction in the energy rate, although small, is directionally counter to energy conservation.

In BC Hydro’s view, there are no rate design objectives to be traded off. Increasing the SGS basic charge recovery to 45 per cent of customer-related costs aligns with the Bonbright fairness criterion by matching embedded cost recovery in rates with cost causation. Moreover, there is no conflict with the economic efficiency criterion:

- The predicted increase to the SGS basic charge results in a small reduction to the SGS energy rate (from 11.16 cents/kWh to 11.01 cents/kWh (F2017)) which remains reflective of the energy LRMC;

- Any reduction in natural conservation (at the default -0.5 per cent elasticity BC Hydro assumes for RRA rate increase-related price responsiveness) would be very small.

Illustrative Simulations

While BC Hydro is filing for a SGS rate design change in F2018 (effective April 1, 2017), the RDA stakeholder engagement-related simulation of SGS rate estimates and bill impact assumed a one-time rate design change in F2017 for illustrative purposes. The actual rates in F2018 will be finalized through the F2017 RRA.

Table 6-2 lists the key calculation features of the alternative rate structures, and the rates estimated for F2017. All rates are modelled to be revenue neutral to the status quo SGS rates; that is, all alternatives recover the same target revenue of $471 million given a consumption forecast of 3,882 GWh. Further details about the modelling calculations are found in Appendix H-1A.

Table 6-3 highlights that the bill impacts of the proposed basic charge cost recovery increase are minimal to the majority of SGS customers on both a percentage and absolute basis. The basic charge is a relatively high percentage of the total bill for only a very small percentage of SGS customers. The analysis found that the bill difference is below 10 per cent for almost all SGS customers, and below 5 per cent for 80 per cent of SGS customers.

Table 6-3 Annual bill impacts of an increase in the SGS Basic Charge to recover 45 per cent of customer-related costs

Percentile by Consumption	Annual kWh	F2017 Annual Bill Status Quo ($)	F2017 Annual Bill BC Hydro Proposal ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo ($)	Annual Bill Difference between F2017 BC Hydro Proposal and F2017 Status Quo (%)	Bill Impact (%) of F2017 BC Hydro Proposal (vs. F2016 Rates)
Min	1	86	117	31	36	42
10	2,001	309	337	28	9	13
20	4,773	618	642	24	4	8
30	7,797	956	975	19	2	6
40	11,184	1,334	1,348	14	1	5
50	15,288	1,792	1,800	8	0	4
60	20,648	2,390	2,390	0	0	4
70	28,435	3,259	3,247	-12	0	-4
80	40,838	4,643	4,613	-30	-1	-3
90	65,174	7,359	7,292	-67	-1	-3
Max	615,810	68,810	67,918	-892	-1	-3

6.3 Medium General Service

6.3.1 BC Hydro's Medium General Service Proposal

BC Hydro is proposing a new substantively simplified rate structure for customers who take service under RS 15xx: a flat demand charge established to recover approximately 35 per cent of BC Hydro's demand-related costs attributable to the MGS rate class in the F2016 COS study and a flat energy rate established to maintain forecast revenue neutrality based on the MGS revenue target calculated using any applicable rate increases arising from the F2017 RRA.

The MGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 8.83 cents/kWh; a flat demand charge of approximately $4.92 per kW (reflecting BC Hydro's preferred 35 per cent level of cost recovery); and a basic charge of about 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These illustrative charges are calculated assuming the F2018 rate cap increase of 3.5 per cent. Final F2018 MGS pricing will be determined by the F2017 RRA decision.

As set out in section 6.5.1, BC Hydro proposes a one-time transition on April 1, 2017 (F2018) from the current MGS rate structure to BC Hydro's proposed MGS rate structure.

6.3.2 Background

The MGS rate class consists of 16,427 accounts with total consumption of about 3,329 GWh (F2015). The existing MGS default rate structures are:

- A two-part energy rate approved in 2010 pursuant to Commission Order No. G-110-10 on June 29, 2010 as an outcome of the 2009 LGS Application NSA. Prior to implementation of the existing two-part energy rate, MGS customers were served under a declining block energy rate as part of a single large general service class (35 kW and over). All MGS customers were transitioned to the existing rate by April 1, 2013 (refer to section 6.3.2.1);
- A three-step inclining block demand charge (refer to section 6.3.2.2). BC Hydro has had an inclining block demand charge since at least 1974. The five-step inclining block was changed to a four-step inclining block charge in 1976, and changed to the existing three-step structure in 1980;[232] and
- A basic charge and a monthly minimum charge. The current MGS basic charge is 22.57 cents/day. The MGS monthly minimum charge is 50 per cent of the highest maximum demand charge billed in any billing period in the on-peak

[232] At Workshop 8a Commission staff asked BC Hydro what the rationale was for the inclining block demand charge, and BC Hydro responded that it was not able to determine the rationale; refer to Attachment 1 to the Workshop 8a/8b consideration memo, Part 2, BC Hydro response to Question 1. The ratio of charges for demand greater than 150 kW as compared to for demand between 35 kW and 150 kW has remained 1.9 since 1980.

period of November through March during the immediately preceding eleven billing periods.

There is one Commission Order No. G-110-10 direction that is relevant to RDA Module 1 as noted in Table 6-4.

Table 6-4 Summary of Relevant Commission Order No. G-110-10 Direction

Direction	Status
4 – BC Hydro is to file, within 36 months of the Implementation Date of January 1, 2011, a report which addresses the issues outlined in paragraph 16 of the NSA	The Three-Year Evaluation Report referenced in section 6.1.2 was filed with the Commission in compliance with the Commission Order No. G-110-10 to respond to paragraph 16 of the 2009 LGS Application NSA requiring BC Hydro to report on, among other items: whether the control groups are still adding value; whether there is any evidence of customers opening new accounts to avoid exposure to the Part 2 rate under the two-part rate structure; and estimated energy savings to date. The Three-Year Evaluation Report is discussed in the context of the LGS rate options in section 6.4.2 as it is more relevant to the LGS options than the MGS options for the reasons set out in section 6.3.4.

6.3.2.1 Existing MGS Energy Rate

The existing MGS energy rates are set out in Table 6-5.

Table 6-5 Existing MGS Energy Rates (F2016)

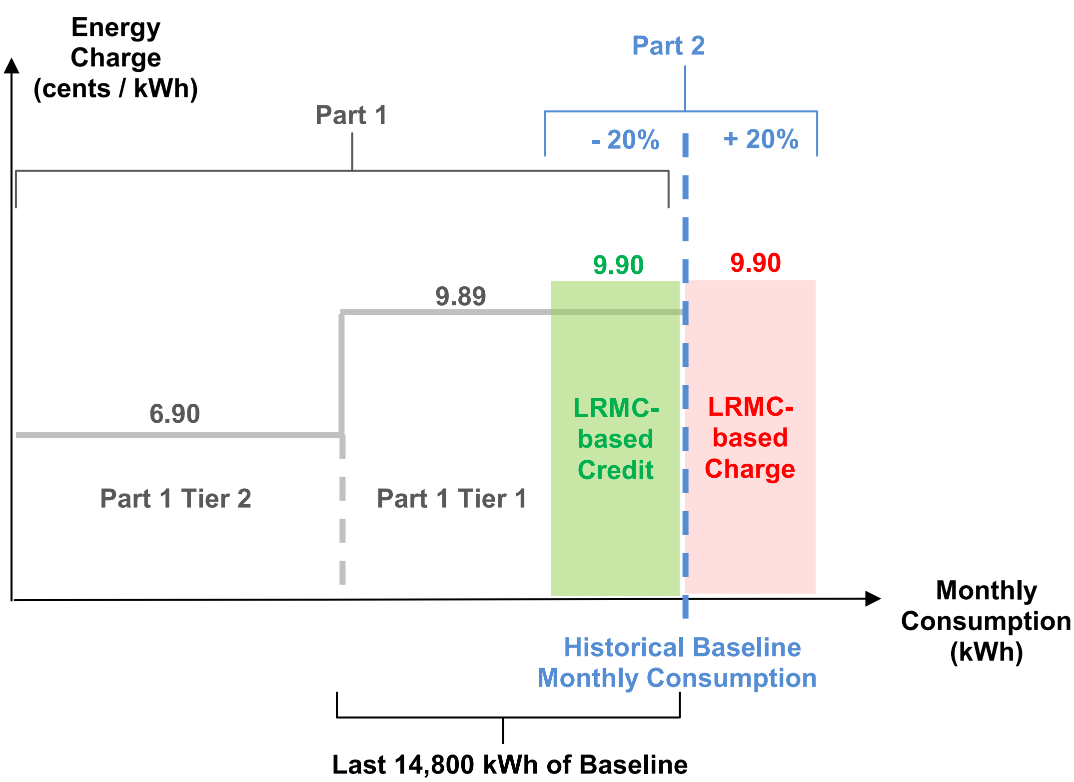
Part 1 Energy Rate – Tier 1 (cents/kWh)	9.89
Part 1 Energy Rate – Tier 2 (cents/kWh)	6.90
Part 2 Energy Rate (cents/kWh)	9.90

As described in section 2.3.1.7 of the Application, as part of the 2009 LGS Application BC Hydro proposed a flat energy rate for the MGS rate class. BC Hydro emphasized the novelty of the two part baseline-based energy rate it was proposing for the LGS rate class and stated the following with respect to extending a baseline-based rate to the MGS rate class:

> … the specific two part rate proposed for the new LGS class is quite complex … The novelty and complexity of BC Hydro's proposed two part rate means it would be much more challenging to manage, and therefore much riskier to both BC Hydro and its customers, if it were to be applied at the outset to all 23,000 … accounts, rather than to the 5,000 [LGS] accounts with demand of 150 kW or greater.[233]

The two-part energy rate structure was approved for the MGS class under the terms of the NSA. The overarching objective of the two-part rate structure was to provide MGS customers with an efficient price signal to induce energy conservation. Figure 6-4 illustrates the MGS two-part energy rate structure.

Figure 6-4 MGS 2-Part Energy Rate Structure



The Part 1 Tier 1 energy rate applies to the last 14,800 kWh of an individual customer's historically determined monthly consumption level, or 'baseline' (HBL),

[233] BC Hydro 2009 LGS Application, page 2-14; http://www.bcuc.com/Documents/Proceedings/2009/DOC_23224_2009_10_16%20APPL_09LGS.pdf.

and the Part 1 Tier 2 energy rate applies to all remaining baseline consumption. The Part 2 energy rate is a credit on the difference between actual billed consumption and baseline consumption when consumption is lower than baseline and a charge on the difference between actual consumption and baseline consumption when consumption is higher than baseline. The LRMC-based credits or charges under the Part 2 energy rate are limited to differences of plus or minus 20 per cent of baseline consumption, defined as the Price Limit Band (**PLB**). Consumption differences beyond the PLB receive credits or charges under the applicable Part 1 energy rates. For further illustration of the mechanisms of the MGS two-part rate under example customer consumption levels, refer to slides 32 to 34 of the Workshop 8a presentation at Appendix C-4A to the Application.

The MGS two-part energy rate and the LGS two-part energy rate described in Section 6.4.2 are atypical rate structures; to BC Hydro's knowledge, they are the only baseline-based default rates for general service customers in North America. As noted in section 6.2.3.1, other Canadian electric utilities serve their general service customers through either a flat or declining block energy rate.

As discussed in section 6.3.3, the key issue with the existing MGS two-part energy rate is that it has not met the purpose for which it was intended. The existing MGS energy rate structure does not provide a clear price signal for conservation and is poorly understood by customers. The result is that BC Hydro has not been able to detect any conservation savings to date and that BC Hydro cannot count on and does not forecast any conservation savings going forward.

6.3.2.2 Existing MGS Demand Charge

BC Hydro has a three-step inclining block demand charge for the MGS rate class as depicted in Table 6-6.

Table 6-6 Existing MGS Demand Charges (F2016)

First 35 kW of Billing Demand per Billing Period (Tier 1)	$0.00 per kW
Next 115 kW of Billing Demand per Billing Period (Tier 2)	$5.50 per kW
All additional kW of Billing Demand per Billing Period (Tier 3)	$10.55 per kW

Most jurisdictions have flat or declining demand charges. The key issue associated with the existing MGS three-step inclining block demand charge is that it does not align with BC Hydro's cost to serve MGS customer peak demand, which is generally flat on a $/kW basis.

6.3.2.3 MGS Customer Characteristics

Table 6-7 shows that of the 37 site types identified in BC Hydro's F2014 billing data, the top ten site types have 78 per cent of the consumption in the class. In particular, Offices, Non-Food Retail and Restaurants are the highest consuming sectors, with about 45 per cent of total class consumption.

Table 6-7 MGS Consumption by Site Type

Site Type	Percentage of class consumption
Offices	19
Non-Food Retail	14
Restaurants	12
Other Commercial	6
Hotels	5
Warehouses	5
Residential-High-Rise Apt Common Area	5
Public School	5
Industrial-Light Manufacturing	4
Food Retail	3
Other	22

Seventy-eight per cent of accounts in the MGS Class are also represented by the top ten site types (Table 6-8). In particular, Offices, Non-Food Retail, and Restaurants site types stand out as the sectors with the largest portion of accounts, at 44 per cent of all accounts.

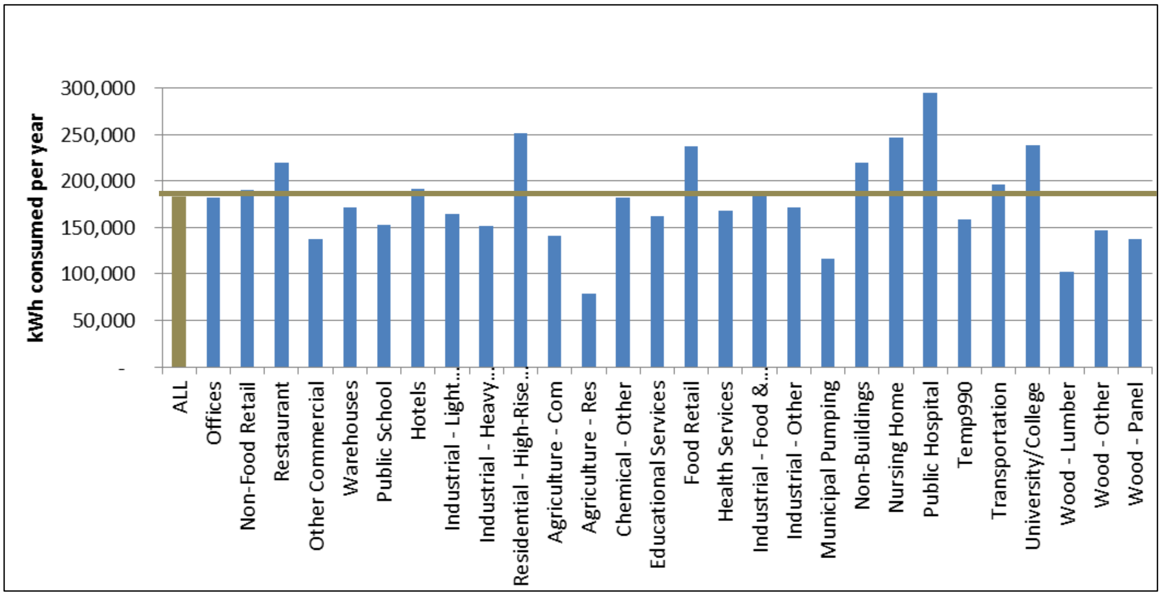
Table 6-8 MGS Accounts by Site Type

Site Type	Percentage of accounts
Offices	20
Non-Food Retail	14
Restaurants	10
Other Commercial	7
Warehouses	6
Public School	5
Hotels	5
Industrial-Light Manufacturing	5
Industrial-Heavy Manufacturing	3
Residential-High-Rise Apt Common Area	3
Other	22

The MGS class is heterogeneous in terms of consumption. Consumption also tends to vary substantively by site type, as shown by the variations of the medians for each site type in Figure 6-5. In terms of annual load factor, about 80 per cent of the class has a load factor between 20 per cent and 60 per cent (refer to the Workshop 8a presentation materials).[234]

[234] Refer to slides 17 to19, 24, 25 and 26 to 27 in particular; the Workshop 8a presentation is found at Appendix C-4A.

Figure 6-5 Median MGS Consumption by Site Type



6.3.3 MGS Two-Part Energy Rate Evaluation Reports

6.3.3.1 Methodology

As noted in section 6.1.2, the 2011-2012 LGS and MGS Evaluation Report and the F2014 LGS and MGS Evaluation Report were inputs into BC Hydro's assessment of the existing MGS and LGS rates and the development of alternative rate structures. Copies of both evaluation reports are found at Appendix C-4A of the Application. The 2011-2012 LGS and MGS Evaluation Report was filed with the Commission as part of the Three-Year Evaluation Report referenced in Table 6-4. The results of both 2011-2012 LGS and MGS Evaluation Report and the F2014 LGS and MGS Evaluation Report were discussed at Workshop 8a.

The 2011-2012 LGS and MGS Evaluation Report and F2014 LGS and MGS Evaluation Report provided comprehensive evaluations of the impacts and customer response to the MGS and LGS rates. The evaluation of electricity savings was achieved through the use of a randomized control trial research design. This approach is generally viewed as the most accurate method for estimating net impacts, and it is widely accepted in the natural and social sciences as the gold standard of research designs.[235] Secondary analysis of conservation at twelve key account customer sites was also conducted using customer level regression models.

Awareness, understanding, acceptance and response to the rates across all LGS and MGS customers were evaluated using three customer surveys: the first in 2010, the second in 2012 and the a third in 2014. Each survey generated hundreds of responses and these respondents were broadly representative of the population. In addition, customer focus groups and key account manager interviews were completed to gain a deeper understanding of individual customer experiences with the LGS and MGS rates. For example, the F2014 LGS and MGS Evaluation Report utilized customer surveys, interviews with BC Hydro key account managers, and four 90-minute customer focus groups made up of 18 LGS and MGS customers (these September 2014 focus groups sessions are summarized in section 2.2.2.3 of the Application). For further detail on the focus group methodology, refer to page 8 of Appendix F of the F2014 LGS and MGS Evaluation Report at Appendix C-4A.[236]

6.3.3.2 Results

The evaluation of these multiple lines of evidence indicated that the customer response to the MGS two-part energy rate was considerably less than forecast. Awareness and demonstrated understanding of the MGS rates was low. Evaluated net energy savings for MGS rate were not statistically different than zero in 2011, 2012 and F2014, relative to calendar year 2010, as compared to a forecast conservation savings of about 140 GWh/year.[237]

As set out in the F2014 LGS and MGS Evaluation Report:

[235] National Renewable Energy Laboratory, U.S. Department of Energy, *Estimating Net Saving: Common Practice* September 2014, pages 14 & 15; http://www.nrel.gov/docs/fy14osti/62678.pdf.

[236] Each focus group consisted of LGS and MGS accounts, but across all groups, LGS and MGS customers were similar in their awareness, understanding and opinions expressed.

[237] The MGS forecasted conservation savings were based on the overall commercial customer price elasticity of -0.1 (consisting of rate structure induced conservation and natural conservation) based on the jurisdictional assessment set out in Appendix E to the BC Hydro's 2008 Long-Term Acquisition Plan, with adjustments.

- About 25 per cent of MGS customers correctly identified their rate structure out of four possible rate structure selections; and
- Results from the focus groups indicate low demonstrated understanding of the two-part energy rate. Out of 18 focus group participants, only a few were able to correctly explain, unprompted, how the two-part rate worked. Two main areas of confusion are the concept and calculation of a rolling HBL, and the value and mechanism of the Part 2 energy charge or credit; knowledge of these concepts are critical to understanding how changes in electricity consumption translate into bill impacts or energy savings. Most commercial customers reportedly look at their electricity bills, but this is mainly in regards to total dollar amount. The rate structures were rarely mentioned as a motivator for conservation.

6.3.4 Options Reviewed

In BC Hydro's view, there are two MGS rate structure alternatives for consideration in this Application, as developed and reviewed with stakeholders:

1. A flat energy rate and a flat demand charge; and
2. The status quo two-part energy rate and three-step inclining block demand charge for comparison purposes.

In addition, BC Hydro carries forward in this Application an increase to the flat demand charge under alternative (1) above to recover 35 per cent of demand-related costs allocated to the MGS class in the 2016 COS study, an increase from the existing 15 per cent recovery under the current demand charge. The MGS rate alternatives brought forward into the 2015 RDA from the stakeholder engagement processes are summarized in Table 6-9.

Table 6-9 Alternative MGS Pricing (F2017)

Pricing Element	Status Quo MGS Rates	BC Hydro Proposal (35% demand-related cost recovery)	Sensitivity on BC Hydro Proposal (existing demand-related cost recovery ~15%)
Energy rate (cents/kWh)	Part 1, Tier (T) 1: 10.33 Part 1, T2: 7.21 Part 2: 10.10	8.54	9.35
Demand charge ($/kW)	T1: 0.00 T2: 5.72 T3: 10.97	4.76	2.14
Basic charge (cents/day)	23.47	23.47	23.47

The next two sub-sections summarize the processes employed to develop (section 6.3.4.1), and review and narrow (section 6.3.4.2) the alternatives using stakeholder and other inputs. Details are contained in Appendix C-4D.

6.3.4.1 Alternatives Development

At the September 2014 focus groups sessions, several MGS (and LGS) participants suggested as alternatives a flat energy rate or a simple inclining block rate, which would both entail elimination of the baseline-based rate structure. This was the starting point, together with the jurisdictional review, for the development of three broad approaches to MGS (and LGS) energy rate design:

1. Existing baseline-based rate, which is an economically efficient rate intended to deliver an efficient level of energy conservation by exposing customers to an energy LRMC price signal. Within this category a number of options were developed to address MGS customer concerns about the complexity of the MGS rate and its impact on growth. These include flattening the Part 1 energy rate;
2. Inclining block rate, such as the RIB rate; and
3. Flat energy rate, which would deliver energy savings through customer response to RRA rate increases (referred as ‘natural conservation’). Virtually all

jurisdictions surveyed to date adopt flat rates for their general service customer classes, and rely on DSM programs and codes and standards to deliver energy savings.

BC Hydro used its jurisdictional assessment and cost of service to develop three broad approaches to MGS demand charge structure:

1. *Existing three-step inclining block demand charge*;
2. *Two-step inclining block demand charge*. This alternative would retain the current zero Tier 1 and flatten the Tier 2 and Tier 3 into a single Tier 2 rate. A number of Canadian electric utilities (FortisBC for its Commercial class, SaskPower, Manitoba Hydro, Hydro Quebec for its Small Power class, New Brunswick Power) have an inclining two-step demand charge where the first step up to a kW level (typically 50 kW) is $0;
3. *Flat demand charge*. A number of Canadian electric utilities (FortisBC for its Large Commercial class, YECL, Hydro Quebec for its Medium Power and Large Power classes, Nova Scotia Power) have flat demand charges.

Through modelling in preparation for Workshop 8a/8b it became apparent that the energy rate and demand charge structures could not be reviewed in isolation due to bill impacts. This observation is explained in section 6.3.4.2.

6.3.4.2 Screening of Alternatives and Stakeholder Engagement

The review and screening of MGS alternatives occurred in four phases.

Phase 1, Initial Internal Screening

This was necessary given the large number of options, some of which differed only in minor ways, which would frustrate stakeholder engagement if they were all carried forward for detailed review. Screening was accomplished by modelling, feasibility assessment and internal review using the criteria of high bill impacts, suitability for a heterogeneous group of customers and/or performance against the eight Bonbright rate design criteria, as described in Appendix C-4D. A number of potential alternatives were 'screened out'. For example:

- On the demand charge side, a demand charge recovery of 100 per cent of demand-related costs, as it produced excessive bill impacts;
- On the energy rate side, with input from E3, it was determined that an inclining block rate would not be feasible given that it would be very difficult to set a fair and reasonable threshold between Tier 1 and Tier 2 pricing for the heterogeneous MGS rate class; and
- Also on the energy rate side, an alternative that retained the baseline and adjusted the Part 2 rate structure to provide for credit-only pricing, and not charges. This alternative results in Part 1 energy rate increases to all customers and only some growing customers substantively benefitting, while not mitigating any baseline-related complexity issues.

Stakeholders requested a list of screened out alternatives and this was provided in the summary notes for Workshop 8b to inform feedback.[238] In feedback concerning Workshop 8b, participants generally agreed that the criteria BC Hydro used to screen out alternatives are appropriate. By extension, most participants agreed that screened-out alternatives should not be advanced for further review.

The result of the initial internal screening was to reduce the number of alternative MGS rate designs from 18 to the five alternatives shown in Table 6-10.

[238] Refer to Attachment 1 to the Workshop 8b summary notes, which in turn are part of Attachment 1 to the Workshop 8a/8b consideration memo at Appendix C-4A.

Table 6-10 Screened-in MGS Alternatives for Stakeholder Engagement

Screened-in MGS Alternative (MS)		Flatten Part-1 Energy Rate	Flatten Demand Charge	Remove Part 2 Energy Rate (No Baseline)
MS-1	Status Quo Energy Status Quo Demand	Not applicable		
MS-2	Flat Part 1 Energy Status Quo Demand	Yes		
MS-3	Status Quo Energy Flat Demand		Yes	
MS-4	Flat Part 1 Energy Flat Demand	Yes	Yes	
MS-5	Flat Part 1 Energy, No Part 2 Energy Flat Demand	Yes	Yes	Yes

Phase 2, Workshop 8b: Focus on MGS Energy Rate Structures

The categories of alternatives in Table 6-10 were reviewed with stakeholders at Workshop 8b. BC Hydro described alternatives MS-2 and MS-3 as illustrative given that the component rate structures should properly be considered together in evaluating the trade-offs between alternatives. The bill impacts of the energy rate alternatives and demand charge alternatives considered in isolation impacted different types of customers, based on consumption and load factor; these bill impacts are generally offset through coincident flattening of energy rates and flattening of demand charges across all three tiers.

BC Hydro identified that one drawback of MS-4 is that some customers experience large bill impacts, but that relative to the existing MGS rate, the benefits of MS-4 above are:

- A minor improvement in customer understanding and acceptance given that flattening the energy and demand rates simplifies the rate structure;
- An improvement in fairness between customers within the MGS class by aligning cost recovery with the pattern of cost causation to serve MGS

customers. The cost to serve a General Service customer's peak demand is generally flat on a $/kW basis; and

- Demand charge alignment with the rate design practice of other Canadian electric utilities; a three-step inclining block demand charge is unique to BC Hydro.

In comparison to MS-4, BC Hydro described the additional benefits of MS-5 as:

- Substantial improvement in customer understanding and acceptance by removing the baseline-based rate of the existing MGS rate's complexity; and
- BC Hydro believes that the substantial gain in customer understanding can be achieved with: only a minor loss in economic efficiency because the MS-5 energy rate is still reflective of LRMC; and minor bill impacts from removal of the Part 2 energy rate since on implementation the baseline structure by its design controlled for bill impacts to individual customers.

BC Hydro sought input concerning the alternatives set out in Table 6-10, and in particular whether to retain the baseline and attempt to refine the existing structure to address known issues. Stakeholders generally concluded that the existing MGS energy rate does not send a clear price signal for conservation because it is poorly understood. A portion of those customers who did understand the design did not like it because they highlighted the detrimental impacts of the two-part rate structure on customer business expansion; for example, AMPC stated that the inability to annually adjust baselines to reflect changes in use is a significant problem for a heterogeneous class, and thus a flat energy rate may be more useful in providing a conservation price signal than a tiered energy rate. Commission staff noted that the existing MGS rate is administratively complex and has failed to generate conservation savings.

Loblaws, with mostly LGS but with some MGS accounts, was the only MGS customer at Workshops 8a/8b preferring the existing MGS energy rate. In contrast, TransLink, also with mostly LGS but some MGS accounts, proposed that BC Hydro only carry forward MGS alternatives that do not retain the baseline. TransLink believes incentives for MGS class energy efficiency are best provided through DSM programs. The May 2015 BOMA and BCFPA/CME/key accounts sessions yielded the following results: 15 of the 22 feedback forms submitted by attendees favoured the MS-5 MGS flat energy rate alternative with many emphasizing DSM programs as the better vehicle for conservation; three preferred the MS-2 flatten the energy charges but retain the baseline alternative; and two favoured the existing MGS rate.

In response to stakeholder feedback, BC Hydro established a preference for a flat energy rate with no baseline for the MGS class. This preference was also based on the results of the two evaluation reports discussed in section 6.3.3, the jurisdictional review, discussions with E3 regarding both the empirical results and the survey results and BC Hydro's review of complaints lodged by MGS customers with BC Hydro (refer to Appendix C-4D for a summary). The general theme of the complaints was that the current MGS rate inhibits growth because the first 20 per cent of consumption above the baseline is priced at the higher Part 2 rate.

Phase 3, Workshop 11a: Focus on MGS Demand Charge Structures and Cost Recovery

In its Workshop 8b feedback, both CEC and Commission staff noted that the current level of demand charge cost recovery (about 15 per cent) could be increased. Accordingly, at Workshop 11a BC Hydro reviewed two MGS demand charge-related items:

1. The three demand charge structure alternatives. The main issue was whether the two-step inclining block demand charge should be brought forward for RDA purposes in addition to the flat demand charge and the existing three-step inclining block demand charge. BC Hydro highlighted that the two-step inclining block demand charge would not substantially differ from the existing demand charge with respect to fair cost recovery because few MGS customers typically

face Tier 3 of the existing demand charge (Tier 3 is the highest third step of the existing demand charge, for monthly demand greater than 150 kW). For the same reason, flattening only Tier 2 and Tier 3 into a single tier results in demand charge pricing similar to existing demand charge pricing given revenue neutrality. The result is that the MGS two-step inclining block demand charge alternative does not generally offset the bill impacts of the MGS flat energy rate.

There was a general consensus among stakeholders that the MGS flat demand charge is superior to the existing MGS demand charge and the MGS two-step inclining block demand charge structures. The MGS single flat demand charge will improve fairness between customers; a single demand charge is better aligned with the cost to serve a General Service customer's peak demand. A flat demand charge also simplifies the rate structure, which will improve customer understanding and acceptance relative to the existing MGS demand charge structure.

2. An increase in demand charge recovery of demand-related costs from 15 per cent to 35 per cent. The 35 per cent cost recovery level was arrived at by targeting an increase that would result in a flat energy rate that remained generally reflective of the energy LRMC, thereby balancing the competing Bonbright economic efficiency criterion. There is no single 'correct' level of demand charge cost recovery and demand charge cost recovery cannot be targeted in isolation from other factors. The effect of an increase to 35 per cent cost recovery is to more evenly offset and distribute the bill impacts of BC Hydro's preferred MGS flat energy rate and MGS flat demand charge among customers with differing load factors and consumption levels. This result is illustrated by comparing the 35 per cent and 15 per cent cost recovery bill impacts in Figure 6-6 and Figure 6-7 in section 6.3.5.

There was no general consensus among stakeholders with respect to the level of MGS demand charge recovery of demand-related costs.

Phase 4, Workshop 11a/11b Consideration Memo: MGS Demand Ratchet

BC Hydro's preferred MGS demand ratchet is addressed in section 7.2 of the Workshop 11a/11b consideration memo found at Appendix C-4B. The demand ratchet ensures that customers with high winter consumption and low summer consumption pay a share of BC Hydro's costs to maintain its infrastructure related to serving peak demand. The demand ratchet was reduced from 75 per cent to 50 per cent in April 1980.[239]

AMPC and Commission staff sought more information concerning whether the MGS demand ratchet should remain at 50 per cent of the highest maximum demand charge billed in any billing period in the on-peak period of November through March during the immediately preceding eleven billing periods or be increased to match the 75 per cent level set out in RS 1823. In section 7.2 of the Workshop 11a/11b consideration memo, BC Hydro surveyed the bills of customers that incur demand ratchet charges. To put the MGS and LGS demand ratchets in context, Table 6-11 provides summary information on MGS (and LGS) demand ratchet charges in F2015 (F2013 and F2014 data are comparable); the table highlights that the number of MGS and LGS customers incurring demand ratchet charges is relatively few in comparison to the total number of customers in each class. The amount of MGS and LGS demand ratchet revenue is a very small percentage of total MGS and LGS class revenue.

Table 6-11 Summary of F2015 demand ratchet charges, MGS and LGS

F2015 Demand Ratchet Charge	MGS	LGS
Total Customers Incurring Demand Ratchet	211	213
Percentage of Total Customers of Class	~ 1	~ 3
Total Demand Ratchet Revenue	$122,744	$1,794,043
Percentage of Total Revenue	~ 0.04	~ 0.2

[239] The change to the demand ratchet was approved by BC Hydro's Board of Directors in February 1980 as part of a package of electric tariff revisions. The reason for the change was not noted.

