British Columbia Utilities Commission

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March 8, 2016

BC HYDRO
2015 RATE DESIGN **EXHIBIT A-22**

Mr. Tom Loski
Chief Regulatory Officer
Regulatory & Rates Group
British Columbia Hydro and Power Authority
16th Floor – 333 Dunsmuir Street
Vancouver, BC V6B 5R3

Dear Mr. Loski:

Re: British Columbia Hydro and Power Authority
Project No. 3698781/Order G-156-15
2015 Rate Design Application Module 1

Further to your September 24, 2015 filing of the above noted and the Regulatory Timetable amended in British Columbia Utilities Commission Order G-12-16, enclosed please find Commission Information Request No. 2. In accordance with the Regulatory Timetable, please file your response no later than Tuesday, April 12, 2016.

Please note that the Commission has modified its practice with respect to numbering information requests. We will apply continuous numbering through rounds of IRs for ease of reference later in the proceeding, to avoid duplicate or similar numbering. We ask that you make note of the continuous numbering and identify responses accordingly.

Yours truly,

Laurel Ross

/nd
Enclosure
cc: registered interveners

British Columbia Hydro and Power Authority
2015 Rate Design Application Module 1

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A. GENERAL

137.0 Reference: Exhibit B-5, BCUC IR 60.1, BCUC IR 60.3; Exhibit B-17, Evidentiary Update, p. 9 Energy rate and LRMC

The British Columbia Hydro and Power Authority (BC Hydro) does not consider it is necessary for a flat rate, as proposed for the medium general service (MGS) rate class, to be reflective of the Long-Run Marginal Cost (LRMC) although BC Hydro's initial estimation of an increase in demand-related cost recovery was based on targeting a flat energy rate equal to the lower end of the LRMC range.

On page 9 of the Evidentiary Update on Load Resource Balance (LRB) and Load Forecast, BC Hydro considers if updating the energy LRMC to $85/MWh may result in questions regarding whether any changes should be made to the Residential Inclining Block (RIB) rate design. BC Hydro also notes that a steady price signal is beneficial for encouraging a conservation culture and that given the continued need for capacity resources in the system, there may be merit in exploring the inclusion of a generation capacity value in the LRMC for the purpose of the RIB Step 2 rate.

137.1 Please reconcile the views that on the one hand, the target was to have the flat energy rate equal to the lower end of the LRMC and, on the other hand, BC Hydro doesn't believe it is necessary for a flat rate to be reflective of LRMC.

137.2 Please provide the data on energy LRMC, updated energy LRMC, updated energy and capacity LRMC and the proposed demand and energy rates in the Application for BC Hydro's major customer classes for F2017 in tabular format similar as shown below.

Customer Class	Residential Inclining Block Rate	Small General Service (<35 kW)	Medium General Service (≥ 35 kW and < 150 kW and energy consumption is = or < 550,000 kWh)	Large General Service (≥150 kW)	Transmission Stepped Rate Over 60kV
Proposed rates and charges	Step 1 and Step 2 energy rates: Basic charge:	Basic charge: Energy rate:	Energy rate: Demand charge: Basic charge:	Energy rate: Demand charge: Basic charge:	Tier 1 and Tier 2 Energy rates:
Proposed energy LRMC range in Application					
Proposed energy LRMC in Evidentiary Update					
Proposed energy and capacity LRMC in Evidentiary Update					

B. RESIDENTIAL RATE DESIGN AND E-PLUS

138.0 Reference: Exhibit B-5, BCOAPO IR 26.1
Sample size

BC Hydro states that for the purpose of rate modelling, where the 10 percent bill impact test is a modelling constraint, BC Hydro generally uses the representative sample of 10,000 to determine the most adversely affected customer.

138.1 What is the total number of residential customers in BC Hydro's service territory? What portion is the 10,000 sample over the total number of residential customers? Please discuss the confidence level from this sample size.

139.0 Reference: Exhibit B-5, BCUC IR 37.2
Incremental conservation

In BCUC IR 37.2, BC Hydro provided a table showing the forecast conservation savings and the "evaluated" or actual conservation from F2009 to F2012.

139.1 Please update the table for F2013 and F2014, if available.

139.2 For each of the years shown on the table in the IR response (from F2009 to F2012), the "evaluated" or actual conservation is lower than the forecast conservation. Please comment on the variance and discuss the assumptions used in the forecast and explain why the assumptions were not met.

139.3 Would BC Hydro consider revising the forecast conservation going forward? Why or why not?

140.0 Reference: Exhibit B-17, Evidentiary Update; Exhibit B-1, Application, Figure 5-18, p. 5-34
Update to LRMC

BC Hydro has reduced its forecast LRMC to $85/MWh.

Under the proposed option 1 pricing principle for RIB, the Tier 1 energy rate is higher than the $85/MWh LRMC in F2018 and F2019, and the Tier 2 price is arguably much higher in all years presented in Figure 5-18 of the Application.

140.1 Given the evidentiary update to the LRMC, does BC Hydro propose any changes to its status quo proposal for the RIB rate? For example, should the basic charge be increased? Should Tier 1 and Tier 2 energy charges be adjusted in light of the LRMC update? Why or why not?

141.0 Reference: Exhibit B-5, BCOAPO IR 26.1; Exhibit B-1, p. 2-22
Customer Focus Groups

BC Hydro explains that it held two Customer Focus Groups: In the August 2014 session, BC Hydro explains that the purpose was to canvass participants on their values (as part of BC Hydro's determination on how to prioritize the eight Bonbright criteria), and participants ranked "fairness" and

"customer understanding" and "acceptance" most highly.[1] In the February 2015 session, participants ranked "fairness" above all other values at first, and then only after viewing rate designs did "efficiency" emerge as the most important value followed closely by fairness.[2]

There were 54 participants in the first session and 50 participants in the second.

BC Hydro also stated in response to BCUC IR 6.1 that "In the context of the overall 2015 RDA, the reduced need for energy and capacity is one of the factors leading BC Hydro to prioritize customer understanding and acceptance and stable rates for customers over the Bonbright efficiency criterion."

141.1 Considering the number of participants in attendance at the Customer Focus Groups, please discuss how BC Hydro weighs and balances between the customer results, BC Hydro's own generation and capacity resource needs, and the province's energy objectives.

141.2 During these Customer Focus Groups, did BC Hydro raise any concerns relating to E-Plus rates?

142.0 Reference: Exhibit B-5, BCUC IR 6.1; Exhibit B-14, BCUC IR 43.1
E-Plus rates – problem identification

BC Hydro explained in Attachment 3 of BCUC IR 43.1 that under the current Special Condition 1 of Rate Schedule (RS) 1105, BC Hydro has the right to interrupt E-Plus service whenever there is a lack of "surplus hydro energy" and "the service cannot be provided economically from other energy sources." As a result of the language in Special Condition 1, BC Hydro explained that it has never interrupted E-Plus service.

142.1 Please clarify the underlying problems with the existing wording of the current tariff, in particular the statements in quotations above. How will the proposed amendments resolve the problems identified.

BC Hydro stated that under the proposed amendments to the Residential E-Plus rate, it "may interrupt E-Plus service if we do not have sufficient energy and capacity to serve the demand of our customers"[3] and that the proposals are for the "utility needing to derive some value from E-Plus interruptible Service…"[4]

However, in BCUC IR 6.1, BC Hydro also stated that there are a number of factors that underpin the 2015 Rate Design Application's (RDA) prioritization of the eight Bonbright criteria, including a reduced forecasted need/self-sufficiency which has led to a reduced forecasted energy and capacity need since 2007.

142.2 Please reconcile the statements above. If there has been a reduced need for energy and capacity since 2007, why is there a need to amend the tariffs in order to make E-Plus customers interruptible? What value would be derived for the BC Hydro system?

142.3 Please explain, from an operational perspective, how will BC Hydro determine that it does not have the "energy or capacity" to provide service to E-Plus customers.

[1] Exhibit B-1, p. 2-22.
[2] Exhibit B-1, p. 2-23.
[3] Exhibit B-14, BCUC IR 43.1, Attachment 5, p. 1.
[4] Exhibit B-14, BCUC IR 43.1, Attachment 1, p. 2.

143.0 Reference: Exhibit B-1, Section 5.3, p. 5-48; Exhibit B-14, BCUC IR 43.1
E-Plus - practically interruptible service

On page 5-48 and in response to BCUC IR 43.1, BC Hydro explains:

> The Residential E-Plus Amendment…will enable BC Hydro to practically interrupt the service… It is envisioned that RS 1105, if the amendments are approved by the Commission, could be used during times of high load such as during cold weather events…BC Hydro is proposing to provide an Interruption Notice giving two calendar days' notice for E-Plus Residential customers to switch to their alternative back-up systems.

143.1 If the proposed amendments are approved, what is the probability of BC Hydro interrupting an E-Plus residential customer in the next ten years? Please explain.

143.2 Please provide industry accepted definitions of planned and unplanned interruptions.

143.3 Does BC Hydro consider that an interruption with 2-days' notice to be a planned interruption? Please explain.

143.4 Please fully describe a specific situation where an E-Plus residential customer would be interrupted and would be provided two calendar days' notice, but BC Hydro would not take other mitigating action to avoid the interruption, for example, by procuring energy from the spot market, or reconfiguring feeders.

143.5 Similarly, is there a practical system situation where all E-Plus residential customers (or a very large portion of them) would be interrupted at the same time and would all be provided two calendar days' notice, but BC Hydro would not take other mitigating action? If so, please fully describe that situation and estimate the probability of such an event occurring.

143.6 Please confirm, otherwise explain, that practically speaking unplanned interruptions to all or large groups of E-Plus customers would likely be for system reliability reasons (e.g. as a last resort to maintain system stability, that is, to shed large amounts of load to maintain frequency stability under very short notice).

143.6.1 Please further confirm, otherwise explain, that for large scale unplanned interruptions, for practical reasons, E-Plus residential customers would be treated no different than firm residential customers. That is, there would not be enough time to shed E-Plus residential customers specifically in large enough numbers to support system stability.

143.6.2 Please further confirm, otherwise explain, that under large scale unplanned interruptions, transmission service customers that are part of the BC Hydro load shedding scheme are those that would be interrupted first, not E-Plus residential customers.

143.6.3 Does BC Hydro have a hierarchy of interruption for interruptible rates customers? Please describe the ranking of E-Plus customers with the other non-firm loads.

143.7 Does BC Hydro foresee circumstances where all non-firm customers could be interrupted immediately without the two days' notice in the event of, e.g., transmission capability on

Vancouver Island?

143.8 Practically speaking, is the only situation where an interruption to an individual E-Plus customer or small group of E-Plus customers that could reasonably be foreseen is a situation where:

- a radial feeder (or substation) has recently experienced high load growth;
- BC Hydro did not have enough time or resources available to implement a feeder (or substation) design change to alleviate the problem;
- a severe cold weather event is expected; and
- shedding the E-Plus residential customer(s) on the affected feeder (or on various feeders supplied by an affected substation) is the only practical solution to maintain the supply to all the other customers on that same radial feeder (or same substation) without tripping?

143.8.1 If not confirmed, please explain why not.

144.0 Reference: Exhibit B-1, Section 5.3, p. 5-51
E-Plus – peak demand and energy considerations

On page 5-51 of the Application, BC Hydro explains: "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."

144.1 How does BC Hydro design/select the size of a distribution station and feeder? Do they include E-Plus load and/or demand in their calculations? Please elaborate.

144.1.1 If BC Hydro identifies the potential for too high load or demand on a feeder (or in a substation) that has E-Plus load and demand, would BC Hydro plan upgrades to that feeder (or substation) (e.g. switch loads, replace/increase feeder size etc…), or would BC Hydro plan to curtail the E-Plus customers? Please elaborate.

144.2 If approved, would the proposed changes to the E-Plus tariff change BC Hydro's design practices? Please explain.

145.0 Reference: Exhibit B-5, CEC IR 5.1 and 5.2
E-Plus rates – impact to Load Forecast and COS

In response to CEC IR 5.1 and 5.2, BC Hydro described three major reasons for proposing to phase out the E-Plus rates over ten years in the 2007 RDA: (i) they do not recover the cost of service and therefore do not support the principle of fairness; (ii) they do not align with the need to encourage conservation; and (iii) there was no practical way to interrupt E-Plus customers during the periods when BC Hydro's system was typically constrained.

BC Hydro indicates that two of the reasons advanced in the 2007 RDA still exist, although BC Hydro is no longer in an environment of rising marginal energy costs.

145.1 The Application states that "E-Plus load should not be in the energy load forecast."[5] Please confirm whether the E-Plus load is in the energy load forecast in the 2015 annual 20-year Load Forecast.

145.2 Assuming that E-Plus services to residential customers become interruptible as a result of changes to the Special Condition, please confirm that E-Plus residential loads will no longer be included in BC Hydro's electric load forecast, and the E-Plus customers will not be included in the 4CP calculation in the cost of service (COS).

146.0 Reference: Exhibit B-1, Appendix C-3B, Attachment 6, pp. 10–13
E-Plus – investments in back-up supply

In Appendix C-3B, Attachment 6, BC Hydro explains at a high level the metering configuration for E-Plus.

146.1 Please provide one-line diagrams showing a typical residential E-Plus customer's electric supply system. On the diagram, please identify the BC Hydro electric supplies including their sizes, the meters, the back-up supply (including its size, any additional panels, switches and/or plugs required to provide the back-up supply to the home) and which items the customer pays for.

146.2 For a typical residential customer, approximately how much would it cost today to provide the most economical back-up service in the form necessary to comply with E-Plus? Approximately how much would this have cost in 1990?

146.3 What is a typical residential E-Plus customer's annual bill?

146.4 What would that typical residential E-Plus customer's annual bill be if they were under the RIB rate?

146.5 Using the above bill differentials, and assuming the customer had invested in the most economical back-up today, approximately how many years would it take for a typical residential E-Plus customer to recover their up-front investment in their back-up supply? Have these numbers changed since the 2007 RDA? Please explain.

147.0 Reference: Exhibit B-14, BCUC IR 43.1, Attachment 6, p. 2, Attachment 1, p. 2
E-Plus – customer and BC Hydro reaction

The E-Plus Homeowners Group have voiced their concern that BC Hydro's "proposed Business Practice stoke the fears of E-Plus customers that interruptions will be applied in a punitive way that is designed to drive them off the rate."[6]

147.1 Please discuss if BC Hydro agrees that there is a punitive element to this interruptible rate proposal.

147.2 Assuming that BC Hydro's proposed terms for RS 1105 are approved, what is the projected number of E-Plus residential customers who might opt for the default RIB rate due to the inconvenience of an interruptible rate.

[5] Exhibit B-1, p. 5-51. [Emphasis added]
[6] Exhibit B-14, BCUC IR 43.1, Attachment 6, p. 2.

BC Hydro indicates that non-performance by E-Plus customers could result in the customer being charged the higher of 30.37 cents/kWh energy rate set out in the "Rate" clause of RS 1105, or the E-Plus customer may be removed from E-Plus service.[7]

147.3 Please confirm that the interruption would not affect supply for non-space heating use of electricity (e.g., lighting, refrigerator, stove, water heat)?

147.4 Does BC Hydro have the ability to verify that customers under Interruption Notice would not use electric baseboards to augment any other heating fuel? Would there be instances of dispute over the 30.37 cents/kWh surcharge and could that lead to significant work and cost to BC Hydro?

148.0 Reference: Exhibit B-5, BCSEA IR 9.1; Exhibit B-1, Appendix C-3B, pp. 254, 571, 573
E-Plus rates – potential phase-out

In response to BCSEA IR 9.1, BC Hydro indicated that it rejected Option 2 – to phase out E-Plus rate over a period of time – on the basis of large bill impacts of about 40 percent, before the general rate increase. However, in Appendix C-3B on page 254 of 609, it appears that this impact is about a 10 percent increase each year over a four-year transition and about a 4 percent increase each year under a ten-year transition.

148.1 Annually for each phase-out period (the 4-year and 10-year), please provide the energy rates, total revenue, total cost, revenue shortfall and revenue to cost (R/C) ratio of the E-Plus rate?

148.2 Please identify the total additional revenue each year that would be earned if all E-Plus customers were transitioned onto the default RIB rate for all their electricity consumption, without a transition period. Given the 40 percent rate increase for E-Plus customers under this option, what is the corresponding percentage rate decrease that would be seen by non E-Plus residential customers as a result?

148.3 Please comment if BC Hydro anticipates potential adverse social consequences by interrupting residential customers' heat source (e.g. If back-up/secondary heat fails to operate as expected, adverse health implications of under heating, etc.).

148.3.1 Would it be more direct and straightforward for BC Hydro to propose an orderly phase-out of this rate instead of the proposed practical interruption? Please discuss.

148.4 The E-Plus rate was closed in 1990 and the inability to transfer to any new ownership was directed in 2008, what was the number of E-Plus customers in 1990 and in 2008 compared to the current customer count?

In Appendix C-3B on page 573 of 609 (Note 1 in BC Hydro's response to BCSEA workshop question 3.5) BC Hydro states that over the course of the E-Plus compliance initiatives activities after the 2007 RDA Decision, about 2,000 customers have come off the rate due to attrition.

148.5 Is BC Hydro able to estimate the number of years remaining for full attrition if no action were to occur?

[7] Exhibit B-14, BCUC IR 43.1, Attachment 1, p. 2.

148.6 If the Commission ordered similar compliance initiatives activities after the 2007 RDA, does BC Hydro anticipate further attrition of the E-Plus rate? If so, please estimate.

In Appendix C-3B on page 571 of 609 (BC Hydro's response to BCSEA workshop question 2.2.1) BC Hydro states that "a financial issue with respect to E-Plus rate is cross-subsidization between E-Plus and non E-Plus customers."

148.7 What are the general concerns that have been raised by non E-Plus customers about: (i) the E-Plus rate status quo; and/or (ii) interrupting customers on the E-Plus rate?

C. GENERAL SERVICE RATE DESIGN

149.0 Reference: Exhibit B-5, BCUC IR 52.1, 52.2
RS 1278

In this Application, BC Hydro has not assessed the alternative options for the one customer on this closed rate.

149.1 Please provide BC Hydro's assessment of continuing the subsidy for this rate schedule in terms of cost per kWh and annual difference in gross and net revenue recovery.

149.2 What are the reasons for the proposed phase out in 1991? Are those reasons still valid today?

149.3 Please explain BC Hydro's rationale and the fairness to other customers of continuing the rate for electric arc furnaces?

150.0 Reference: Exhibit B-5, BCUC IR 60.1, 60.2, 60.4, 62.3, 63.2
MGS demand charges

BC Hydro has proposed moving the demand-related cost recovery of MGS from 15 percent to 35 percent and stated that:

> BC Hydro's initial estimation of an increase in demand-related cost recovery was based on targeting a flat energy rate equal to the lower end of the LRMC range.[8]
>
> Economic efficiency is a largely relative criterion – prices are considered more economically efficient the closer they are to actual LRMC.[9]
>
> …more than 90 percent of customers would have a bill impact less than 10 percent under any of the demand cost recovery proposals between the existing 15 percent and the proposed 35 percent.[10]
>
> BC Hydro's decision to propose an increase in the demand charge to recover 35 per cent of demand-related costs reflects prioritization of the Bonbright fairness and customer understanding criteria:

[8] Exhibit B-5, BCUC IR 60.1.
[9] Ibid., BCUC IR 60.4.
[10] Ibid., BCUC IR 62.3.

•Fairness – improve alignment of embedded cost recovery in rates with cost causation. Increasing the level of demand charge cost recovery more fairly matches the recovery of the cost to serve a customer's peak demand with the customer's utilization of the system, but within limits based on avoiding excessive bill impacts (for example, such as associated with 100 per cent demand charge cost recovery); and

•Customer Understanding – BC Hydro's proposal leads to a general offsetting in the bill impacts of its energy and demand rate structure proposals, and in particular with respect to customers with high utilization and load factor.[11]

150.1 Focusing on the table in response to BCUC IR 60.2, please provide BC Hydro's assessment of the trade-offs between the Bonbright criteria for the demand cost recoveries identified and the resultant energy rates. Does BC Hydro have a strong preference among the options? Why?

151.0 Reference: Exhibit B-5, BCOAPO IR 144.3
MGS basic charge

BC Hydro stated that "Approximately 9 per cent of customer-related costs assigned to the MGS class are recovered through the basic charge."

151.1 Please discuss whether BC Hydro has considered raising the current MGS basic charge from its existing rate towards a basic cost recovery similar to the Residential and small general service (SGS) classes? Does BC Hydro have a strong preference between the options of 9 percent or 45 percent cost recovery of the customer related costs in the basic charge? Why?

152.0 Reference: Exhibit B-5, BCOAPO 150.2
Large general service (LGS) basic charge

BC Hydro stated that "Approximately 7 per cent of customer-related costs assigned to the LGS class are recovered through the basic charge."

152.1 Please discuss whether BC Hydro has considered raising the current LGS basic charge from the existing rate towards a basic cost recovery similar to the SGS class? Does BC Hydro have a strong preference between the options of 7 percent or 45 percent cost recovery? Why?

153.0 Reference: Exhibit B-5, CEC 60.1
MGS and LGS demand ratchet

BC Hydro discussed the reasons why it considers it is important to have a demand ratchet for MGS and LGS customers, even though it affects a very small percentage of customers and collects little revenue.

153.1 Can BC Hydro's billing programs automatically calculate individual customer demand ratchet charges? If not, is it cost effective to have a demand ratchet?

[11] Ibid., BCUC IR 63.2.

154.0 Reference: Exhibit B-17, Evidentiary Update, p. 1
LRMC – general service

BC Hydro has reduced its forecast LRMC to $85/MWh.

154.1 Recognizing that the forecast LRMC is considerably below the SGS proposed energy charge, does BC Hydro propose any changes to its SGS proposal in the Application? For example, would BC Hydro consider increasing the basic charge to recover more than 45 percent of customer related costs or should a demand charge be introduced? Why?

154.2 Does BC Hydro suggest any changes to its MGS or LGS proposals as a result of the reduced LRMC? Why?

D. TRANSMISSION SERVICE RATE DESIGN

155.0 Reference: Exhibit B-5, BCUC IR 100.1
Real Time Pricing (RTP)

BC Hydro provided an example of the asymmetry of RTP of Mid C market rates for excess consumption over baseline and RS 1823 Tier 2 credits for consumption below baseline. BC Hydro also stated:

> In this example, there's an asymmetry because increases in load cost the customer $35/MWh while decreases in load are credited at $85/MWh. For such a rate to work, the decreases in load must be firm and result in a decrease in BC Hydro's long run costs while the increases in load must be non-firm and result in no increases in BC Hydro's long run costs. As stated in the Workshop 5 consideration memo at page 129, Appendix C-5A of Exhibit B-1, BC Hydro has already taken steps to acquire resources to meet its long term load forecasts. An RTP rate that converts a portion of this firm load growth to non-firm risks stranding investment that is already in service, under construction, or that BC Hydro has committed to build.

155.1 Based on BC Hydro's most recent LRB projections and its commitments to build or purchase new supply to meet its long term load forecast, in what year would an RTP rate that converts a portion of load from firm to non-firm not risk stranding assets?

156.0 Reference: Exhibit B-5, BCUC IR 116.1
RS 1880 – standby and maintenance

BC Hydro updated its best estimate of an administrative charge per incident from $150 to $174.

156.1 Please confirm that BC Hydro will now propose the $174 administrative charge per incident. If not, why not?

157.0 Reference: Exhibit B-5, BCOAPO IR 160.4
RS 1823 – options for Tier 1 and Tier 2 energy pricing

BC Hydro updated its estimates of under and over recovery of revenue targets for the three options for RS 1823 energy pricing and stated that:

The following table shows the rates for the three RS 1823 pricing principle options shown in Table 7-3 of Exhibit B-1, the resulting forecast revenues and the resulting under/over recovery of revenue compared to the revenue targets calculated in BC Hydro's response to BCOAPO IR 1.160.3. Please note that these estimates replace the revenue impacts of the three options reported in section 7.2.3.1, page 7-13 of Exhibit B-1 and in Attachment 4 to the Workshop 5 consideration memo. The earlier analysis did not use the same rates as in Table 7-3 of Exhibit B-1 or the October 2014 Load Forecast for the Tier 1 and Tier 2 forecast loads.