While an increase in the level of the demand ratchet to 75 per cent of peak monthly demand would provide consistent rate treatment between BC Hydro's MGS and LGS classes and RS 1823 customers, BC Hydro prefers to maintain the level of the MGS and LGS demand ratchets at the existing level of 50 per cent of peak monthly demand given that the level of the demand ratchet is not a major issue with customers.

6.3.5 BC Hydro Proposal and Stakeholder Engagement

At Workshop 11a, BC Hydro identified its proposed MGS rate, and focused on its proposal to increase demand charge recovery of demand-related costs given the lack of consensus from Workshop 8a on this issue:

- BC Hydro acknowledged that as a result of the proposed increase to the demand charge, the MGS flat energy rate under its proposal drops below the lower bound of the energy LRMC range (F2017: MGS flat energy rate is 8.54 cents/kWh and the lower end of the energy LRMC range is 9.46 cents/kWh). In its Workshop 11a/11b consideration memo, BC Hydro adopted the perspective of AMPC that the energy LRMC should not be relied on with a 'false precision'. BC Hydro regards the MGS flat energy rate under its proposed demand charge cost recovery increase to be reflective of the energy LRMC;
- BC Hydro reviewed that under the existing level of demand charge cost recovery, the weight of the benefit (in terms of bill impacts) from a move to its preferred MGS energy and demand rate structures would tend toward customers who consume near the median in terms of consumption and load factor. The weight of the burden would tend toward high load factor with high consumption customers, as well as low load factor with low consumption customers. The effect of an increase in demand charge recovery of demand-related costs is to more evenly distribute the bill impacts of BC Hydro's

MGS rate structure proposal among customers with differing load factors and consumption levels. These impacts are discussed below.

Illustrative Simulations

Table 6-12 lists the key calculation features of the alternative rate structures, and the MGS rates estimated for F2017. All F2017 rates are modelled to be revenue neutral to the status quo MGS rate; that is, all alternatives recover the same target revenue of $371 million given a consumption forecast of 3,517 GWh and 10.9 GW of billed demand. Illustrative F2017 rates are used in this Chapter for the bill impact simulations. BC Hydro is filing for the rate structure change in F2018 (effective April 1, 2017), and the actual rates for F2018 will be finalized through the F2017 RRA Commission decision. Further details on the modelling calculations are shown on Appendix H-1A.

Table 6-12 MGS Rate Estimates for Rate Structure Transition in F2017

<table>
<tr><th>MGS</th><th>F2016</th><th>F2017 Status Quo</th><th>F2017 BC Hydro Proposal (35% Demand Recovery)</th><th>F2017 Sensitivity (15% Demand Recovery)</th></tr>
<tr><td>Basic cents/day</td><td>22.57</td><td>23.47</td><td>23.47</td><td>23.47</td></tr>
<tr><td colspan="5">Demand $/kW</td></tr>
<tr><td>T1</td><td></td><td>–</td><td rowspan="3">4.76 Flat</td><td rowspan="3">2.14 Flat</td></tr>
<tr><td>T2</td><td>5.50</td><td>5.72</td></tr>
<tr><td>T3</td><td>10.55</td><td>10.97</td></tr>
<tr><td colspan="5">Energy cents/kwh</td></tr>
<tr><td>T1</td><td>9.89</td><td>10.33</td><td rowspan="4">8.54 Flat</td><td rowspan="4">9.35 Flat</td></tr>
<tr><td>T2</td><td>6.90</td><td>7.21</td></tr>
<tr><td>Part 2</td><td>9.90</td><td>10.10</td></tr>
<tr><td>Minimum</td><td>3.30</td><td>3.43</td></tr>
<tr><td>Key calculation features of alternatives to Status Quo</td><td></td><td></td><td>• Flat Energy Rate
• Flat Demand Charge
• Basic Charge is increased by RRA
• Revenue recovered from demand portion of the rate in F2017 is escalated by a factor of 2.22 from status quo, to yield a projected cost recovery from the demand portion of the rate of 35 per cent</td><td>• Flat Energy Rate
• Flat Demand Charge
• Basic Charge is increased by RRA
• Revenue recovered from demand portion of the rate is same as that of Status Quo</td></tr>
</table>

6.3.5.1 Bill Impacts under BC Hydro's Proposed MGS Rate Structure

Table 6-13 shows the difference in the annual bills under BC Hydro's proposed MGS rate structure as compared to the status quo MGS rate for a 'typical' MGS customer with consumption of 153,240 kWh per year and billed demand of 49 kW each month, which is near the median in terms of consumption and load factor. Under the proposed MGS rate structure, such customers tend to be better off when compared to the status quo MGS rates. Due to the elimination of the baseline, the amount of benefits would be slightly lower for customers that experienced a reduction in consumption, due to removal of Part 2 energy rate credits, and slightly higher for customers that experienced an increase in consumption, due to avoidance of Part 2 energy rate charges.

Table 6-13 F2017 Illustrative Customer Bill – BC Hydro MGS Proposal (Demand 35 Per Cent Recovery)

Customer Scenario	Demand Charge ($)	Energy Charge ($)	Basic Charge ($)	Total Bill ($)	SQ Bill ($)	Variance ($)
Consume at baseline	2,896	12,998	86	15,979	16,876	-897 (-5%)
+5% from baseline	2,896	13,647	86	16,629	17,650	-1,021 (-6%)
-5% from baseline	2,896	12,348	86	15,329	16,102	-773 (-5%)

The bill impact statistic compares the change in annual bills of each customer account from F2016 to F2017, given identical consumption in energy and demand and a baseline that is equal to consumption:

- Under the status quo MGS rate, the bill impact is at about the RRA rate increase (4 per cent) for all MGS customers;
- Under the MGS Proposal, the 20th to 80th percentile bill impact for F2017 ranges from zero per cent to 7 per cent, with the full range between -17 per cent to +168 per cent. This trend is similar across the major sectors. About 6 per cent of customers are expected to experience bill impacts over 10 per cent. Of these customers (the 6 per cent), the highest bill impact in terms of nominal dollars is about $6,000 (a bill impact of 14 per cent). Overall, about half of the MGS customers (53 per cent) are better off in terms of bill impacts under the MGS Proposal as compared to the status quo.

Figure 6-6 shows the impact of rate structure change in the transition year, net of RRA rate increases, under the MGS Proposal. The distribution shows that the typical customers (as shown by the blue circle) are mostly better-off. The larger consuming customers tend to have small bill impacts during the transition. The customers experiencing the highest bill impact are characterized by low consumption and low load-factor, with bill impacts mostly triggered by having demand charges for all kW.

Figure 6-6 F2017 Bill Impacts less RRA – BC Hydro MGS Proposal (Demand 35 Per Cent Recovery)

Annual Consumption kWh — Highest kw

Load Factor *	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	44.6%	47.0%	6.9%	-2.6%	-6.8%	-14.0%	-20.1%	-22.3%	-23.9%	-25.1%	-26.0%	-26.8%	-27.4%	-27.9%	-28.3%	-28.7%	-29.0%
20%	14.1%	14.9%	15.1%	2.4%	-3.4%	-6.6%	-8.3%	-6.4%	-5.0%	-4.6%	-6.4%	-7.9%	-9.1%	-10.1%	-10.9%	-11.6%	-12.2%
30%	4.0%	4.2%	4.3%	4.3%	-1.7%	-5.3%	-7.3%	-5.1%	-3.5%	-2.2%	-1.1%	-0.2%	0.6%	1.2%	0.3%	-0.6%	-1.5%
40%	-1.1%	-1.1%	-1.2%	-1.2%	-1.2%	-4.6%	-6.7%	-4.4%	-2.0%	-1.2%	0.0%	0.9%	1.7%	2.5%	3.1%	3.6%	4.1%
50%	-4.1%	-4.3%	-4.4%	-4.4%	-4.4%	-4.4%	-6.3%	-3.9%	-2.1%	-0.6%	0.6%	1.7%	2.5%	3.3%	3.9%	4.5%	5.0%
60%	-6.1%	-6.5%	-6.6%	-6.6%	-6.6%	-6.6%	-6.2%	-3.5%	-1.6%	-0.1%	1.1%	2.2%	3.1%	3.9%	4.5%	5.1%	5.6%
70%	-7.6%	-8.0%	-8.1%	-8.2%	-8.2%	-8.2%	-7.8%	-3.5%	-1.3%	0.2%	1.5%	2.6%	3.5%	4.3%	5.0%	5.6%	6.1%
80%	-8.7%	-9.2%	-9.3%	-9.3%	-9.3%	-9.4%	-9.0%	-4.8%	-1.3%	0.5%	1.8%	2.9%	3.8%	4.6%	5.3%	5.9%	6.5%
90%	-9.5%	-10.0%	-10.2%	-10.2%	-10.3%	-10.3%	-9.9%	-5.7%	-2.3%	0.5%	2.0%	3.1%	4.1%	4.9%	5.6%	6.2%	6.8%

Lowest kw

Red underline indicates bill impact higher than RRA
Blue oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load

*Note: Very high sensitivity on low load factor, lower consumption customers due to T1 kW charge.

6.3.5.2 MGS Demand Sensitivity Rate Structure (15 per cent Recovery)

As a comparison, BC Hydro modelled a MGS Demand Sensitivity where demand cost recovery is maintained at 15 per cent (status quo). Comparing Figure 6-7 with Figure 6-6, the analysis shows:

- The typical customers (inside the oval) are slightly better off under the MGS Demand Sensitivity than the MGS Proposal, as are the customers with low consumption and low load factor;
- High load factor and high consumption customers are worse off under the MGS Demand Sensitivity;
- The range of bill impact for the typical customers (those between the 20th percentile to 80th percentile) is from -1 per cent to 8 per cent, with a full range of between -43 per cent and 74 per cent. This distribution is similar across the major sectors. About 8 per cent of customers experience bill impacts over

10 per cent. Just over half of the customers (59 per cent) are better off under the MGS Demand Sensitivity as compared to the status quo, which is slightly higher than under the MGS Proposal. The customers with the highest impacts are characterized by low consumption and low load-factor.

AMPC notes that it believes that the MGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system.[240] Comparing the bill impacts in Figure 6-7 with that of the MGS Proposal in Figure 6-6 highlights that by increasing demand charge cost recovery, the bill impacts of the MGS Proposal are further offset and distributed among customers with differing load factors and consumption levels. For further description of interpreting these bill impact tables, please refer to Appendix H-1A of the Application.

Figure 6-7 F2017 Bill Impacts less RRA – MGS Demand Sensitivity (15 Per Cent Recovery)

Annual Consumption kWh

Highest kw

Load Factor

*	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	18.6%	19.6%	-13.4%	-21.2%	-24.7%	-30.5%	-35.6%	-37.4%	-38.7%	-39.6%	-40.4%	-41.0%	-41.5%	-41.9%	-42.2%	-42.5%	-42.8%
20%	4.9%	5.2%	5.3%	-6.4%	-11.7%	-14.7%	-16.2%	-14.5%	-13.2%	-12.9%	-14.6%	-15.9%	-17.0%	-17.9%	-18.6%	-19.3%	-19.9%
30%	0.4%	0.4%	0.4%	0.4%	-5.4%	-8.9%	-10.7%	-9.7%	-7.1%	-5.8%	-4.8%	-3.9%	-3.2%	-2.6%	-3.4%	-4.3%	-5.2%
40%	-1.9%	-2.0%	-2.0%	-2.0%	-2.0%	-5.4%	-7.5%	-5.2%	-3.5%	-2.1%	-0.9%	0.0%	0.8%	1.5%	2.2%	2.7%	3.2%
50%	-3.3%	-3.4%	-3.5%	-3.5%	-3.5%	-3.5%	-5.3%	-3.0%	-1.1%	0.4%	1.6%	2.7%	3.5%	4.3%	4.9%	5.5%	6.0%
60%	-4.2%	-4.4%	-4.5%	-4.5%	-4.5%	-4.5%	-4.1%	-1.3%	0.6%	2.2%	3.4%	4.5%	5.4%	6.2%	6.9%	7.5%	8.0%
70%	-4.8%	-5.1%	-5.2%	-5.2%	-5.2%	-5.2%	-4.8%	-0.4%	1.9%	3.5%	4.8%	5.9%	6.9%	7.7%	8.4%	9.0%	9.6%
80%	-5.3%	-5.6%	-5.7%	-5.7%	-5.7%	-5.7%	-5.3%	-0.9%	2.6%	4.5%	5.9%	7.0%	8.0%	8.8%	9.5%	10.2%	10.7%
90%	-5.7%	-6.0%	-6.1%	-6.1%	-6.1%	-6.1%	-5.7%	-1.4%	2.2%	5.1%	6.7%	7.9%	8.9%	9.7%	10.5%	11.1%	11.7%

Lowest kw

Red underline indicates bill impact higher than RRA

Blue oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load

*Note: Very high sensitivity on low load factor, lower consumption customers due to T1 kW charge.

6.4 Large General Service

6.4.1 BC Hydro's Large General Service Proposal

BC Hydro is proposing a new rate structure for customers who take service under RS 16xx: a flat demand charge established to recover approximately 65 per cent of

[240] In its decision on the 2007 RDA, page 162, the Commission also expressed concern about the detrimental impacts of flattening energy and demand charges on high load factor - high consumption customers.

BC Hydro's demand-related costs attributable to the LGS rate class in the F2016 COS study and a flat energy rate established to maintain forecast revenue neutrality based on LGS revenue target calculated using any applicable rate increases arising from the F2017 RRA (LGS Proposal).

The LGS Proposal would result in the following illustrative charges in F2018: a flat energy rate for all kWh of approximately 5.56 cents/kWh; a flat demand charge of approximately $11.21 per kW (reflecting BC Hydro's preferred 65 per cent level of cost recovery); and a basic charge of approximately 24.29 cents per day. BC Hydro proposes to continue with the current monthly minimum charge definition. These illustrative charges are calculated assuming the F2018 rate cap increase of 3.5 per cent. Final F2018 LGS pricing will be determined by the F2017 RRA decision.

As set out in section 6.5.2, BC Hydro proposes a one-time transition on April 1, 2017 from the current LGS rate structure to BC Hydro's proposed LGS rate structure.

6.4.2 Background

The LGS rate class consists of 6,852 accounts with total consumption of 10,885 GWh (F2015). The LGS default rate structures to the class are:

- A two-part energy rate approved in 2010 pursuant to Commission Order No. G-110-10 as an outcome of the 2009 LGS Application NSA. The existing LGS energy rate is further described in section 6.4.2.1;
- A three-step inclining block demand charge. Refer to section 6.3.2 for the background to this demand charge. The existing LGS demand charge is reviewed in section 6.4.2.2; and
- A basic charge and a monthly minimum charge. The current LGS basic charge is 22.57 cents/day. The LGS monthly minimum charge is 50 per cent of the highest maximum demand charge billed in any billing period in the on-peak

period of November through March during the immediately preceding eleven billing periods.

The relevant Commission Order No. G-110-10 direction concerning the Three-Year Evaluation Report filing is noted in Table 6-4. BC Hydro expands on the Three-Year Evaluation Report in this section as it is relevant to one of the LGS energy rate alternatives (the SQ LGS Simplified Energy Rate described in section 6.4.4).

The scope for the Three-Year Evaluation Report was set through paragraph 16 of the NSA.[241] A summary of the relevant findings of the Three-Year Evaluation Report on these items is:

- There was no evidence that customers were opening new accounts at an existing premise to benefit by avoiding exposure to the Part 2 energy rate. This finding pertains to the 85/15 Pricing-related amendment described in section 6.6;
- No changes to the PLB were desirable or necessary:
  - In F2013, the percentage of bills outside the PLBs was about 19 per cent (13 per cent of bills with load below the 20 per cent HBL and 6 per cent of bills with load above the 20 per cent HBL);
  - In the absence of any direct evidence regarding the impact of PLBs on conservation, BC Hydro determined that no changes to the PLBs were warranted. BC Hydro also concluded that changing the PLBs would require significant customer communication, which could be challenging for customers to understand and keep abreast of, given the complexity of the rates;
- BC Hydro also noted:

[241] The NSA is found at Appendix A to Commission Order No. G-110-10; http://www.bcuc.com/Documents/Proceedings/2010/DOC_25757_G-110-10_%20BCH-Large-General-Service-Rate_Reasons-NSA.pdf.

- BC Hydro encountered significant operational challenges implementing the LGS (and MGS) rates as they are difficult to administer. The billing process is complicated by BC Hydro having to manage exceptions to the customer baselines which is time consuming. In addition, customers have difficulty understanding the rates which adds to the administrative effort;
- Unaided awareness and understanding of the LGS and MGS rate structures was low;
- Inquiries and complaints typically concern the baselines when historical consumption may not reflect current or expected operating conditions.

6.4.2.1 Existing LGS Energy Rate

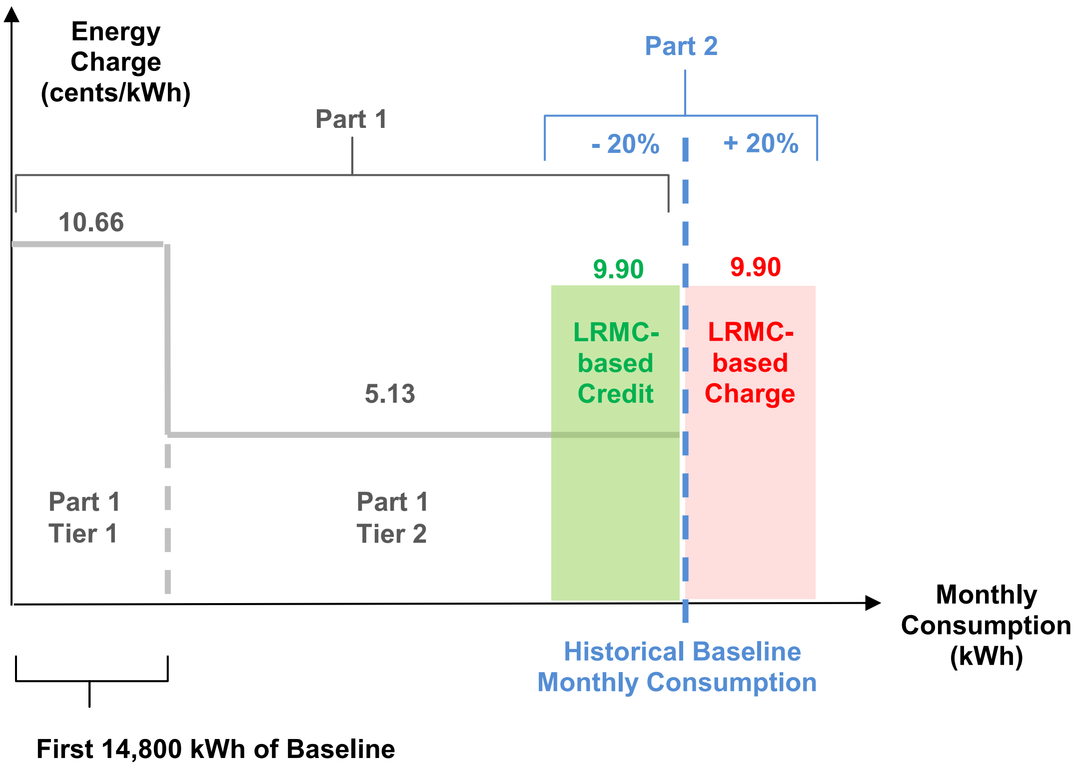
The existing LGS energy rates are set out in Table 6-14.

Table 6-14 Existing LGS Energy Rates (F2016)

Part 1 Energy Rate – Tier 1 (cents/kWh)	10.66
Part 1 Energy Rate – Tier 2 (cents/kWh)	5.13
Part 2 Energy Rate (cents/kWh)	9.90

The overarching objective of the LGS two-part energy rate was to provide LGS customers with an efficient price signal to induce energy conservation. Figure 6-8 illustrates the LGS two-part energy rate structure.

Figure 6-8 Illustrated LGS 2-Part Energy Rate Structure



The mechanism of LGS Part 2 energy rate is the same as described for the MGS rate structure in Section 6.3.2.1. The LGS Part 1 energy rate differs from MGS as it is not inverted: for LGS customers, the Part 1 Tier 1 energy rate applies to the first 14,800 kWh of baseline consumption in one month and the Part 1 Tier 2 energy rate applies to all remaining consumption of a customer's monthly baseline. For further illustration of the mechanisms of the LGS two-part energy rate under example customer consumption levels, refer to slides 30 to 31 of the Workshop 8a presentation at Appendix C-4A to the Application.

The baseline-based rate structure also led to the following provisions, which were included in the 2009 LGS Application NSA to address anticipated customer growth-related concerns and new accounts:

- *Anomaly rule*, allowing up to four historic baselines to be adjusted per year. When the lowest consumption month used in baseline calculation is less than 50 per cent of the second lowest month, the lowest month is excluded from baseline calculation;
- *Growth Adjustment or Formulaic growth rule* (**FGR**), allowing baselines to be based on the most recent two years of consumption history in the year (Y2) following a year (Y1) in which energy consumption exceeded the previous year's (Y0) energy consumption by at least i) 30 per cent or ii) 4,000,000 kWh;
- *Application for Prospective growth adjustment,* allowing LGS customers who anticipate significant, permanent increases in energy consumption to apply to BC Hydro for special pricing that may reduce energy rates for three years. "Permanent" means arising from a significant capital investment in plant and "Significant" means increases in energy consumption totaling at least 30 per cent, or 4,000,000 kWh. To address this provision, BC Hydro applied for and received Commission approval of TS 82 which sets the rules for LGS prospective growth applications for modified LGS pricing. BC Hydro's request with respect to TS 82 is discussed in section 6.7.1;
- *Application for exemption,* allowing LGS customers to apply to the Commission for an exemption on the basis that they are electricity re-sellers under regulated tariffs with conservation rates for their end-use customers. To date, Corix is the only customer that has received such an exemption, for its utility operations at Sun Rivers and Sonoma Pines (these operations would have fallen under the default LGS rates). Refer to section 6.7.3; and
- *New accounts (85/15 Pricing)*, specifying that for new accounts the last 15 per cent of energy consumed in a monthly billing period will be charged at the Part 2 energy rate rather than at the Part 1 Energy rate until a baseline level of consumption is established one year hence. The 85/15 Pricing is the subject of a requested order as described in section 6.6.

As discussed in section 6.4.3, the key issue with the existing LGS two-part energy rate is that it does not provide a clear price signal for conservation and is poorly understood by customers. The result is that minimal conservation savings have been delivered to date, and that BC Hydro cannot count on and does not forecast any conservation savings going forward.

6.4.2.2 Existing LGS Demand Charge

BC Hydro has a three-step inclining block demand charge for the LGS rate class which is the same structure and the same charges as applicable to the MGS rate class set out in Table 6-6. The key issue with the LGS demand structure is the same key issue identified with respect to the MGS demand structure in section 6.3.2.2; the LGS three-step inclining block demand charge does not align with BC Hydro's cost to serve LGS customer peak demand.

6.4.2.3 LGS Customer Characteristics

The LGS rate class is diverse. Table 6-15 shows that of the 37 site types identified in our F2014 billing data, the top 10 site types have 69 per cent of the consumption in the class. In particular, Offices, Non-Food Retail, and Other Commercial stand out as the highest consuming sectors, with 33 per cent of total class consumption.

Table 6-15 LGS Consumption by Site Type

Site Type	Percentage of Class Consumption
Offices	19
Non-Food Retail	8
Other Commercial	7
Wood - Lumber	6
Food Retail	6
Industrial - Food & Beverages	5
Industrial - Heavy Manufacturing	5
Industrial - Light Manufacturing	5
Transportation	4
Public Hospital	4
Other	31

Sixty-seven per cent of accounts in the LGS Class are represented by the top 10 site types (Table 6-16). In particular, Offices, Non-Food Retail, and Other Commercial also stand out as the sectors with the largest portion of accounts, at about 36 per cent of all accounts.

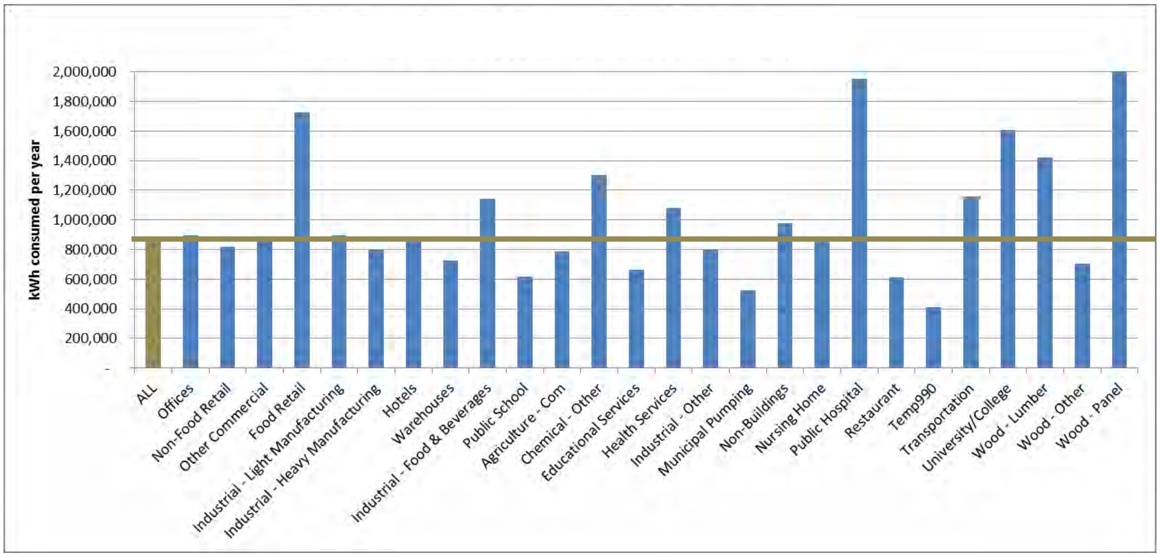
Table 6-16 LGS Accounts by Site Type

Site Type	Percentage of Accounts
Offices	19
Non-Food Retail	9
Other Commercial	7
Food Retail	5
Industrial - Light Manufacturing	5
Industrial - Heavy Manufacturing	5
Hotels	4
Warehouses	4
Industrial - Food & Beverages	4
Public School	4
Other	33

The LGS class is heterogeneous in terms of consumption. Consumption also tends to vary substantively by site type, as shown by the variations of the medians for each site type in Figure 6-9. In terms of annual load factor, about 80 per cent of the class has a load factor between 20 per cent and 70 per cent (see Workshop 8a presentation materials).[242]

[242] Refer to slides 17 to 19, 24, 25 and 26 to 27 in particular; the Workshop 8a presentation is found at Appendix C-4A.

Figure 6-9 Median LGS Consumption by Site Type



6.4.3 LGS Two-Part Energy Rate Evaluation Reports

6.4.3.1 Methodology

Section 6.3.3.1 summarizes the coincident LGS and MGS methodologies that support the 2011-2012 LGS and MGS Evaluation Report and the F2014 LGS and MGS Evaluation Report. Refer also to section 6.3.3.1 for further context and references to the review with stakeholders of the respective reports.

In addition to the coincident LGS and MGS evaluation methodologies, the F2014 LGS and MGS Evaluation Report employed the following with respect to LGS customers:

1. Interviews with the key account managers of BC Hydro's largest LGS Industrial, Commercial, Institutional and Government (key) accounts.
2. Separate regression analysis of a small sample of key accounts:
   - The research question was: "Can a response to the introduction of the LGS conservation rate be detected at the site level for a selection of key account customers with energy management initiatives?";

- The research methodology employed customer-level regression modelling of 12 industrial key account LGS customer's energy consumption, using BC Hydro rates and billing data and customer-specific production data;
- Regression models were run on twelve sites whose customers agreed to share production data with BC Hydro for the purpose of this analysis, thereby ensuring the validity of results through complete data inputs. However, the results are not generalizable to all LGS accounts because only twelve sites were modeled. The method must therefore be considered a case study analysis. For further detail on the methodology, refer to pages 24, D-13 and D-14 of the F2014 LGS and MGS Evaluation Report at Appendix C-4A of the Application.

6.4.3.2 Results

The LGS two-part energy rate has been evaluated through the 2011-2012 LGS and MGS Evaluation Report and F2014 LGS and MGS Evaluation Report to have delivered lower than expected conservation savings with a declining confidence in the persistence of the savings, as shown in the Table 6-17. Forecast LGS energy savings were 780 GWh/year in F2014.

Table 6-17 Cumulative Net Evaluated Conservation Savings: Gigawatt Hours per Year

Year	Level of Statistical Significance		
	80%	**85%**	**90%**
Fiscal 2014	77	77	0
Calendar 2013	200	200	200
Calendar 2012	144	144	144

As set out in the F2014 LGS and MGS Evaluation Report:

- Awareness and demonstrated understanding of the LGS rates was low. About 35 per cent of LGS customers correctly identified the two-part energy rate as applicable across four possible rate structure selections. Larger customers generally have higher unaided awareness than smaller customers;

- The top three drivers of energy conservation were: “want energy costs to be as low as possible”; “right thing to do”; and “overall level of electricity prices”. The incentive to save electricity built into the rate was cited as a driver of conservation for 27 per cent of LGS customer respondents; and
- Analysis of 12 key account customers did not detect a statistically significant response to the introduction of the existing LGS two-part energy rate. BC Hydro’s expectation was that these customers might be particularly responsive to the LGS rate because they both consume considerable amounts of electricity and have staff dedicated to energy management.

As reviewed in the 2011-2012 LGS and MGS Evaluation Report, regression analysis indicates that awareness of the rate structure was not required for the conservation response estimated for 2011 and 2012. This finding was one reason BC Hydro concluded in the Three-Year Evaluation Report that consideration be given in a future evaluation to using focus groups or structured interviews to better understand the mechanisms by which customers respond to the two-part energy rate:

- Results of the key account manager interviews indicate that while most energy managers or finance personnel at key accounts understood the intent of the rates, few people within an organization understood the mechanics;
- Focus group results confirm that the complexity of the LGS two-part energy rate is a barrier to customer understanding of the price signal and customer ability to act upon it. Part 1 and Part 2 of the current energy rate structure are confusing or flawed in the eyes of customers in several ways:
  - The 14,800 kWh threshold of Part 1 appeared arbitrary and the declining block structure of Part 1 was regarded as counterintuitive;
  - Customers have particular difficulty understanding the calculation of rolling, historical average monthly HBLs and the value and mechanism of the Part 2 energy charge or credit. Only a few companies had a record of previous

energy bills needed to be able to predict and analyze long term energy consumption patterns. Customers stated that the baseline appeared to draw on too many moving numbers and calculations to be practical in terms of understanding a bill, forecasting, budgeting, or sharing energy conversations with colleagues or management. The perceived complexity of the energy rate structure makes customers disengage from trying to understand the billing process or finding ways to reduce the total bill amount; and

- Most customers reportedly look at their electricity bills, but this is mainly in regards to total dollar amount; rate structures were rarely mentioned as a motivator for conservation.

It is clear from the customer surveys and focus groups that the LGS rate design is overly complex and poorly understood. The finding that awareness of the LGS rate was not required for a conservation response may offer an explanation of why LGS energy savings have diminished over time. Some customers may have responded to the introduction of the LGS rate without understanding its details, either because their total bill went up, or because they expected their bill to go up in anticipation of a pricing change. However, LGS customers may have greater, longer lasting responses if they understand the details of the rate well enough to quantify the benefits they may receive by responding. The low unaided awareness of the LGS rate, and the finding that awareness was not associated with savings, may indicate that overall, the response to the LGS rate was not the type of informed response that would result in substantial investments in energy efficiency.

6.4.4 Options Reviewed

In BC Hydro’s view, there are three LGS rate structure alternatives for consideration in this Application, as developed and reviewed with stakeholders:

1. A flat energy rate and a flat demand charge;

2. A simplified version of the existing (status quo (**SQ**)) two-part energy rate (referred to as the **SQ LGS Simplified Energy Rate**) and a flat demand charge. This alternative includes consideration of ways to simplify the existing two-part energy rate structure, through flattening the Part 1 Tier 1 and Tier 2 energy rates and/or by modifying the provisions that support the two-part rate structure summarized in section 6.4.2.1; and
3. The existing two-part energy rate and the existing three-step inclining block demand charge, for comparison purposes.

The reason for carrying forward the SQ LGS Simplified Energy Rate is that in contrast to the MGS rate: the LGS energy rate has resulted in some energy conservation; some LGS customers desire to retain the baseline-based rate structure; and as described below, the LGS flat energy rate is not reflective of the energy LRMC range, so simplification does in this case have some trade-off with losses in efficiency and conservation.

In addition, BC Hydro carries forward in this Application an increase to the flat demand charge under alternative (1) above to recover 65 per cent of demand-related costs allocated to the LGS class, an increase from the existing 50 per cent recovery of such costs under the existing demand charge. The proposed change improves fairness and does so without a loss in efficiency.

The LGS rate alternatives brought forward into the 2015 RDA from the stakeholder engagement processes are summarized in Table 6-18.