The results for Option 1 shown in the table to IR response BCOAPO 160.4 show that the under recovery of revenue in F2017 due to the bill neutrality definition persists in F2018 and F2019. This is because the rates are only escalated by the revenue requirements application increase in F2018 and F2019 and do not account for the shortfall in revenue in F2017. Thus, footnote 262 on page 7-13 appears to be incorrect in stating that "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."

157.1 Do the relatively small changes to revenue over/under collection of the three options impact BC Hydro's preference for the customer bill neutrality approach to determine RS 1823 rates? Why?

158.0 Reference: Exhibit B-17, Evidentiary Update, p. 1
LRMC – transmission service rate (TSR)

BC Hydro has reduced its forecast LRMC to $85/MWh.

158.1 Does BC Hydro suggest any changes to its TSR and other transmission rate schedules (e.g., RS 1825, RS 1880) proposals as a result of the reduced LRMC? Why?

E. ELECTRIC TARIFF TERMS AND CONDITIONS/LOW INCOME TARIFFS

159.0 Reference: Exhibit B-5, BCUC IR 120.1, 120.2
Minimum Connection Charges – Total Labour

BC Hydro provided the breakdown of the loaded standard labour rate (SLR) of $143.57 in response to BCUC IR 120.1.

In response to BCUC IR 120.2, BC Hydro stated that one of the reasons for the increase in SLR from $65.08 in the 2007 RDA to $143.57 in the 2015 RDA is: "A change in loading methodology on distribution work."

159.1 Please provide the same breakdown of the $65.08 loaded SLR from the 2007 RDA which was provided in response to BCUC IR 120.1. Please explain the causes of the increase in each of the line items.

159.2 Please further explain the change in loading methodology on distribution work and how this has impacted the loaded SLR. Please also explain why BC Hydro made this change in methodology and why it is more appropriate than its previous methodology.

160.0 Reference: Exhibit B-5, BCUC IR 119.3
Minimum Connection Charges – 400A Overhead

BC Hydro states in response to BCUC IR 119.3 that it proposes eliminating the 400A standard charge "primarily to avoid misleading customers as the 400A charge typically requires additional work, and therefore additional costs of construction beyond the charge set out in the Standard Charges."

160.1 What is the net revenue difference between the status quo (i.e. leaving the 400A Overhead Minimum Connection Charge in the standard charges) and BC Hydro's proposal to address service requests through section 8 of the Electric Tariff? Please show all calculations and explain all inputs.

160.2 Did BC Hydro consider, as an alternative to eliminating the 400A standard charge, providing additional communication/wording regarding the potential additional costs in the tariff? If yes, please explain why BC Hydro determined this approach was not appropriate. If no, please explain why not and please discuss whether such an approach could be taken.

160.3 Please discuss the potential risks and drawbacks of addressing the 400A service requests through section 8 of the Electric Tariff.

161.0 Reference: Exhibit B-1, Section 8.3.2, p. 8-11;
Exhibit B-1-1, Attachment 2 - Electric Tariff Amendments – Clean, Sections 6.7, 11.3
Minimum Reconnection Charge

BC Hydro stated on page 8-11 of the Application: "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."

161.1 Please explain whether BC Hydro's use of the <u>full cost</u> of the manual disconnection and reconnection by power line technicians (PLT) for the Minimum Reconnection Charge is consistent with the calculation of other additional charges related to access refusals.

161.1.1 Please provide a list of all standard charges which are based on the full cost instead of being based on a blended charge.

Section 6.7 of BC Hydro's Electric Tariff states: "BC Hydro may add to the Minimum Reconnection Charges set out in section 11.3 (Minimum Reconnection Charges), an amount to cover the costs incurred by BC Hydro when there are unusual circumstances."

Section 11.3 of BC Hydro's Electric Tariff provides the $700.00 per meter charge with the following description: "Manual reconnections at the Point of Delivery because the Customer failed to provide access to the meter."

161.2 Please discuss the advantages and disadvantages of providing a more fulsome description in the Electric Tariff to clarify the statement that the Customer "failed to provide access to the meter."

161.3 Please discuss whether applying the full cost to the access refusal reconnection charge raises potential issues of fairness given that the other Minimum Reconnection Charges are calculated using a blended charge.

162.0 Reference: Exhibit B-5, BCUC IR 125.1, 125.3
Late Payment Charge - $30 threshold

BC Hydro stated in response to BCUC IR 125.1 that New Brunswick Power does not assess a Late Payment Charge unless it is a minimum of $0.50, which at a rate of 1.25 percent equals a minimum outstanding balance of $40.

BC Hydro further stated in response to BCUC IR 125.3 that an overdue balance has to be greater than $59 for the Late Payment Charge to be sufficient to recover the cost of the Late Payment Notice letter.

162.1 Has BC Hydro considered increasing the Late Payment Charge threshold? Please discuss the pros and cons of increasing the threshold.

162.2 If BC Hydro were to propose an increase to the threshold, what amount would it be and why?

162.3 Based on BC Hydro's response to BCUC IR 125.3, please confirm, or explain otherwise, that in order for BC Hydro to "break-even" when assessing a late payment charge, the overdue bill must be at least $59.

163.0 Reference: Exhibit B-5, BCUC IR 127.1, 127.4; Exhibit B-1, Appendix G-1B, p. 9
Returned Payment Charge

In response to BCUC IR 127.1, BC Hydro indicated that the number of returned payments in F2015 is 11,892.

BC Hydro stated in response to BCUC IR 127.4 that the Returned Payment Charge was assessed 6,472 times.

163.1 Please explain why, if the total number of returned payments in F2015 was 11,892, the Returned Payment Charge was only assessed 6,472 times.

On page 9 of Appendix G-1B, BC Hydro provides the calculation for the Returned Payment Charge.

163.2 Are there any other direct or indirect costs incurred by BC Hydro for the handling of returned cheques and electronic funds transfer which have not been included in the Returned Payment Charge calculation? If yes, please provide a breakdown of these additional costs with supporting calculations and descriptions.

164.0 Reference: Exhibit B-1, Section 8.3.5, p. 8-15; Exhibit B-5, BCUC IR 128.6, 128.7
Account charge

In response to BCUC IR 128.6, BC Hydro stated:

> …the IT requirements for a differentiated account charge for new customers, versus existing customers who move, would be more than originally thought. For example, configuring the billing system to distinguish between a new customer and an existing customer during the online move-in process would be challenging, in light of name changes, name variations, and gaps in service.

164.1 Please further elaborate and quantify where possible the required investment and effort that would be required to implement a differentiated account charge for new customers versus existing customers who move.

BC Hydro states on page 8-15 of the Application: "Costs have increased since the 2007 RDA because of general increase 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."

In response to BCUC IR 128.7, BC Hydro stated that of the F2015 fees paid to Equifax for credit checks and ID validation of $442,804, the amount related to the ID validation which BC Hydro plans to implement in F2016 or early F2017 is $315,622.

164.2 For F2015, how much does BC Hydro estimate it will incur in bad debt costs resulting from accounts being created in fraudulent names? How does this amount compare to F2007? Please quantify and discuss.

164.3 Does BC Hydro anticipate that the savings expected from the mitigation of accounts being created in fraudulent names will offset the cost of introducing the Equifax ID validation software? Please explain and provide an analysis of the payback period of this software investment.

164.4 Please explain how BC Hydro determined that implementation of the Equifax ID validation software was the most appropriate course of action for addressing the creation of accounts under fraudulent names.

164.4.1 Please describe other options, if any, which were explored by BC Hydro, including whether other ID validation software options were considered.

164.5 Did BC Hydro have a process/system in place to perform ID validation prior to the introduction of the Equifax ID Validation software? Please explain.

165.0 Reference: Exhibit B-1, Section 8.4, pp. 8-20 to 8-21;
Exhibit B-1-1, Attachment 2, Section 2.6.3
Security deposits

On page 8-20 of the Application, BC Hydro states:

> …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…
>
> …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 actual consumption is found to be significantly higher than the consumption that was estimated when the account was created.

Section 2.6.3 of Attachment 2 of Exhibit B-1-1 provides the revised Electric Tariff Terms and Conditions

related to Security Deposits.

165.1 Please specifically reference the revised wording in Section 2.6.3 of the Electric Tariff Terms and Conditions which provides BC Hydro with the ability to assess a further security deposit (i.e. change the amount of an existing security deposit) if it is determined at a later date through actual consumption that a customer's account is under-secured.

166.0 Reference: Exhibit B-1, Section 8.5, p. 8-22; Exhibit B-1-1, Attachment 2 – Electric Tariff Amendments – Clean, Section 1.2, pp. 15, 20–25
Disconnection versus Termination

On page 8-22 of the Application, BC Hydro states that it 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" and that examples include "additional and revised definitions for improved clarity and readability."

As part of the proposed revisions to the Electric Tariff Terms and Conditions, BC Hydro has added the following two terms: "Disconnection" and "Termination" which are defined separately in Section 1.2.

Additionally, BC Hydro proposes changes to Section 2.7 – Termination of Service by Customer and proposes a new section, Section 2.9 – Customer Request for Disconnection.

166.1 Please explain how the revisions to the Electric Tariff described in the above preamble are expected to improve the customer's understanding and achieve greater clarity and readability.

166.2 What other purpose, beyond improved understanding/clarity/readability, do the changes to the terms and conditions related to Disconnection and Termination serve? Please explain.

166.3 Please explain, in greater detail, the difference between the terms "Termination" and "Disconnection".

166.4 Please clarify at what point, if ever, a termination request would result in a physical disconnection of service.

166.4.1 If a customer terminates their account, when will BC Hydro physically disconnect the service if no new application for service is received?

166.5 Please describe any customer service protocols BC Hydro plans to implement, or has already implemented, to ensure customers understand the distinction and applicability of a Disconnection versus a Termination.

167.0 Reference: Exhibit B-1-1, Attachment 2 – Electric Tariff Amendments – Clean, Section 1, pp. 17, 20
Definition of Month and Two Months

BC Hydro defines a Month as "a period of from 27 to 33 consecutive days" and "Two Months" as "a period of from 54 to 66 consecutive days."

167.1 Please explain BC Hydro's rationale for defining a month and two months. Please explain whether or not BC Hydro has considered revising the definition to reflect a calendar month (i.e. not exceeding 31 days). If not, why not?

168.0 Reference: Exhibit B-1-1, Attachment 2, Section 7.2
Power factor requirements

168.1 Please identify and explain the rate-related mechanisms BC Hydro uses to encourage medium and large general service customers to maintain their power factor at efficient levels. Please include a discussion addressing whether BC Hydro considers that the power factor of these customer classes are at sub-optimal levels and if more could be done through rate design to encourage efficient behaviour.

169.0 Reference: Procedural Conference Transcript, Volume 1, p. 33
Low-income Terms and Conditions

Mr. Godsoe of BC Hydro stated on page 33 of the Procedural Conference transcript:

> Currently, BC Hydro is not seeking an order with respect to potential low-income terms and conditions, but that could change, subject to the Round 2 IRs and continued discussions with British Columbia Old Age Pensioners and other interested interveners.

169.1 Based on the statement referenced in the above preamble, does BC Hydro consider the Commission to have the jurisdictional authority to approve either low-income terms and conditions or a low-income rate? Please explain why or why not and provide the supporting material.

F. RATE DESIGN EVALUATION AND EVIDENTIARY UPDATE ON LRB AND LRMC

170.0 Reference: Exhibit B-1, Section 2.4, p. 2-57, Section 5.2, p. 5-35, Section 6.2, p. 6-10, Section 6.3, p. 6-24, Section 6.4, p. 6-50, Section 7.2, p. 7-5
Evaluation framework - general

BC Hydro describes the Bonbright framework on page 2-57 of the Application. On page 5 of the Commission decision on the BC Hydro Residential Inclining Block (RIB) Rate Re-Pricing Application, the Commission lists eight "Bonbright Principles."[12] These principles were also included, among others, in the Commission's 2014 decision on the BC Hydro RS 3808[13] and the Commission's decision on the FortisBC Inc. (FBC) 2009 Rate Design and Cost of Service Application.[14]

Rate design principles are also addressed in the Commission's decision on the BC Hydro 2007 Rate Design Application (RDA)[15] and the Commission's February 1, 2016 reasons for decision related to this proceeding.[16]

170.1 For each of the six proposals listed below, please complete a table which evaluates the rate proposal against each of the eight Bonbright principles (including brackets) listed on page 2 of Appendix A to BCUC IR No. 2. For each evaluation, please describe the rate proposal effects (whether the effect is favourable/unfavourable/neutral and, where possible, quantify). For each

[12] Appendix A to BCUC IR No.2, p. 2.
[13] Appendix B to BCUC IR No. 2, p. 2.
[14] Appendix C to BCUC IR No. 2, pp. 2, 3.
[15] Appendix D to BCUC IR No. 2, pp. 2, 3.
[16] Appendix E to BCUC IR No. 2.

rate proposal, please rank the eight Bonbright principles from most important to least important.

- BC Hydro's proposed residential rate compared to Option 2 as described on page 5-35 of the Application.
- BC Hydro's proposed SGS rate compared to the status quo.
- BC Hydro's proposed MGS rate, compared to the sensitivity rate option as shown on page 6-24 of the Application (demand charge of $2.14/kW) which keeps demand related cost recovery at approximately 15 percent.
- BC Hydro's proposed LGS rate, compared to the sensitivity rate option as shown on page 6-50 of the Application (demand charge of $8.35/kW) which keeps demand related cost recovery at approximately 50 percent.
- BC Hydro's proposed LGS rate, compared to a rate with the same basic charge, a demand charge of $2.14/kW (equal to the MGS sensitivity rate demand charge), and remaining costs recovered in a flat energy charge.
- BC Hydro's proposed stepped transmission rate (RS 1823) on a stand-alone basis.

Bonbright Criteria (from Order G-45-11)	**Evaluation**	**Ordinal Ranking**
Principle 1: Recovery of the revenue requirement		
Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates)		
…		
Principle 8: …	.	

170.2 For each of the six rate proposals evaluated, please provide a summary evaluation which states whether the rate is supported/not-supported overall (against the Bonbright evaluation framework described on page 2 of Appendix A to BCUC IR No. 2, including the brackets), and note the key trade-offs made.

170.3 Please evaluate BC Hydro's proposal to interrupt E-Plus customers against the Bonbright evaluation framework described on page 2 of Appendix A to BCUC IR No. 2.

171.0 Reference: Exhibit B-1, Section 2.4, p. 2-57; Exhibit A2-2, pp. 480, 481, 511–513; Exhibit A2-3, pp. 198, 216
Evaluation framework: fairness "intra-class" definition

BC Hydro proposes application of the fairness criteria to rate structures includes: "Intra-class: Cost causation, including cost recovery through fixed versus variable charges."[17]

The Commission's rate design principles in the BC Hydro RIB Re-Pricing Application included principle 8: "Avoidance of undue discrimination (interclass equity must be enhanced and maintained)."[18] The Commission's decision on BC Hydro's 1991 Rate Design Application describes BC Hydro's rate design objectives, which include: "Fairness of specific rates in the apportionment of total cost of service among the different rate payers so as to avoid arbitrariness and to attain equity" and states "A FACOS study is

[17] Exhibit B-1, Section 2.4, p. 2-57.
[18] Appendix A to BCUC IR No. 2.

used to measure the extent to which the revenues contributed by a particular customer class cover the historical costs attributed to serving that customer class."[19]

The Commission's decision on the BC Hydro 2007 RDA states: "[BC Hydro explains that] Fair means that each customer bears a fair share of the costs caused by that customer, to the extent practicable" and describes the purpose of the Fully Allocated Cost of Service (FACOS) study.[20] FBC describes the purpose of the FACOS study in the Commission's decision on the FBC 2009 rate design and cost of service analysis.[21]

Bonbright, in the *Principles of Public Utility Rates* (1988), provides guidance on the reliance of fully distributed costs for rate design[22] and states on pages 511 and 512:

> In our opinion, these merits [of using fully distributed cost apportionment as points of departure for public utility ratemaking] are so dubious that they fully justify the skepticism with which utility cost analysis has been received by public utility companies and public service commissions. … Among the more specific deficiencies … three seem especially serious. …the really important analysis are … analysis designed to disclose differential, or incremental, or marginal, or escapable costs … It is these costs which should be the primary object of study of the utility cost analyst.

171.1 Please explain: (i) what BC Hydro means by "Intra-class: Cost causation, including cost recovery through fixed versus variable charges"; (ii) whether this is a duplication of Order G-45-11 Bonbright principle No. 8; and (iii) whether this is consistent with the fairness evaluation principle used by BC Hydro in the 1991 and 2007 BC Hydro RDA.

171.2 Does BC Hydro consider Bonbright (1988) to be generally supportive of using fully allocated cost studies (as opposed to marginal costs) as a point of departure for rate design purposes (i.e., setting demand charges)? Please explain.

171.2.1 For each of the three "especially serious" deficiencies identified by Bonbright on pages 511 to 512 of Bonbright (1988), please explain whether they apply to any of BC Hydro's rate proposals.

171.2.2 Please describe the purpose of the FACOS study, and explain whether there has been a change in purpose compared to the 1991 and 2007 BC Hydro RDAs. Specifically, was the FACOS study used to set demand charges in 1991 and 2007?

171.3 Hypothetically, if fully allocated costs are not used as a point of departure for rate design (i.e., setting demand charges), please explain: (i) whether this would affect BC Hydro's SGS/MGS/LGS rate design proposal, and if so, how; and (ii) the relevance of the FACOS study to this proceeding.

The California Public Utilities Commission (CPUC) July 3, 2015 Decision 15-07-001 discusses use of the extension policy and minimum bills (instead of fixed charges) on pages 198 and 216.[23]

171.4 For SGS/MGS/LGS commercial customers, please discuss whether: (i) a minimum bill/demand

[19] Appendix F to BCUC IR No. 2, pp. 2, 4.
[20] Appendix D to BCUC IR No. 2, pp. 2, 4.
[21] Appendix C to BCUC IR No. 2, p. 4.
[22] Exhibit A2-2, Extract E, pp. 480, 481, 511–513.
[23] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF, Exhibit A2-3, Extract D.

ratchet; and/or (ii) the extension policy, instead of higher fixed charges, could address any intra-class fairness concerns.

172.0 Reference: Exhibit B-1, Section 5.2, p. 5-41, Section 6.2, p. 6-12, Section 6.3, p. 6-24, Section 6.4, p. 6-50, Section 7.2, p. 7-16, Appendix C-3B, p. 28; Exhibit B-5, BCOAPO IR 40.5, BCUC IR 73.1; Exhibit A2-3, pp. 190, 191, 214; Exhibit A2-2, p. 512 Evaluation framework: fairness "intra-class" cost recovery percentages

Bonbright (1988) states on page 512 of Exhibit A2-2 "Here, too, one may suspect that the choice of the formula depends, not on principles of cost imputation but rather on types of apportionment which tend to justify whatever rate structure is advocated for non-cost reasons."

BC Hydro stated in response to BCUC IR 73.1, regarding the LGS demand charge: "There is not a 'correct' level of demand-related cost recovery to target in isolation of other factors."

The CPUC Decision 15-07-001 discusses linking fixed charges to costs, and states: "…we find that a fixed charge linked to costs that do not change as a result of individual customer usage is not appropriate unless certain requirements are met. These requirements include … establishing a consistent methodology across utilities."[24]

In BCOAPO IR 40.5, BC Hydro models the effect of six different cost allocation methodologies, including the minimum system method and the zero intercept method. In Appendix C-3B of the Application, BC Hydro compares BC Hydro and FBC residential fixed charges.

Staff have prepared the following table showing the linkage between BC Hydro's proposed rates and FACOS allocated sunk costs:

Rate Design	FACOS fixed cost category	Percentage recovery in fixed charge	Reference (Exhibit B-1)
Residential	Customer related costs	45%	Page 5-41
SGS	Customer related costs	33% currently, 45% proposed	Page 6-12
MGS	Demand related costs	15% currently, 35% proposed	Page 6-24
LGS	Demand related costs	50% currently, 65% proposed	Page 6-50
Transmission	Demand related costs	65%	Page 7-16

172.1 Please confirm the accuracy of the table above, or explain otherwise.

172.2 Please explain why, in the table above, the proposed: (i) fixed cost category; and (ii) percentage recovery of fixed costs in fixed charges, varies by customer class. Specifically, were these cost categories and percentages chosen for non-cost reasons?

172.3 Please update the table above to show how the percentage recovery of fixed costs in fixed charges would change if the FACOS cost allocation methodology was changed to the methodology in place: (i) in the 2007 BC Hydro RDA; and (ii) in the 1991 BC Hydro RDA. Please explain any significant changes.

[24] Exhibit A2-3, Extract C, pp. 190, 191, 214..

172.3.1 Does BC Hydro consider that linking fixed charges to a set percentage of FACOS fixed costs could result in rate instability over time as costs, load profiles and allocation methods change? Please explain.

BC Hydro shows on page 28 of Appendix C-3B to the Application that its residential fixed charges are $5/month and represent 45 percent of BC Hydro's total allocated fixed costs, while FBC's residential fixed charges are $15/month ($30.33/60 days) and represents 44 percent of their total allocated fixed costs.

172.4 Is BC Hydro aware of any significant difference in FACOS methodology between BC Hydro and FBC that could account for similar percentages of total allocated fixed costs while resulting in different fixed residential charges? If yes, please explain and comment on whether both FACOS allocation methodologies could be considered fair.

172.4.1 Is BC Hydro aware of whether the six different cost allocation methodologies described in BCOAPO IR 40.5 are considered acceptable approaches of allocating fixed costs in other jurisdictions? Would adoption of these alternative approaches by BC Hydro have a material effect on the percentages recovery of fixed costs in fixed charges? Please explain.

173.0 Reference: Exhibit B-1, Section 2.4, p. 2-57; Exhibit A2-2, p. 475; Exhibit B-5, BCUC IR 82.3, FBC IR 5.2
Evaluation framework: undue discrimination definition

BC Hydro describes the "Avoid undue discrimination" principle on page 2-57 of the Application as: "… rate structures must not be divorced from the nature and quality of the associated service, including cost of service." The Commission's decision on BC Hydro's 1991 RDA describes BC Hydro's rate design objectives which include: "Avoidance of undue discrimination in rate relationships."[25] The Commission's decision on the BC Hydro 2007 RDA describes BC Hydro's rate design principles which include: "avoidance of undue discrimination."[26]

Bonbright (1988) on page 475 states: "To the extent that prices differ from the marginal cost of producing, selling, storing, and delivering service (with due allowance for risk and uncertainty), they are discriminatory. Therefore, a good working rule is that rates should deviate as little as possible from marginal costs, if the utility's revenue requirement is met."[27]

BC Hydro stated in response to BCUC IR 82.3 "…for [MGS] customers with the same demand, the high load factor customers is subsidizing the low load factor customers, other consumption patterns being equal" and in FBC IR 5.2 that 15 transmission service customers have a revenue to cost (R/C) ratio exceeding 170 percent.

173.1 Please explain what is meant when BC Hydro refers to "avoid undue discrimination" principle in the cost of service. Specifically, does BC Hydro consider that to avoid undue discrimination within a rate class, rate structures should not be divorced from: (i) embedded costs; and/or (ii) marginal costs?

[25] Appendix F to BCUC IR No. 2, p. 2.
[26] Appendix D to BCUC IR No. 2, p. 2.
[27] Exhibit A2-2, Extract D.

173.1.1 Does BC Hydro consider that Bonbright (1988) supports rate structures reflecting marginal costs (not embedded costs) to avoid discriminatory pricing? Please explain.

173.1.2 Please explain how BC Hydro interpreted the Bonbright undue discrimination principle in the 1991 and 2007 BC Hydro RDAs, and whether there has been any change in the interpretation of this principle for this Application.

173.2 Please explain whether BC Hydro's statement in BCUC IR 82.3 (that high load factor MGS customers are subsidizing the low load factor customers) was based on a comparison of inter-class revenues to embedded costs or marginal costs.

173.2.1 To what extent would BC Hydro's assessment of the existence of a subsidy change if the analysis compared, for high load factor and low load factor MGS customers, inter-class revenues with the marginal cost to serve these customer segments? Please explain.