Table 6-18 Alternative LGS Pricing (F2017)

Pricing Element	Existing LGS Rates	SQ LGS Simplified Energy Rate/Flat Demand (Status Quo demand-related cost recovery ~50%)	BC Hydro Proposal: Flat Energy/Flat Demand (65% demand-related cost recovery)	Sensitivity on BC Hydro Proposal (Status Quo demand-related cost recovery: ~50%)
Energy rate (cents/kWh)	Part 1, T1: 11.17 Part 1, T2: 5.37 Part 2: 10.10	Flat Part 1 energy rate not modeled under this alternative for F2017 but expected = ~5.98 cents/kWh, subject to Part 2 energy rate adjustments; Potential changes to the current LGS-related provisions are considered under this alternative	5.37	5.98
Demand charge ($/kW)	T1: 0.00 T2: 5.72 T3: 10.97	8.35	10.83	8.35
Basic charge (cents/day)	23.47	23.47	23.47	23.47

The next two sub-sections summarize the processes employed to develop (section 6.4.4.1), and review and narrow (section 6.4.4.2) the alternatives using stakeholder and other inputs. Details are contained in Appendix C-4D.

6.4.4.1 Alternatives Development

The process and approach to LGS rate alternatives development was the same as described for MGS in section 6.3.4.1.

6.4.4.2 Screening of Alternatives and Stakeholder Engagement

The screening, assessment and review of LGS alternatives were similar to that of MGS as set out in section 6.3.4.2; accordingly only the differences are noted in this section. There were five phases to the LGS alternatives review.

Phase 1, Initial Internal Screening

The LGS initial screening process was identical to the MGS initial screening process. Initial internal screening and feedback from stakeholders reduced the number of alternative LGS rate designs from 18[243] to the five alternatives shown in Table 6-19.

Table 6-19 Screened-in LGS Alternatives for Stakeholder Engagement

Screened-in LGS Alternative (LS)		Flatten Part-1 Energy Rate	Flatten Demand Charge	Remove Part 2 Energy Rate No Baseline)
LS-1	Status Quo Energy Status Quo Demand	Not applicable		
LS-2	Flat Part 1 Energy Status Quo Demand	Yes		
LS-3	Status Quo Energy Flat Demand		Yes	
LS-4	Flat Part 1 Energy Flat Demand	Yes	Yes	
LS-5	Flat Part-1 Energy, No Part 2 Energy Flat Demand	Yes	Yes	Yes

Phase 2, Workshop 8b: Focus on LGS Energy Rate Structures

The categories of alternatives reported in Table 6-9 were reviewed with stakeholders at Workshop 8b. The assessment of alternatives LS-2 and LS-3 was illustrative for reasons identical to the MGS rate structure analysis: the energy and demand

[243] Refer to Attachment 1 to the Workshop 8b summary notes, which in turn are part of Attachment 1 to the Workshop 8a/8b consideration memo at Appendix C-4A.

components should properly be considered together in evaluating the trade-offs between alternatives. The benefits and drawbacks of alternatives LS-4 and LS-5 are as described above for MS-4 and MS-5 in section 6.3.4.2, with one exception: a drawback of LS-5 is that the resulting flat energy rate is below the lower end of the LRMC range and not reflective of BC Hydro's LRMC.

BC Hydro sought input concerning the alternatives set out in Table 6-19, and in particular whether to retain the baseline and attempt to refine the existing structure to address known issues. Commission staff considered that the merits of the LS-5 flat energy rate are an open question and that alternatives retaining the baseline should be carried forward. BC Hydro received mixed feedback from LGS customers and stakeholders:

- The May 2015 BOMA and BCFPA/CME/key accounts sessions yielded the following results: 14 of the 22 feedback forms submitted by attendees favoured the LS-5 LGS flat energy rate with many emphasizing DSM programs as the better vehicle for conservation; three preferred the LS-2 flatten the energy charges but retain the baseline alternative; and three favoured the existing LS-1 energy rate.
- Among customer feedback on Workshop 8b:
  - One customer, Loblaws, preferred the existing LS-1 energy rate, which it states provides a clear price signal to conserve electricity;
  - Four customers, TransLink, Panorama Mountain Village Inc., Toby Creek Utility and Viterra preferred the LS-5 flat energy rate with no baseline, noting the impact of the existing LGS rate on growth and the difficulty budgeting for electricity costs and consequent poor incentive for conservation. Viterra also favoured a LGS TSR-Like Rate targeted to larger LGS customers, as described below;

- Three customers, Peterson Commercial Property Management, Vancouver Aquarium and Ivanhoe Cambridge preferred the LS-2 energy rate, suggesting revisions to or guidelines for baseline determinations, the new account rule (85/15 Pricing is unfair) and the prospective growth rule (too restrictive).

- AMPC and CEC, who represent LGS customers, favoured the LS-5 flat energy rate with a BC Hydro commitment to explore alternative concepts. AMPC considered that the current baseline approach is not sufficiently flexible for larger LGS customers who tend to experience significant changes in operations and conservation investments. AMPC suggests that a LGS TSR-Like Rate similar to RS 1823 where baselines can be individually administered would be more appropriate and effective for the largest LGS customers (Viterra also strongly favoured a LGS TSR-Like Rate targeted to larger LGS customers);[244]
- BCSEA and BCOAPO were inclined to support the LS-5 flat energy rate subject to exploring the trade-offs between customer understanding and acceptance and economic efficiency.

As an outcome of Phase 2 and in response to customer and stakeholder feedback, BC Hydro identified four energy rate alternatives to bring forward for further review and feedback at Workshop 11b:

1. SQ LGS Energy Rate;
2. SQ LGS Simplified Energy Rate aimed at simplifying the LGS energy rate while retaining the baseline;
3. LGS Flat Energy Rate flattening the LGS energy rate and removing the baseline structure; and

[244] This option is discussed in the Phase 3 section. Refer also to section 4.3.2.2 of the Application for a review of BC Hydro's commitment to explore in RDA Module 2 the appropriateness of segmenting some of the largest LGS customers into a separate rate class for the purpose of defining a rate similar to RS 1823 under which consumption baselines would be defined and adjusted annually.

4. LGS TSR-Like Rate segmenting the existing LGS rate class to create a new large LGS rate class with the ability to define and adjust baselines annually similar to RS 1823.

Phase 3, Workshop 11b: Focus on LGS Energy Rate and Demand Charge Structures

BC Hydro did not identify a preferred LGS rate design as an outcome of Phase 2, and through Workshop 11b it further reviewed and received feedback on the performance of the four alternatives against the Bonbright rate design criteria:

1. SQ LGS Energy Rate - BC Hydro reviewed that the SQ LGS Energy Rate is not performing as expected: it is demonstrably complex, difficult to act on, perceived as inhibiting growth and delivering limited conservation. BC Hydro stated at this workshop that it is forecasting zero conservation from the LGS rate for planning purposes. BC Hydro advanced that this alternative should be reviewed for comparison purposes only.
2. SQ LGS Simplified Energy Rate - BC Hydro set out its view that a flat Part 1 energy rate would be a nominal simplification only as the Part 1 consumption threshold of 14,800 kWh/month is not material to most LGS customers and would not be expected to materially improve customer understanding and acceptance of the overall energy rates. The central issue is that the SQ LGS Energy Rate and related provisions attempt to strike a balance between sending an efficient price signal and addressing customer concerns with respect to growth and expected bill impacts. As reviewed in Workshop 11b and as described in section 5.2.1 of the Workshop 11a/11b Consideration Memo at Appendix C-4B of the Application, possible changes to any one provision are unlikely to substantially improve customer understanding and acceptance nor improve the status quo in terms of providing an efficient price signal.

3. LGS Flat Energy Rate - A LGS flat energy rate eliminates all complexity-related issues resulting from the baseline component of the SQ LGS Energy Rate and aligns with how other similarly situated Canadian electric utilities structure larger general service energy rates (predominantly flat). However, there is a trade-off between the customer understanding and acceptance and the economic efficiency criteria because the flat energy rate would not be reflective of LRMC (F2017: LGS flat energy rate is 5.37 cents/kWh with demand charge cost recovery at 65 per cent, and the lower end of the energy LRMC range is 9.46 cents/kWh).
4. LGS TSR-Like Rate - The overall objective of this alternative would be to induce conservation and potentially address customer understanding and acceptance concerns such as the impact of the SQ LGS Energy Rate on customer growth. BC Hydro reviewed a rate patterned on RS 1823 for a segment of large LGS customers with an initial annual CBL determined by historic baseline year(s), allowable adjustments for DSM, plant capacity increase and force majeure, and annual CBLs approved each year by the Commission. A TSR-Like Rate would leverage RS 1823 among larger customers that also take Transmission service as it is now well understood and provides a clear LRMC price signal.

BC Hydro also had not identified a preferred demand charge structure and brought forward the following alternatives for review at Workshop 11b:

1. LGS SQ Demand Charge – three-step inclining block
2. LGS Flat Demand Charge – single charge; and
3. LGS Two-step Inclining Block – zero Tier 1 charge and Tier 2 charge.

The same review process used for the MGS demand charge alternatives was used for the LGS demand charge alternatives, with similar feedback favoring a flat demand charge. For example, AMPC commented at Workshop 8b that a flat demand charge would better reflect cost causation and the rate design practice of other utilities, which either have flat or two step demand charges.

At Workshop 11b BC Hydro reviewed that a flat demand charge would generally offset the bill impacts of flattening the LGS energy rate, but given the current level of the demand charge the highest bill impacts tended toward customers with high load factors and high consumption, in the range of 1 per cent to 6 per cent in F2017 net of RRA rate increases. BC Hydro reviewed that the offsetting effect on bill impacts from the two-step inclining block demand charge alternative would be somewhat lower in comparison to the offsetting effect from a flat demand charge.

The issue of LGS demand charge cost recovery also arose at Workshop 11b. On the basis of the F2016 COS, the LGS demand charge recovers about 50 per cent of demand-related costs assigned to the LGS class. Commission staff, AMPC and BCOAPO suggested that BC Hydro should consider what level of demand charge collection would best meet BC Hydro's rate design objectives. AMPC questioned whether higher bill impacts to high load factor and high consumption customers would be fair and acceptable given that such customers make more efficient use of BC Hydro's system. On the basis of the Bonbright fairness criterion, AMPC recommended that BC Hydro consider an increase in the LGS demand charge to recover demand-related costs at a level consistent with customers taking service under RS 1823; this would result in an increase from 50 per cent to 65 per cent demand-related cost recovery.

As an outcome of Phase 3 BC Hydro identified:

1. The LGS Flat Energy rate and LGS Flat Demand Charge are its preferred LGS rate structures to carry forward to the 2015 RDA, which is supported by many LGS customers and organizations representing such customers, and most other stakeholders;

2. The SQ LGS Energy Rate should be carried forward to the 2015 RDA for comparison purposes only;
3. The SQ LGS Simplified Energy Rate should be carried forward to the 2015 RDA to allow further consideration by the Commission and among stakeholders of whether the price signal or customer understanding and acceptance of the price signal could be improved to any material and certain degree. BC Hydro also noted there are LGS customers such as Thrifty Foods that prefer the SQ LGS Energy Rate to the LGS Flat Energy Rate but with suggested changes (such as amendment of the 85/15 Pricing).

While BC Hydro set out considerations for a LGS TSR-Like Rate as a potential rate design for very high consumption LGS customers, it noted that its consideration of a LGS TSR-Like Rate and a segmented LGS class would be proposed only in the overall context of a LGS Flat Energy Rate applicable to the remaining majority of LGS customers. With the support of stakeholders, notably AMPC, a LGS TSR-Like Rate will be explored in RDA Module 2.

There was a general consensus among stakeholders that the LGS Flat Demand Charge is superior to the LGS SQ Demand Charge and the LGS Two-Step Inclining Block Demand Charge. Accordingly, BC Hydro did not analyze the LGS Two-Step Inclining Block Demand Charge any further and the LGS SQ Demand Charge is advanced for comparison purposes only.

Based on stakeholder feedback, BC Hydro carried forward to Phase 4 a review of an increase in the LGS demand charge recovery of demand-related costs.

Phase 4, Workshop 12: Focus on LGS Demand Charge Cost Recovery

BC Hydro undertook further jurisdictional assessment to determine if there was a readily identifiable ‘utility practice’ in terms of demand charge cost recovery. As reported at Workshop 8a, the surveyed Canadian electric utilities of SaskPower, Manitoba Hydro, Hydro Quebec, Nova Scotia Power, New Brunswick Power, ATCO

YECL and FortisBC either have a flat demand charge or an inclining two step demand charge with the first step set to $0. BC Hydro was unable to obtain information concerning demand cost recovery, except to note that the Newfoundland Power seasonal demand charge recovers about 45 per cent of demand-related costs from its large industrial customer segment.

At Workshop 12 BC Hydro presented the results of an increase in LGS demand charge recovery of demand costs from about 50 per cent to 65 per cent, a level consistent with RS 1823 demand cost recovery. As shown by comparing Figure 6-10 and Figure 6-11, reproduced from the Workshop 12 presentation found at Appendix C-1B to the Application, an increase in demand cost recovery will improve fairness in cost allocation and will further offset the impacts of energy rate flattening and dampen the range of bill impact variation among LGS customers across size and load factor.

Figure 6-10 F2017 Bill Impacts less RRA for LGS Flat Energy and Flat Demand, Demand Cost Recovery = ~50 Per Cent

Annual Consumption kWh

Highest kW

Load Factor *	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	-10.9%	-12.8%	-13.5%	-13.8%	-14.0%	-14.1%	-14.2%	-14.2%	-14.3%	-14.3%	-14.4%	-14.4%	-14.4%	-14.4%	-14.5%	-14.5%	-14.5%
20%	-11.4%	-6.1%	-7.1%	[illegible]	[illegible]	-8.2%	-8.3%	-8.4%	-8.5%	-8.6%	-8.6%	-8.7%	-8.7%	-8.8%	-8.8%	-8.8%	-8.8%
30%	-18.0%	-1.5%	-2.9%	-3.6%	-4.0%	-4.3%	-4.5%	-4.6%	-4.7%	-4.8%	-4.9%	-4.9%	-5.0%	-5.0%	-5.1%	-5.1%	-5.1%
40%	-22.0%	-4.7%	0.1%	-0.7%	-1.2%	-1.5%	[illegible]	-1.9%	-2.0%	-2.1%	-2.2%	-2.3%	-2.3%	-2.4%	-2.4%	-2.5%	-2.5%
50%	-24.5%	-7.1%	0.6%	1.5%	0.9%	0.6%	[illegible]	0.1%	0.0%	-0.1%	-0.2%	-0.3%	-0.4%	-0.4%	-0.5%	-0.5%	-0.5%
60%	-26.3%	-8.8%	[illegible]	3.1%	2.6%	2.2%	1.9%	1.7%	1.6%	1.4%	1.3%	1.2%	1.2%	1.1%	1.1%	1.0%	1.0%
70%	-28.3%	-10.1%	-2.2%	2.2%	[illegible]	3.5%	3.2%	3.0%	2.8%	2.7%	2.6%	2.5%	2.4%	2.3%	2.3%	2.2%	2.2%
80%	-30.3%	-11.1%	-3.2%	1.3%	4.2%	4.5%	4.2%	4.0%	3.8%	3.7%	3.6%	3.5%	3.4%	3.3%	3.3%	3.2%	3.2%
90%	-31.9%	-11.9%	-3.9%	0.6%	3.5%	5.4%	5.1%	4.8%	4.6%	4.5%	4.4%	4.3%	4.2%	4.1%	4.1%	4.0%	4.0%

Lowest kW

Red font indicates bill impact higher than RRA
Oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load factor.

Figure 6-11 F2017 Bill Impacts less RRA for LGS Flat Energy and Flat Demand, Demand Cost Recovery = ~65 Per Cent

Annual Consumption kWh — Highest kW

Load Factor

Load Factor	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	0.5%	-1.7%	-2.4%	-2.7%	-2.9%	-3.1%	-3.2%	-3.2%	-3.3%	-3.3%	-3.4%	-3.4%	-3.4%	-3.4%	-3.5%	-3.5%	-3.5%
20%	-4.8%	0.9%	-0.2%	-0.8%	-1.1%	-1.3%	-1.5%	-1.6%	-1.7%	-1.8%	-1.8%	-1.9%	-1.9%	-1.9%	-2.0%	-2.0%	-2.0%
30%	-14.5%	2.7%	1.2%	0.5%	0.1%	-0.2%	-0.4%	-0.5%	-0.6%	-0.7%	-0.8%	-0.9%	-0.9%	-1.0%	-1.0%	-1.0%	-1.1%
40%	-20.2%	-2.6%	2.3%	1.4%	1.0%	0.6%	0.4%	0.2%	0.1%	0.0%	-0.1%	-0.2%	-0.2%	-0.3%	-0.3%	-0.3%	-0.4%
50%	-24.0%	-6.5%	1.2%	2.1%	1.6%	1.2%	1.0%	0.8%	0.7%	0.6%	0.5%	0.4%	0.3%	0.3%	0.2%	0.2%	0.1%
60%	-26.7%	-9.2%	-1.5%	2.7%	2.1%	1.7%	1.5%	1.3%	1.1%	1.0%	0.9%	0.8%	0.7%	0.7%	0.6%	0.6%	0.5%
70%	-29.2%	-11.3%	-3.5%	0.9%	2.5%	2.1%	1.8%	1.6%	1.4%	1.3%	1.2%	1.1%	1.0%	1.0%	0.9%	0.9%	0.8%
80%	-31.8%	-12.9%	-5.1%	-0.7%	2.1%	2.4%	2.1%	1.9%	1.7%	1.6%	1.5%	1.4%	1.3%	1.2%	1.2%	1.1%	1.1%
90%	-33.7%	-14.2%	-6.4%	-2.0%	0.8%	2.7%	2.4%	2.1%	2.0%	1.8%	1.7%	1.6%	1.5%	1.5%	1.4%	1.3%	1.3%

Lowest kW

Red font indicates bill impact higher than RRA

Oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load factor.

BC Hydro favours increasing the LGS demand charge cost recovery level. AMPC strongly supports increasing the LGS demand charge recovery of demand-related costs. BCSEA supports such a change on the basis that the increase will blunt bill impacts of flattening the LGS energy charge. Given that this topic was only discussed at Workshop 12 at the end of the stakeholder engagement process, BC Hydro brought forward the LGS Flat Demand Charge under both demand charge cost recovery scenarios (status quo 50 per cent and preferred 65 per cent).

Phase 5, Workshop 11a/11b Consideration Memo: LGS Demand Ratchet

BC Hydro prefers to maintain the level of the LGS demand ratchet at the existing level of 50 per cent of peak monthly demand given that the level of the demand ratchet is not a major issue. Refer to section 6.3.4.2 regarding the discussion of the MGS demand ratchet.

6.4.5 BC Hydro Proposal and Stakeholder Engagement

The LGS Proposal is supported by AMPC (which represents some LGS customers; refer to the AMPC support letter at Appendix C-5E) Canada West Ski Areas Association, and the following LGS customers who sent BC Hydro support letters: Shape Property Management (**Shape**), Whistler Blackcomb, Ivanhoe Cambridge, Colliers International, Cadillac Fairview Corporation, Triovest Realty Advisors (B.C.)

Inc. and Gateway Casinos & Entertainment Limited (**Gateway**). Refer to the support letters at Appendix C-4E. Other LGS customer support conveyed through the 2015 RDA stakeholder engagement process is referenced in section 6.4.4.2.

6.4.5.1 LGS Flat Energy Rate

BC Hydro's preferred LGS Flat Energy Rate prioritizes customer understanding and acceptance by significantly simplifying the SQ LGS Energy Rate and aligning it with how other similarly situated Canadian electric utilities structure general service energy rates.

BC Hydro notes the participant concern that the resulting flat energy rate under its preferred alternative is not reflective of LRMC. BC Hydro acknowledges that unlike with the proposed MGS flat energy rate, there is a trade-off with the LGS Flat Energy Rate. BC Hydro prioritizes the Bonbright customer understanding and acceptance and fairness criteria at this time above the economic efficiency criteria for the reasons set out in sections 1.1.1, 1.5.1 and 2.4.1.2 of the Application. BC Hydro also notes two additional considerations: First, maintaining the SQ LGS Energy Rate would make improving the design and cost recovery of the LGS demand charge untenable in light of the bill impacts which makes some form of simplification of the design a priority; and second, the gains in simplification in moving to a flat energy rate appear to be worth the apparent small loss in economic efficiency in the status quo LGS rate design.

BC Hydro notes and agrees with the RDA workshop participants that questioned the SQ LGS Simplified Energy Rate:

- Commission staff questioned if the SQ LGS Simplified Energy Rate would address the real problems of the SQ LGS Energy Rate other than nominal simplification;
- AMPC remarked that changes to the provisions other than elimination of the baseline will only make matters worse, noting for example that the concept of a

PLB for the LGS rate class is too complex and that none of the administratively burdensome procedures such as the FGR or anomaly rules are necessary if the LGS rate is simplified so as to remove the baseline structure for the majority of LGS customers;

- CEC suggested that modifying the baseline provisions under SQ LGS Simplified Energy Rate would only add complication to the SQ LGS Energy Rate;
- BCOAPO commented that flattening the Part 1 energy rate under the SQ LGS Simplified Energy Rate would only be acceptable if it was considered as part of an overall package of changes aimed at improving customer acceptance and understanding of the rate design, but if it was not the case that the alternative would be understandable then BCOAPO was of the view that there is little point in pursing it further;
- BCSEA was not convinced that either flattening the Part 1 LGS energy rate or modifying baseline provisions would increase conservation or simplify the rate structure enough to overcome the complexity problems; and
- FNEMC would support flattening the Part 1 energy rate and modifying provisions as necessary to possibly improve customer understanding and acceptance.

6.4.5.2 LGS Flat Demand Charge and 65 Per Cent Recovery of Demand-related Costs

A flat demand charge for the LGS class:

- Improves fairness by aligning cost recovery with the cost to serve a LGS customer's peak demand, which is generally flat on a $/kW basis;
- Simplifies the rate structure and will improve customer understanding and acceptance. As compared to the existing three-step inclining block structure, a

flat LGS demand charge will also better reflect the rate design practice of other utilities, which either have flat or two step demand charges; and

- Generally offsets bill impacts associated with BC Hydro's preferred LGS Flat Energy Rate (and to a greater extent than a two-step inclining block demand charge structure).

Increasing the level of demand-cost recovery through the flat demand charge from ~50 per cent to 65 per cent will improve fairness in cost allocation and will further offset the impacts of energy rate flattening and dampen the range of bill impact variation among LGS customers across size and load factor. This result is illustrated in Figure 6-11. Bill impacts are generally low (1 per cent to 3 per cent) and evenly distributed across LGS customer consumption and load factor.

6.4.5.3 Illustrative Simulations

While BC Hydro is filing for a LGS rate structure change in F2018 (effective April 1, 2017), the simulation of LGS rate estimates and bill impacts assumes a one-time transition in rate structure in F2017 for illustrative purposes. The final LGS rates in F2018 will be determined by both the 2015 RDA and the F2017 RRA Commission decisions.

Table 6-20 lists the key calculation features of the alternative rate structures, and the rates estimated for F2017. All F2017 rates are modelled to recover the same target revenue of $937 million given a consumption forecast of 11,223 GWh and 27.7 GW of billed demand. Further details about the modelling calculations are shown in Appendix H-1A.

Table 6-20 LGS Rate estimates given rate structure transition in F2017

LGS	F2016	F2017 Status Quo	F2017 BC Hydro Proposal (65% Demand Recovery)	F2017 Sensitivity (50% Demand Recovery)
Basic cents/day	22.57	23.47	23.47	23.47
Demand $/kW				
T1			10.83 Flat	8.35 Flat
T2	5.50	5.72		
T3	10.55	10.97		
Energy cents/kwh				
T1	10.66	11.17	5.37 Flat	5.98 Flat
T2	5.13	5.37		
Part 2	9.90	10.10		
Minimum	3.30	3.43		
Key calculation features of alternatives to Status Quo			• Flat Energy Rate • Flat Demand Charge • Basic Charge is increased by RRA • Revenue recovered from demand portion of the rate in F2017 is escalated by a factor of 1.30 from status quo, to yield a projected cost recovery from the demand portion of the rate of 65 per cent.	• Flat Energy Rate • Flat Demand Charge • Basic Charge is increased by RRA • Revenue recovered from demand portion of the rate is same as that of Status Quo

6.4.5.4 Proposed LGS Rate Structure (65 Per Cent Demand cost recovery)

Table 6-21 shows the difference in the annual bills under the proposed rate structure as compared to the status quo for a “typical” LGS customer with consumption of 744,240 kWh per year and billed demand 185 kW each month, which is near the median in terms of consumption and load factor. Under the proposed structure, such customers tend to have similar bills as under the status quo rate structure (about 2 per cent higher) if consumption stays at about baseline over time. Due to the elimination of the baseline, the amount of benefits would be slightly lower for customers who experienced a reduction in consumption, due to removal of credits at the Part 2 energy rate, and higher for customers who experienced an increase in consumption, due to avoidance of charges at Part 2 energy rate.

Table 6-21 F2017 Illustrative Customer Bill – BC Hydro LGS Proposal (Demand 65 Per Cent Recovery)

Customer Scenario	Demand Charge ($)	Energy Charge ($)	Basic Charge ($)	Total Bill ($)	SQ Bill ($)	Variance ($)
Consume at baseline	24,045	39,953	86	64,085	62,864	1,221 (2%)
+5% from baseline	24,045	41,951	86	66,082	66,622	-539 (-1%)
-5% from baseline	24,045	37,956	86	62,087	59,106	2,981 (5%)

The bill impact statistic compares the change in annual bills of each customer account from F2016 to F2017, given identical consumption in energy and demand and a baseline that is equal to consumption:

- Under the status quo rate, the bill impact is at about the RRA rate increase (4 per cent) for all LGS customers;
- Under the LGS Proposal, the 20th to 80th percentile bill impact for F2017 ranges from 4 per cent to 8 per cent, with the full range between -23 per cent to +78 per cent. This distribution is similar across the major sectors. About 2.5 per cent of customer accounts are expected to experience bill impacts over 10 per cent. Of these 2.5 per cent of customers, the highest bill impact in terms of nominal dollars is about $11,000 (a bill impact of 50 per cent). Overall, about 25 per cent of LGS customer accounts are better off under the LGS Proposal when compared with the status quo.

Figure 6-12 shows the impact of rate structure change in the transition year, net of RRA rate increases under BC Hydro's LGS rate proposal. The distribution shows that the typical customers (as shown by the oval) are slightly impacted. The larger consuming customers tend to have minimal impacts during the transition, while the low load factor, and low consumption tend to see the biggest impacts due to charges on the first 35 kW of demand. Although more customer accounts will have higher bill impacts than the LGS Demand Sensitivity described below, the impact distribution shows that the bills are much less sensitive to changes in consumption and load factor (and therefore more predictable).

Figure 6-12 F2017 Bill Impacts less RRA – BC Hydro LGS Proposal (Demand 65 Per cent Recovery)

Annual Consumption kWh — Highest kw

Load Factor *	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	3.5%	1.3%	0.6%	0.2%	0.0%	-0.1%	-0.2%	-0.3%	-0.4%	-0.4%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%	-0.6%	-0.6%
20%	-2.9%	2.9%	1.7%	1.2%	0.8%	0.6%	0.4%	0.3%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	-0.1%	-0.1%	-0.1%
30%	-13.4%	4.0%	2.5%	1.8%	1.4%	1.1%	0.9%	0.7%	0.6%	0.5%	0.5%	0.4%	0.3%	0.3%	0.2%	0.2%	0.2%
40%	-19.6%	-1.9%	3.1%	2.2%	1.7%	1.4%	1.2%	1.0%	0.9%	0.8%	0.7%	0.6%	0.6%	0.5%	0.5%	0.4%	0.4%
50%	-23.7%	-6.1%	1.7%	2.6%	2.0%	1.7%	1.4%	1.2%	1.1%	1.0%	0.9%	0.8%	0.7%	0.7%	0.6%	0.6%	0.6%
60%	-26.6%	-9.1%	-1.3%	2.8%	2.3%	1.9%	1.6%	1.4%	1.3%	1.1%	1.0%	0.9%	0.9%	0.8%	0.8%	0.7%	0.7%
70%	-29.3%	-11.3%	-3.6%	0.8%	2.4%	2.0%	1.8%	1.5%	1.4%	1.3%	1.1%	1.1%	1.0%	0.9%	0.9%	0.8%	0.8%
80%	-31.9%	-13.1%	-5.3%	-0.9%	1.9%	2.2%	1.9%	1.7%	1.5%	1.3%	1.2%	1.1%	1.1%	1.0%	0.9%	0.9%	0.9%
90%	-34.0%	-14.5%	-6.8%	-2.4%	0.5%	2.3%	2.0%	1.7%	1.6%	1.4%	1.3%	1.2%	1.1%	1.1%	1.0%	1.0%	0.9%

Lowest kw

Red font indicates bill impact higher than RRA
Oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load factor.

*Note: Very high sensitivity on low load factor, lower consumption customers due to T1 kW charge.

6.4.5.5 LGS Demand Sensitivity Rate Structure (50 Per Cent Recovery)

As a comparison, BC Hydro modelled a LGS Demand Sensitivity where demand cost recovery is maintained at 50 per cent (same as status quo):

- About 36 per cent of customer accounts are better off than under the status quo. Under this scenario, the 20th to 80th percentile bill impact for F2017 ranges from 1 per cent to 7 per cent, with the full range between -24 per cent to +44 per cent. This trend is similar across the major sectors. About 0.5 per cent of customers experience bill impacts over 10 per cent. Of these customers (the 0.5 per cent), the highest bill impact in terms of dollars is about $9,000 (a bill impact of 10 per cent). As with the LGS Proposal, customers experiencing high bill impacts are characterized by low consumption and low load factor;

- Comparing the LGS Demand Sensitivity (Figure 6-13) with the LGS Proposal (Figure 6-12), the LGS Demand Sensitivity demonstrates that high load factor and high consumption customers are worse off. There is also much higher sensitivity in bill impacts, as shown by the large changes in bill impacts with slight variations in load factors or consumption.

AMPC argues that the LGS Demand Sensitivity outcome is not acceptable given that high load factor customers make more efficient use of BC Hydro's system. By comparison, Figure 6-12 highlights that by increasing demand charge cost recovery, the bill impacts of BC Hydro's LGS rate structure proposal are further offset and distributed among customers with differing load factors and consumption levels. For further description of interpreting these bill impact tables, please refer to Appendix H-1A of the Application.

Figure 6-13 F2017 Bill Impacts less RRA – LGS Demand Sensitivity (50 Per Cent Recovery)

Annual Consumption kWh

Highest kw

Load Factor

*	200,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	-11.3%	-13.2%	-13.8%	-14.1%	-14.3%	-14.4%	-14.5%	-14.6%	-14.6%	-14.7%	-14.7%	-14.7%	-14.8%	-14.8%	-14.8%	-14.8%	-14.8%
20%	-11.5%	-6.2%	-7.2%	-7.8%	-8.1%	-8.3%	-8.4%	-8.6%	-8.6%	-8.7%	-8.8%	-8.8%	-8.8%	-8.9%	-8.9%	-8.9%	-9.0%
30%	-18.0%	-1.5%	-2.9%	-3.6%	-4.0%	-4.2%	-4.4%	-4.6%	-4.7%	-4.8%	-4.8%	-4.9%	-4.9%	-5.0%	-5.0%	-5.1%	-5.1%
40%	-21.8%	-4.6%	0.2%	-0.6%	-1.0%	-1.3%	-1.6%	-1.7%	-1.9%	-2.0%	-2.1%	-2.1%	-2.2%	-2.2%	-2.3%	-2.3%	-2.4%
50%	-24.3%	-6.9%	0.8%	1.7%	1.2%	0.8%	0.6%	0.4%	0.2%	0.1%	0.0%	-0.1%	-0.1%	-0.2%	-0.2%	-0.3%	-0.3%
60%	-26.1%	-8.5%	-0.7%	3.4%	2.8%	2.5%	2.2%	2.0%	1.8%	1.7%	1.6%	1.5%	1.5%	1.4%	1.3%	1.3%	1.3%
70%	-28.1%	-9.8%	-1.9%	2.6%	4.2%	3.8%	3.5%	3.3%	3.1%	3.0%	2.9%	2.8%	2.7%	2.7%	2.6%	2.6%	2.5%
80%	-30.1%	-10.8%	-2.8%	1.7%	4.6%	4.9%	4.6%	4.4%	4.2%	4.1%	3.9%	3.8%	3.8%	3.7%	3.6%	3.6%	3.5%
90%	-31.7%	-11.5%	-3.6%	1.0%	3.9%	5.8%	5.5%	5.2%	5.1%	4.9%	4.8%	4.7%	4.6%	4.6%	4.5%	4.4%	4.4%

Lowest kw

Red font indicates bill impact higher than RRA
Oval indicates "typical" customers, who are between the 20th and 80th percentile by annual consumption and load factor.