174.0 Reference: Exhibit B-1, Section 2.4, p. 2-57; Exhibit A2-2, p. 383; FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan (LTRP) proceeding, Exhibit B-1, pp. 20, 21 Evaluation framework: efficiency – definition (environment and energy policy)

On page 2-57 of the Application, BC Hydro defines efficiency as: "Price signals that encourage efficient use and discourage inefficient use." The Commission's rate design principles for the BC Hydro RIB Re-Pricing Application included as principle 3: "Price signals that encourage efficient use and discourage inefficient use *(*consideration of social issues including environmental and energy policy*)*."[28]

Bonbright (1988) includes principle 5 on page 383: "Reflection of all the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities)."[29]

The Commission's decision on the BC Hydro RS 3808 application states: "The Panel also considers any effect on British Columbia social issues, including environmental and energy policy."[30]

In the FEU 2014 LTRP Application, FEU provides a comparison of gas rates to BC Hydro Step 1 and Step 2 electricity rates[31] and a comparison of the cost difference for space and water heating – natural gas vs. electricity.[32]

174.1 Please explain why BC Hydro has omitted "(consideration of social issues including environmental and energy policy)" from its efficiency definition on page 2-57 of the Application.

174.1.1 When evaluating alternative rate options, did BC Hydro include consideration of social issues, including environmental and energy policy (specifically, the conservation and provincial GHG reduction goals included in the *Clean Energy Act* and BC's energy objectives, and the 2007 Energy Plan objectives)? Please elaborate for each rate class and discuss any trade-offs.

[28] Appendix A to BCUC IR No. 2. [Emphasis added]
[29] Exhibit A2-2, Extract A.
[30] Appendix B to BCUC IR No. 2, p. 3.
[31] FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan (LTRP) proceeding, Exhibit B-1, Figure 2-5, p. 20.
[32] FEU 2014 LTRP proceeding, Exhibit B-1, Table 2.1, p. 21.

174.2 Does BC Hydro consider that electricity is currently cost competitive with natural gas for residential space and water heating? Please explain.

174.2.1 Does BC Hydro consider that rate design options which further increase residential Tier 2 prices beyond BC Hydro's proposal could result in an increase emissions in BC as a result of customer fuel switching to natural gas? Please explain.

175.0 Reference: Exhibit B-1, Section 2.4, p. 2-57; Exhibit A2-2, pp. 383, 384; Exhibit B-5, BCUC IR 53.3, 60.3 Evaluation framework: efficiency – definition (discouraging waste)

On page 2-57 of the Application, BC Hydro describes its proposed application of the Bonbright efficiency criteria to rate structures as "Energy [LRMC] reference; energy conservation (total GWh)." The Commission's decision on BC Hydro's 1991 RDA describes BC Hydro's rate design objective 4 (static efficiency of rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use) and 8 (dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns).[33]

The Commission's decision on BC Hydro's 2007 RDA states: "[BC Hydro explains that] Efficient means that the rates and Terms and Conditions provide efficient price signals at the margin, including appropriate price signals to encourage energy conservation and load management, to the extent practicable."[34]

Bonbright (1988) includes on page 383 and 384 principle 4 (static efficiency) and 8 (dynamic efficiency).[35]

BC Hydro stated in BCUC IR 53.3 that the SGS flat energy rate is not intended to signal BC Hydro's energy LRMC, and in BCUC IR 60.3 that it is not necessary for the MGS flat rate to be reflective of LRMC.

The Commission's decision on the BC Hydro RS 3808 application described efficiency benefits as promotion of: (i) efficient customer consumption and investment decisions; (ii) efficient utility investment and operational decisions; and (iii) innovation. The Commission states in the May 2014 decision on the FBC application for stepped and stand-by rates for transmission voltage customers: "…the key question … is whether the Stepped Rate promotes efficient customer behaviour rather than merely results in less electricity consumption."[36]

175.1 Please explain to what extent reliance should be placed on an "energy LRMC reference; energy conservation" being indicative of a rate design that will encourage efficient use and discourage inefficient use. Please consider and discuss the following in the response:

- complex rate designs such as the existing MGS/LGS conservation rates;
- rate designs for customers who are not price responsive or have short-pay back periods;
- rate designs where the customers are considering short-term operational decisions (such as a temporary increase/decrease in production);

[33] Appendix F to BCUC IR No. 2, p. 2.
[34] Appendix D to BCUC IR No. 2, p. 2.
[35] Exhibit A2-2, Extract A.
[36] Appendix B to BCUC IR No. 2, p. 3 and Appendix G to BCUC IR No. 2, p. 2.

- rate designs where customers can fuel switch or otherwise bypass BC Hydro's network; and
- rate designs where the customer responds to the total electricity bill as opposed to the incremental price.

176.0 Reference: Exhibit B-1, Section 2.3, p. 2-46; Exhibit B-5, BCUC IR 6.1; Exhibit A2-2, pp. 473–475; BC Hydro 2013 Integrated Resource Plan (IRP), Table 9-5, p. 9-11; Exhibit B-17, Evidentiary Update, p. 9 Evaluation framework: efficiency – appropriate marginal costs

In the Application, BC Hydro states: "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 states in its evidentiary update: "BC Hydro notes that a steady price signal is beneficial for encouraging a conservation culture. …there may be merit in exploring the inclusion of a generation capacity value in the energy LRMC for the purpose of the Residential Inclining Block Step 2 rate."

Bonbright (1988) on pages 473-475 discusses appropriate marginal costs and states "Clearly, peaking is relevant to the proper calculation of marginal cost."[37]

Table 9-5 in BC Hydro's 2013 IRP shows expected capacity savings from rate structures.

176.1 Please provide BC Hydro's planned energy and capacity savings from rate design as included in the 2013 IRP.

176.2 When BC Hydro refers to "energy LRMC" on page 2-57 of the Application, does BC Hydro mean that avoidable generation capacity and network capacity costs should not be a relevant consideration in a Bonbright efficiency analysis, or does "energy LRMC" instead refer to a specific rate design pricing principle that could change over time? Please explain.

BC Hydro stated in response to BCUC IR 6.1 that forecast spot market prices are relevant to non-firm (interruptible) rates. The Commission's May 2014 decision on the FBC application for stepped and stand-by rates for transmission voltage customers[38] discusses non-firm service and states "The Panel finds that FortisBC does not have to provide non-firm service given there are no benefits to FortisBC of doing so even if it is what the customer is requesting."

176.1 Please identify BC Hydro's non-firm rates, and for each non-firm rate explain whether any discount provided relative to the firm rate generally reflects: (i) the value of generation and network capacity to BC Hydro; (ii) the discount required to incent additional efficient consumption that would not occur at the full rate (with the non-firm nature of the tariff being used to discourage free-riders from accessing the discounted rate); or (iii) another reason (if so please explain).

[37] Exhibit A2-2, Extract C.
[38] Appendix G to BCUC IR No. 2, p. 5.

177.0 Reference: Exhibit B-1, Section 2.3, p. 2-55; Exhibit A2-4, pp. 1, 9; Draft seventh Northwest Conservation and Electric Power Plan, Appendix G, p. G-15[39]; ACEEE, Everyone Benefits, 2015, pp. 6, 21[40] Evaluation framework: efficiency – capacity LRMC estimate/losses

In the Application, BC Hydro states that including a capacity cost value would increase the energy LRMC by about $11/MWh ($F2013), and that FBC's 2015/2016 Demand Side Management (DSM) filing included a capacity estimate of $36.60 kW/year as a proxy to represent the value of avoided network costs.

Avoided network costs are discussed in the Commission's 2008 decision on BC Hydro's RIB rate application[41] and capacity benefits in the Commission's 2016 decision on the transmission service freshet pilot.[42]

On October 23, 2014, Mendota Group report titled *Benchmarking Transmission and Distribution [T&D] Costs Avoided by Energy Efficiency Investments,* states on page 1: "Utilities have used a number of methods for estimating avoided T&D and there is no one 'best' approach to developing these estimates." Page 9 of this report states: "In the Pacific Northwest, the Northwest Conservation and Electric Power Plan uses an average of avoided costs from a selection of utilities."[43]

Appendix G of the draft seventh Northwest Conservation and Electric Power Plan, page G-15 states: "The Council used data from eight transmission utilities and eight distribution utilities to estimate this value: $26/kW-yr for deferred transmission and $31/kW-year for deferred distribution (both in 2012$)."

A June 2015 ACEEE energy efficiency paper titled "Everyone Benefits" stated on page 6 that Maryland included an avoided cost adder for ancillary services and assumed marginal losses were 1.5 times average losses, and on page 21 that the range of avoided network costs was US $25 to $50 kW-year.

177.1 Does BC Hydro consider that a reasonable proxy for the "network LRMC" could be: (i) US $26/kW-yr for deferred transmission and US $31/kW-year for deferred distribution used by the Northwest Conservation and Electric Power Plan; and/or (ii) $36.60 kW-year as estimated by FBC? Please explain.

177.1.1 Please estimate BC Hydro's embedded transmission and distribution network costs on a $kW-year basis, and comment on whether this could be a reasonable proxy for the "network LRMC."

177.2 Please update table 2-5 and 2-6 in the Application to show "Total LRMC" by adding to "Energy LRMC" to: (i) generation capacity costs of $11/MWh ($F2013); and (ii) network capacity costs of $36.60 kW-year converted to a $/MWh estimate using BC Hydro's domestic load shape.

177.2.1 Please repeat this analysis, this time using a network capacity cost estimate of US $57/kW-year (2012). Please describe any assumption made.

[39] https://www.nwcouncil.org/media/7149692/7thplandraft_appndxg_consresorcs_20151020.pdf.
[40] http://aceee.org/sites/default/files/publications/researchreports/u1505.pdf.
[41] Appendix H to BCUC IR No. 2.
[42] Appendix I to BCUC IR No. 2.
[43] Exhibit A2-4, pp. 1, 9.

177.3 Please estimate: (i) BC Hydro's average transmission and distribution energy loss percentage; and (ii) BC Hydro's marginal transmission and distribution energy loss percentage. Please explain which approach BC Hydro has used in its LRMC estimate, and why.

177.4 Please explain whether BC Hydro's LRMC includes avoided ancillary services.

178.0 Reference: Regulatory Assistance Project (RAP), Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed, 2013, Appendix A, pp. 64, 65[44]; Exhibit A2-3, pp. 41–43, 58–60, 103–107; Exhibit B-17, Evidentiary Update, p. 9 Evaluation framework: efficiency – residential load response

Appendix A of the April 2013 RAP report titled *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed* (RAP report) states: "The result of this illustrative calculation is that a hypothetical inclining block design would reduce consumption by about 8.6 percent compared with a flat rate. …we will assume that the short-run price elasticity of demand is -0.25 … We assume it applies uniformly to any change in price. Some analyses show that elasticity is greater for higher levels of residential usage."

BC Hydro's price elasticity model is addressed in pages 41 to 43 of the CPUC Decision 15-07-001 which states: "Without an estimate of the [price elasticity of small customers], it is not possible to conclude that the introduction of tiered rates by BC Hydro reduced consumption overall. However, the study did find that customers living in single-family detached houses have more elasticity than customers in town houses, apartments or mobile homes."[45]

The CPUC Decision 15-07-001 also addressed customer response to tiered rates on pages 58-60, 103-107, and on page 60 stated: "Of the methodologies proposed, we believe the average price methodology is the closest approximation of how most customers will respond."[46]

BC Hydro notes on page 9 of Exhibit B-17 that "…steady price signal is beneficial for encouraging a conservation culture."

178.1 Please discuss the CPUC's finding that, in modelling alternative RIB designs, BC Hydro assumes that a decrease in the Tier 1 price will not result in a corresponding increase in consumption.

178.1.1 Does BC Hydro consider that Appendix A of the RAP report supports a conclusion that residential inclining block rates provide overall efficiency benefits compared to a flat rate, even where low use customers are assumed to be as price elastic as high use customers? Please explain.

178.2 Does BC Hydro agree with the CPUC findings that residential customers respond to average prices, rather than just marginal rates? Please explain.

178.2.1 Please comment on whether a RIB pricing principle of maintaining an "easy to remember" 50 percent Tier 1/Tier 2 pricing differential would promote: (i) efficiency by being easier for customers to understand; and (ii) rate stability? Please explain.

[44] www.raponline.org/document/download/id/6516, Appendix A.
[45] Exhibit A2-3, Extract A.
[46] Exhibit A2-3, Extract B.

178.3 Please provide any strategic plans on how BC Hydro leverages and integrates the marketing of the BC Hydro's DSM programs/measures with the RIB rate promotion.

179.0 Reference: Exhibit B-1, Section 5.2, p. 5-35;
Draft seventh Northwest Conservation and Electric Power Plan[47], Appendix G, p. G-15
Evaluation framework: efficiency – residential alternative rate designs

BC Hydro describes RIB Option 2 on page 5-35 of the Application and states that it will result in a forecast loss of conservation compared to Option 1.

Appendix G of the draft seventh Northwest Conservation and Electric Power Plan, page G-15 states: "The Council used data from eight transmission utilities and eight distribution utilities to estimate this value: $26/kW-yr for deferred transmission and $31/kW-year for deferred distribution (both in 2012$)."

179.1 In table form, please provide the Tier 1 and Tier 2 energy charge of the following the rate designs: Proposed RIB rate Option 1; RIB Option 2; RIB rate with a Tier 1/Tier 2 price differential of 40 percent; and RIB rate of a Tier 1/Tier 2 price differential of 60 percent. For each rate design, please note whether the Tier 2 price is within: (i) the energy-LRMC range; and (ii) the total-LRMC range (including generation capacity from the 2013 BC Hydro IRP and assuming a network capacity cost of US $57/kW-year [2012]). Please comment on whether the results of the evidentiary would affect this result and if so, how?

179.1.1 For each rate design option above, please use BC Hydro's price elasticity estimates for Tier 1 and Tier 2 customers to estimate (at a high level only) the expected increase/decrease in energy conservation of that option compared to BC Hydro's proposal. Please document key assumptions made.

The Commission's rate design principles for the BC Hydro RIB Re-Pricing Application included principle 3: "Price signals that encourage efficient use and discourage inefficient use *(*consideration of social issues including environmental and energy policy*)*."[48]

179.2 In table form, please evaluate the same rate design options against the broader efficiency criteria of: encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy). Please include in this analysis the following sub-categories and an overall efficiency summary:

- ability of the rate to encourage efficient use/discourage inefficient use for low use/average use/high use customers, and whether there is an expected overall net benefit;
- ability of customers to understand (and therefore respond to) the rate;
- social considerations, for example risk of under-heating homes; and
- environmental considerations, for example fuel switching.

[47] https://www.nwcouncil.org/media/7149692/7thplandraft_appndxg_consresorcs_20151020.pdf.
[48] Appendix A to BCUC IR No. 2.

180.0 Reference: Exhibit B-1, Section 6.2, p. 6-10, Section 6.3, p. 6-24, Section 6.4, p. 6-50 Evaluation framework: efficiency – general service rate, distributed generation

BC Hydro compares its proposal for SGS/MGS/LGS rates against alternative options on pages 6-10, 6-24, and 6-50 of the Application.

180.1 Please use BC Hydro's price elasticity estimate (which can be a range) for SGS, MGS and LGS customers to estimate the reduction in conservation that would result from BC Hydro's proposal compared to the following options. Please provide a total MWh and $ estimate (using energy LRMC to value the reduction in conservation) and state all major assumptions used:

- SGS: BC Hydro's proposal compared to the status quo.
- MGS: BC Hydro's proposal compared to the sensitivity proposal on page 6-24 of the Application.
- LGS: BC Hydro's proposal compared to the sensitivity proposal on page 6-50 of the Application.
- LGS: BC Hydro's proposal compared to an option where the demand-charge is set equal to the MGS sensitivity demand charge on page 6-24 of the Application, and the short-fall in revenues is addressed by an increase in the energy charge.

180.2 Will the proposed changes to SGS, MGS, and LGS rate classes when compared to existing rates negatively affect some of the BC Hydro Net Metering customers who rely on the applicable tariff rates to be compensated (via energy kWh bill savings) for the energy delivered by the customers to the BC Hydro grid? If possible, please specify in what circumstances.

180.2.1 With regards to the rate design issue of recovering utility costs through a fixed vs. variable charge, would a Net Metering customer be more financially disadvantaged if there was a shift in the cost recovery in the tariff from a variable charge to a fixed charge because Net Metering customers receive compensation primarily in the energy savings (kWh) multiplied by the variable charge tariff rate? Please explain.

181.0 Reference: Exhibit B-1, Section 6.3, p. 6-22, Section 6.4, p. 6-46; Exhibit B-5, BCUC IR 37.1; BC Hydro 2013 IRP, pp. 9-10, 9-11; Exhibit B-17, Evidentiary Update, p. 8 Evaluation framework: weighting - fairness/efficiency

BC Hydro stated in response to BCUC IR 37.1 that "…where the default rate is performing as expected and continues to be useful it should not be replaced with a new rate." BC Hydro states on page 6-22 of the Application: "… customer response to the MGS two-part energy rate was considerably less than forecast" and on page 6-46: "The LGS two-part energy rate has … delivered lower than expected conservation savings …"

BC Hydro includes rate structure energy and capacity savings in its 2013 IRP. On page 8 of Exhibit B-17, BC Hydro states: "DSM savings from conservation rate structures are lower than expected, energy savings from codes and standards have increased…"

181.1 To what extent does BC Hydro consider that, in designing the new MGS/LGS rate structure, it should attempt to develop a two-part rate design that incents conservation in order to meet the conservation targets in the 2013 IRP? Please explain.

181.1.1 Does BC Hydro consider that the proposed MGS/LGS rate structure will result in lower or higher levels of conservation compared to options that maintain the percentage of demand-related costs recovery in the demand charge? Please explain, and comment on whether BC Hydro's proposed decreases of the MGS/LGS demand charges are consistent with the 2013 IRP.

182.0 Reference: Exhibit B-5, BCUC IR 6.1, BCOAPO IR 12.1
Evaluation framework: weighting – reduced forecasted need/self-sufficiency

BC Hydro stated in response to BCUC IR 6.1 that it has modified its prioritization of the eight Bonbright criteria as a result of several items, including a reduced forecasted need/self-sufficiency, government policy and changing customer expectations/stakeholder input.

The Commission addresses short-term surplus considerations in its May 2014 decision on the FBC application for stepped and stand-by rates by transmission voltage customers.[49] BC Hydro stated in its response to BCOAPO IR 12.1: "At the second [residential focus] session in February 2015, participants ranked fairness above all other values at first, and then only after viewing rate designs did efficiency emerge as the most important value followed closely by fairness."

182.1 Is it BC Hydro's position that a reduced forecasted *energy* need means that, while efficiency can still be a relevant consideration, the BC $ benefit from rate designs that discourage waste of electricity will likely be lower than was previously the case? Please explain.

182.1.1 Does BC Hydro consider the Shore Power rate and Freshet pilot reflect an enhanced focus on the efficiency principle as a result of the energy surplus? Please explain.

182.2 Please explain why reduced forecast *capacity* needs resulted in a lower efficiency weighting. Specifically, has there been a significant change in BC Hydro's LRMC of capacity between 2007 and this application?

182.3 Please explain BC Hydro's statement in BCUC IR 6.1 of changing customer expectations in light of the response to BCOAPO IR 12.1.

183.0 Reference: BC Energy Plan, p. 5
Evaluation framework: weighting - Government policy

The 2007 BC Energy Plan states: "Utilities are also encouraged to explore and develop rate designs to encourage efficiency, conservation and the development of renewable energy."

The Commission states in its May 2014 decision on the FBC application for stepped and stand-by rates by transmission voltage customers: "The Panel acknowledges that the Government's objective is the promotion of energy conservation and efficiency, including self-generation in the entire Province."[50]

183.1 Please explain whether BC Hydro considers Government policy has changed since the 2007 application in the following three areas, and why: (i) achieve conservation (i.e., a reduction in consumption); (ii) encourage efficiency; and (ii) encourage the development of renewable energy.

[49] Appendix G to BCUC IR No. 2, p. 3.
[50] Appendix G to BCUC IR No. 2, p. 4.

184.0 Reference: Exhibit B-17, Evidentiary Update, Cover Letter
Load Resource Balance (LRB) and Long-Run Marginal Cost (LRMC) Evidentiary Update

On February 18, 2016, BC Hydro submitted an evidentiary update of BC Hydro's LRB and LRMC. BC Hydro submitted its "…current view on the energy Long-Run Marginal Cost has shifted towards $85/MWh from $85 to $100/MWh…" and "The Load Forecast and Load Resource Balance do not reflect more recent information that is expected to be material…Given the possible significance of these recent developments, BC Hydro believes it is prudent to undertake an additional update…BC Hydro will file the updated Load Resource Balance and Load Forecast as an Evidentiary Update."

184.1 Considering BC Hydro plans to file another evidentiary update, what weight should the Commission place on this evidentiary update, and why?

184.2 Similarly, BC Hydro notes its view has changed on the energy Long-Run Marginal Cost since the 2013 IRP. As such, what weight should the Commission place on BC Hydro's new view versus the view BC Hydro had for the 2013 IRP, and why?

184.2.1 Was the forecast information in the evidentiary update approved in the same manner that the 2013 IRP was approved? Does BC Hydro require Lieutenant Governor in Council approval for its change of view? Please explain.

185.0 Reference: Exhibit B-17, Evidentiary Update, p. 9
Evidentiary update: LRMC

BC Hydro notes that "a steady price signal is beneficial for encouraging a conservation culture."

In the Commission's decision on BC Hydro's 1991 RDA, the Commission stated:

> B.C. Hydro suggests that no bills to any customer should decline since allowing decreases would result in customers receiving mixed messages as to the future of electricity costs, thereby diluting the incentive to avoid wasteful use of the resource" and "Mr. Fussel testified that B.C. Hydro used a 20-year [long run incremental cost (LRIC)] result to set R2 [the trailing block rate set at LRIC] (T. 2163). This diminishes the impact of short-term fluctuations and made the customer's decision regarding the rate consistent with the time frame of B.C. Hydro's system planning decisions.[51]

185.1 Does BC Hydro consider that a decrease in the rate design pricing signal would result in customers receiving mixed messages as to the future of electricity costs, thereby diluting the incentive to avoid wasteful use of the resource? Please explain.

[51] Appendix F to BCUC IR No. 2, pp. 5, 6.

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY
RESIDENTIAL INCLINING BLOCK RATE RE-PRICING APPLICATION

REASONS FOR DECISION

March 14, 2011

BEFORE:

L.A. O'Hara, Panel Chair / Commissioner
C. Brown, Commissioner
D. Morton, Commissioner

In any rate design application review, including the 2008 Residential Inclining Block Decision, the Commission is guided by the eight "Bonbright Principles" which can be described as follows:

Principle 1: Recovery of the revenue requirement;

Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates);

Principle 3: Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);

Principle 4: Customer understanding and acceptance;

Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives);

Principle 6: Rate stability (customer rate impact should be managed);

Principle 7: Revenue stability; and

Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

Source: James C. Bonbright, *Principles of Public Utility Rates,* Columbia University Press, 1961

1.3 Orders Sought

BC Hydro seeks an order allowing it to continue to apply general revenue requirement rate increases to each of the RIB rate's Basic Charge, Step-1 energy rate and Step-2 energy rate as was done in F2011. Specifically, BC Hydro proposes that the pricing principle approved for F2011 "be sustained until such time as circumstances require that it be re-visited, and in any case no sooner than the final resolution of BC Hydro's Time-of-Use (TOU) rate application (which is currently under development) and government's approval of BC Hydro's 2011 Integrated Resource Plan (2011 IRP)." (Exhibit B-1, p. 1)

1.4 Regulatory Process

By Order G-204-10 the Commission ordered that the Application be reviewed by a Written Hearing Process which was to include one round of Information Requests (IR). The following five Interveners filed Final Submissions with further alternative proposals provided in two of those submissions:

- British Columbia Old Age Pensioners' Organization, *et al* (BCOAPO)
- B.C. Sustainable Energy Association and Sierra Club of British Columbia (BCSEA)
- Commercial Energy Consumers Association (CEC)
- Energy Solutions for Vancouver Island Society (ESVI)
- Terasen Utilities (Terasen)

G-60-14

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

May 6, 2014

Before:

L.A. O'Hara, Panel Chair and Commissioner
B.A. Magnan, Commissioner
R.D. Revel, Commissioner

"the historic relationship has seen a customer-type contract dating from the 1993 decision of the Commission" (BCMEU Final Submission, p. 2). CEC also submits that "the relationship between the utilities is increasingly that of arrangements between independent utilities" (CEC Final Submission, p. 5).