*Note: Very high sensitivity on low load factor, lower consumption customers due to T1 kW charge.

6.5 Transition Analysis for Medium General Service and Large General Service Proposals

BC Hydro proposes one-step transitions for both the MGS Proposal and the LGS Proposal rate on April 1, 2017.

Rate design phase-in is typically implemented to soften the effect of implementation where adverse bill impacts would be imposed on specific customer segments (such as the largest 25 per cent of customers). BC Hydro understands that the bill impact test has in the past been used to slow down the transition to rate structures that would improve future economic efficiency. The benefits of more efficient rate design is that they would encourage efficient customer behavior that would lower customer bills in the future and it made sense that rates could transition to being more efficient to mitigate severe bill impacts on a few customers for the benefit of all customers. As part of the 2015 RDA, BC Hydro is proposing to redesign rates that unfairly allocate fixed costs among customers and have been doing so for some time now. Delays or lengthy transitions lengthen the time that some customers are required to subsidize others.

As part of and subsequent to Workshop 12, BC Hydro assessed the need for phase-in periods for its preferred MGS and LGS rates. Please refer to section 6 and Attachment 4 of the Workshop 11a/11b consideration memo at Appendix C-4B for further analysis.

6.5.1 Medium General Service

BC Hydro modelled a three year phase-in for the MGS Proposal as follows:

1. Revenue to be recovered from demand is determined by escalating the demand revenue recovered by the existing MGS rate by one-third of the increase needed to move from 15 per cent cost recovery to the final cost recovery of 35 per cent;
2. Demand tiers are priced to move each tier towards a flat rate in about one-third increments, with Tier 2 and Tier 3 merging from the start; and
3. The energy rates are determined so that the ratio between Part 1 Tier 1 and Tier 2 equals 1.0 in three years.

A three-year phase-in period for BC Hydro's preferred MGS rate (F2017-F2019) would have only minor mitigation of bill impacts as compared to no phase-in (i.e., one-time F2018 implementation) impacts:

- Under a three-year phase-in, customers who experience adverse bill impacts greater than 10 per cent are limited to about 800 accounts with less than about 40 MWh/year of annual consumption; and
- For the majority of MGS customers the three-year phase-in will delay the offsetting effect of the flat energy rate, flat demand charge and increasing demand cost recovery.

Refer to Figure 6-14 and Figure 6-15.

Figure 6-14 No MGS Proposed Rates Phase-In

	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	50.1%	52.5%	12.0%	2.4%	-1.8%	-9.1%	-15.3%	-17.5%	-19.1%	-20.3%	-21.2%	-21.9%	-22.6%	-23.1%	-23.5%	-23.9%	-24.2%
20%	18.6%	19.4%	19.6%	6.8%	1.0%	-2.2%	-3.9%	-2.0%	-0.6%	-0.2%	-2.0%	-3.5%	-4.7%	-5.7%	-6.5%	-7.2%	-7.8%
30%	8.1%	8.3%	8.4%	8.4%	2.4%	-1.2%	-3.1%	1.0%	0.6%	1.9%	3.0%	3.9%	4.7%	5.4%	4.5%	3.5%	2.7%
40%	2.9%	2.8%	2.8%	2.8%	2.8%	-0.6%	-2.7%	-0.4%	1.3%	2.7%	3.9%	4.9%	5.7%	6.4%	7.0%	7.6%	8.0%
50%	-0.3%	-0.5%	-0.6%	-0.6%	0.6%	-0.6%	-2.4%	-0.1%	1.8%	3.3%	4.5%	5.5%	6.4%	7.1%	7.7%	8.3%	8.8%
60%	-2.4%	-2.7%	-2.8%	-2.8%	-2.9%	2.9%	-2.5%	0.2%	2.1%	3.6%	4.9%	5.9%	6.8%	7.6%	8.3%	8.8%	9.4%
70%	-3.9%	-4.3%	-4.4%	-4.4%	-4.5%	-4.5%	-4.1%	0.2%	2.4%	3.9%	5.2%	6.3%	7.2%	8.0%	8.6%	9.2%	9.8%
80%	-5.0%	-5.5%	-5.6%	-5.6%	-5.7%	-5.7%	-5.3%	-1.1%	2.3%	4.1%	5.4%	6.5%	7.5%	8.3%	8.9%	9.6%	10.1%
90%	-5.9%	-6.4%	-6.5%	-6.6%	-6.6%	-6.6%	-6.3%	-2.1%	1.3%	4.1%	5.6%	6.7%	7.7%	8.5%	9.2%	9.8%	10.4%

Figure 6-15 Three Year MGS Proposed Rates Phase-In

	10,000	30,000	60,000	90,000	120,000	150,000	180,000	210,000	240,000	270,000	300,000	330,000	360,000	390,000	420,000	450,000	480,000
10%	11.5%	11.9%	8.2%	7.3%	6.9%	1.2%	-4.4%	-7.4%	-9.6%	-11.2%	-12.5%	-13.5%	-14.3%	-15.0%	-15.6%	-16.1%	-16.6%
20%	4.8%	4.9%	4.9%	4.1%	3.8%	3.6%	3.6%	4.8%	5.8%	5.7%	3.4%	1.6%	0.1%	-1.2%	-2.2%	-3.1%	-3.9%
30%	2.6%	2.5%	2.5%	2.5%	2.2%	2.1%	2.1%	3.5%	4.5%	5.4%	6.1%	6.6%	7.1%	7.6%	6.4%	5.3%	4.2%
40%	1.5%	1.3%	1.3%	1.3%	1.3%	1.2%	1.2%	2.6%	3.8%	4.6%	5.4%	6.0%	6.5%	6.9%	7.3%	7.7%	8.0%
50%	0.8%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	2.1%	3.2%	4.2%	4.9%	5.6%	6.1%	6.5%	6.9%	7.3%	7.6%
60%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	1.7%	2.9%	3.8%	4.6%	5.2%	5.8%	6.3%	6.7%	7.0%	7.3%
70%	0.1%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%	-0.1%	1.4%	2.6%	3.6%	4.4%	5.0%	5.6%	6.0%	6.5%	6.8%	7.2%
80%	-0.2%	-0.4%	-0.5%	-0.5%	-0.5%	-0.5%	-0.4%	1.2%	2.4%	3.4%	4.2%	4.8%	5.4%	5.9%	6.3%	6.7%	7.0%
90%	-0.4%	-0.6%	-0.7%	-0.7%	-0.7%	-0.7%	-0.6%	1.0%	2.2%	3.2%	4.0%	4.7%	5.3%	5.7%	6.2%	6.5%	6.9%

The three-year phase-in is highly complex. While there are some softening of bill impacts for high load factor, high consuming customers, the key trade-off is an expected decline in customer understanding and bill predictability.

6.5.2 Large General Service

BC Hydro modelled a three year phase-in for the LGS Proposal as follows:

1. Revenue to be recovered from demand is determined by escalating the demand revenue recovered by the existing LGS rate by one-third of the increase needed to move from 50 per cent cost recovery to the final cost recovery of 65 per cent;
2. Demand tiers are priced to achieve a flat rate within three years; and
3. The energy charges are determined so that the ratio between Part 1 Tier 1 and Tier 2 equals 1.0 in three years.

As depicted in Figure 6-12 in section 6.4.5.4, the effects of combining the changes in energy and demand charges offset and soften the bill impacts to any set of LGS customers. For most LGS customers a three year phase-in yields higher bill impacts for a longer period of time than no-phase-in. The key reason is that the phase-in delays the benefits of the rate design changes. With a three year phase-in, BC Hydro estimates that about 3,200 accounts (just under half of all LGS accounts) will experience bill impacts of 10 per cent or greater; impacted customers include 'typical' customers. Refer Figure 6-16 and Figure 6-17.

Figure 6-16 No LGS Preferred Rates Phase-In

	150,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	12.1%	2.3%	1.6%	1.3%	1.1%	0.9%	0.8%	0.8%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%	0.5%
20%	-2.6%	4.9%	3.8%	3.2%	2.9%	2.7%	2.5%	2.4%	2.3%	2.2%	2.2%	2.1%	2.1%	2.1%	2.0%	2.0%	2.0%
30%	-12.3%	6.7%	5.2%	4.5%	4.1%	3.8%	3.6%	3.5%	3.4%	3.3%	3.2%	3.1%	3.1%	3.0%	3.0%	3.0%	2.9%
40%	-18.0%	1.4%	6.3%	5.4%	5.0%	4.6%	4.4%	4.2%	4.1%	4.0%	3.9%	3.8%	3.8%	3.7%	3.7%	3.7%	3.6%
50%	-22.0%	-2.5%	5.2%	6.1%	5.6%	5.2%	5.0%	4.8%	4.7%	4.6%	4.5%	4.4%	4.3%	4.3%	4.2%	4.2%	4.1%
60%	-26.4%	-5.2%	2.5%	6.7%	6.1%	5.7%	5.5%	5.3%	5.1%	5.0%	4.9%	4.8%	4.7%	4.7%	4.6%	4.6%	4.5%
70%	-29.5%	-7.3%	0.5%	4.9%	6.5%	6.1%	5.8%	5.6%	5.4%	5.3%	5.2%	5.1%	5.0%	5.0%	4.9%	4.9%	4.8%
80%	-31.9%	-8.9%	-1.1%	3.3%	6.1%	6.4%	6.1%	5.9%	5.7%	5.6%	5.5%	5.4%	5.3%	5.2%	5.2%	5.1%	5.1%
90%	-33.7%	-10.2%	-2.4%	2.0%	4.8%	6.7%	6.4%	6.1%	6.0%	5.8%	5.7%	5.6%	5.5%	5.5%	5.4%	5.3%	5.3%

Figure 6-17 Three Year LGS Preferred Rates Phase-In

	150,000	400,000	600,000	800,000	1,000,000	1,200,000	1,400,000	1,600,000	1,800,000	2,000,000	2,200,000	2,400,000	2,600,000	2,800,000	3,000,000	3,200,000	3,400,000
10%	25.2%	2.4%	-1.5%	-3.3%	-4.5%	-5.2%	-5.8%	-6.2%	-6.5%	-6.7%	-6.9%	-7.1%	-7.2%	-7.4%	-7.5%	-7.6%	-7.6%
20%	13.8%	12.3%	6.1%	2.1%	1.2%	0.0%	-0.8%	-1.5%	-2.0%	-2.4%	-2.7%	-3.0%	-3.2%	-3.4%	-3.5%	-3.7%	-3.8%
30%	4.2%	19.0%	11.1%	7.3%	5.0%	3.5%	2.4%	1.6%	1.0%	0.5%	0.1%	-0.2%	-0.5%	-0.8%	-1.0%	-1.2%	-1.3%
40%	-1.4%	13.7%	14.7%	10.3%	7.7%	6.0%	4.7%	3.8%	3.1%	2.5%	2.1%	1.7%	1.4%	1.1%	0.8%	0.6%	0.5%
50%	-4.9%	9.8%	14.8%	12.6%	9.7%	7.8%	6.5%	5.5%	4.7%	4.1%	3.6%	3.1%	2.8%	2.5%	2.2%	2.0%	1.8%
60%	-6.1%	6.9%	11.9%	14.3%	11.3%	9.2%	7.8%	6.7%	5.9%	5.2%	4.7%	4.2%	3.9%	3.5%	3.3%	3.0%	2.8%
70%	-7.1%	4.8%	9.7%	12.5%	12.5%	10.4%	8.9%	7.7%	6.9%	6.2%	5.6%	5.1%	4.7%	4.4%	4.1%	3.8%	3.6%
80%	-7.8%	3.2%	8.0%	10.7%	12.5%	11.3%	9.7%	8.6%	7.7%	6.9%	6.3%	5.9%	5.4%	5.1%	4.8%	4.5%	4.3%
90%	-8.3%	1.9%	6.6%	9.4%	11.1%	12.1%	10.5%	9.3%	8.3%	7.6%	7.0%	6.5%	6.0%	5.7%	5.3%	5.1%	4.8%

A phase-in for the proposed LGS rates would delay the offsetting benefits and result in the opposite effect of what a phase-in is intended to accomplish.

6.6 Requested Order for the LGS and MGS New Account Rule

BC Hydro requests a final order effective January 1, 2016 approving a change in the pricing for new accounts that do not have a HBL on RS 15xx or RS 16xx from 85 per cent of monthly consumption billed at the Part 1 energy rate and 15 per cent of monthly consumption at the Part 2 energy rate (85/15 Pricing) to 100 per cent of the monthly consumption billed at the Part 1 energy rate (100 per cent Part 1 Pricing). The draft requested order is provided in Appendix A-1A, and the revised clean and black-lined tariff pages for RS 15xx and RS 16xx are provided in Appendix F-1A.

The LGS and MGS RS 16xx and RS 15xx Special Conditions require that new accounts be established under 85/15 Pricing for the first year prior to the establishment of a baseline. As discussed in section 6.4.2.1, the 85/15 Pricing was agreed on as part of the 2009 LGS Application NSA and approved by the Commission. In the 2009 LGS Application, BC Hydro proposed 90 per cent of monthly consumption billed at the Part 1 energy rate and 10 per cent of monthly consumption billed at the Part 2 energy rate. The 10 per cent was increased to 15 per cent during the LGS NSA. This was to reduce the concerns expressed by some stakeholders that existing customers with growing load might open new accounts to have their HBLs reset and to obtain bill savings.

BC Hydro's business practices do not allow the opening of new accounts except under specific circumstances which make gaming difficult and BC Hydro is not aware of gaming being an issue.[245] A number of LGS and MGS customers have complained formally to the Commission and/or informally to BC Hydro about the 85/15 Pricing. For example, the 85/15 Pricing applies to new accounts (e.g., those opened as a result of a legal change in ownership) that have taken over existing businesses and not changed operations. One of the Commission-related complaints was initiated by Sobeys West Inc. (**Sobeys**). The result was Commission Order No. G-142-15[246] which did not revise the new account rule; instead under section 63 of the UCA, BC Hydro was to waive the difference in the amount Sobeys was to be billed under the new account rule as compared to the acquired asset's baseline. There have been a number of other new account-related complaints.[247]

BC Hydro proposes that new MGS and LGS accounts pay 100 per cent Part 1 Pricing. This pricing recovers BC Hydro's embedded costs and therefore does not harm other ratepayers. Although new accounts will not be exposed to the LRMC price signal, this will be for a one year period only. BC Hydro's proposal is supported by the following customers who sent in support letters: Shape; Gateway; and The Bay Centre. Refer to copies of the support letters at Appendix C-4E. In addition, Ivanhoe Cambridge and Thrifty Foods raised concerns with the 85/15 Pricing at Workshops 8b and 11b.

There would be no new account rule if the Commission approves BC Hydro's proposed LGS and MGS rates effective April 1, 2017; in other words, if the Commission approves BC Hydro's proposed LGS and MGS rates effective April 1, 2017, the resulting order supplants the order concerning the 85/15 Pricing.

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245 See the BC Hydro responses to CEC IRs 1.5.3 and 1.5.4, Exhibit B-5 in the LGS Application proceeding; http://www.bcuc.com/Documents/Proceedings/2009/DOC_23845_B-5_BCHydro_IR_1-to-BCUC.pdf.

246 http://www.bcuc.com/Documents/Orders/2015/DOC_44450_G-142-15_Sobeys-Amend.pdf.

247 Other examples of 85/15 Pricing complaints are: Strata KAS3058's complaint to the Commission (refer to the Commission's letter of July 23, 2012, Log No. 39756); and City of Vernon (informal, to BC Hydro).

6.7 Three Matters Associated with Medium General Service and Large General Service Proposals

BC Hydro's proposals for MGS and LGS rates raise three related matters:

- There would be no need for TS 82. Refer to section 6.7.1;
- There would be no need for the existing LGS and MGS control groups used to help evaluate the conservation effects of the existing MGS and LGS rates. Refer to section 6.7.2;
- There would be no need for RS 26xx which exempts Corix from the LGS two-part rate. See section 6.7.3.

6.7.1 Tariff Supplement No. 82

BC Hydro requests the termination of TS 82, which are the rules for LGS prospective growth applications for modified LGS pricing, and the transfer of any remaining LGS customers on TS 82 modified LGS pricing to RS 16xx effective April 1, 2017. Refer to a copy of the requested order found at Appendix A-1D of the Application.

As noted in section 6.4.2.1, TS 82 was developed to address the prospective growth adjustment provision in the LGS NSA. It allows eligible customers with prospective growth who apply to BC Hydro to be billed under modified LGS pricing. The Commission approved TS 82 by Order Nos. G-22-12[248] and G-20-13.[249] TS 82 will not be required if the Commission approves BC Hydro's proposal for the LGS rate structure as set out in section 6.4.1.

6.7.2 Medium General Service and Large General Service Control Groups

BC Hydro requests an order dissolving the LGS and MGS control groups and related amendments to RS 12xx. Refer to a copy of the order found at Appendix A-1D, and to the black-lined copies of the current RS 12xx showing the proposed changes at Appendix F-1E for illustrative purposes.

[248] http://www.bcuc.com/Documents/Orders/2012/DOC_29913_G-22-12_BCH-Amended-TS-No82.pdf.
[249] http://www.bcuc.com/Documents/Orders/2012/DOC_29913_G-22-12_BCH-Amended-TS-No82.pdf.

In its 2009 LGS Application, BC Hydro proposed that randomly selected MGS and LGS accounts remain on the pre-existing general service rate structure. These MGS and LGS control groups were established to provide a method to help isolate the effects of the LGS and MGS rates from other factors that affect consumption. The control groups will not be required if the Commission approves BC Hydro's proposed MGS and LGS rate structures as described in sections 6.3.1 and 6.4.1. There are 320 LGS and MGS control accounts currently served on RS 12xx. These accounts would be transferred to the new LGS and MGS rates on April 1, 2017 if the Commission approves BC Hydro's proposed MGS and LGS rates.

6.7.3 Corix and Rate Schedule 26xx

As noted in section 6.4.2.1, Corix applied for an exemption from the LGS two-part energy rate. The Commission granted Corix's request for an exemption from the LGS two-part rate by Commission Order No. G-36-11,[250] and ordered Corix and BC Hydro to negotiate a flat rate to be filed with the Commission. As a result of the negotiation with Corix, BC Hydro filed RS 26xx in compliance with Commission Order No. G-36-11.

BC Hydro's proposal to replace the LGS two-part rate with a flat rate removes the need for having an exempt rate. Thus, BC Hydro contacted Corix to determine if it had any objection to BC Hydro applying for the termination of RS 26xx and the transfer of Corix's Sun Rivers and Sonoma Pines accounts to the default LGS rate as part of BC Hydro's proposal for the LGS rates. The transfer would only occur if the Commission approves BC Hydro's LGS rate proposal identified in section 6.4.1. On September 11, 2015 Corix confirmed that it is not opposed to BC Hydro's applying for the termination of RS 26xx and the transfer of Corix's Sun Rivers and Sun Pines accounts to the default LGS rate. Refer to BC Hydro's requested order at Appendix A-1D.

[250] http://www.bcuc.com/Documents/Orders/2011/DOC_27077_G-36-11_Corix-Exemption-BCH-LGS-Rate-Reasons.pdf.

6.8 Rate Schedule 1253

6.8.1.1 Background

RS 1253 (IPP Station Service) was implemented in October 2001, and is available to IPP customers served at distribution voltage for forced outages, scheduled maintenance requirements and black-start re-energization of generators:

- Energy is provided on an 'as available' basis at Mid-C market rates;
- There is no demand charge associated with RS 1253 because service is non-firm; and
- There is a monthly minimum charge currently set at $41.37 (F2016) to recover costs incurred by BC Hydro under RS 1253. BC Hydro would continue with its existing practice of applying RRA rate increases to the RS 1253 monthly minimum charge of $41.37 (F2016).

6.8.1.2 BC Hydro Proposal and Stakeholder Engagement

No IPP customer expressed any concern with this rate.

BC Hydro did not specifically discuss RS 1253 with stakeholders. However, as set out in section 7.4.2 of the Application, RS 1853 - which is available to IPP customers served at transmission voltage for forced outages, scheduled maintenance requirements and black-start re-energization of generators, and has identical energy rate pricing and monthly minimum charge was discussed at Workshops 5 and 10. The only issue identified concerning RS 1853 is whether the non-firm energy rate pricing should be aligned with another non-firm rate, RS 1880 – like RS 1253, RS 1853 is based on Mid-C market prices whereas RS 1880 is set to the prevailing RS 1823 Tier 2 rate. At Workshop 10, BC Hydro provided its view that non-firm energy sold to IPPs should be priced off the Mid-C market because non-firm energy acquired from IPPs is typically priced at Mid-C, thus ensuring that non-firm energy is consistently valued whether it flows from BC Hydro to the IPP customer or from the IPP service provider to BC Hydro.

2015 Rate Design Application

Chapter 7

Transmission Service Rate Design

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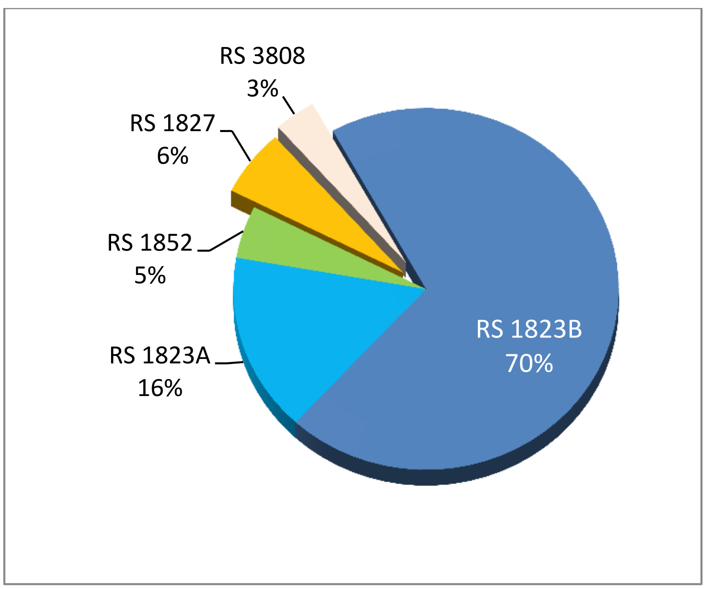
7.1 Introduction and Structure of Chapter

This Chapter outlines BC Hydro's proposals for Transmission Service rates. As described in sections 1.4 of the Application, Transmission Service customers are served at transmission voltage level (69 kV and above). There are eight existing Transmission Service rate schedules: RS 1823 (Stepped Rate); RS 1825 (TOU Rate); RS 1827 (Rate for Exempt Customers); RS 1852 (Modified Demand); RS 1853 (IPP Station Service); RS 1880 (Standby and Maintenance Supply); RS 1891 (Shore Power Service); and RS 3808, the PPA between BC Hydro and FortisBC discussed in sections 2.1 and 2.5 of the Application. Figure 7-1 sets out the F2015 Transmission Service voltage energy sales; RS 1823 (A and B)[251] represented about 86 per cent of total Transmission Service voltage sales.[252]

Figure 7-1 F2015 Transmission Service Voltage Energy Sales



[251] As described in Table 7-1 below, RS 1823 A is the flat energy rate for new accounts and customers that do not have a CBL, while RS 1823 B is the stepped rate (Tier 1 and Tier 2 pricing).

[252] F2015 RS 1880 sales were 50 GWh or about 0.3 per cent of total Transmission Service voltage sales, and F2015 RS 1853 sales were 16 GWh. There were no sales under RS 1891 as this rate was approved by the Commission on June 25, 2015; refer to section 2.5 of the Application.

7.1.1 Summary of BC Hydro Proposals

On the basis of the inputs summarized in section 7.1.2, BC Hydro concludes the following:

- Existing Rates:
  - RS 1823, RS 1827, RS 1853 and RS 1880 are generally working well and no changes are required;
  - RS 1852 requires minor amendments to the definitions of availability and HLH; and
  - While there has been no take-up of RS 1825, BC Hydro's efforts to provide Transmission Service customers with options to reduce their electricity bills are better directed at the freshet rate pilot (and the two to three-year load curtailment program pilot initiated on August 19, 2015). As set out in section 2.3.1.8 of the Application, the load curtailment pilot is a DSM program, not a rate, and so is not addressed any further in this Chapter).
- Rate Options:
  - RTP and retail access should not be pursued given the significant issues associated with each of these potential rates as described below in section 7.3.3; and
  - A two-year freshet rate pilot should be implemented on March 1, 2016.

7.1.2 Summary of Stakeholder Engagement and Other Inputs

As part of the 2015 RDA stakeholder engagement processes, BC Hydro reviewed the existing Transmission Service rates with the exception of RS 1891 given the recent Commission review and June 25, 2015 decision[253] (refer to section 2.5 of the Application). BC Hydro also sought input on three potential new Transmission

[253] Commission Order No. G-111-15; http://www.bcuc.com/Documents/Proceedings/2015/DOC_43962_06-25-2015_BCH-Shore-Power-Decision_G-111-15.pdf.

Service rate options – retail access, RTP and a freshet rate pilot. Inputs into BC Hydro's Transmission Service rate proposals consisted of:

- Prior Commission decisions, including those summarized in sections 2.3.1.1, 2.3.1.2, 2.3.1.3 and 2.3.1.4 of the Application;
- Submissions made to the 2013 IEPR task force, the IEPR final task force report and B.C. Government responses outlined in section 2.3.1.8 of the Application;
- Two workshops on Transmission Service rates (Workshop 5 on October 22, 2014 and Workshop 10 on May 7, 2015) as described in section 2.2.3.2 of the Application; and the May to June 2014 regional sessions with Transmission Service customers and individual meetings with AMPC, CAPP, MABC and Transmission Service customers (including the four exempt customers served pursuant to RS 1827), all as described in section 2.2.3.4 of the Application;
- Jurisdictional review of Canadian electric utilities with market structures similar to BC Hydro (vertically integrated monopolies);[254] and
- Internal review.

7.1.3 Chapter Structure

The remainder of this Chapter is structured as follows:

- Section 7.2 provides background on and BC Hydro proposals concerning RS 1823. As discussed in section 2.2.1.3 of the Application, subsection 3(1) of Direction No. 7 restricts the Commission's jurisdiction concerning core rate design elements of RS 1823, including the Tier 1/Tier 2 90/10 split. Accordingly, section 7.2 focuses on BC Hydro's proposals for the three RS 1823 elements over which the Commission has jurisdiction: pricing principles for F2017 to

[254] As noted in section 7.3 below, BC Hydro undertook a jurisdictional review for purpose of identifying and developing Transmission Service rate options, but not for RS 1823 given that Direction No. 7 prescribes the core elements of RS 1823.

F2019 (section 7.2.2); the definition of revenue neutrality (section 7.2.3); and the demand charge (section 7.2.4);

- Section 7.3 contains BC Hydro's assessment of both existing rate options RS 1825 (section 7.3.1) and RS 1852 (section 7.3.2), and the three potential new rate options listed above. Retail access and RTP are the subject of section 7.3.3, while the proposed two-year freshet rate pilot is described in section 7.3.4;
- Section 7.4 reviews BC Hydro's two non-firm rates applicable to customers with generation – RS 1853 (for IPPs) and RS 1880 (for RS 1823 customers with self-generation); and
- Section 7.5 concludes this Chapter with a discussion of RS 1827.

7.2 Rate Schedule 1823: Default Transmission Service Stepped Rate

RS 1823 is the default two-step rate for Transmission Service customers implemented on April 1, 2006 after a NSA.[255] Refer to section 2.3.1.4 of the Application for a description of the regulatory history of RS 1823. RS 1823 has been reviewed on multiple occasions by both the Commission and the B.C. Government, most recently as part of the 2013 IEPR task force as discussed in section 2.3.1.8 of the Application. In its October 2013 final report, the IEPR task force noted that BC Hydro does not have a "conservation problem in the short term, so there is little incentive to make drastic changes to a regime (RS 1823) that appears to be working", and recommended that the B.C. Government need not act on the

[255] Commission Order No. G-79-05 and accompanying Reasons for Decision; http://www.bcuc.com/Documents/Orders/2005/DOC_8391_G-079-05_BCHydro_TSRA%20Reasons%20for%20Decision.pdf.

Commission 2009 TSR Report.[256] The B.C. Government accepted this recommendation.

The background and structure of RS 1823 is outlined in section 1 of the Workshop 5 consideration memo found at Appendix C-5A and summarized here. The F2016 pricing elements of RS 1823 are set out in Table 7-1.

Table 7-1 Existing RS 1823 Rates (F2016)

Energy Rate A	4.303 cents/kWh (this is the flat rate for new accounts and customers that do not have a CBL)
Energy Rate B Tier 1	3.836 cents/kWh
Energy Rate B Tier 2	8.503 cents/kWh
Demand	7.341 $/kV.A

Under RS 1823, a CBL is initially determined for each specific customer site to represent the customer's normal historic annual energy consumption. The CBL is then subject to revision annually, and at other times in accordance with TS 74. Under Energy Rate B of RS 1823, a customer purchases annual energy volumes at the Tier 1 rate up to 90 per cent of its CBL and at the Tier 2 rate above 90 per cent of CBL (as noted in section 2.2.1.3 of the Application, this is referred to as the Tier 1/Tier 2 90/10 split). Since inception, RS 1823 was designed to be "customer bill neutral" when annual energy consumption is equal to 100 per cent of a customer's CBL. That is, a customer whose annual consumption equals 100 per cent of its CBL will pay an average energy rate equal to the RS 1823 flat Energy Rate A for new accounts or for customers that, from time to time, do not have a CBL in accordance with TS 74. The Tier 2 rate is set as a signal of BC Hydro's energy LRMC, ascertained through the 2013 IRP to be between 8.5 cents/kWh and 10.0 cents/kWh ($F2013). As described in section 2.3.2.2 of the Application, for F2017 to F2019, BC Hydro includes an inflation factor of 2 per cent for the LRMC for Transmission Service rate-making. Table 2-5 in Chapter 2 is reproduced below as Table 7-2 for

[256] *Industrial Electricity Policy Review Task Force Final Report*, October 31, 2013, page 29; https://news.gov.bc.ca/files/Newsroom/downloads/industrial_electricity_policy_review_task_force_final_report.pdf.

ease of reference given its importance to the RS 1823 pricing principle discussion in section 7.2.2.

Table 7-2 Inflation Adjusted Range in Energy LRMC

Inflation (%/year)[257]		
Energy LRMC	**Lower Bound (cents per kWh)**	**Upper Bound ($/MWh)**
F2017	8.92	10.50
F2018	9.10	10.71
F2019	9.28	10.92

7.2.1 Commission Jurisdiction and Scope of RS 1823 Review

As discussed in section 2.2.1.3 of the Application, subsection 3(1) of Direction No. 7 requires that the Commission, in designing rates for BC Hydro's Transmission Service customers, ensure that those rates are consistent with Recommendation #8 of the Heritage Contract Report.[258] As a result, RS 1823 must adhere to the following:

- The Tier 2 rate should reflect BC Hydro's energy LRMC;
- The quantity of Tier 1 power sold to Transmission Service customers should be set at 90 per cent, and the Tier 2 quantity should make up the remaining 10 per cent; and
- The Tier 1 rate should be derived from the Tier 2 rate and the Tier 1/Tier 2 90/10 split to achieve, to the extent reasonably possible, revenue neutrality.

As discussed at Workshop 5 and Workshop 10 and in section 2.5.2 of the Application, it is BC Hydro's view that the Commission cannot unilaterally amend these principles under its section 58 to 61 *UCA* rate setting power; instead, the Commission can only be given jurisdiction to review and make recommendations

[257] F2014 and F2015 inflation are -0.03 per cent and 1.3 per cent respectively, based on B.C. CPI; forecasted F2016 inflation is 1.9 per cent and Forecasted F2017, F2018, and F2019 inflations are 2 per cent per year based on December 2014 BC Treasury Board forecasts. Values exclude 6 per cent distribution line loss.

[258] Refer especially pages 58 to 62 of the Heritage Contract Report; citation found at footnote 9 in Chapter 1. Recommendations No. 8 to No. 15 are described in Table 2-2 and section 2.3.1.3 of the Application.

concerning these matters through a section 5 *UCA* inquiry review process, and only the LGIC can refer this matter to the Commission under section 5 of the *UCA*. The B.C. Government confirmed that it will not refer the Tier 1/Tier 2 90/10 split to the Commission. Accordingly, while BC Hydro reviewed the Tier 1/Tier 2 90/10 split at Workshop 5 to gather stakeholder input for purposes of informing the B.C. Government referral decision, and while BC Hydro reported out on the B.C. Government's decision at Workshop 10 and answered questions, the Tier 1/Tier 2 90/10 split is not addressed any further in this Chapter.

In BC Hydro's view, the Commission has jurisdiction over the following three RS 1823 elements under sections 58 to 61 of the *UCA*:

- Setting pricing principles for F2017 to F2019 as long as Tier 2 remains within BC Hydro's energy LRMC range. 'Pricing principles' refer to the manner in which RRA rate increases are applied to the pricing elements of RS 1823 (Tier 1 energy rate, Tier 2 energy rate, demand charge, the flat Energy Rate A and the minimum monthly charge). Refer to section 7.2.2 for BC Hydro's RS 1823 F2017-F2019 Pricing Principles;
- Definition of revenue (customer bill) neutrality, which differs from the forecast revenue neutral approach used for the Residential and SGS/MGS/LGS rate classes. The term "revenue neutrality" used in Recommendation #8 is not defined, and could be either customer bill neutrality or forecast revenue neutrality. At Workshop 5, BC Hydro presented its view that there is no legal prohibition against changing the specific RS 1823 customer bill neutrality methodology after F2016 because the term "revenue neutrality" used in Recommendation #8 is not defined. It is important to note that when both the Tier 1 rate and the Tier 2 rate are increased by the RRA rate increase, both definitions of revenue neutrality (customer bill neutrality and forecast revenue

neutrality) are satisfied.[259] Conversely, only if one or the other of the Tier 1 rate or the Tier 2 rate increase by an amount different than the RRA rate increase is it necessary to choose between customer bill neutrality and forecast revenue neutrality to residually calculate the other rate. See section 7.2.3;

- Demand charge, with BC Hydro concluding there is no compelling reason to change the definition of billing demand which is based on the highest kV.A demand during HLH in the billing period. Refer to section 7.2.4.

7.2.2 Tier 1 and Tier 2 Energy Rates: Proposed Pricing Principles for F2017 to F2019

BC Hydro is seeking approval of the RS 1823 F2017-F2019 Pricing Principles(labelled Option 1 below in section 7.2.2.2) pursuant to which (in F2017) Tier 2 is set to the lower end of the energy LRMC range and Tier 1 is set so that customer bill neutrality results, and thereafter (F2018/F2019) RRA increases are applied equally to both Tier 1 and Tier 2.

7.2.2.1 Background

The F2016 Tier 2 rate is 8.50 cents/kWh. Increasing it by 4 per cent – the maximum allowed RRA increase in F2017 per section 9 of Direction No. 7 – would only take it to 8.84 cents/kWh, which is less than the lower bound of the F2017 LRMC range shown in Table 7-2 (8.92 cents/kWh). Therefore, to conform with the requirements of Recommendation #8, in F2017 it is necessary to increase Tier 2 by more than the RRA rate increase to bring RS 1823 into lawful compliance with Direction No. 7, regardless of what the RRA rate increase actually turns out to be in that year. It follows that the change in F2017 to Tier 1 must be done either on the basis of customer bill neutrality or forecast revenue neutrality (again, to conform with the legal requirements of Direction No. 7). That is, in F2017, and F2017 alone, both definitions of revenue neutrality cannot be met and choice between them has to be

[259] Both definitions of revenue neutrality are satisfied **only** when RRA rate increases are applied to each of the Tier 1 rate and the Tier 2 rate.

made. As explained below, that choice is not necessary in F2018 and F2019, provided the Tier 2 rate is set in F2017 at the lower bound of LRMC, since RRA rate increases thereafter will result in RS 1823 pricing that in F2018 and F2019 satisfies all of the requirements of Direction No. 7 (LRMC-based Tier 2, revenue neutral under either definition, Tier 1 rate calculated residually).

7.2.2.2 Options Reviewed

At Workshop 5 and Workshop 10, BC Hydro presented three pricing options for the application of RRA rate increases during the F2017 to F2019 period:

- Option 1: In F2017 Tier 2 is set to the lower end of the energy LRMC range set out in Table 7-2 above and Tier 1 is set to attain customer bill neutrality. Thereafter (F2018/F2019), RRA rate increases would be applied equally to each element of RS 1823. Accordingly, the application of the RRA rate increases to both the Tier 1 and Tier 2 rates in F2018 and F2019 maintains Tier 2 within the range of LRMC (with inflation). Option 1 is not forecast revenue neutral in F2017 since the bill neutrality definition of revenue neutrality is used to determine the Tier 1 rate once the Tier 2 rate is increased by an amount greater than the RRA rate increase so that it is at the lower end of the LRMC range. Since in F2018 and F2019 the RRA rate increases are applied to the Tier 1 and Tier 2 rates equally, Option 1 is forecast revenue neutral in F2018 and F2019 as well as customer bill neutral. Option 1 prioritizes the Bonbright rate and bill stability, and customer understanding and acceptance, criteria by continuing with the Direction No. 6 approach, and is supported by Transmission Service customers who take service under RS 1823, and by organizations representing such customers (AMPC, who speaks for MABC on matters concerning RS 1823, and CAPP);
- Option 2: In F2017, F2018, and F2019 the Tier 2 rate is set to the lower end of the LRMC range set out in Table 7-2 and Tier 1 is calculated using the customer bill neutrality definition of revenue neutrality (and RRA rate increases

are then applied to Tier 1 as long as Tier 2 tracks the lower end of the energy LRMC range). Since the bill neutrality approach is used to determine the Tier 1 rate from the Tier 2 rate, Option 2 is not forecast revenue neutral. Option 2 was developed to reflect the Commission's decision concerning BC Hydro's 2008 Application to Vary Pricing of RS 1823, 1825 and 1880;[260] and

- Option 3: In F2017, all of the RRA rate increase is applied to Tier 2 and Tier 1 is held constant at its F2016 level. For F2018, applying all of the RRA rate increase to Tier 2 results in Tier 2 being above the upper end of the LRMC range. As a result, Tier 2 is capped at the upper end of the LRMC range, and Tier 1 is adjusted accordingly. For F2019, both Tier 1 and Tier 2 are calculated as in F2018. Option 3 is not forecast revenue neutral. Option 3 reflects the prioritization of the Bonbright efficiency criterion by increasing Tier 2 to the upper end of the energy LRMC range.

The pricing arising from the three options is set out in Table 7-3.

Table 7-3 F2017 to F2019 Pricing Principle Options[261]

	F2017 (cents/kWh)	F2018 (cents/kWh)	F2019 (cents/kWh)
Option 1			
Tier 1	3.981	4.121	4.244
Tier 2	8.920	9.232	9.509
Option 2			
Tier 1	3.981	4.135	4.270
Tier 2	8.920	9.100	9.280
Option 3			
Tier 1	3.836	3.956	4.087
Tier 2	10.227	10.710	10.920

Option 1 and Option 2 result in similar rates whereas Option 3 yields a much higher Tier 2 rate compared to the other two options.

[260] Approved by Commission Order No. G-97-08; http://www.bcuc.com/Documents/Orders/2008/DOC_19036_G-97-08_BCH_Transmission_Svce_Rate-Reasons-for-Decision.pdf.

[261] Using the bill neutrality definition of revenue neutrality where required.

7.2.2.3 BC Hydro Proposal and Stakeholder Engagement

BC Hydro's preferred pricing principle is Option 1 on the basis of the Bonbright criterion of customer understanding and acceptance, and rate stability:

- As described in detail in section 1.3.1 of the Workshop 5 consideration memo and section 1.2.1 of the Workshop 10 Consideration Memo (found at Appendices C-5A and C-5B respectively), the majority of stakeholders prefer Option 1. Groups representing customers who take service under RS 1823 (AMPC, CAPP) strongly favour Option 1. The majority of non-Transmission Service stakeholders also support Option 1, citing that the approach maintains the relative price differential between Tier 1 and Tier 2, maintains customer bill neutrality in all years and forecast revenue neutrality in two of the three years, is easily understood and is consistent with how RRA increases have been applied to other rates such as the RIB rate;
- Option 1 is consistent with Heritage Contract Recommendation #8 because Tier 2 is set within the LRMC range in all years. In F2017, Option 1 is close to forecast revenue neutral; it is forecast revenue neutral in F2018 and F2019. Option 1 is also bill neutral in all of F2017, F2018 and F2019, which is consistent with the revenue neutrality concept used in the 2005 TSR Application (discussed in section 2.3.1.4 of the Application) and BC Hydro's 2008 Application to Vary Pricing of RS 1823, 1825 and 1880. Therefore in all years, Option 1 is consistent with Recommendation #8 irrespective of what definition of revenue neutrality is adopted;
- BC Hydro rejects Options 2 and 3 for the reasons described in section 1.3.2 of the Workshop 5 consideration memo and section 1.2.2 of the Workshop 10 consideration memo. As CAPP, BCSEA and FNEMC note in their written comments, Option 2 diminishes the signal to conserve because over time the Tier 1 and Tier 2 differential will decrease as RRA rate increases are applied to the Tier 1 rate only. AMPC commented that individual customers who have

made conservation investments experience higher than average rate increases when, under Option 2, all of the rate increase is applied to Tier 1 rate (by the calculated higher rate increase). Only COPE 378 unequivocally supports Option 2. No stakeholder supports Option 3.

7.2.3 Revenue Neutrality

BC Hydro is not seeking any order regarding the general application of a revenue neutrality definition. BC Hydro is proposing pricing principles for three years (Option 1) that in all three years achieves customer bill neutrality; in two of the three years also achieves forecast revenue neutrality; and in the one-year it doesn't achieve forecast revenue neutrality (F2017), Tier 2 is within the energy LRMC range in accordance with the first element of Recommendation #8. The result is an approach that yields RS 1823 pricing that in F2018 and F2019 satisfies all of the requirements of Recommendation #8.

7.2.3.1 Options Reviewed

At Workshop 5, BC Hydro identified two definitions of revenue neutrality that could be used to set RS 1823 rates:

- Customer Bill Neutrality – if the RS 1823 customer does not change its usage relative to its CBL, the customer's bill remains unchanged. Bill neutrality approach is defined by following equation:

  Current Flat Rate (RS 1823A and RS 1827) x (RRA per cent increase) = [0.90 x current Tier 1 Rate] x [Tier 1 Rate per cent increase] + [0.10 x current Tier 2 Rate] x [Tier 2 Rate per cent increase];

- Forecast Revenue Neutrality – target revenue is calculated by the forecast load multiplied by the previous year's rates and the RRA rate increase. Forecast revenue neutrality is defined by following equation:

  Target RS 1823 Revenue = [Forecast Tier 1 GWh x current Tier 1 Rate x RRA per cent increase] x [Tier 1 Rate per cent increase/RRA per cent] + [Forecast Tier 2 GWh x current Tier 2 Rate x RRA per cent increase] x [Tier 2 Rate per cent increase/RRA per cent increase].

The bill neutrality definition of revenue neutrality is unique to RS 1823. The RIB, LGS, MGS and SGS rates are all determined on a forecast revenue neutrality basis. This means that the calculated RIB, LGS, MGS and SGS rates collect the same revenue as the target revenue in each rate class by design and on a forecast basis.

BC Hydro reviewed the revenue impacts associated with the three pricing principle options relative to forecast revenue neutrality in Attachment 4 to the Workshop 5 consideration memo:

- Option 1 under-recovers revenue in F2017 by $2.2 million;[262]
- Option 2 under-recovers revenue by $2.2 million, $1.4 million and $0.9 million for F2017, F2018 and F2019 respectively; and
- Option 3 under-recovers revenue by $8.8 million, $12.0 million and $11.7 million for F2017, F2018 and F2019 respectively.

7.2.3.2 BC Hydro Proposal and Stakeholder Engagement

BC Hydro favours the customer bill neutrality approach to determine RS 1823 rates in F2017 so that the Tier 2 rate is set at the lower range of LRMC. Although the RS 1823 F2017-F2019 Pricing Principles (Option 1) is not forecast revenue neutral in F2017, the under-recovery of revenue is relatively small and the pricing is close to

[262] In Attachment 4 to the Workshop 5 consideration memo, BC Hydro reported for Option 1 under recoveries of $2.3 million and $2.4 million for F2018 and F2019 respectively. However, this wrongly assumed that an under-recovery in one year continues through in future years and this is not true in the case when forecast revenue neutrality is satisfied as in F2018 and F2019.

revenue neutral as required by Recommendation #8; the Tier 2 rate is increased by a higher than RRA rate increase in F2017 so that it is within the energy LRMC range. This allows the Tier 1 and Tier 2 rates to be increased across the board by the RRA rate increase in F2018 and F2019 which is both forecast revenue neutral and customer bill neutral. Therefore, customer bill neutrality is achieved under pricing principle Option 1 for all of F2017, F2018 and F2019:

- As described in section 1.3.1 of the Workshop 10 consideration memo, AMPC and customers taking service under RS 1823 support the continued use of customer bill neutrality. AMPC stated that adoption of the forecast revenue neutrality approach is unacceptable to customers taking service under RS 1823 as it unfairly results in impacts to customers that have successfully conserved energy in response to the Tier 2 rate price signal. BC Hydro notes that non-Transmission Service customer participants (except BCSEA) favour using the forecast revenue neutrality approach applied to other rate classes to ensure consistency;
- The customer bill neutrality pricing method appears to work well in F2017 by allowing BC Hydro to maintain the price differential between Tier 2 and Tier 1 while keeping Tier 2 in the LRMC range;
- The customer bill neutrality definition aligns with Policy Action No. 21 of the 2002 Energy Plan,[263] and is the basis upon which Transmission Service customers accepted RS 1823 as part of the 2005 TSR Application NSA;
- The F2014 Fully Allocated COS shows the Transmission Service class R/C ratio as 104.4 per cent using the 2007 RDA Decision COS methodology, and the Transmission Service rate class R/C ratio is 101.5 per cent for F2016 using the F2016 COS study methodology. In both cases the Transmission Service R/C ratios are above 100 per cent, indicating that the Transmission Service rate class is not being subsidized by other rate classes.

[263] Copy found at Attachment 3 to the Workshop 5 consideration memo at Appendix C-5A.

7.2.4 Demand Charge

BC Hydro is not proposing any changes to the demand charge provisions of RS 1823.

The two primary issues considered in regard to the RS 1823 demand charge are:

1. Whether it yields an appropriate recovery of demand-related costs; and
2. The related issue of the appropriateness of the monthly minimum charge or 'demand ratchet'.

7.2.4.1 Options Reviewed

There was general consensus that the existing demand charge is appropriate as it is consistent with industry practice, matches BC Hydro's system peak period and recovers 65 per cent of demand-related costs. As a result, no options were developed by BC Hydro or brought forward by stakeholders.

7.2.4.2 BC Hydro Proposal and Stakeholder Engagement

BC Hydro supports maintaining the RS 1823 existing demand charge and is not proposing any increase or decrease to the demand charge recovery of demand-related costs for three main reasons:

- The definition of HLH (0600 to 2200 Monday to Saturday, except Sundays and statutory holidays) is a 16-hour block consistent with BC Hydro's system capacity requirements and aligns with industry practice;[264]
- Stakeholders commenting on this topic agreed with BC Hydro's proposal, including AMPC and CAPP, indicating that they favour continuing with the current definition. Non-Transmission Service customers also supported

[264] Refer to North American Energy Standards Board (**NAESB**, which is an industry forum for the development and promotion of standards) at https://www.naesb.org//pdf/weq_iiptf050504w6.pdf; and North American Electric Reliability Corporation at http://www.nerc.com/comm/oc/rs%20agendas%20highlights%20and%20minutes%20dl/additional_off-peak_days.pdf which references the NAESB.

BC Hydro's proposal. Refer to section 1.1.1 of the Workshop 10 consideration memo at Appendix C-5B;

- The amount of demand-related costs the demand charge is recovering, at approximately 65 per cent of demand-related costs identified in the F2016 COS study, is appropriate. In BC Hydro's view, the demand charge aligns with the Bonbright criterion of fair apportionment of costs among customers. As described in section 1.1.2 of the Workshop 10 consideration memo, it is common utility practice to recover some portion of demand-related costs through energy rates; in the case of RS 1823, about $110 million of $305 million of demand-related costs are recovered in this fashion. If all demand-related costs were recovered through the RS 1823 demand charge, RS 1823 energy rates would be decreased by about 15 per cent with the result that the Tier 2 rate would fall below the lower end of the energy LRMC. As discussed in section 7.2.1, the Commission does not have discretion to set a RS 1823 Tier 2 rate that is not within the energy LRMC range.

7.2.4.3 Monthly Minimum Charge

BC Hydro proposes to continue with the current RS 1823 monthly minimum charge (demand ratchet).

The demand ratchet ensures that some portion of fixed costs is recovered from customers even though they do not impose a significant demand on the system in a particular month. The principle is that the system is built to meet their loads and the utility can recover some portion of fixed costs even in the event that the customer has little demand in a particular month. Most surveyed Canadian electric utilities employ demand ratchets for their large industrial customers.

The RS 1823 demand charge is specified as $/kV.A of Billing Demand per Billing Period. BC Hydro proposes to continue with the current RS 1823 definition of Billing Demand for purposes of determining the demand charge, which is the higher of:

1. Highest kV.A demand during HLH in the billing period;
2. 75 per cent of the highest Billing Demand during the immediately preceding period of November to February; or
3. 50 per cent of Contract Demand in the customer's Electricity Supply Agreement.

As set out above, in the Billing Demand definition there is a reference to (ii) "75 per cent of the highest Billing Demand during the immediately preceding period of November to February". This is the demand ratchet provision. The '75 per cent of the previous winter peak' provision has been in place since 1991. Prior to that, since the early 1960s, the demand ratchet was defined as 75 per cent of the highest Maximum Demand registered in any one of the immediately preceding 11 months.

Transmission Service customers have not raised any issue with the RS 1823 demand ratchet during the 2015 RDA engagement processes. The demand ratchet has not been an issue in previous Transmission Service rate proceedings. Given that the 75 per cent demand ratchet has historically been in place without issue and that it helps BC Hydro recover its fixed costs, BC Hydro proposes no changes to the current RS 1823 monthly minimum charge.

7.3 Existing and Potential Transmission Service Rate Options

As noted in section 2 of the Workshop 5 consideration memo, BC Hydro assessed the two rate options available to its Transmission Service customers (RS 1825, which is a TOU rate and RS 1852, which is an interruptible rate) and developed three other potential options using the following:

- The October 2013 IEPR task force final report, which among other things recommended that BC Hydro develop a revised retail access program and options that take advantage of industrial power consumption flexibility such as TOU rates and interruptible rates;

- 2013 IRP Recommended Action 5, which states that BC Hydro will investigate incentive-based pricing mechanisms over the short-term that could encourage new customers and existing industrial customers looking to establish new operations or expand existing operations in BC Hydro's service area (referred to as **surplus rate**);
- Prior BC Hydro experience with rate options, including:
  - Three optional industrial CBL-based rates approved by the Commission between 1996 and 2001: (1) RS 1848, a two-part RTP option for Transmission Service customers who were on the now discontinued RS 1821 with flat demand and energy charges; (2) RS 1850, a two-part TOU rate option for Transmission Service customers; and (3) RS 1854, a two-part TOU industrial rate option similar to RS 1850 for Transmission Service customers. Refer to Attachment 5 of the Workshop 5 consideration memo for a detailed description of these three options;
  - The Commission's 2009 TSR Report (referenced in section 2.3.1.4 of the Application) review of why there has been no take-up of RS 1825;[265]
  - BC Hydro's 2011 Application to Suspend the Retail Access Program; and
- Jurisdictional assessment. BC Hydro reviewed Canadian jurisdictions with vertically integrated monopoly market structures and thus did not consider Alberta and Ontario for purposes of Transmission Service rate structures. The

[265] The Commission's 2009 TSR Report states the following as reasons why no customer has elected to use RS 1825:

- *Insufficient Price differential* - RS 1825 does not provide sufficient TOU price differentials to incent customers to shift load. The price differential only applies to Tier 2 energy and thus there is no incentive for customers that have done significant DSM and may only purchase at Tier 1;
- *Default RS 1823 has more benefits* - A TOU component is integrated into RS 1823 through the replacement of an "all hour" peak demand charge with a HLH peak demand charge, and thus Transmission Service customers do not need to switch to RS 1825 to get a price incentive to shift usage to off-peak periods; and
- *Customer Suitability and Complexity* – The Transmission Service customer would need to have sufficient flexibility in their production process to shift load from winter HLH to LLH periods or from winter to spring or remainder months. Some Transmission Service customers raised the complexity of RS 1825, and in particular the number of CBLs (four, one for each of the four pricing periods), as an obstacle.

jurisdictional assessment revealed that: no surveyed Canadian electric utility offers its industrial customers TOU rates and only one utility (Nova Scotia Power) offers RTP to industrial customers; interruptible and/or surplus rates are offered by a number of utilities. Refer to Table 4 of the Workshop 5 consideration memo.

7.3.1 Existing Rate Option: Rate Schedule 1825

BC Hydro is not proposing any changes to RS 1825.

7.3.1.1 Background

Since BC Hydro is a winter-peaking utility, the intent of RS 1825 is to shift winter load from HLH to LLH, and to shift load from winter months to all other months of the year. The RS 1825 design adds a TOU element to the default RS 1823 structure by overlaying four TOU pricing periods designed to encourage consumption pattern changes on winter days and between the winter months and remainder months. Each TOU pricing period requires a unique CBL. In each pricing period, RS 1825 customers pay a Tier 1 rate for the first 90 per cent of period energy consumption relative to their CBL and a Tier 2 rate for any energy in excess of 90 per cent of their CBL. F2016 rates are set out in Table 7-4.

Table 7-4 Existing RS 1825 Rates (F2016)

Demand rate ($/k.VA)	7.341
Winter HLH energy rate - Tier 1 (cents/kWh)	3.836
Winter HLH energy rate – Tier 2 (cents/kWh)	9.489
Winter LLH energy rate – Tier 1 (cents/kWh)	3.836
Winter LLH energy rate – Tier 2 (cents/kWh)	8.600
Spring energy rate – Tier 1 (cents/kWh)	3.836
Spring energy rate – Tier 2 (cents/kWh)	7.660
Remaining energy rate – Tier 1 (cents/kWh)	3.836
Remaining energy rate – Tier 2 (cents/kWh)	8.398

Since its implementation on April 1, 2006, no Transmission Service customer has taken service under RS 1825.

7.3.1.2 BC Hydro Proposal and Stakeholder Engagement

At Workshop 5, BC Hydro sought comment on: (1) the Commission's 2009 TSR Report conclusion that it is unlikely any Transmission Service customers will elect to take service under RS 1825 as currently designed; and (2) two options BC Hydro examined to make an optional Transmission Service TOU rate less complex.

BC Hydro stated that, in its view, it is not possible to design an optional cost-based TOU rate that provides sufficient price differentials and/or offers Transmission Service customers more benefits than RS 1823:

- Eliminate CBLs - BC Hydro could abandon the stepped rate concept currently embedded in RS 1825 and offer customers a TOU option with seasonal and HLH/LLH prices. However, if such a rate was based on the blended RS 1827 rate, customers that have undertaken substantial self-funded DSM (and only consume Tier 1 energy) would lose the Tier 2 reduction benefit they currently receive and would be less likely to opt for such a TOU rate; and
- Apply TOU prices to the existing Tier 1 in RS 1825 - Currently TOU pricing only applies to Tier 2. However, the resulting differentials would be too small.

Aside from COPE 378 (at Workshop 10), no stakeholder providing feedback on this topic supported BC Hydro pursuing a reconfigured RS 1825. AMPC and its members favoured BC Hydro focusing on the freshet rate pilot (and load curtailment pilot). AMPC reasoned that overall complexity, low margins, price risk and the current three-year commitment requirement combine to make RS 1825 less attractive to Transmission Service customers than RS 1823. AMPC's feedback is consistent with the feedback received at the May to June 2014 regional sessions with Transmission Service customers outlined in section 2.2.3.4 of the Application, at which a majority of Transmission Service customers indicated that TOU rates would not work for their businesses since they operate a continuous manufacturing process that does not support load shifting.[266] CAPP and MABC also indicated to BC Hydro that their members have little or no flexibility in production scheduling and so would not likely be able to take advantage of a voluntary TOU rate.

BC Hydro is not proposing a reconfigured RS 1825 for two main reasons:

- First, AMPC, which represents a subset of Transmission Service customers that could potentially take advantage of a reconfigured RS 1825, favours BC Hydro directing its efforts at other options;
- Second, in BC Hydro's view it is unlikely that there can be a significant enough difference between on-peak and off-peak rates to encourage a change in consumption patterns. The IEPR task force also questioned whether the differential could be significant enough in this jurisdiction[267] to make a voluntary TOU rate effective. BC Hydro understands from E3 that generally speaking a ratio of three or four of on-peak to off-peak pricing is required to change consumption.[268] For F2016, the RS 1825 ratio of winter HLH Tier 2 price to winter LLH Tier 2 price is 1.1 (9.489 cents/kWh to 8.60 cents/kWh). Regarding RS 1825, the long-term forecast of Mid-C monthly price shape for HLH and LLH is used to shape the Tier 2 rate for each TOU season. Mid-C HLH/LLH ratios across the past five years have averaged 1.45. Based on the current forward curve, BC Hydro estimates the ratio will average 1.30 for the next year. Refer to section 2.1.2 of the Workshop 5 consideration memo for additional detail.

[266] *Engagement Summary Report: Rate Design Feedback from the May/June Customer Engagement Workshops*, pages 19 to 20 (copy found at Appendix C-5C).

[267] IEPR task force issue paper, "Time of Use Rates"; copy available at http://www.empr.gov.bc.ca/EPD/Documents/Task%20Force%20Issue%20Paper%20-%20Time%20of%20Use%20Rates%20FINAL.pdf.

[268] In 2010, the Ontario Energy Board commissioned The Brattle Group to study about 50 TOU rates across North America and elsewhere, and reported that the average ratio is about four to one; A. Faruquai *et al*, "Assessing Ontario's regulated Price Plan: A White Paper", page 3; copy available at http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0364/Report-Assessing%20Ontarios%20Regulated%20Price%20Plan.pdf.

7.3.2 Existing Rate Options: Rate Schedule 1852

BC Hydro proposes a change in the current RS 1852 definition of HLH (06:00 hours to 10:00 hours and 16:00 hours to 20:00 hours, Monday through Friday, except for Statutory holidays), to provide BC Hydro discretion to determine the HLH periods that will apply based on a customer location/region which affords BC Hydro the option to curtail to alleviate potential local or regional transmission constraints or take advantage of a market opportunity. For clarity, BC Hydro is also proposing to amend the definition of Availability in RS 1852 as follows. TS 54 is referenced as the Modified Demand Agreement. Customers are defined to be in locations that will allow BC Hydro to curtail load to alleviate a potential local or regional transmission constraint, or take advantage of a market opportunity. A black-lined copy of the current RS 1852 showing the proposed changes is included in Appendix F-1C for illustrative purposes. Refer also to the copy of the draft requested order at Appendix A-1B.

7.3.2.1 Background

RS 1852 came into effect in September 2000[269] and is an interruptible rate that applies only to the demand charge for customers already taking service under RS 1823. All energy consumption is charged under RS 1823. The Billing Demand and Excess Demand charge under RS 1852 reflects the same $ per k.VA charge as under RS 1823, but the periods in which demand is calculated are modified.

RS 1852 affords benefits from the availability of demand flexibility within the transmission limits set out in the Modified Demand Agreement (TS 54) in exchange for daily load curtailments during HLH as nominated in TS 54. RS 1852 customers are also required to make themselves available for additional mandatory curtailments (up to twelve times per year) at the request of BC Hydro or Powerex. The value of any curtailment to BC Hydro is expected to be greatest during winter HLH periods. Accordingly, the annual subscription period for new subscribers is from

[269] Commission Order No. G-82-00; http://www.bcuc.com/Documents/Orders/Orders2000_2/G4_Orders/G82_BCH.pdf.

September 1 to October 31 (i.e., before the winter period begins). Only one Transmission Service customer has taken service under RS 1852 at any one time.

7.3.2.2 BC Hydro Proposal and Stakeholder Engagement

There was little feedback regarding RS 1852 from any of the stakeholder sessions, including Workshops 5 and 10. The central issue is how to address the low take-up of RS 1852:

- Catalyst asked that BC Hydro provide clarity as to where RS 1852 may be available as this might lead to greater take-up. BC Hydro confirmed in section 4.2 of the Workshop 10 consideration memo that the South Peace region is currently transmission constrained. However, at the September and October 2014 meetings with AMPC and CAPP (refer to section 2.2.3.4 of the Application), both of which have members with operations in the South Peace region, neither group expressed interest in the use of RS 1852. RS 1852 is complex and best suited for customers with large, discrete load centres, load control systems, and product storage or ability to 'make up' lost production;
- CEC suggested RS 1852 should be retained but refined to better match BC Hydro's system demand issues. BC Hydro agrees with the suggestion. RS 1852 was originally designed around Vancouver Island's unique 'two peak' system load (6 a.m. to 10 a.m. and 4 p.m. to 8 p.m.). However, as demonstrated in section 4.2 of the Consideration Memo, the South Peace region does not have a two peak system load. Areas that may be transmission constrained in the future include the Lower Mainland (depending on the number of LNG proposals that proceed) and the North Coast/Prince Rupert region. Accordingly, BC Hydro prefers to have discretion to determine the HLH period(s) that will apply based on customer location/region because transmission constraints change over time and by location.

7.3.3 Potential Rate Options Rejected by BC Hydro: Retail Access and Real Timing Pricing

7.3.3.1 Retail Access

BC Hydro is not applying to the Commission to establish a retail access program as part of the 2015 RDA.

While the IEPR task force recommended that BC Hydro develop a revised retail access program, the LGIC subsequently issued Direction No. 7; section 14 prevents the Commission from setting rates that result in direct or indirect provision of unbundled transmission service to retail customers in BC Hydro's service area or those who supply such customers, except on application by BC Hydro (refer to section 2.2.1.3 of the Application). Retail access was discussed at Workshop 5 so that BC Hydro could determine if it would make a voluntary application to the Commission. Section 2.4.2 of the Workshop 5 consideration memo explains why a new retail access program would be problematic. The key reasons for BC Hydro's decision are:

- The only stakeholder championing retail access was COPE 378. The general stakeholder consensus is that a retail access program will be complicated because of the number of safeguards required to protect non-participating customers. When industrial loads go to retail access there is significant revenue loss and risk of stranded assets, which costs all other customers through increased rates. When embedded cost supply looks attractive as compared to market rates, industrial loads want to return to utility service, which can put upward pressure on rates to the extent new infrastructure has to be built at a cost greater than incremental revenues. Examples of safeguards to address these risks are listed on page 47 of the Workshop 5 consideration memo and include exit fees, re-entry fees, lengthy notice periods to return to utility supply (e.g., five to 10 years to reflect the amount of time required to advance new generation and/or transmission resources to serve the customer), obligations to return to the queue and pay transmission extension fees as if the customer were a new customer when returning, and no arbitrage provisions; and

- BC Hydro concludes that pursuing the freshet rate pilot better balances offering Transmission Service customers choice with other ratepayer interests. A key reason customers advocated for retail access in the past is that it can provide financial benefits if the delivered cost of market-priced electricity is lower than BC Hydro's embedded cost rates. As discussed below in section 7.3.4, market prices typically reach seasonal lows during the May to July freshet period. Consequently, BC Hydro believes the freshet rate option can provide customers some of the financial benefit they might have otherwise received under a retail access program without negatively impacting non-participating customers and without the complexity required to mitigate negative impacts.

7.3.3.2 Real Time Pricing

BC Hydro is not pursuing RTP as an option for Transmission Service customers as part of the 2015 RDA.

An RTP rate would reflect a 'hybrid rate' with firm service for the CBL and maximum demand, and non-firm service for incremental usage above CBL (market prices for incremental electrical consumption). As part of the Workshop 5 consideration memo process and at Workshop 10, BC Hydro outlined its view that section 14 of Direction No. 7 does not prevent the Commission from setting a RTP rate (in contrast to retail access) because Transmission Service customers would be buying some portion of electricity from BC Hydro (based on Mid-C or other market pricing). At Workshop 10, BC Hydro asked participants whether BC Hydro should apply to the Commission to establish an optional Transmission Service RTP rate. To assist with feedback, BC Hydro set out a number of points for consideration in section 2.4.2 of the Workshop 5 consideration memo, including outlining the main ingredients of a RTP rate design. It would be difficult to integrate a stepped rate structure into RTP; the CBL could be priced at the stepped rate, but the marginal price signal would be spot market pricing and not BC Hydro's energy LRMC. The hybrid RTP rate would be asymmetrical if customers receive an energy LRMC price signal for saving energy (i.e., Tier 2 credit) but then receive a market price signal for increasing energy consumption.

The result was that no Transmission Service customer submitting comments on this topic believes BC Hydro should pursue RTP at this time. As described in section 2.2.3.4 of the Application, on March 19, 2015 BC Hydro met with AMPC to among other things determine if there was interest in RTP. AMPC responded that it agreed the concerns laid out by BC Hydro in section 2.4 of the Workshop 5 consideration memo were valid concerns, and that it was not interested in pursuing RTP at this time. Refer to section 2.1.1 of the Workshop 10 consideration memo for additional detail.