Commission Determination

The Commission Panel concludes that the relationship between FortisBC and BC Hydro continues to be unique, one that is characterized as a hybrid, in which FortisBC is partly a customer of BC Hydro and partly an independent utility. The Panel determines that the ratemaking principles should continue to be applied in this context. The Panel continues to consider BC Hydro's obligations to serve FortisBC as a customer is limited, and beyond those limits the relationship is to be that of two independent utilities. The Commission recognizes that as an independent utility, FortisBC has the responsibility for its own resource planning at rates reflective of fair market arrangements.

7.1.2 Evaluation Framework

In reviewing rate design applications, which typically reflect a utility to customer relationship, the Commission is typically guided by the eight Bonbright Principles. These principles are described on page 5 of the Reasons for Decision to Order G-45-11:

> "Principle 1: Recovery of the revenue requirement;
>
> Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates);
>
> Principle 3: Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);
>
> Principle 4: Customer understanding and acceptance;
>
> Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives);
>
> Principle 6: Rate stability (customer rate impact should be managed);
>
> Principle 7: Revenue stability; and
>
> Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained)."

7.2.2 Commission Summary Determination on Fairness

On balance, the Commission Panel determines that the New PPA and EEA pass the Bonbright Fairness Principle evaluation.

FortisBC's access to Regional Energy Markets allows it flexibility to import electricity to displace some Tranche 1 energy with market priced energy. The Panel considers this a significant advantage that other Transmission Customers do not have. However, the advantage is somewhat offset by the addition of the Energy Nomination and Scheduling Restrictions term in the New PPA.

Further, but to a much smaller extent, FortisBC benefits from the option, but not the obligation, to purchase some additional energy at Tranche 2 prices that other Transmission Service Customers do not have.

In conclusion, the Panel considers that these benefits are fully offset by 200 MW capacity limit and associated energy which has not been increased to reflect FortisBC's load growth since 1993. Thus, the overall finding that, on balance, the New PPA and EEA pass the Bonbright Fairness Principle evaluation.

7.2.3 Efficiency

The Panel has considered whether the New PPA and Energy Export Agreement result in an improvement in efficiency compared to the 1993 PPA. Efficiency benefits can be described as promotion of: (i) efficient customer consumption and investment decisions, (ii) efficient utility investment and operational decisions and (iii) innovation. The Panel also considers any effect on British Columbia social issues, including environmental and energy policy.

F

BC Hydro stated that the key inefficiencies of the existing PPA are: (i) it allows FortisBC to increase firm energy purchases up to 100 percent load factor at a price below BC Hydro's marginal cost of energy and (ii) it allows FortisBC to plan on the full use of RS 3808 power and then opportunistically displace the planned purchases by buying from the spot market. (Exhibit B-13, BCUC IR 2.7.1)

G-156-10

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

FORTISBC INC.

2009 RATE DESIGN AND COST OF SERVICE ANALYSIS

DECISION

October 19, 2010

BEFORE:

A.J. Pullman, Panel Chair/Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commissioner

1.2 Rate Design: Overview

The purpose of a RDA is threefold: (i) to examine whether the structure of existing rates continue to promote an economically efficient consumption of electricity by the utility's customers; (ii) to assess whether the charges to customers that result from the application of these rates are fair and reasonable; and (iii) to provide an opportunity for all parties to examine the relevance of a utility's tariffs including its terms and conditions of service to ensure they remain relevant and valid.

An assessment of the fairness of rates is typically based on a comparison of the revenues collected from each class of customer with the cost of providing service to them. The cornerstone of this assessment is the COSA which attempts to equitably allocate the revenue requirement of the utility to the various customer classes of service (i.e., residential, commercial, etc.).

One of the seminal textbooks on rate design is "Principles of Public Utility Rates" by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, first published in 1961 by Public Utilities Reports, Inc.

FortisBC states that the COSA and RDA processes were guided by the eight "Bonbright Principles" which it describes as: D

Principle 1: Recovery of the revenue requirement;

Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates);

Principle 3: Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);

Principle 4: Customer understanding and acceptance;

Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives);

Principle 6: Rate stability (customer rate impact should be managed);

Principle 7: Revenue stability; and

Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

Exhibit B-1, p. 33; Exhibit B-22

The three basic steps of a COSA are:

(i) functionalization which separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production, transmission, distribution, and general;

(ii) classification which determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related; and

(iii) allocation of costs to specific customer classes which is based on the customer's contribution to the specific classifier selected.

1.3 The Applicant

FortisBC is an investor-owned utility engaged in the business of generation, transmission, distribution and sale of electricity in the southern interior of British Columbia. FortisBC currently serves more than 158,000 customers both directly and indirectly through sales to five municipally-owned electric utilities. The Company owns assets with a gross book value in excess of $1 billion, including four hydroelectric generating plants located on the Kootenay River with a combined capacity of 223 MW and approximately 7,000 circuit km of transmission and distribution power lines for the delivery of electricity to major load centers and customers in its service area.

Until 1988 the company was controlled by Cominco Ltd. and was known as West Kootenay Power Ltd. (WKPL). From 1988 to 2003 it was owned by Utilicorp Inc., after which it was purchased by Fortis Inc. and renamed FortisBC.

The Company had previously filed RDAs with the Commission in 1983 and 1997.

2.0 FORTISBC COST OF SERVICE ANALYSIS

This Section first presents an overview of FortisBC's COSA, followed by a discussion of the foundational aspects of the COSA – the revenue requirement, load data and the identification of customer classes. The Section then discusses the differences between the 1997 COSA and the 2009 COSA and the impact on the costs allocated to each customer class. Finally the Section reviews the major issues regarding the choice of Contract Demands to allocate transmission plant costs, the use of 2 Coincident Peaks (CP), and IRG's complaint that their members were disadvantaged by the COSA.

2.1 Overview of FortisBC's 2009 COSA

The COSA in the 2009 FortisBC Rate Design Application was prepared by EES Consulting (EES), which has been responsible for the preparation of several COSA studies for FortisBC and its predecessor companies, including the 1997 COSA which served as the starting point of the 2009 study, and also established the basis for the existing FortisBC tariff.

FortisBC states that a COSA is a process used to assign or allocate a fair share of total cost or revenue requirement of a utility to its various customer rate classes or schedules. The primary output of the study is the cost to be collected by rate class, which is used as a basic input for rate design (Exhibit B-1, p.36). The revenue from each class under prevailing rates is divided by the costs allocated to that class in order to compute Revenue-to-Cost (R/C) ratios. The R/C ratios for each class derived by the 2009 COSA as provided in the Application and as modified in subsequent errata filings are shown below:

E

G-130-07

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

2007 RATE DESIGN APPLICATION
PHASE -1

DECISION

October 26, 2007

Before:

Anthony J. Pullman, Panel Chair & Commissioner
Robert J. Milbourne, Commissioner
L.A. O'Hara, Commissioner

from the information requests contains numerous examples of rate design practices that send appropriate pricing signals in other jurisdictions, which have relevance to BC Hydro's Application.

These matters are also addressed in Section 2.7.

2.6 Hydro's Rate Design Principles and Foundational Aspects of the RDA

2.6.1 Rate Design Criteria

BC Hydro's proposed rate design criteria, in no particular order, are as follows:

- recovery of the revenue requirement;
- fair apportionment of costs among customers;
- price signals that encourage efficient use and discourage inefficient use;
- customer understanding and acceptance;
- practical and cost-effective to implement;
- rate stability;
- revenue stability; and
- avoidance of undue discrimination (Exhibit B-1, p. 27).

BC Hydro submits that these well-known and recognized rate design criteria are consistent with and satisfy the statutory test of "fair, just and not unduly discriminatory" (BC Hydro Argument, p. 15).

Furthermore, BC Hydro explains that given the length of time since its last RDA, the principal focus of the 2007 RDA is to ensure that BC Hydro's rates and Terms and Conditions are fair, efficient and simple and provides the following definitions for its three rate design objectives:

- **Fair** means that each customer bears a fair share of the costs caused by that customer, to the extent practicable.
- **Efficient** means that the rates and Terms and Conditions provide efficient price signals at the margin, including appropriate price signals to encourage energy conservation and load management, to the extent practicable.

The Commission Panel contrasts the Stakeholder consultations BC Hydro conducted in order to inform the 2007 RDA, with those it conducted in support of its 2006 IEP/LTAP proceedings before this Commission. In finding that BC Hydro had appropriately engaged its stakeholders in those matters (IEP/LTAP Decision, May 11, 2007, p. 31) the Commission had before it a 286 page document entitled "First Nations and Stakeholder Report (ibid p. 27). In this proceeding, BC Hydro filed a 20 page "Stakeholder Engagement Summary" fully 40 percent of which is concerned with the relatively small and unique E-Plus customer subset.

The Commission Panel also observes that a sense of urgency appears to be missing in the 2007 RDA, which contradicts with the message to be found in the external communications of the BC Hydro Executive. BC Hydro's assertion that it has conducted significant rate design work over the past three years (Opening Statement, Exhibit B-24) is at odds with the absence of innovative proposals in the 2007 RDA.

In summary, the Commission Panel finds itself in a rather unusual position: BC Hydro asks it to approve only a foundation for future innovative rate designs, to defer development of the long-term rate strategy to BC Hydro and to only approve future filings piecemeal as they are submitted in due course. To resolve this the Commission Panel will make no ruling on the "foundational aspects" of the Application nor the "Threshold Policy" question as it does not believe that such findings would be of value in these circumstances. Instead, the Commission Panel will make its determinations on all the elements of the 2007 RDA having regard to the full body of evidence before it, and in accordance with the public interest.

With regard to rate design criteria, the Commission Panel finds that the 2007 RDA lacks some clarity regarding the interrelationship between the eight rate design criteria and the three principal rate design objectives, which makes assessment of the specific proposals somewhat more challenging. That notwithstanding, the Commission Panel finds that the basic rate design criteria themselves are appropriate and consistent with the statutory test of "fair, just and not unduly discriminatory" and accepts them as filed. A

3.0 BC HYDRO'S COST OF SERVICE STUDY

This Section addresses BC Hydro's Fully Allocated Cost of Service Study ("FACOS"). It first summarizes the methodology used by BC Hydro, which is based on historical embedded cost pursuant to the Heritage Contract as compared to a marginal cost study, and then addresses marginal cost studies in rate setting. It then reviews the range of reasonableness proposed by BC Hydro for the revenue-to-cost ("R/C") ratios for the various customer classes. Lastly, it examines the methodology and assumptions used by BC Hydro in the performance of its FACOS.

3.1 Fully Allocated Cost of Service Study

The purpose of a FACOS is to allocate historical accounting costs to distinct customer classes in accordance with the costs incurred in serving each class. The total cost to be allocated is the utility's revenue requirement, which is the sum of operating and maintenance expense, depreciation and amortization, and financing charges, less miscellaneous revenues. In the case of BC Hydro, the total approved revenue requirement for F2008 is $ 2,836 million (Exhibit B-1, Appendix A, p.2). The revenue from each class under prevailing rates is divided by the costs allocated to that class in order to compute R/C ratios. BC Hydro states that the use of the revenue requirement net of the two percent rate rider revenue allows an easy comparison of the cost to serve by rate class with revenue by rate class, and results in a R/C ratio of 1.0 for total revenue and total cost (Exhibit B-1, p. 10).