There is currently a lack of demand for a RTP rate by Transmission Service customers. BC Hydro concludes that a freshet rate, based on incremental consumption during the May to July freshet period, may yield comparable benefits for Transmission Service customers as a year round RTP rate based on non-firm service for incremental consumption. This is because during the freshet period Mid-C spot market prices are often significantly below the RS 1823 Tier 1 rate, especially during LLH, and are generally closer to the Tier 1 rate during other months of the year.

7.3.4 Proposed Freshet Rate Pilot

BC Hydro seeks approval of the freshet rate no later than February 1, 2016 as a two-year pilot to run between the May to July 2016 and May to July 2017 freshet periods.

As discussed in sections 1.1.3 and 7.1 of the Application, BC Hydro is proposing to create a new optional rate (RS 1892) for non-firm service during these freshet periods. RS 1892 would be available to customers taking service under RS 1823.

The rate would provide RS 1823 customers with a Mid-C market energy price signal for incremental energy consumption above a predetermined baseline. Since Mid-C market prices during freshet periods are typically lower than the RS 1823 Tier 1 rate, the freshet rate would provide an incentive for RS 1823 customers to increase electricity use from BC Hydro during each freshet period. A copy of the proposed RS 1892 is found at Appendix F-1B to the Application.

The proposed freshet rate is designed to meet the three objectives set out below in a manner that holds harmless, where practical, non-participating customers. BC Hydro discussed the freshet rate at Workshops 5 and 10 and received broad stakeholder support to further develop the rate. BC Hydro noted on page 21 of the Workshop 10 consideration memo that "stakeholders agree there may be merit in a freshet rate including representatives of BC Hydro's residential, General Service and Transmission Service customers".

The sections that follow set out the key objectives for the freshet rate pilot, and a description of the proposed rate structure provisions, baseline determination, billing mechanism and evaluation considerations.

7.3.4.1 Key Objectives and System Context

In comments submitted in response to Workshop 10, Commission staff suggested that BC Hydro elaborate on the objectives of the proposed freshet rate. These are:

1. Respond to the IEPR task force's recommendation to develop additional options for industrial customers;[270]
2. Assist in the management of the freshet oversupply in the BC Hydro system by providing the option to:

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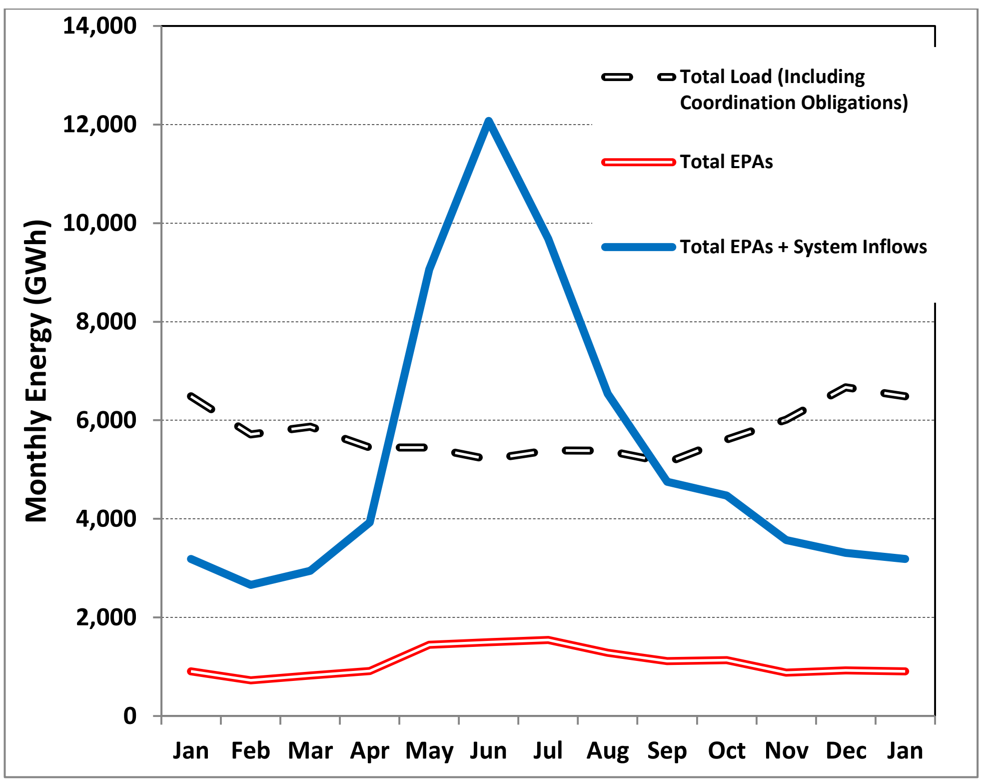
[270] The 2013 IEPR task force process culminated in 17 recommendations, which the B.C. Government responded to in November 2013 (refer to section 2.3.1.8 of the Application). Recommendation 13 of the IEPR task force final report stated "BC Hydro should work with its industrial customers and the Commission to develop options that take advantage of industrial power consumption flexibility" and the B.C. Government responded to the recommendation by committing to launch a "a rate design review process…to provide industrial customers with more options to reduce their electricity costs." The 2015 RDA Module 1 is that process.

- increase the ability to import cheap electricity during low priced periods;
- reduce the volume of surplus energy being forced to export markets; and/or
- reduce spill at BC Hydro facilities;

3. Recover what BC Hydro would otherwise obtain on the export market, but with potential economic benefits for B.C.

The freshet rate would encourage customers to increase electricity consumption during the freshet period (May – July), when BC Hydro has a long-term recurring issue of energy oversupply. Figure 7-2, based on normal water conditions and forecast calendar 2017 load and generation, shows that system inflows and contracted IPP supply (Total EPAs) on the BC Hydro system are expected to exceed load by a significant margin between mid-April and the end of August.

Figure 7-2 System Inflows



The issue associated with the freshet oversupply is related to the combination of the large volume of surplus (non-flexible) energy passing through run-of-river projects with no or limited storage capability, low spring-summer system loads and depressed power market prices. The coincidence of these three factors can require BC Hydro to sell surplus energy into power markets, often at exceptionally low prices.

During the freshet period, there is a higher risk of minimum generation constraints[271] which reduce BC Hydro's flexibility to take advantage of low Mid-C prices,[272] especially in LLH, by importing more energy from the U.S. market. Depending on the load, minimum generation constraints may also force BC Hydro to export. In addition, the oversupply can increase the risk of spill from BC Hydro's dams,[273] especially during years where hydroelectric storage levels and inflows exceed normal conditions. Accordingly, the purpose of the freshet rate is to encourage higher electricity use from customers during this period to help reduce any over-supply and mitigate, where possible, other possible impacts from minimum generation constraints and spill risk.

Additional information on these objectives can be found on pages 28 and 29 of the Workshop 10 consideration memo at Appendix C-5B.

7.3.4.2 Market Prices and the Tier 1 Rate

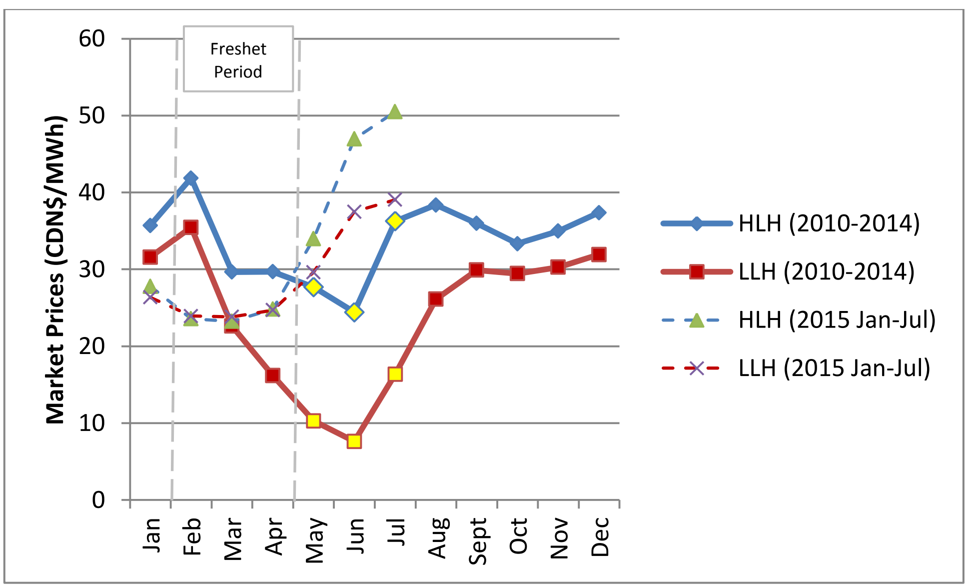
Figure 7-3 below shows a five-year average of Mid-C market prices in Canadian dollars and includes updated information for January to July 2015, including this year's freshet period.

The 2015 freshet period was unusual as the U.S. Columbia system saw a combination of early melt of winter snowpack in February/March, coupled with low

[271] Discussed on slide 22 of the Workshop 10 slide deck presentation at Appendix C-5B and page 7 of Attachment 1 to the Workshop 5 consideration memo at Appendix C-5A.
[272] Refer to slide 21 of the Workshop 10 presentation and updated for 2015 data in Figure 7-3 of this chapter.
[273] Additional information found on pages 31 and 32 of the Workshop 10 consideration memo at Appendix C-5B.

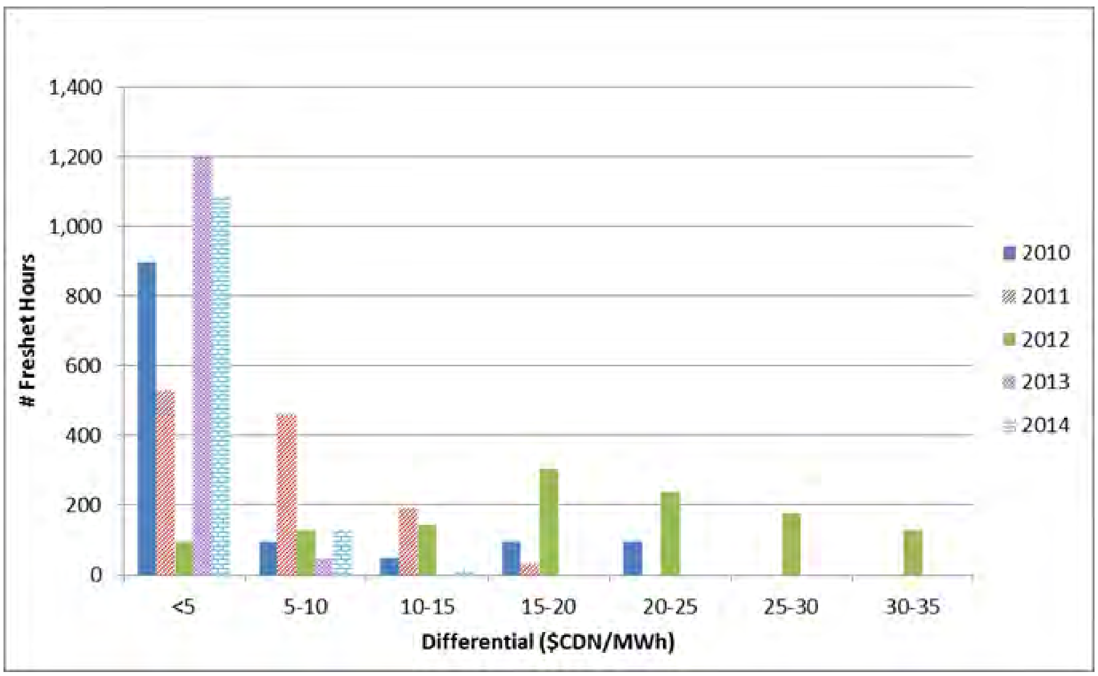
rainfall across the freshet months. As a result, overall flow for the May to July 2015 period in the U.S. Columbia River was the third lowest in 55 years. Consequently, Canadian dollar Mid-C market prices during the 2015 freshet were considerably higher than past periods given these drought conditions and a significant depreciation in the Canadian/U.S. dollar exchange rate from an average of 0.97 in the period 2010 to 2014 to an average of 0.80 during the first seven months of 2015. At Workshop 10, BC Hydro pointed out that average August prices over the 2010 to 2014 period are noticeably higher than May to July prices and that differentials between HLH and LLH periods have generally averaged about $15/MWh during the freshet compared to about $5/MWh during other times of the year. This price spread indicates there may be greater incentive for customers to shift load from HLH to LLH during the freshet period relative to other times of the year (provided they have the ability to do so). In addition, Figure 7-3 shows that market prices typically reach annual lows during the freshet period.

Figure 7-3 Five-Year Average of Mid-C Market Prices (2010 – 2014) – Updated with 2015 Prices to the End of July



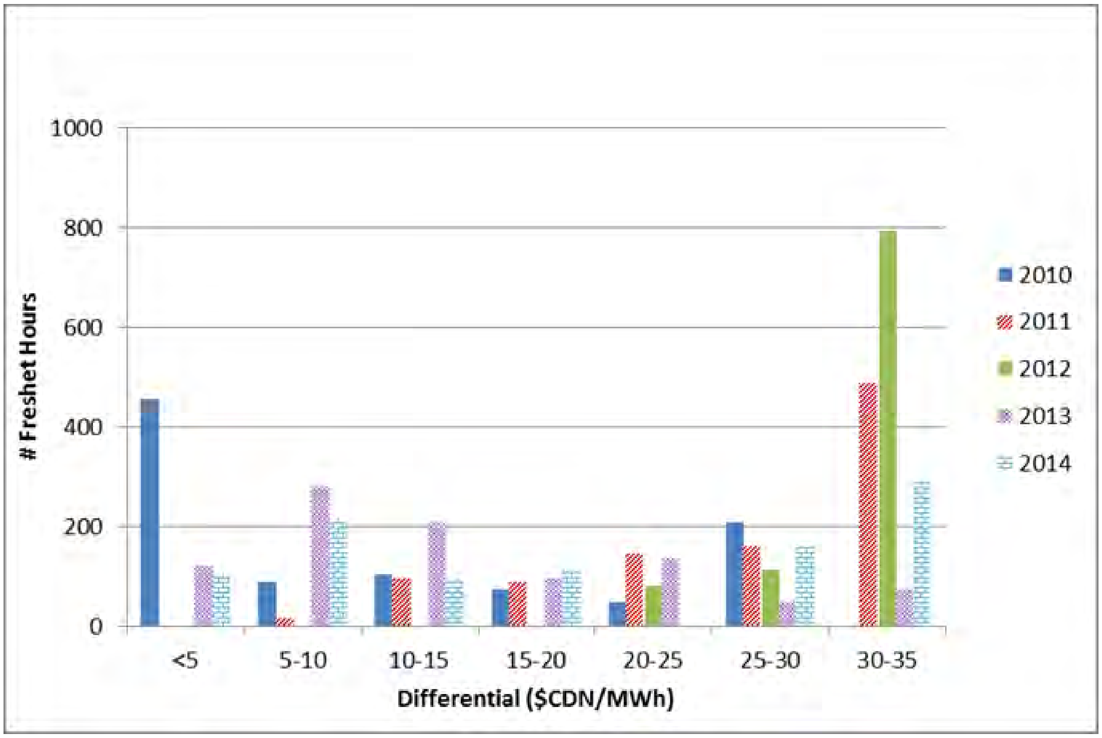
Figures 7-4 and 7-5 are histograms showing the number of hours in which there was a positive differential between the RS 1823 Tier 1 rate[274] and Canadian dollar Mid-C market prices in both HLH and LLH freshet periods. Figure 7-4 and Figure 7-5 show positive differentials in both HLH and LLH periods which indicates there is economic opportunity for customers to benefit from a freshet rate priced at the Mid-C market energy price, which is BC Hydro's proxy for its short run opportunity cost. Differentials and potential benefits to participating customers are generally higher in LLH periods than in HLH periods.

Figure 7-4 HLH Differentials between Tier 1 Rate and $CDN Mid-C Price



274 Slide 37 of the Workshop 10 presentation shows historic RS 1823 Tier 1 prices; copy found at Appendix C-5B of the Application.

Figure 7-5 LLH Differentials between Tier 1 Rate and $CDN Mid-C Price



7.3.4.3 Overview of the Proposed Rate

Pilot Proposal

During Workshop 10, BC Hydro acknowledged there are uncertainties[275] associated with the freshet rate including take-up volumes. The best way to explore this while limiting risk to non-participating customers is to run the rate as a pilot for a period of time and evaluate results against predefined evaluation criteria (discussed below in section 7.3.4.6). BC Hydro considers that a two-year pilot is necessary to test the sensitivity of incremental load to changing market prices and to provide customers with sufficient potential benefit from the pilot to promote take-up. Stakeholders generally supported BC Hydro's two-year proposal.

[275] Refer to slides 38 and 39 of the Workshop 10 presentation at Appendix C-5B of the Application.

Availability

The rate is open to any RS 1823 customer during the freshet period. BC Hydro excluded RS 1827 customers because many of these customers, including New Westminster, naturally increase consumption year over year and might benefit from the freshet rate without a behavioural change. In addition, UBC, SFU and New Westminster supply residential customers and BC Hydro has fairness concerns with (indirectly) offering such customers market priced energy.

Sign Up Process

Under Special Condition 3 of RS 1892, RS 1823 customers will notify BC Hydro by March 1, 2016 (for the first year) or March 1, 2017 (for the second year), if they wish to take service under the freshet rate. BC Hydro will work with the customer to set baselines (including any required adjustments) to separate RS 1823 electricity from freshet rate electricity. BC Hydro will also consider how the customer plans to utilize the rate (e.g., production increases, shifting changes, energy-intensive product grades, shutdown scheduling, generation turndown, etc.). The customer will be notified of a final freshet baseline no later than seven days prior to the start of the freshet period. The setting and management of baselines is described below under the heading “Reference Baselines”.

Freshet Period Determination

BC Hydro explained its rationale for selecting the May to July freshet period at Workshop 10. The evidence presented on slides 20 to 22 of the Workshop 10 presentation demonstrates that there is generally: surplus freshet energy between May and August; import constraints between May and August; and lower than normal electricity prices between May and July, especially in LLH. Taken together, these facts support the selection of a May to July freshet period for the purposes of the two-year pilot. All stakeholders, with the exception of COPE 378, support using this period.

Freshet Load is Non-Firm

BC Hydro is proposing that all incremental freshet electricity, above predetermined energy and demand baselines, be considered non-firm. Accordingly, anticipated RS 1892 load will not be included in BC Hydro's load forecast and therefore will not lead to any incremental costs associated with generation or transmission resource advancement.

Special Conditions 1 and 2 in RS 1892 mirror RS 1880's interruptibility conditions. BC Hydro can interrupt customers if it does not have energy or capacity available to serve the incremental load. As a winter peaking utility,[276] BC Hydro typically has excess energy and capacity during the freshet so the likelihood of a curtailment during this period is low. Two possible scenarios in which a curtailment might occur include:

- If the domestic system is unable to meet incremental freshet load and BC Hydro cannot import additional energy from the U.S. market because of an intertie constraint or outage, or
- Multiple interior to Lower Mainland transmission lines are forced out of service.

Neither of these conditions would be likely to occur due to ample supply of both energy and capacity in the system during the freshet coupled with redundancy in the BC Hydro transmission system.

Billing

Customers will be initially billed for demand and energy under RS 1823 during each of the 2016 and 2017 freshet periods (May to July) only up to the established baselines as described below. Subsequently, metered energy above the energy baseline will be billed retroactively in August after a reconciliation of the customer's

[276] Refer to page 29 of the Workshop 10 consideration memo where BC Hydro indicated that all nine of its transmission regions, in addition to the overall generation system, peak during the winter period.

total electricity use has been performed and freshet energy has been allocated between RS 1823 and RS 1892 electricity, in accordance with the provisions of RS 1892.

Demand Charge

Since the rate is non-firm, BC Hydro proposes that there be no demand charge for load above a Reference Demand baseline[277] which will be set using the average of peak kVA demands during HLH from each month of the 2015 freshet period. Customers on RS 1892 will be billed for demand up to their Reference Demand baseline under RS 1823 in each of the freshet months (May, June and July) during the 2016 and 2017 freshet periods so long as they have consumed energy on RS 1892.

Energy Determination

Initially, freshet energy volumes will be calculated hourly by determining energy consumption in excess of an average MW (**aMW**) baseline determined in consultation with the participating customer.[278] Separate aMW baselines will be initially determined for both HLH and LLH periods by dividing a participating customer's actual RS 1823 energy purchases during the 2015 freshet baseline period by the number of hours during the period.

At the end of the freshet period, the initial hourly freshet volumes will be multiplied by a corresponding HLH or LLH Net to Gross ratio (ranging between 0 per cent and 100 per cent and discussed below) to derive a final hourly freshet volume to be billed on the RS 1892 rate. Any remaining hourly excess energy (which results if the Net-to-Gross ratio is less than 100 per cent) is billed on RS 1823.

[277] Further information below under the heading "Reference Baselines".

[278] BC Hydro sought feedback on four baseline options on slide 27 of the Workshop 10 presentation and ultimately received broad stakeholder support for pursuing Option 3, an average MW baseline discussed on page 34 of the Workshop 10 consideration memo, giving customers the ability to respond to daily HLH and LLH price signals. Options 1 and 2 were rejected because they used average freshet prices, across an entire month or season, and would have sent customers an inferior price signal relative to the use of an average MW baseline in Option 3.

Net to Gross Ratio

At the end of the freshet period, for both HLH and LLH periods, the total volume of hourly energy above the average MW baseline (referred to as Gross Freshet Energy) will be compared to the total volume of hourly energy below the average MW baseline to determine the net volume of excess energy (Net Freshet Energy).[279] The corresponding ratio of Net Freshet Energy to Gross Freshet Energy will be termed the “Net to Gross ratio”. Separate Net to Gross ratios will be determined for both HLH and LLH.

The purpose of the Net to Gross ratio is to ensure that customers only receive the potential benefits of market-based pricing if there is a net gain in consumption across the entire freshet period relative to the baseline. This mitigates any potential risk of shifting consumption between freshet months (e.g., use more in May, but less in June, for no net increase over the period). Without a net gain in freshet consumption, the customer’s participation in the rate would not bring the benefits discussed in section 7.3.4.4 below (e.g., reduction in over supply conditions, mitigation of minimum generation constraints, etc.). However, the use of separate Net to Gross ratios for HLH and LLH periods,[280] rather than a combined ratio across all freshet hours, will permit customers to shift consumption from HLH to LLH freshet periods where they have the ability to do so. Such a shift would have benefits for BC Hydro as it would alleviate over-supply conditions in LLH periods and mitigate minimum generation constraints and spill risk.

Using this approach, a customer consuming 5 MW above the aMW HLH baseline in every May HLH and 5 MW below the baseline in every June HLH would have a Net to Gross ratio of zero and would have all energy purchased during the freshet period billed at RS 1823 rather than the freshet rate. Similarly, a customer consuming

[279] Net freshet energy can also be thought of as the difference between the customer’s total energy purchases in the freshet period and the baseline period. Like Gross Freshet Energy it is calculated separately for both HLH and LLH periods.

[280] Customers could also shift from LLH to HLH periods, but BC Hydro considers this unlikely given prevailing price signals and an average $15/MWh differential between these periods in past freshet periods.

5 MW above the baseline during every May HLH and 3 MW below the baseline during every June HLH would have a net to gross ratio of 40 per cent (net gain of 2 MW/gross increase of 5 MW across the period) and would have 40 per cent of their hourly HLH incremental energy consumption at a market price with the remainder billed on RS 1823. Appendix H-1B contains an hourly billing example for a single 16-hour period to illustrate the rate's energy billing mechanics. The example contains the same tariff terms used in RS 1892.

Energy Charge

Once the final RS 1892 volume is known, the volume is multiplied by the RS 1892 energy charge. The energy charge is equal to the higher of daily Intercontinental Exchange Inc. (**ICE**) Mid-C Peak/Off Peak Price or a $0/kWh price floor, plus a proxy wheeling fee. The proxy replaces BC Hydro's original proposal to charge BPA's wheeling rate from Mid-C to the U.S.-B.C. Border.[281] Both the price floor and the BPA wheeling rate were discussed in the presentation slides for Workshop 10 and at pages 32 to 34 of the Workshop 10 consideration memo. Most stakeholders supported use of the price floor and the BPA wheeling fee.

In the Workshop 10 presentation slide deck and consideration memo, BC Hydro stated the wheeling fee was both a cost recovery mechanism and a tool to protect non-participating ratepayers from risks associated with the freshet rate. BC Hydro now proposes a lower proxy (fixed at $CDN 3/MWh) for the following reasons.

Cost justification – The wheeling fee ensures there is a notional contribution from users of the freshet rate towards the cost of transmission during times of import. During times of export, the fee would be to the benefit of non-participating customers. At Workshop 10 BC Hydro presented historical information for the 2010 to 2014 freshet periods showing that BC Hydro was generally exporting in ~40 per cent of LLH periods on average. Assuming average reservoir inflow

[281] The BPA wheeling rate is $USD 4.78/MW, which translates into $CDN 5.61/MW under the current exchange rate.

conditions, BC Hydro now expects to be in an export position for the freshet period (May to July) of 2017 in a higher percentage of LLH periods,[282] when customers would be most likely to use the freshet rate.

Risk justification – BC Hydro addresses shifting in section 7.3.4.5 and explains why the risks to non-participating customers are expected to be low. As a result, any risk associated with shifting is not included in the revised wheeling fee. The wheeling fee helps mitigate other risks to non-participants, such as:

- The uncertainty during pre-schedule trading of whether or not customers will have incremental load increases. BC Hydro asked customers for notification of load increases greater than 10 MW but there is no penalty in RS 1892 that compels them to do so;
- If there are differences between the real time market and the day ahead prescheduled market. Customers are billed using the pre-schedule market price, however it is the real-time markets that BC Hydro would be making incremental transactions to cover higher RS 1892 loads. Differences in prices between the real-time and pre-schedule markets represent a risk to BC Hydro; and
- Tie line constraints may limit BC Hydro's ability to import from the U.S. market, which means storage could be the source of energy used to supply incremental freshet load. In this situation, there would be opportunity costs if BC Hydro could have instead used the stored energy during a higher valued period.

BC Hydro considers a proxy wheeling fee of $CDN 3/MWh appropriate given the cost rationale and the fact there are risks to non-participating customers. This proposed fee is approximately 50 per cent of the BPA wheeling fee that BC Hydro proposed at Workshop 10.

[282] For example, higher minimum generation levels are now expected during LLH periods which increases the likelihood of exports.

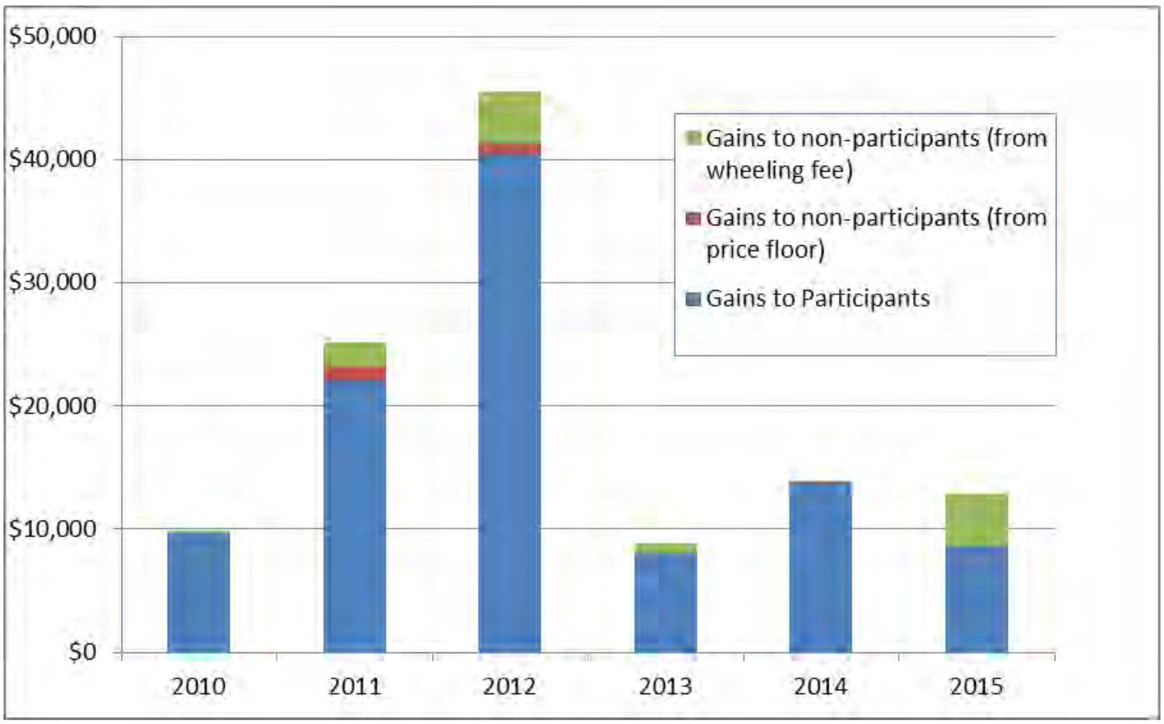
Reference Baselines

The Reference Demand and the HLH and LLH energy baselines (measured in average MW) will be set using RS 1823 demand and energy billing information from the 2015 freshet period. So long as 2015 freshet purchases are within +/- 10 per cent of a customer's historical freshet load, BC Hydro expects to use the 2015 data without further adjustment. However, BC Hydro recognizes there may be cases where an adjustment is necessary to achieve baselines that are representative of "normal" operations. This could occur if customers had a force majeure event, a prolonged shutdown, generation changes, or non-normal production during the baseline period (or in the 2016 and 2017 freshet periods). In these cases, BC Hydro may substitute billing data from prior periods or make adjustments, as appropriate and in consultation with the customer, to set an appropriate baseline. Special Condition 4 of RS 1892 states that Commission approval will be sought if BC Hydro and the customer mutually agree that the LLH and HLH baselines or Reference Demand, calculated using 2015 billing information, is not representative of the customer's expected electricity usage (if the freshet rate did not exist) and that BC Hydro will file the agreed-to baselines or Reference Demand with the Commission.

7.3.4.4 Benefits of the Rate

Pages 43 and 44 of the Workshop 5 consideration memo contained a five-year estimate of benefits from the freshet rate, to both participants and non-participants, spanning the period 2010 to 2014 and based on 1 MW of incremental load across the entire freshet period. BC Hydro updated the analysis shown to include calendar 2015 data and the results are summarized in Figure 7-6. The assumptions underlying the updated figure are based on those discussed in the Workshop 5 consideration memo.[283] The benefits to participating customers relate to the price spread between the RS 1823 Tier 1 rate and Mid-C prices (discussed in section 7.3.4.2) while the benefits to non-participating customers relate to the price floor and wheeling fee (discussed in section 7.3.4.3 under the heading "Energy Charge"). BC Hydro acknowledges the rate could bring other benefits to both groups, but these have not been quantified.

Figure 7-6 Gains from an Incremental 1 MW of Load Over Freshet Period



7.3.4.5 Types of Incremental Load and Load Shifting

RS 1823 customers might take advantage of the freshet rate in a number of different ways, including but not limited to:

283 Two changes were made to the original analysis: 1) the wheeling fee has been reduced to $CDN 3/MWh instead of an assumed $CDN 6/MWh fee; and 2) when calculating benefits to non-participating customers during times of export, actual flows on the US intertie have been used to determine import / export behaviour, rather than scheduled flows on both the US and Alberta interties. The US intertie is more appropriate because Mid-C reflects BC Hydro's short run opportunity cost. In addition, flows on the US intertie are much greater than on the Alberta intertie.

- Increasing production during the freshet to increase electrical energy purchases. This might be achieved through any combination of operating new equipment, re-start of existing shutdown equipment; utilization of idle capacity from existing equipment (including through shifting changes); and/or removing production controls designed to minimize demand peaks;
- Production of more energy-intensive product grades or materials;
- Shifting production from non-freshet months to freshet months or from high load freshet hours to low load freshet hours;
- Re-scheduling of planned maintenance from freshet months to non-freshet months (e.g., if a customer previously took maintenance downtime during the freshet and is able to move the downtime to a non-freshet period);[284]
- Turn-down of generation output that is contracted to BC Hydro:
  - On pages 41 and 42 of the Workshop 5 consideration memo, BC Hydro explained why customers with contracted generation are unlikely to turn down their generation to use the freshet rate. Essentially, turndown will result in lower EPA sales which will generally harm customers since firm EPA prices are often higher than the market prices they would receive under the freshet rate. Accordingly, BC Hydro has not prevented such customers from turning down contracted generation, and possibly paying liquidated damages, should they choose to participate in the rate; and
- Turn-down of generation output that is not contracted to BC Hydro and that is at the customer's discretion to control; such turn-down may include the prospective use of RS 1892 (rather than RS 1880) during periods of planned or forced generation curtailment.

[284] For more information on shifting, refer to pages 35 to 37 of the Workshop 10 consideration memo and slides 33 to 37 of the Workshop 10 presentation at Appendix C-5B.

Load Shifting

Load shifting occurs if customers are able to reduce RS 1823 energy in the non-freshet months and increase RS 1892 energy during the freshet months. On pages 35 to 37 of the Workshop 10 consideration memo, BC Hydro acknowledged that shifting of load is a complicated issue and explained why customers are unlikely to shift significant volumes and why the risks to non-participating customers are likely low. BC Hydro also indicated that, in its view, shifting is a valid method by which customers might use the freshet rate.

Since Workshop 10, BC Hydro further considered the issue of shifting and notes that shifting could be beneficial for non-participating customers in at least two scenarios:

- To the extent a drop in RS 1823 non-freshet load is reflected in BC Hydro's long term load forecast and leads to a reduction in long run marginal costs that exceeds the reduction in RS 1823 revenue.[285] In the short run, BC Hydro believes this is unlikely because the freshet rate is proposed as a two-year pilot and customer behavioural changes are unlikely to be reflected in the long term load forecast; however, the pilot may enable customers to make more long term behavioural changes that would reduce long term load forecasts and costs;
- If the load reduction in the non-freshet months occurs during the winter there could be capacity benefits to BC Hydro and/or higher value (relative to other non-freshet periods) from the additional energy not being consumed by customers.

BC Hydro will consider shifting when evaluating the pilot but notes that it could be challenging to identify.[286]

[285] For example, if shifting results in a drop in both RS 1823 Tier 1 revenue and long run marginal costs, there could be benefits to other ratepayers because the Tier 1 rate is significantly less than BC Hydro's LRMC. If shifting results in a drop in RS 1823 Tier 2 revenue, the outcome may be neutral for non-participating customers as the revenue reduction would be reasonably offset by the fall in long run costs.

[286] Refer to example on page 36 of the Workshop 10 consideration memo.

7.3.4.6 Evaluation Criteria and Reporting

At Workshop 10, BC Hydro proposed the following evaluation criteria for the freshet rate pilot:

- Did the rate provide RS 1823 customers with lower cost options?;
- Did the rate have positive or negative impacts on non-participating customers?;
- How many RS 1823 customers used the rate? What were the volumes of use? How did customers use the rate?;
- To what extent did shifting contribute to higher freshet energy?;[287]
- Was there any shifting within the freshet period from HLH to LLH?; and
- Were there any issues with setting baselines, implementation, or billing?

Based on stakeholder comments from Workshop 10 and its own further analysis, BC Hydro will consider the following additional criteria when preparing the proposed evaluation reports described below:

- Did the pilot impact RS 1823 customers' conservation and efficiency measures?;
- How quickly did customers respond to changes in market prices?;
- Did customers with aggregated RS 1823 loads shift consumption between plants to take advantage of this rate?;
- Did BC Hydro curtail any customers under the non-firm provisions of the rate? If so, what led to the curtailments? If not, were there any financial impacts on BC Hydro from not curtailing customers during constrained periods?; and
- Was there any impact on RS 1880 events? Did customers use the rate as a substitute for RS 1880?

[287] BC Hydro noted in the Workshop 10 consideration memo that may be hard to measure shifting depending on the magnitude of the shift relative to the customer's overall load.

As shown in Table 5 of the Workshop 10 Consideration Memo, BC Hydro proposes that three evaluation reports be submitted to the Commission as follows:

Report	RDA Proposal
Preliminary evaluation report	Report A: • Fall 2016 – Report take-up of the pilot in Year 1 and identify total sales and revenue under the rate. Report B: • Fall 2017 – Report take-up of the pilot in Year 2 and identify total sales and revenue under the rate. Report the impact of shifting in Year 1, which BC Hydro can only do at the end of F2017.
Final evaluation report	Report C: • Spring 2018 – summary of take-up and shifting over the two-year pilot program.

7.4 Two Existing Self-Generation Rates

7.4.1 BC Hydro Proposal

BC Hydro is not proposing any changes to RS 1853 or RS 1880.

7.4.2 Rate Schedule 1853: IPP Station Service

7.4.2.1 Background

RS 1853 (IPP Station Service) was implemented in 2001,[288] and is available to IPP customers served at transmission voltage for forced outages, scheduled maintenance requirements and black-start re-energization of generators:

- Energy is provided on an 'as available' basis at Mid-C market prices;
- There is no demand charge associated with RS 1853 because service is non-firm; and
- There is a minimum monthly charge currently set at $41.37 (F2016) to recover costs incurred by BC Hydro under RS 1853. BC Hydro would continue with its existing practice of applying RRA rate increases to the RS 1853 minimum monthly charge of $41.37 (F2016).

[288] Commission Order No. G-12-01; http://www.bcuc.com/Documents/Orders/Orders2001_2/G2_Orders/G12_BCH.pdf.

7.4.2.2 BC Hydro Proposal and Stakeholder Engagement

No IPP customer expressed any concern with this rate. Clean Energy BC, a group representing IPPs, attended Workshop 5 and Workshop 10 and raised no issues with respect to RS 1853.

Feedback from other stakeholders was limited, with the only issue identified concerning whether the energy rates for RS 1853 and RS 1880 should be aligned – RS 1853 is based on Mid-C market prices and RS 1880 is set to the prevailing RS 1823 Tier 2 rate. At Workshop 10, BC Hydro provided its view that non-firm energy sold to IPPs should be priced off the Mid-C market because non-firm energy acquired from IPPs is typically priced at Mid-C, thus ensuring that non-firm energy is consistently valued whether it flows from BC Hydro to the IPP customer or from the IPP service provider to BC Hydro. As described in section 7.4.3 below, BC Hydro accepts the status quo because in the case of RS 1880, it was Transmission Service customers who requested the RS 1823 Tier 2 pricing on the basis that it produced a more stable (if higher) rate.

7.4.3 Rate Schedule 1880: Standby and Maintenance

7.4.3.1 Background

RS 1880 was implemented prior to 1991 and is available to Transmission Service customers with self-generation for replacement of energy due to curtailment of the customer's on-site generation:

- Energy is provided on an 'as available' basis at the RS 1823 Tier 2 price. BC Hydro proposed a RS 1880 energy charge based on the Mid-C hourly index as part of the 2005 TSR Application. In the subsequent 2005 TSR Outstanding Matters Application, BC Hydro stated that "some stakeholders are concerned about the potential volatility of the Mid-C prices, particularly given the inability to control the timing of forced outages and on-site generation". Consequently, BC Hydro proposed that the RS 1880 energy charge should be the same as the

RS 1823 Tier 2 price. Commission Order No. G-19-06 approved BC Hydro's RS 1880 proposal;

- There is no demand charge associated with RS 1880 because the service is non-firm; and
- There is an administrative charge of $150 per incident (period of use) to recover the incremental costs incurred by BC Hydro resulting from a customer's request for service under RS 1880. This charge has been unchanged since it came into effect in early 2006.

7.4.3.2 BC Hydro Proposal and Stakeholder Engagement

The RS 1880 status quo is reasonable as no concerns have been expressed by Transmission Service customers who use the rate. The 'as available' non-firm energy supplied at the RS 1823 Tier 2 price is likely above cost. However, as noted in section 4.2 of the Workshop 10 consideration memo, basing the RS 1880 energy rate on the RS 1823 Tier 2 rather than lower spot market prices helps ensure that any additional incremental costs are recovered from customers using the non-firm services. While the RS 1880 administrative charge is reasonable, and while labour costs associated with administering RS 1880 (e.g., manual billing adjustments for RS 1880 requests) are minor, it is difficult to say with certainty whether the administrative charge under or over recovers actual labour costs.

7.5 Rate Schedule 1827: Rate for Exempt Customers

BC Hydro is not proposing any changes to RS 1827.

7.5.1 Background and Commission Jurisdiction

As part of Workshops 5 and 10, BC Hydro described RS 1827. There are presently four exempt customers: New Westminster; UBC; SFU; and YVR), accounting for about 6 per cent of Transmission Service sales. RS 1827 consists of a flat energy charge which is the same as RS 1823 Part A – in F2016, 4.303 cents/kWh. The demand charge is the same as that under RS 1823.

At Workshop 5 and Workshop 10, BC Hydro outlined its legal position with respect to RS 1827:

- Section 3(1) of Direction No. 7 states that “In designing rates for the authority's transmission rate customers, the commission must ensure that those rates are consistent with Recommendations No. 8 to No. 15 inclusive in the [Heritage Contract Report]”. The B.C. Government accepted Recommendation No. 15, which provides “That … [New Westminster] and UBC, as entities that distribute all or a significant portion of their load to others, be exempted from the application of stepped rates at this time and form a new rate schedule(s)”. It is BC Hydro’s view that the Commission cannot unilaterally transfer New Westminster and/or UBC to RS 1823 or set a stepped rate similar to RS 1823 for New Westminster and/or UBC under its section 58 to 61 *UCA* rate setting power; the Commission can only be given jurisdiction to review and make recommendations concerning this issue through a section 5 *UCA* inquiry review process, and only the LGIC can refer this matter to the Commission under section 5 of the *UCA*. The B.C. Government confirmed that it will not refer the matter of New Westminster’s and UBC’s exemption from stepped rates to the Commission. Accordingly, while BC Hydro engaged with the four exempt customers in August to September 2014 and discussed New Westminster’s and UBC’s exemption at Workshop 5 to gather stakeholder input for purposes of informing the B.C. Government referral decision, and while BC Hydro reported out on the B.C. Government’s decision through section 3 of the Workshop 10 at Appendix C-5B of the Application and answered questions, New Westminster and UBC are not addressed any further in this section except to reference the stakeholder engagement processes;

- The Commission has jurisdiction under sections 58 to 61 of the *UCA* with regard to SFU and YVR. The Commission established their exemption from stepped rates in Commission Order No. G-10-06, on the basis that SFU and YVR share similar characteristics to New Westminster and UBC in that they distribute a significant portion of their load to others, and that exempting SFU and YVR is consistent with Recommendation No. 15.

7.5.2 BC Hydro Proposal and Stakeholder Engagement

In August and September 2014 BC Hydro engaged with each of the four Transmission Service exempt customers concerning three potential RS 1827 options: (1) status quo; (2) transfer to RS 1823; and (3) transfer to a rate along the lines of RS 3808, the FortisBC PPA. Bill impacts depend on the level of growth – based on a RS 3808 type structure, bill impacts would be about 9.2 per cent by Year 5 of the transfer if load growth is about 2 per cent per year. The four exempt customers strongly opposed (2) and (3). The four exempt customers agreed to provide BC Hydro with details concerning their DSM initiatives as part of the Workshop 5 written comment process.

SFU and YVR took the position that a review of the reasons for exemption should not be examined as part of the 2015 RDA. A common element of their respective responses is that application of a stepped rate has not been required to induce investment in energy efficiency since a significant amount of DSM projects have been undertaken to date while receiving electrical service under RS 1827:

1. SFU commented that the reasons for its exemption from stepped rates remain valid, and that additional price signals are not necessary to encourage DSM activities. Since 2007, DSM projects implemented by SFU resulted in a savings of 8.6 GWh per year and 20,000 gigajoules of natural gas annually. Without a stepped rate, SFU intends to continue the identification and implementation of DSM measures. In a letter dated September 10, 2013 SFU states that it agrees with BC Hydro’s proposal to continue to serve SFU pursuant to RS 1827. As

part of that letter SFU provided BC Hydro with a list of DSM initiatives SFU undertook from 2007 to 2015 together with future potential DSM projects. A copy of SFU's letter is found at Appendix C-5E; and

2. YVR indicated that the reasons for its exemption from stepped rates remain unchanged, and YVR continues to have little control over the use of electricity as the vast majority of load is required to support continuous operations and is either legislated (e.g., safety, security, baggage and passenger screening) or resold to airport tenants. Since the year 2000, YVR employs an energy manager who is dedicated to energy conservation. Despite its recent expansion and passenger growth, annual load has remained virtually unchanged for the past five years. Peak demand in 2014 was 5 per cent less than it was in 2009. In a letter dated September 11, 2015, YVR outlines the reasons why it agrees with BC Hydro's proposal to continue to serve YVR pursuant to RS 1827. YVR states that it has "little control over the use of electricity and the vast majority of the load is required to support continuous operations at the airport (24 hours a day, seven days a week)". YVR goes on to state that despite having little control over the use of electricity, it has taken significant steps towards conservation. YVR's letter describes a number of the DSM initiatives it has taken. A copy of YVR's letter is found at Appendix C-5E.

While overall the RS 1827 energy charge is not an efficient rate as it is below BC Hydro's energy LRMC range, there does not appear to be any significant change in circumstance for SFU or YVR since their original exemption from stepped rates in 2006. All customers continue to resell energy to others. In addition, SFU and YVR commented that they have undertaken a significant amount of energy conservation through DSM initiatives, and have plans to continue to do so in the future.

Non-exempt customer stakeholders commenting on this topic agreed with BC Hydro's proposal to continue with the status quo RS 1827 rates; refer to section 3.1 of the Workshop 10 consideration memo at Appendix C-5B of the Application. In addition, refer to the MEM Policy Letter at Appendix C-1C of the

Application; the B.C. Government is of the view that the Commission's original rationale for exempting SFU and YVR from RS 1823 and other stepped rates continues to apply.

2015 Rate Design Application

Chapter 8

Electric Tariff Terms and Conditions

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8.1 Introduction and Chapter Structure

BC Hydro's Electric Tariff contains Terms and Conditions for service set out in eleven sections as follows:

Electric Tariff Section and Heading
1 - Definitions
2 - Application for Service
3 – Supply of Electricity
4 - Metering
5 - Meter Reading and Billing
6 – Rates and Charges
7 – Load Changes and Operation
8 – Distribution Extensions - 35 kV or Less
9 – General Provisions
10 – Rate Zone IB and Rate Zone II
11 – Schedule of Standard Charges

The scope of RDA Module 1 includes the Terms and Conditions with the exception of:

- Section 8 of the Electric Tariff governing Distribution extensions. RDA Module 2 will address this topic;
- Section 10 of the Electric Tariff concerning Rate Zone IB and Rate Zone II issues. Review of rates for NIAs is part of Module 2; and
- Resale of Electricity (Electric Tariff section 9.2) and the Transformer Rental Charge (Electric Tariff section 11.3) are to be reviewed alongside Distribution extension matters. In particular, BC Hydro proposes to use RDA Module 2 to address the Commission's suggestion concerning Templeton DOC Limited Partnership's application for exemption that the Electric Tariff re-sale of electricity be clarified.[289]

[289] OIC No. 454, approved July 27, 2015; http://www.bclaws.ca/civix/document/id/oic/oic_cur/0454_2015.

As described in section 2.5 of the Application, BC Hydro proposed at Workshop 1 that rate design issues which had been the subject of recent Commission decisions should not be in scope for Module 1, including the Commission's April 2014 decision concerning Meter Choices Program charges.[290] No stakeholder commenting on this topic as part of the Workshop 1 feedback suggested that Meter Choices Program charges should be reviewed as part of 2015 RDA Module 1. Accordingly, Meter Choices Program charges (the section 11.3 Electric Tariff Failed Installation Charge, Legacy Meter Charge, Radio-off Meter Installation Charges, Radio-off Meter Charge and the Radio-off Meter Removal Charge) are not addressed any further in this Application. Net Metering is another area that has been the subject of recent Commission decisions, and thus the Electric Tariff section 11.3 Net Metering Site Acceptance Verification Fee is not addressed in this Application.

8.1.1 Summary of Terms and Conditions Assessment Process

The Terms and Conditions, including the Standard Charges, were last considered by the Commission as part of the 2007 RDA based on F2006 costs. Consequently, there is a need to update the Standard Charges to reflect BC Hydro's current costs. The cost structure for the Minimum Reconnection Charge (discussed in section 8.3.2 below) emerged as the most significant proposed change. Costs such as vehicles and labour related to disconnection and reconnections have decreased as a result of the implementation of the RDR switch in most smart meters. In addition to cost updates, BC Hydro used the following as the starting point for its assessment of the Terms and Conditions:

- Sections 5.3 and 5.4 of the 2007 RDA Decision; and
- The jurisdictional assessment described in section 2.4.2 of the Application, modified to take into account BCOAPO's suggestion that Ontario and Alberta could be relevant for purposes of the Terms and Conditions review. Jurisdictional references are provided in section 8.3 below in reference to some

[290] Meter Choices Program Decision, *supra*, note 110 in Chapter 2.

of the Standard Charges and in section 8.4 below with respect to security deposits.

BC Hydro's proposals for the Terms and Conditions were the subject of Workshop 3 and Workshop 9a, and focused on the Standard Charges and security deposits. BC Hydro also met with BCOAPO on June 11, 2014, May 4, 2015 and August 18, 2015 to discuss the default Minimum Reconnection Charge, BC Hydro's disconnection process, and the potential for separate low income customer terms and conditions as described in sections 8.3.2 and 8.6 below. Finally, as discussed in section 2.2.3.3 of the Application, certain Standard Charges matters were canvassed at the first residential focus group series in August 2014. Stakeholder feedback and how BC Hydro incorporated such feedback into its Terms and Conditions proposals is referenced throughout this Chapter.

8.1.2 Structure of Chapter

The remainder of this Chapter is organized as follows:

- Section 8.2 describes BC Hydro's proposal to review cost updates of existing Standard Charges more frequently with RRAs in the future;
- Section 8.3 canvasses BC Hydro's proposals for a number of Standard Charges, with emphasis on the three charges garnering the most attention at Workshop 3 and Workshop 9a – the Minimum Reconnection Charges (section 8.3.2); the Late Payment Charge (section 8.3.3); and the new Meter Test Charge (section 8.3.6);
- Section 8.4 contains BC Hydro's proposals concerning aspects of section 2.4 of the Electric Tariff governing security deposits. BC Hydro seeks flexibility to charge a lower amount and to allow a security deposit to be assessed or increased if actual consumption is significantly greater than what was initially assumed;

- Section 8.5 provides an overview of the proposed changes to the Terms and Conditions, which are administrative in nature. With the 2015 RDA BC Hydro has the opportunity to update the Terms and Conditions to reflect modern drafting techniques and recent regulatory developments, and ensure consistency and clarity of language. BC Hydro will file its proposed changes to the Terms and Conditions for Module 1 with its responses to the first round of IRs (BC Hydro's suggested date for responding to the first round of IRs is December 2, 2015 as noted in section 1.6.1 of the Application); and
- Section 8.6 consists of BC Hydro's assessment of the business case for separate low income terms and conditions. The section currently comprises: (1) a summary of engagement with BCOAPO to the date of the filing of the Application, including BC Hydro's jurisdictional review of low income rates as defined in section 5.4 of the Application, low income terms and conditions and low income DSM programs; and (2) context for the business case, including an overview of BC Hydro's existing billing mechanisms available to all customers that benefit low income customers and discussion of BC Hydro's work with MSDSI to streamline credit actions for customers receiving direct social assistance. Engagement with BCOAPO is on-going at the time of the Application filing and the business case itself, together with a summary of the on-going engagement, will be provided as part of BC Hydro's responses to Round 1 IRs.

8.2 Proposed Review of Standard Charges Between Rate Design Applications

To date, Standard Charges have been reviewed as part of RDAs. At Workshop 9a BC Hydro sought feedback concerning mechanisms that could be used to update the Standard Charges between RDAs to ensure that the charges are more reflective of BC Hydro's current costs. BC Hydro agrees with BCOAPO's, Commission staffs' and COPE 378's combined suggestions[291] that:

- RRAs are the appropriate forum for updates of existing Standard Charges to reflect current costs; and
- Fundamental changes to Standard Charges, introduction of new Standard Charge(s) and/or major changes to the terms and conditions related to these charges are preferably filed with and examined through RDAs.

BC Hydro seeks Commission endorsement of the review process described above as part of 2015 RDA Module 1 to provide greater certainty for future filings and regulatory review process efficiency. BC Hydro first used the term 'endorsement' in the 2008 Long-Term Acquisition Plan (**LTAP**) proceeding;[292] the endorsement is requested to give parties clarity and BC Hydro direction by declaring a treatment will be presumed unless there is a good reason for another treatment.

8.3 Electric Tariff Standard Charges

BC Hydro presented a summary of its proposals for the Standard Charges at Workshop 12,[293] reproduced in Table 8-1 below. Note that the Minimum Connection Charges cost updates were discussed at Workshop 7[294] on December 16, 2015 as part of the Distribution extension policy discussion, and are not shown in Table 8-1 but are addressed in section 8.3.1 below.

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[291] Summarized in section 1.1.1 of the Workshop 9a/9b consideration memo at Appendix C-3B.

[292] Refer to BC Hydro's response to BCUC IR 1.4.1 in the 2008 LTAP proceeding (Exhibit B-3); http://www.bcuc.com/Documents/Proceedings/2008/DOC_19530_B-3_BCH%20-%20IR%20Rsps.pdf.

[293] Slides 61 to 62 of Workshop 12 presentation slide deck, copy at Appendix C-1B.

[294] Refer to slides 46 to 49 of the Workshop 7 presentation slide deck; copy at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2014-12-16-wkshp-presentation.pdf.

Table 8-1 Summary of Proposed Standard Charges

Standard Charge	Current	Proposed	Section of Chapter/Rationale
Minimum Reconnection Charge – default	$125	$30	Section 8.3.2 - Updated to reflect current costs; does not include IT costs based on stakeholder input
Late Payment Charge	1.5% per month	1.5% per month	Section 8.3.3 - Late Payment Charge recovers BC Hydro's costs and is a means to incent prompt payments
Returned Cheque Charge, to be re-named Returned Payment Charge	$20	$6	Section 8.3.4 - Currently, this charge is tied to BC Hydro's lead bank's non-sufficient funds (**NSF**) fee; change to reflect BC Hydro's actual costs
Account Charge	$12.40	$12.40	Section 8.3.5 - Two different cost drivers offset each other so charge remains the same
Meter Test Charge	$125 (Minimum Reconnection Charge)	$181	Section 8.3.6 - Proposed new charge reflecting cost recovery of first meter connection charge
Collection Charge	$39	Remove	Section 8.3.7 - Outdated as most meters are disconnected remotely
DataPlus Service	$360 per year	Remove	Section 8.3.7 - New enhanced data download service planned to be released to customers in early 2016 free of charge

8.3.1 Minimum Connection Charges

BC Hydro proposes updated Minimum Connection Charges as set out in Table 8-2 below. The current Minimum Connection Charges for new services are based on calculations using F2006 material and labour costs, and have been updated based on F2016 costs. Refer to Appendix G-1B for the derivation of the proposed Minimum Connection Charges.

Table 8-2 Summary of Proposed Standard Charges

	Current Charge ($)	Proposed Charge ($)
100A Overhead	463	799
200A Overhead	496	838
400A Overhead	798	Remove
100A Underground	605	957
200A Underground	855	1270
First Meter	92	181
Additional Meter	23	46
Call back Charge	194	368

The Minimum Connection Charges for Zone I are applied for single phase secondary service connections, plus one meter for various main switch amperage ratings as found in section 11.1 of the Electric Tariff. Additional service connection charges may apply as set out in the Electric Tariff for each additional meter installed at the same time as the service connection installation, as well as for one or more additional meters installed subsequent to the service connection installation.

The Minimum Connection Charges reflect average costs based on the customer's service requirements. 100A and 200A services typically do not require transformation costs that exceed the average costs. However, due to system requirements 400A service requests often require additional transformation costs that are not included in the Minimum Connection Charge and would often require the creation of a distribution design for the installation which would include additional non-standard charges. To avoid customer confusion, BC Hydro is proposing to eliminate the 400A Minimum Connection Charge and address such service requests through the Distribution extension provisions in section 8 of the Electric Tariff.

8.3.2 Minimum Reconnection Charges

BC Hydro proposes updated Minimum Connection Charges set out in Table 8-3 below. Refer to Appendix G-1B for the derivation of the proposed Minimum Reconnection Charges.

Table 8-3 Proposed Minimum Reconnection Charges

Minimum Reconnection Charge	Standard Charge ($)
Minimum Reconnection Charge (default) – remote and manual reconnections during regular working hours and remote reconnections outside of regular working hours	30 per meter
Manual reconnection performed on overtime	280 per meter
Manual reconnection requiring a call out	Remove
Manual reconnection at the point of connection because the customer refused access to the meter	700 per meter

The Minimum Reconnection Charge is applied when a premises is reconnected after being disconnected for a variety of reasons as described in section 6.7 of the Electric Tariff. The primary application of this charge is the reconnection of customers following disconnection for non-payment of balances in arrears or for vacant accounts.

The default Minimum Reconnection Charge that is applicable to reconnections performed during regular working hours is currently $125, as set out in section 11.2 of the Electric Tariff. It is based on the direct costs of manually disconnecting and reconnecting the affected customer. The costing assumed two trips to premises and was provided as a single average price reflecting variations in travel times and utilization of different skill types across the service territory.

At a meeting of June 11, 2014, BCOAPO identified the default Minimum Reconnection Charge as one of its priorities for the 2015 RDA (refer to the summary notes for this meeting at Appendix C-3D). As discussed at Workshop 3, and in regard to the default Minimum Reconnection Charge, the introduction of RDR capability through smart meters changed the nature of costs associated with a disconnection. Over 95 per cent of disconnections are now performed remotely, without the need to dispatch crews. Manual disconnections or reconnections are now required only when:

- The premises does not have a meter enabled for RDR (including legacy meters, poly-phase meters and some special metering types);
- The account is not metered;
- The nature of the disconnection request requires service to be de-energized from the distribution line, not just beyond the meter; or
- An attempted remote disconnection or reconnection fails.

Four cost methodology options were discussed in Workshop 3, with the difference between them being the proportion of IT investment costs in RDR to be recovered through the default Minimum Reconnection Charge. As discussed in sections 1.3.1 and 1.3.2 of the Workshop 3 consideration memo, there was general agreement from stakeholders that IT costs should not be included in the derivation of the charge on the basis that such costs are part of the basic functionality of the smart meter program and benefit all users of the system. BC Hydro agrees with this rationale; RDR is a standard functionality with benefit to all customers, rather than an incremental cost to be recovered in the default Minimum Reconnection Charge. Accordingly, BC Hydro proposes a default Minimum Reconnection Charge that does not include any IT capital or sustainment costs:

- Allocating the entire RDR investment to the default Minimum Reconnection Charge would not follow acceptable rate making principles. As the incremental cost of including the RDR functionality was approximately $30 per meter, at most it would be acceptable to attribute $30 to the specific customers being disconnected and this would have a minimal impact on the default Minimum Reconnection Charge (e.g., $30/20 years = $1.5). The impact to other ratepayers of this allocation would be minimal (approximately $40,500 reduction to the revenue requirement);

- BC Hydro's primary use of RDR is for account management and collections, which were the drivers for the investment. Remote disconnection benefits all customers by limiting consumption by non-account holders and allows disconnection of accounts shortly after being vacated. BC Hydro recently implemented a new process such that accounts are automatically disconnected 21 days after a customer terminates service unless a new customer has applied. This stops energy consumption at premises with no account holder. Currently, there are approximately 1,000 vacant account disconnections each week, which exceeds the number of non-pay disconnections.

As discussed at Workshop 9a, the revised costing methodology for the default Minimum Reconnection Charge includes:

- Labour for customer service and credit agents to review files and issue the disconnection order;
- Labour for customer service or credit agents to issue a reconnection order following the reporting of a payment, for customers not electing or able to report a payment and initiate the reconnection using self-service tools; and
- Direct labour costs to manually disconnect or reconnect a service, for the proportion of disconnections and reconnections that cannot be performed remotely.

The default Minimum Reconnection Charge is applicable for any remote reconnection, as well as when a manual reconnection is performed during regular working hours. When a manual reconnection is requested by the customer outside of regular working hours, and if a crew is available to be dispatched, the overtime Minimum Reconnection Charge will apply to recover the additional costs. BC Hydro proposes to update the overtime Minimum Reconnection Charge from $158 to $280 to recover increased costs associated with a manual reconnection done on overtime hours. After-hour reconnections at call-out rates are extremely rare and so it is proposed that the Call-Out charge be removed; any reconnections requiring call-outs would be charged at the overtime rate of $280 per meter set out in Table 8-3 above.

An additional charge is proposed to reflect the higher costs incurred when a customer's meter is not enabled for RDR and the customer refuses access to the meter. In this situation it is necessary for a Power Line Technician (**PLT**) crew to manually disconnect (and later reconnect) the service at the point of connection to the distribution system. It is not appropriate to apply the blended reconnection charge when additional costs are incurred because of a customer refusing access. BC Hydro already has the option under section 6.7 of the Electric Tariff to "add to the Minimum Reconnection Charges … an amount to cover the costs incurred by BC Hydro when there are unusual circumstances". For transparency and consistency in application of additional charges in case of access refusals, an additional Standard Charge is proposed based on the full cost of the manual disconnection and reconnection by PLT.

8.3.3 Late Payment Charge

BC Hydro proposes continuation of the Late Payment Charge on the basis that it recovers BC Hydro's costs.

Pursuant to sections 6.2 and 11.3 of the Electric Tariff, BC Hydro's Late Payment Charge of 1.5 per cent per month is assessed on a bill with an unpaid balance of $30 or more that has not been paid in full on or before the due date of the bill. As noted by the OEB with respect to its Customer Service Rules for Electricity,[295] the rationale for late payment charges is that all customers benefit from encouraging prompt payment of bills, which in turn reduces costs to electric utilities. The 1.5 per cent charge and the $30 threshold have been in place since their

[295] http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Customer+Service+Rules.

introduction in 1977. The Commission in the 2007 RDA Decision approved the continued use of the 1.5 per cent Late Payment Charge.[296]

As part of its assessment of the Late Payment Charge, BC Hydro undertook a jurisdictional review of the Canadian electric utilities listed in Table 8-4 below, and determined that its Late Payment Charge is in line with those utilities surveyed.

Table 8-4 Canadian Electric Utility Late Payment Charges

Canadian Electric Utility	Late Payment Charge
Nova Scotia Power (% per month)	1.5
New Brunswick Power (% per month)	1.5
Hydro Quebec (% per month)	1.2
Ontario[297] – Hydro One, Toronto Hydro Electric System, Hydro Ottawa (% per month)	1.5
Manitoba Hydro	1.25
Enmax Power Corporation (**Enmax**) (% one-time charge) [298]	3.25
FortisBC (% per month)	1.5

At Workshop 3, BC Hydro sought feedback on:

- Whether the $30 threshold for application of the Late Payment Charge should be continued; and
- The level of the Late Payment Charge.

For the reasons set out in section 1.2.2 of the Workshop 3 consideration memo at Appendix C-3A, BC Hydro is not proposing to eliminate the $30 threshold.

[296] 2007 RDA Decision, pages 199 to 200; refer to the citation at note 49 in Chapter 2 of the Application.
[297] A late payment charge of 1.5 per cent is the maximum allowed by the OEB under its Customer Service Rules for Electricity.
[298] The Enmax Distribution Tariff Terms and Conditions provides in section 18: “This fee applies to Retailers or Customers. A one-time penalty charge of 3.25% will be applied no less than 25 days following the current Invoice Date indicated on the bill to total current charges outstanding”; https://www.enmax.com/ForYourHomeSite/Documents/DT-TandCs-Jan-1-2015.pdf.

At Workshop 9, COPE 378 requested that BC Hydro provide the rationale for the 1.5 per cent Late Payment Charge. BC Hydro stated that the Late Payment Charge is foremost a cost recovery mechanism to compensate BC Hydro for expenses incurred as a result of the late payment and to take into account the time value of money, and also a means to induce prompt payments on the part of customers. BCOAPO, COPE 378 and FNEMC in their written comments concerning Workshop 9 asked that BC Hydro set out the cost basis for the 1.5 per cent Late Payment Charge. BC Hydro did so in section 1.2.2 of the Workshop 9a/9b consideration memo, with the information reproduced in Table 8-5 for ease of reference. F2015 revenue from the Late Payment Charge was $7,843,653.

Table 8-5 BC Hydro Late Payment Charge Costs (F2015)

Accenture Business Service (ABSBC) Costs (credit and call center) ($)	3,881,143
Customer Late Payment Communications ($)	1,949,170
BC Hydro Interest ($)	1,968,415
BC Hydro Operating and Maintenance ($)	250,000
Total ($)	**8,048,729**

BC Hydro noted in section 1.2.2 of the Workshop 9a/9b consideration memo that it uses its most recent Weighted Average Cost of Debt (**WACD**) for the Fiscal Year, which at the time of the memo was 4.21 per cent. To align with the F2015 Late Payment Charge revenue quoted for this analysis, the interest rate was updated to the F2014 WACD of 4.28 per cent (as reflected in Table 8-5 above) to calculate BC Hydro interest. BC Hydro applies its WACD for purposes of security deposits and any other credits BC Hydro gives back to customers. The Electric Tariff mandates use of the WACD from the previous fiscal year for security deposit-related interest (section 2.4.4.6) and for back-billing purposes (section 5.8.6). If BC Hydro used a bank short-term interest rate (1.32 per cent at the time of the Workshop 9a/9b consideration memo, updated to 0.68 per cent for the Application), the Late Payment Charge would be about 1.25 per cent. BC Hydro provided stakeholders with the revenue impacts of reducing the Late Payment Charge to 1.25 per cent and 1 per cent in Table 2 of the Workshop 9a/9b consideration memo at Appendix C-3B.

8.3.4 Returned Payment Charge

BC Hydro proposes to continue the Returned Payment Charge (formerly called the Returned Cheque Charge) at the lower rate of $6 rather than the current rate of $20. The charge recovers the costs of the following:

- Banking fees charged to BC Hydro;
- Labour required from billing and payments clerks to review and action returned payments; and
- Printing and mailing fees for letters sent to customers with returned payments.

The current Standard Charges in section 11.3 of the Electric Tariff include a "Returned Cheque or Pre-Authorized Payment Charge" for when a customer makes a payment but it is rejected for a reason such as insufficient funds. Currently, this charge is linked to the NSF fee posted by BC Hydro's banking provider, BMO Bank of Montreal. Although BC Hydro's standard charge for a returned payment has remained at $20, the posted NSF fee has been raised several times since the 2007 RDA and is currently $40.

The nature of the Returned Payment Charge has changed because of changes in the Canadian banking industry, as well as in the channels that customers use to pay their bills. In the past, cheques were the predominate form of payment. With cheques it was possible that payment was received and processed, only to later find that the customer had insufficient funds in their chequing account. In this situation, BC Hydro would incur administrative costs to notify the customer and obtain payment, and would also incur a charge from the bank. The bank's posted NSF fee was used as a proxy for recovering these costs.

It is no longer appropriate to link the Returned Payment Charge to the NSF charge from BC Hydro's bank:

- The vast majority of payments are now made through electronic payments, with cheques used for only 8 per cent of payments. With online banking, the customer is unable to make a payment that exceeds available funds. There are also other mechanisms such as overdraft protection that limit the likelihood that a payment will fail; and
- Fees charged by BC Hydro's bank for failed payments are much lower for electronic payments than for cheques. Given that there are now many more failed electronic payments than returned cheques, BC Hydro's average cost of processing failed payments has dropped.

As described in Appendix G-1B, the proposed Returned Payment Charge following this approach is $6.

8.3.5 Account Charge

BC Hydro proposes continuing with an Account Charge of $12.40.

The Account Charge is applied when a customer submits an application for a new account or an existing customer moves an account, regardless of whether it is done online or via a customer service agent. The charge is intended to recover the costs of the customer service representatives processing calls for new and moved services, as well as associated costs such as performing credit checks for new customers without an established credit history. The Account Charge is not applied to landlords and property management companies that take responsibility for electrical service charges at vacant premises between tenants.

Costs have increased since the 2007 RDA because of general increases in labour charges as the result of inflation and by the introduction and use of Identity Validation software for new accounts to mitigate bad debt costs resulting from accounts being created in fraudulent names. However, the increase has been mostly offset by a shift towards applications being received through lower-cost online tools. Overall, while the updated cost basis for the Account Charge increased slightly to $12.55 as described in Appendix G-1B, BC Hydro proposes continuing with an Account Charge of $12.40 given the minimal difference.

In Workshop 3, BC Hydro requested feedback on the potential to utilize a differentiated charge on the basis of the application being processed online versus agent, as well as a new customer account versus a move of an existing customer. As explained in section 1.4.2 of the Workshop 3 consideration memo at Appendix C-3A, BC Hydro is not proposing these differentiated charges. Instead, BC Hydro proposes to continue the existing method for determining the Account Charge.

8.3.6 Proposed Meter Test Charge

BC Hydro proposes a new Meter Test Charge of $181.

In accordance with section 4.3 of the Electric Tariff, a customer that doubts the accuracy of the meter may have the meter tested by Measurement Canada.[299] There is no charge to the customer if the meter is found to be operating outside of normal parameters as described within the *Electricity and Gas Inspection Act*;[300] however in accordance with section 6.7 of the Electric Tariff, the customer is currently charged the default Minimum Reconnection Charge (currently $125) if the meter is deemed to be accurate.

The proposed reduction of the default Minimum Reconnection Charge to $30 as described in section 8.3.2 above creates a situation in which BC Hydro would not recover the costs of dispatching a crew to exchange the customer's meter. At Workshop 9a, BC Hydro set out three options for a new Meter Test Charge:

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[299] Measurement Canada is a federal agency responsible for ensuring that customers receive accurate measure in financial transactions involving goods and services. Measurement Canada develops and administers laws and requirements governing measurement; evaluates, approves and certifies measuring devices; and investigates complaints of suspected inaccurate measurement; http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/h_lm00013.html.

[300] R.S.C. 1985, c.E-4.

option 1 - the updated default Minimum Reconnection Charge of $30; option 2 – the updated Minimum Connection Charge (First Meter) of $181 to more closely reflect cost recovery; and option 3 – the current (not updated) default Minimum Reconnection Charge of $125. No stakeholder supported option 1, but stakeholders were divided as to whether option 2 or option 3 was the best option. COPE 378 expressed concern that both option 2 and option 3 may result in some customers with legitimate concerns foregoing their right to have the meter tested out of concern they would be charged if the meter passes.

BC Hydro agrees with BCOAPO and FNEMC that option 2 is preferable because it provides full cost recovery. As noted in section 1.4.2 of the Workshop 9a/9b consideration memo, option 2 reflects full cost recovery for the first meter connection charge, and therefore is a good proxy for the costs incurred to send a meter to Measurement Canada for testing. Customers would not be charged if the meter failed Measurement Canada's testing.

8.3.7 Other Miscellaneous Standard Charges

8.3.7.1 Collection Charge

BC Hydro proposes the elimination of the Collection Charge.

The Collection Charge is a historic charge applied when a customer facing disconnection for non-payment would pay the crew directly and stop the disconnection. In this situation, BC Hydro incurred costs in dispatching a crew to disconnect the service that could have been avoided had payment come earlier. Currently, the Collection Charge is $39.

The Collection Charge is no longer relevant for the following reasons:

- RDR capability from smart meters means most disconnections are performed without the need to dispatch a crew; and

- Crews are no longer permitted to accept payments for safety and security reasons.

8.3.7.2 DataPlus Service

BC Hydro proposes the elimination of the DataPlus Service Charge.

The DataPlus Service Charge is applied to commercial customers with multiple accounts that are subscribed to the DataPlus Service, which provides them with detailed billing and consumption summaries electronically. The charge is $360 per year per Collective Master Account. The DataPlus Service is closed and is only available to existing DataPlus customers.

Advances in online self-service functionality now make it possible to provide customers with the ability to download billing and consumption data from BC Hydro's internet portal ("MyHydro"). Furthermore, customers with MyHydro profiles can access this information free of charge.

The current self-service features support both Residential and General Service customers, although the tools do not fully meet the needs of General Service customers with multiple accounts billed on a Collective Master Account. Accordingly, BC Hydro continued to provide the DataPlus service. However, an IT project is currently underway to address gaps in data and usability for some of the largest commercial customers. The DataPlus Service would be discontinued once the project is complete (tentatively mid-2016) and existing customers have been transitioned to the new self-service tools.

8.3.7.3 Credit Card Payment

As described in section 2.2.3.3 of the Application and in section 1.6 of the Workshop 3 consideration memo (found at Appendix C3-A), BC Hydro explored whether credit card payments should be accepted and fees recovered through all ratepayers or whether credit card payments should only be accepted if the fees could be passed on to the customer paying by credit card. There appears to be a lack of strong support for recovering credit card payment fees, including customer feedback received through the August 2014 residential focus groups which indicates no desire for paying by credit cards. Accordingly BC Hydro did not explore this option further. Customers wishing to pay by credit card will continue to be able to use a third-party provider where available.

8.4 Security Deposit

Section 2.4 of the Electric Tariff defines the terms and conditions under which BC Hydro can require security deposits. BC Hydro proposes changes to the conditions under which a security deposit can be requested, and the amount that is assessed, as discussed below in sections 8.4.1 and 8.4.2 below. As indicated in section 8.1.2 above, BC Hydro plans to file a copy of the Electric Tariff with BC Hydro's proposed changes to the Terms and Conditions as part of BC Hydro's responses to the first round of IRs, including revisions associated with the security deposit proposals discussed in this section.

8.4.1 Conditions for Assessing a Security Deposit

BC Hydro can assess a security deposit in two situations:

- A security deposit may be required for a new "applicant that has not established credit satisfactory to BC Hydro" (Electric Tariff, section 2.4.2); and
- A security deposit may be required for an existing customer "who has not maintained a credit history satisfactory to BC Hydro" (Electric Tariff, section 2.4.3).

When a new customer applies for service, BC Hydro assesses the need for a security deposit based on factors that include:

- Likelihood of the customer not paying the final bill, as determined through:
  - References indicating good payment history with other utilities, or

- The customer's credit score, which is obtained through an external credit rating agency (Equifax);

- Consequence of the customer not paying the final bill, as determined through expected amount of the customer's average bill.

For a customer with a poor credit history, or credit history that cannot be determined, the expected amount of the customer's bill is a critical factor as this impacts the potential bad debt exposure. In other words, the larger the expected bill the larger the potential bad debt, and so the amount of the security deposit increases accordingly.

As described at Workshop 9a, the existing Electric Tariff language creates a scenario in which BC Hydro may waive or assess a small security deposit on the basis of a small expected bill, only to find that actual consumption is significantly larger than anticipated. In this situation, BC Hydro has under-secured the customer's account relative to the bad debt exposure; however, if the customer continues to pay its bills then BC Hydro does not have the ability to assess a further security deposit. This concern specifically relates to customers believed to be engaging in illegal activities, such as marijuana grow operations. Rather than stealing electricity (e.g., through bypass of the meter), some of these customers apply for service with the intent of closing their accounts without paying their final bill. There can be a significant delay between the customer's last payment and when the premises is disconnected because collection processes do not start until the 21-day payment term has ended, and involves multiple notifications.[301] By that time, these customers can accrue large outstanding balances that are unlikely to be collectable and result in bad debt write-offs.

To address this problem, BC Hydro proposes that the Electric Tariff allow the application of a new security deposit or increase in an existing security deposit if

[301] Refer to the response to Part 2, Q.31 the Workshop 9a summary notes (and accompanying Attachment 1) for a description of BC Hydro's disconnection ('Dunning') process. The Workshop 9a summary notes are found at Attachment 1 to the Workshop 9a/9b consideration memo (Appendix C-3B of the Application).

actual consumption is found to be significantly higher than the consumption that was estimated when the account was created. Workshop 9a participants agreed with this proposal; refer to section 1.5.1 of the Workshop 9a/9b consideration memo.

8.4.2 Amount of the Security Deposit

In situations where a security deposit can be assessed, the amount of the security deposit is defined within Electric Tariff section 2.4 as:

- Two times the customer’s average monthly bill if the account is on monthly billing; and
- Three times the customer’s average monthly bill if the account is on bi-monthly billing.

The jurisdictional review undertaken for security deposits (Canadian electric utilities surveyed were: FortisBC, Enmax, EPCOR, SaskPower, a number of Ontario utilities including Hydro One and Horizon Utilities, Hydro Quebec, New Brunswick Power, Nova Scotia Power, and Newfoundland and Labrador Hydro) revealed that BC Hydro’s Electric Tariff language is among the most prescriptive.

As discussed at Workshop 9a, BC Hydro proposes to change these Electric Tariff provisions to enable security deposits “up to” two or three times the average monthly bill. Workshop 9a participants supported providing BC Hydro with additional flexibility in the application of the security deposit amount. In BC Hydro’s view, the proposal benefits BC Hydro and customers:

- Collection processes can be modified to enable a progressive increase in the security deposit applied in situations warranted by the level of risk posed by the customer. This helps to reduce the financial hardship that sometimes results from a large security deposit requirement; and

- It provides the option of applying security deposits for standardized amounts (e.g., $50 for an apartment), which is simpler for customers to understand and easier to administer.

8.5 Miscellaneous Terms and Conditions Amendments

In addition to the security deposit-related amendments described in section 8.4 above, BC Hydro is proposing a number of changes to various Electric Tariff Terms and Conditions which are primarily of an administrative nature to assist with customer understanding. Examples include additional and revised definitions for improved clarity and readability, replacement of duplicative provisions with cross-referencing, revisions for improved clarity and consistency throughout the Terms and Conditions, and general updates using modern drafting conventions. Note that the part of the current definition of "Residential Service" relating to farms and farm use will be addressed as part of Module 2.

As indicated in section 8.1.2 above, BC Hydro plans to file a copy of the Electric Tariff with BC Hydro's suggested proposed changes to the Terms and Conditions as part of BC Hydro's responses to the first round of IRs.

8.6 Potential Low Income Customer Terms and Conditions

As part of Workshop 9a consideration, BC Hydro met with BCOAPO on May 4, 2015 to discuss the possibility of terms and conditions for BC Hydro's low income residential customers. BCOAPO advised BC Hydro of evidence of Mr. Roger Colton submitted in the Manitoba Hydro 2015 to 2017 Rate Application proceeding raising the issue of how low income terms and conditions, and a 'targeted bill affordability program' with agreed-to monthly payments based on gross income and household size, benefit all ratepayers because they are more cost-effective than disconnect/reconnect for service, imposing late payment charges and requiring cash deposits, all of which the evidence states do not reduce residential bad debt.[302] BC Hydro communicated its view that if BC Hydro were able to demonstrate lower utility costs such as reductions in bad debt and/or collection costs, low income terms and conditions would not be unduly preferential/unduly discriminatory or otherwise unlawful.

8.6.1 Engagement with BCOAPO

The parties agreed to exchange information, and that BC Hydro would develop a business case for potential low income terms and conditions and share this with BCOAPO for comment. [*Note to reader – to be updated as part of BC Hydro's responses to Round 1 IRs*].

8.6.1.1 OEB Low Income Customer Rules

BCOAPO and BC Hydro agreed to use the OEB Electricity Low Income Customer Rules[303] as a starting point for potential low income terms and conditions. The OEB Low Income Customer Rules specify low income customer treatment for:

- Security deposits – security deposits can be waived and if paid, a low income customer can request that the security deposit be returned if there are no arrears on the bill;
- Billing errors – If the electric utility erred and overcharged the low income customer, it will refund the money immediately;
- Equalized billing – Low income customers can request equalized billing (bills spread over 12 months);

[302] Refer to Green Action Centre intervenor evidence (Direct Evidence of Roger Colton) at http://www.pub.gov.mb.ca/pdf/15hydro/gac_colton_direct.pdf.

[303] Summarized at http://www.ontarioenergyboard.ca/oeb/Consumers/Consumer%20Protection/Help%20for%20Low-Income%20Energy%20Consumers.

- Disconnection grace period – Disconnection process must be suspended for 21 days if the Ontario social agency partner advises the low income customer may be eligible for emergency assistance; and
- Arrears payment arrangement – Low income customers are allowed more time to pay outstanding balances.

Table 8-6 compares the OEB Electricity Low Income Customer Rules with BC Hydro's current Electric Tariff Terms and Conditions

Table 8-6 OEB Low Income Terms and Conditions

TERMS/ CONDITIONS	OEB ELECTRICITY LOW INCOME CUSTOMER RULES	BC HYDRO COMMENT
Security Deposit	• Customer can request it be waived; • If paid, customer can request it be returned (if there are no arrears on the bill); • When returned it will be: – Credited to the account if it's less than the customer's average monthly bill; – Refunded by cheque if it's more than the customer's average monthly bill.	• An income-based waiver would require a process to verify income and will have administrative costs; • Waiving security deposits could impact bad debts, though the exact impact cannot be estimated. The risk is likely lower for MSDSI customers if MSDSI is able to provide some type of assurance in lieu of a security deposit; • Pay-As-You-Go is an existing alternative to a security deposit. Pay-As-You-Go is an Equal Payment Plan with payment one month in advance; • Electric Tariff amendments are not necessary for BC Hydro to change the conditions under which security deposits are issued. However, if income becomes a criterion then an amendment would be necessary; • Proposed changes to security deposit amounts set out in section 8.4 above will help to reduce the burden of security deposits to low income customers that do not have a recurring pattern of non-payment.

TERMS/ CONDITIONS	OEB ELECTRICITY LOW INCOME CUSTOMER RULES	BC HYDRO COMMENT
Billing Errors	• If the electric utility erred and overcharged the customer, it will refund the money by cheque immediately; • If the electric utility erred and undercharged the customer, the amount owing will need to be paid back but over a longer period of time than other customers. • The customer has two options if undercharged: • Pay-back period is same time period as the customer was undercharged (to a maximum of two years); or over 10 months if the amount owing is less than twice the customer's average monthly bill or 20 months if it is more than twice the customer's average monthly bill.	• Back-billing rules establish a minimum repayment term available to the customer, being the length of the back-billing period. It is common practice to allow extended repayment terms depending on specific situations; • Back-billing restricts the maximum period of retroactive billing to six months for Residential customers, which protects customers by limiting their liability for under-billed charges; • Refunds for over-billing are provided immediately. The customer has the option of a cheque or credit left on the account; • The OEB rules are substantially achieved without an Electric Tariff amendment.
Equalized Billing	• The customer can request equalized billing (bills are spread out over 12 months) without having to pay by pre- authorized payment (other customers are required to pay by automatic withdrawal); • Equalized Billing rule does not apply if the customer has a contract with a reseller or retailer, or is a customer of a sub-metering provider.	• BC Hydro offers an Equal Payment Plan which spreads costs over 12 months. There is not a requirement to also enroll in pre-authorized payment; • The OEB rules are substantially achieved without an Electric Tariff amendment.
Disconnection Grace Period	• Disconnection process must be suspended for 21 days if the social agency partner advises the customer may be eligible for emergency assistance.	• BC Hydro is working with MSDSI to implement process changes that will achieve this objective; • This can be addressed through a business practice and may not require an Electric Tariff amendment.

TERMS/ CONDITIONS	OEB ELECTRICITY LOW INCOME CUSTOMER RULES	BC HYDRO COMMENT
Arrears Payment Arrangement	• Customers are allowed more time to pay outstanding balances: – eight months if amount is less than twice the customer's average monthly bill; – 12 months if amount is more than twice but less than five times the customer's average monthly bill; – 16 months if amount is more than five times the customer's average monthly bill; – Customers may be required to pay a 10% down payment; – Arrears arrangement cancelled if customer defaults more than two times; – If service is disconnected the customer will not have to pay the disconnection/reconnection charge; non- payment fees and load control device charges are also waived; – Customers may only have one arrangement in 12 months. If a second arrangement is done within the 12 months it will be on the same terms as other customers.	• BC Hydro allows instalment plans, although OEB low income rules allow more time to repay outstanding balances than BC Hydro would typically allow; • An income-based program would require a process to verify income and will have administrative costs. There would also be IT investment to enable differentiated standard charges (e.g., late payment charge) based on income; • Electric Tariff amendments are not necessary to enable longer repayment terms; however, amendments would be necessary to waive charges because of inconsistent treatment across customer groups; • Extended repayment terms increase Accounts Receivables and result in higher bad debts if the customer defaults and/or service is terminated; • Waiving standard charges will result in under-recovery of associated costs. Another mechanism would be necessary to enable full cost recovery.

TERMS/ CONDITIONS	OEB ELECTRICITY LOW INCOME CUSTOMER RULES	BC HYDRO COMMENT
Winter Disconnects	• Hydro One's policy prevents winter cut-offs;[304] • Hydro Quebec: from December 1 to March 31, service is maintained or restored to low income customers whose homes are heated with electricity and who have failed to pay their bills.	• An income-based program would require a process to verify income and will have administrative costs; • Through discussions with Ontario utilities, BC Hydro understands that a winter disconnection moratorium impacts Accounts Receivables and results in a large number of customers being disconnected as soon as the moratorium period ends. While a moratorium avoids issues with lack of electricity during cold weather periods, in many situations it only serves to postpone the disconnection; • BC Hydro is investigating the feasibility of using smart meters to limit the allowable load to a customer. If practical, this would allow a customer facing disconnection to be provided with a minimal supply of electricity (i.e., to allow some heating) but also limit the exposure to further non-collection. If this approach is practical, BC Hydro would prefer a load limiting solution to a broad moratorium on winter disconnections; • The impacts of winter disconnections vary regionally, as temperatures in the Lower Mainland and South Vancouver Island are more moderate than in the remainder of BC Hydro's service. This is different than in Ontario and Quebec, which have cold temperatures in all areas.
Medical Equipment	• Ontario Clean Energy Benefit provides eligible customers (i.e., those with medically necessary medical equipment that requires electricity for operation) with an ongoing 10% discount on their bills (effective for five years starting in 2011, ending December 31, 2015).[305]	• BC Hydro does not have a program to identify and validate reliance on medical equipment. Such a program would incur costs to implement and maintain, and would be essential if the intent is to avoid disconnections for customers with medical equipment; • BC Hydro cannot guarantee continuous electricity supply, including the need for planned maintenance outages; • There is not a cost-of-service argument that supports a differentiated rate for customers with medically necessary electrical equipment.

304 http://www.ombudsman.on.ca/Newsroom/Ombudsman-in-the-News/2015/Hydro-One-issuing-empty-disconnectin-threats-omb.apx

305 http://www.hydroone.com/MyHome/MyAccount/Service/Forms/OCEB%20Exemption%20Declaration%20Medical%20Equipment%20Notice%20Letterand%20Form.pdf.

Table 8-6 results from discussions with BCOAPO:

- On June 3, 2015 BC Hydro provided BCOAPO with the comparison table;
- BCOAPO provided BC Hydro with comments and questions concerning the table on August 18, 2015. Refer to a copy of BCOAPO's table comments at Appendix C-3D of the Application;
- BC Hydro amended the table, with Table 8-6 being the result. In particular, BC Hydro added a new category entitled 'winter disconnections', which while not included in the OEB Electricity Low Income Customer Rules, is based on Hydro One's and Hydro Quebec's respective policies of not disconnecting low income customers in winter months; and
- BC Hydro also added a second new category entitled 'medical equipment', which outlines measures in Ontario intended to support maintenance of electricity service for customers with medically necessary medical equipment that requires electricity for operation. This benefit is also not part of the OEB Electricity Low Income Customer Rules.

As set out in Table 8-6 in some cases, BC Hydro currently offers measures that are similar to the OEB Electricity Low Income Customer Rules; an example is Equal Payment Plan. In addition, some of BC Hydro's proposed changes described above will assist low income customers (such as the reduced default Minimum Reconnection Charge and requested security deposit flexibility). BC Hydro is also working with MSDSI to streamline credit actions for customers receiving direct social assistance. These points are elaborated on in section 8.6.2 below. However, it is the case that offering terms and conditions similar in substance to all of the OEB Electricity Low Income Customer Rules, and in particular waiving security deposits for low income customers, would require amendment to the Electric Tariff.

8.6.1.2 Jurisdictional Assessment

The parties agreed BC Hydro would conduct a review to determine which jurisdictions have low income terms and conditions (and low income rates) consisting of: the Canadian electric utilities BC Hydro surveyed for Residential rate purposes; the WECC U.S. electric utilities BC Hydro surveyed for Residential rate purposes; and additional U.S. jurisdictions suggested by BCOAPO - Pennsylvania, Ohio, New Jersey, New Hampshire, Colorado, Illinois and Maine. BC Hydro provided BCOAPO with a draft of the jurisdictional review for comment on June 26, 2015. The jurisdictional review found at Appendix C-3D is the result of a number of exchanges of information with BCOAPO. These exchanges are described in the jurisdictional review.

The jurisdictional review revealed the following:

- Two Canadian jurisdictions currently have specific terms and conditions for low income customers: arguably section 6.6 of Nova Scotia Power's Regulations,[306] which sets out the terms and conditions of service, as the Regulations do not require a deposit from customers receiving social assistance or similar types of income security payments unless there is a history of bad credit; and the OEB's Electricity Low Income Customer Rules. The Ontario legal regime governing the OEB is described in section 5.4 of the Application concerning low income rates; and
- While many U.S. jurisdictions have low income terms and conditions, the basis for these is legislation enacted by the particular state legislature.

[306] http://www.google.ca/url?url=http://www.nspower.ca/site/media/Parent/Regulations%2520-%2520January%25201%25202015.pdf&rct=j&frm=1&q=&esrc=s&sa=U&ved=0CBMQFjAAahUKEwjr_qvenYvIAhUQO4gKHcNbCAQ&usg=AFQjCNFgL4ve33qbF20vACnisCIDrne4jg

8.6.1.3 Review of Business Case

[*Note to reader – Engagement with BCOAPO is on-going on this topic, and BC Hydro's low income terms and conditions business case together with related stakeholder engagement will be provided as part of BC Hydro's responses to the first round of IRs*].

8.6.2 Background to Business Case: Measures In Place and Proposed Without Low Income Terms and Conditions

BC Hydro considered the following as part of its assessment of potential low income terms and conditions:

- Activities and measures BC Hydro currently engages in which assist with low income customer needs, including existing billing mechanisms and low income DSM programs (section 8.6.2.1);
- BC Hydro's proposals for a lower default Minimum Reconnection Charge and security deposit flexibility (section 8.6.2.2); and
- MSDSI crisis supplements and other programs which provide financial assistance to lower income customers to pay their electricity bills and avoid disconnection of service (section 8.6.2.3).

8.6.2.1 Existing Measures

As noted in Table 8-6 above, BC Hydro has a number of billing mechanisms available to all customers that benefit low income customers:

- Equal Payment Plan – As outlined in section 1.5.2 of the Application, Equal Payment Plans are a service available to all customers to bill their estimated annual cost of service in equal monthly amounts over a 12-month period. As of July 2015, BC Hydro has 447,626 residential customers on Equal Payment Plans. Pre-authorized payment is not a requirement. BC Hydro's Equal Payment Plans are in substance the same as the OEB equalized billing portion of the Electricity Low Income Customer Rules;

- Pay as You Go – Pay as You Go billing is also touched on in section 1.5.2 of the Application and is set out in section 2.4 of the Electric Tariff. Pay as You Go allows monthly payments based on an estimate to be paid one month in advance. Applicants may select this plan as an alternative to providing a security deposit. BC Hydro collects one month of security in advance. As of July 2015, BC Hydro has 4,294 customers on Pay as You Go Billing;
- Instalment Plans – BC Hydro offers instalment plans to customers who are having difficulty making payments. Customers are typically requested to pay a portion of the outstanding balance immediately (typically starting at 50 per cent) and then pay the remainder over a period of up to three months. Longer terms may be offered in the event of large, unexpected charges. Overdue amounts in instalment plans do not incur further Late Payment Charges. The instalment plan automatically cancels if the customer does not pay both the instalment amount and the full amount of any new charges; however, unless there is a pattern of failed instalment plans BC Hydro typically will allow a customer to re-establish the plan because of a missed payment. In June 2015, BC Hydro established 6,047 instalment plans with 5,709 customers, with receivables totaling $4.075 million.[307] As of September 4, 2015, 2,708 instalment plans had been successfully completed and 3,249 instalment plans were cancelled with an outstanding balance of $1.539 million. The average length of instalment plans created in June 2015 was 48 days with three payment instalments of $213 each;
- Payment Deferrals – BC Hydro offers Payment Deferrals for customers who cannot pay their balances by the due date. Most payment deferrals extend customers' payment due date for a short period of time. There were 71,223 payment deferrals set up during F2015;

[307] Refer to Part 2, Question 25 of the 28 April 2015 summary notes for Workshop 9a, at Attachment 1 to the Workshop 9a/9b consideration memo at Appendix C-3B to the Application.

- Extended Payment Deferrals and Instalment Plans for Customers Receiving MSDSI Direct Employment Assistance (**EA**) – MSDSI advised BC Hydro that it cannot pay for the outstanding balance incurred prior to the time the customer started to receive EA. When a customer begins to receive direct assistance from MSDSI, BC Hydro defers any pre-EA balances in arrears indefinitely, with no further Late Payment Charge applied for as long as the customer is still receiving direct EA. For a customer with an overdue amount incurred while receiving assistance from MSDSI, BC Hydro will make payment arrangements with MSDSI. MSDSI pays 50 per cent of the overdue amount, including the reconnection charge if applicable, when the direct EA is set up and pays the remaining 50 per cent over 12 monthly instalments in addition to the customer's Equal Payment Plan bills; and
- Residential low income DSM Programs targeted towards low income customers, as outlined in section 5.6.2 of the Application.

8.6.2.2 Proposed 2015 RDA Measures

RIB Rate

As noted in section 5.2.4.3 of the Application, BC Hydro's preferred default Residential rate is the RIB rate, and the majority of BC Hydro's low-income customers are better off under the RIB rate as compared to a flat rate alternative.

Standard Charges and Security Deposits

As noted above in section 8.3.2, BC Hydro is proposing to significantly reduce the default Minimum Reconnection Charge from $125 to $30. Low income customers will benefit from the lower default Minimum Reconnection Charge.

The proposed amendment to the amount of the security deposit set out in section 8.4.2 above will benefit low income customers as it will provide BC Hydro with the flexibility in the amount that is assessed. It is recognized that the security deposit is a burden to a customer facing potential disconnection because of financial hardship. Enabling introduction of a graduated security amount rather than immediately requiring two or three times the average monthly bill will alleviate some of the financial burden while still providing an element of risk mitigation.

8.6.2.3 Work with Ministry of Social Development and Social Innovation

MSDSI provides its clients with several types of income assistance related to electricity payments, including:

- Monthly payments for EA or Persons with Disabilities Assistance, which include contributions towards shelter and utilities. In most cases payments are made directly to MSDSI's clients; however, in some instances MSDSI pays their clients' utility bills directly and deducts those amounts from their monthly assistance payments. MSDSI indicated it has approximately 130,000 clients receiving income assistance, the majority being BC Hydro customers. MSDSI directly pays BC Hydro for the electricity bills of 5,521 of those customers;
- Crisis supplements may be available where MSDSI clients have exhausted all resources and do not have the ability to maintain essential utilities for their homes when served with a disconnection notice or faced with the inability to re-establish essential utilities.[308] Essential utilities include fuel for heating, hydro, water and fuel for cooking meals. Crisis supplements may be paid to either the client or BC Hydro; and
- Supplements to pay a utility security deposit, which is usually paid directly to the client and is repayable to MSDSI with monthly instalments of $20.

[308] To be eligible, the MSDSI client must be able to demonstrate that the need for funds is "unexpected" and that failure to meet the need will result in imminent danger to the physical health of any person in the MSDSI client's family unit or the removal of a child under the B.C. *Child, Family and Community Service Act*, R.S.B.C. 1996, c.46. Refer to the Employment Assistance Regulation, B.C. Reg. 263/2002, section 59 (http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/263_2002) and the Employment and Assistance for Persons with Disabilities Regulation, B.C. Reg. 265/2002, section 57 (http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/265_2002). BCOAPO advised BC Hydro that BCOAPO's view is that this test can be difficult to establish with disconnections for non-payment of utility bills.

In F2015, BC Hydro received 78,071 payments totaling $6,770,901 directly from MSDSI. Within those payments it is not possible for BC Hydro to distinguish between crisis supplements and direct bill payments.

BC Hydro and MSDSI have recently taken steps that will provide benefits to low income customers through changes in business practices. Through a change in communications practices, the two organizations have improved their ability to identify BC Hydro customers facing potential disconnection that have applied (or will apply) to MSDSI for assistance. In these cases, BC Hydro will agree to defer disconnection pending confirmation from MSDSI, or to reconnect immediately if disconnection has already occurred. This will minimize disruption to electricity service and provide these customers with more time to obtain funds to pay their outstanding balance.

BC Hydro and MSDSI are also reviewing options that may be available to avoid assessing security deposits to MSDSI clients. BC Hydro creates instalment plans for customers with outstanding balances prior to receiving MSDSI support (as these balances remain the responsibility of the customer), as well as for customers receiving EA that are unable to keep their electricity accounts current. However, the instalment plans cancel if payments are not received, at which time the entire balance becomes due and collection notices are issued. Although the instalment plan will typically be re-established, for some very low income customers this can create a cycle of collections activity that may include the requirement to provide a security deposit. It will not be necessary to assess security deposits or commence disconnection if MSDSI is able to provide a guarantee or otherwise establish that these customers pose low credit risk.

8.6.3 Business Case

[*Note to reader – Engagement with BCOAPO is on-going on this topic, and BC Hydro's low income terms and conditions business case together with related stakeholder engagement will be provided as part of BC Hydro's responses to the first round of IRs*].