B

The R/C ratios produced by the F2008 FACOS as provided in the Application at existing February 1, 2007 rates are shown below in Table 3-1:

British Columbia
Utilities Commission

IN THE MATTER OF

British Columbia Hydro and Power Authority
2015 Rate Design Application – Module 1

REASONS FOR DECISION

February 01, 2016

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

2.0 POSITIONS OF PARTIES RELATED TO THE AGENDA ITEMS AND REGULATORY REVIEW PROCESS

2.1 Introduction

At the procedural conference held on January 19, 2016, 14 interveners made submissions (listed below) in addition to the applicant, BC Hydro and Commission staff:

- Commercial Energy Consumers' Association of British Columbia (CEC)
- British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO)
- B.C. Sustainable Energy Association and Sierra Club of British Columbia (BCSEA)
- Clean Energy Association of BC (CEBC)
- Association of Major Power Customers (AMPC)
- Non-Integrated Areas Ratepayers Group (NIARG)
- Zone II Ratepayers Group (Zone II)
- Dewdney Area Improvement District (DAID)
- Canadian Association of Petroleum Producers (CAPP)
- British Columbia Ministry of Energy and Mines (MEM)
- FortisBC Energy Inc. and FortisBC Inc. (FEI/FBC)
- Simon Fraser University (SFU)
- Movement of United Professionals (MoveUP)
- Vancouver Airport Authority (YVR)

The Panel noted that NIARG and Zone II represent distinct ratepayer groups in BC Hydro's non-integrated area, which according to the Application, is the subject of Module 2. NIARG represents ratepayers in Zone 1B and Zone II currently represents the Kwadacha Nation. NIARG submitted that its participation in Module 1 is essential to basic fairness and procedural efficiency and invited guidance from the Panel regarding the nexus between Modules 1 and 2.[7] Zone II, in a submission filed as Exhibit C36-6, argued that their issues should be brought into Module 1. Zone II submitted that it is hopeful that the non-integrated area (NIA) issues can be addressed in a timely manner as part of Module 1 with little or no delay. Zone II's request and BC Hydro's related response[8] is item no. 10 in the procedural conference.

The Panel also noted that YVR and SFU are RS 1827 customers of BC Hydro and shared similar concerns at the procedural conference.[9] YVR made submissions on behalf of SFU at the procedural conference.[10]

At the procedural conference, the two regulatory processes and timetables were filed, one from, BC Hydro and another from Commission staff. The Panel notes that BC Hydro's proposal has the benefit of discussions between BC Hydro and interveners prior to the procedural conference. Although none of the interveners offered an alternative process, the Panel notes a number of concerns expressed by participants:

> I don't think I've seen as disjointed a process in terms of the potential at the end of the day, at the end of this rate design process you'll have had Module 1, Module 2, and within Module 1 at

I

[6] Transcript Volume 1, p. 212
[7] Ibid., pp. 94-95
[8] Exhibit B-8
[9] Transcript Volume 1, p. 114
[10] Ibid., pp. 110-111

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> least five different processes proposed by BC Hydro in terms of dealing with the issues. .....And our concern and an overriding concern that we have as a ratepayer group is that through that process, the principles and the discussions and the negotiations and the approaches to issues don't get confused or disjointed such that there isn't a coherent decision at the end of the day..... at the end of the day the Commission is going to be asked to ensure that what we've done in rate design holds together.[11]
>
> Generally we appreciate and we would adopt the submissions of Mr. Weafer before me regarding his identification of a concern about a potentially disjointed process and the problems that may arise from that.....I don't have an easy solution to that, just I think as Mr. Weafer didn't. I think the best that we can do is the Commission, Hydro and interveners be very alive to that potential problem of making determinations or fixing assumptions and then moving forward to a process where those things inform what's going on in Module 2 for example, ...[12]
>
> we believe it's a useful exercise that as Mr. Weafer and Mr. Weisberg have raised, there be some alertness, including on the part of interveners, to the possibility that given the phased nature of the process, there be some alertness to potential unintended consequences that arise from later decisions on earlier ones; likewise earlier decisions on later stages. We don't have any suggestion to remedy that or to change the process.[13]

CAPP submitted that the process should be followed as laid out and if it turns out that something arises further on in the process that looks like it requires reconsideration, it could be dealt with according to the provisions in the *Utilities Commission Act*.[14]

Unlike the BC Hydro proposed process and timetable, Commission staff's proposed regulatory process and timetable was filed only at the procedural conference. One intervener, MoveUP, stated that receiving this halfway through the day put them at a real disadvantage trying to respond to the rather detailed set of proposed dates.[15]

The Panel agrees that the parties were not in a position to comment in any detail on the alternative Commission staff proposal and, therefore, adopts the format of BC Hydro, as outlined in Exhibit B-9, which organizes the proposed timetable based on rate schedules and review processes as a starting point.

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[11] Transcript Volume 1, pp. 36–38 (CEC).
[12] Ibid., pp. 92–93 (NIARG).
[13] Ibid., pp. 111–112 (FEI/FBC).
[14] Ibid., p. 106.
[15] Ibid., p. 131.

G-36-9.

Appendix F
to Exhibit A-22
BCH 2015 RDA

IN THE MATTER OF

the Utilities Commission Act
S.B.C. 1980, c. 60, as amended

and

IN THE MATTER OF

a Rate Design Application by
British Columbia Hydro and
Power Authority

DECISION

April 24,1992

BEFORE:

John G. McIntyre, Chairman
Ken L. Hall, Commissioner

2.2 Rate Design Principles

In developing its approach to rate design, B.C. Hydro started with the premise that, from a regulatory stand-point, it must fulfill at least two criteria (Exhibit 1, page I-1-2). First, the Act requires that B.C. Hydro's rates must be fair, just and reasonable. Second, government policy, as articulated through Special Direction No. 3 to the Commission, requires that B.C. Hydro's rates:

- contribute to conservation and the efficient use of electricity;
- recognize the higher cost of new electricity supply;
- provide for smooth and stable increases; and
- are otherwise fair, just and reasonable.

To ensure that B.C. Hydro rate design serves the specific objective of Special Direction No. 3 and is otherwise fair, just and reasonable, the Applicant undertook a comprehensive internal analysis of its rates and also retained outside expertise to assist it in developing a rate design appropriate for the future.

The rate design team considered 10 distinct traditional objectives of rate design, used in other North American jurisdictions, which define the fair, just and reasonable standard. These objectives were elaborated upon by B.C. Hydro's consultant, Mr. H.J. Vander Veen as:

1. Effectiveness in yielding total revenue requirements.
2. Revenue stability and predictability, with a minimum of unexpected changes.
3. Stability and predictability of rates themselves, with a minimum of unexpected changes seriously adverse to rate payers and with a sense of historical continuity.
4. Static efficiency of rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.
5. Reflection of all the present and future private and social costs and benefits.
6. Fairness of specific rates in the apportionment of total cost of service among the different rate payers so as to avoid arbitrariness and to attain equity.
7. Avoidance of undue discrimination in rate relationships.
8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

9. The related practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability and feasibility of application.

10. Freedom from controversy as to proper interpretation.

Mr. Vander Veen summarized these objectives as follows (Exhibit 1, page I-10-4):

- the revenue requirement or financial need objective
- the optimum use of consumer rationing objective
- the fair cost apportionment objective
- the acceptability objective.

B.C. Hydro stated that having considered these traditional objectives, it believed that the requirement for fair, just and reasonable rates in the Act was entirely compatible with government policy requiring conservation, efficient use of electricity, and smoothness and predictability in rates. Examination of some of the traditional objectives suggests that the requirements of Special Direction No. 3 are at the heart of establishing fair, just and reasonable rates.

The requirement to conserve and promote the efficient use of electricity found in Special Direction No. 3 is echoed in three of the objectives from the list of traditional objectives in Mr. Vander Veen's testimony (4, 5 and 8). Similarly, the requirement for smoothness and predictability and the need to recognize the higher cost of new electricity supply are found in two objectives (2 and 3). Based on the work of its Rate Design team, B.C. Hydro believed that, generally speaking, the other traditional rate design objectives are adequately served by the Application (Exhibit 1, page I-1-3).

2.2.1 Commission Determinations

The Commission agrees with B.C. Hydro that the traditional rate design objectives, the Act and Special Direction No. 3 are compatible. However, the Rate Design Application has been directly linked to future illustrative changes in its Revenue Requirements. B.C. Hydro stated that it expected its next revenue requirement increase to be between 3 and 7 percent, but has been unable as yet to get to the Application stage. The timing and amount of further revenue requirement increases are even more uncertain. This means that the smooth, stable and predictable objectives cannot be adequately examined in a concrete and specific manner in this Decision.

2.3 B.C. Hydro Policy

Four basic policy judgments underlie B.C. Hydro's Rate Design Application. These judgments are based on the Utility's interpretation of Special Direction No. 3 and on its perception of the current relationships among customer classes. Specifically, the four policy judgments are that:

1. the current allocation of revenues among customer classes is acceptable;
2. the current declining rate block structure is inappropriate;
3. no customer bills should increase by more than ten percent; and
4. no customer bills should decline.

2.3.1 Allocation of Revenues Between Classes

Typically, a primary issue to be addressed by a rate design application is the appropriate allocation of embedded costs among customer classes while intra-class rate design issues are often given lesser priority. A FACOS study is used to measure the extent to which the revenues contributed by a particular customer class cover the historical costs attributed to serving that customer class. Ratios in excess of one indicate that class revenues exceed allocated costs while ratios less than one imply the opposite. The fundamental objective of B.C. Hydro's Application, however, is to change the structure of the current price levels in a manner that serves to alert customers to the rising cost of future power.

In this Application, B.C. Hydro relied primarily on the results of the FACOS study contained in Exhibit 1, Appendix E and later updated in Exhibit 4, Industrial Users' Question 27b. The results of the original and updated studies for major rate classes are given as follows:

"MR. GATHERCOLE: Q: One of the policies of your application as presently filed is it is inappropriate at this time to move to a flat rate structure and to eliminate the declining block totally now.

MR. PETERSON: A: Well it's not inappropriate, but it would have consequences that we don't feel would be acceptable to the customers because of the number of bills that would go up well beyond the ten per cent guideline.

MR. GATHERCOLE: Q: Well as I understood the testimony yesterday and the policy that's inherent in the application there appear to be two reasons for your decision not to move to a flat rate as a first step. The first was rate shock to some customers.

MR. PETERSON: A: Yes.

MR. GATHERCOLE: Q: The second was inappropriate price signals to other customers.

MR. PETERSON: A: Yes, approximately half the customers would get a bill decrease, that's correct." (T. 182)

B.C. Hydro suggests that no bills to any customer should decline since allowing decreases would result in customers receiving mixed messages as to the future of electricity costs, thereby diluting the incentive to avoid wasteful use of the resource (T. 571-572). In order to ensure that no customer's bills decrease, the Utility proposed to make changes only at times of revenue requirement increases.

2.3.4.1 Commission Determinations

The Commission agrees that a substantial decline in rates to a particular customer class or large group within a class would not conform with the spirit of the Special Direction. The Commission does not believe that this precludes decreases in bills to customers who are <u>unlikely</u> to be price sensitive, especially if there are offsetting benefits. The Commission will, where possible, direct the adoption of a strategy which will eliminate the declining block rate structure without creating the problems previously noted or adding to the uncertainties.

> Again to put it in perspective we know that our industrial customers presently consume approximately 15,000 gigawatt hours a year and we know that our load growth, if it were to continue at the existing level, is about 1,500 gigawatt hours a year. As I stated yesterday that is, the load growth accounts for approximately 10 percent of what the industrial customers' load is. So if all of our customers were to go to the inverted rate and if all of our customers were to eliminate their Q2 consumption through alternate sources or through conservation or through their own self-generation over five years, if they were able to do that over five years then our load growth the way we see it presently would have consumed all of that and the benefactor of that are all of the other customers of B.C. Hydro because B.C. Hydro would have had to build no more system in order to accommodate that load growth.
>
> So the winners are not just the industrial customers who have been able to make their savings but everybody else who benefits by Hydro using existing system. That is over, in the shortest term we can even think of, of five years, of all our customers going to 1823 and we don't expect that to happen."

With regard to the perceived fairness between new and old customers or those who have already committed to conservation, B.C. Hydro counsel claimed that any effort to encourage conservation will potentially produce that reaction. He claimed that that is exactly what Power Smart is about (T. 2945).

In B.C. Hydro's view, the IRP was designed to provide the full range of services to which the industrial customers are entitled, and which they have requested, while allowing them to maintain the existing arrangements if that suits their interests (T. 79). It was designed to provide a signal to industry of the future costs of electricity, to maximize their ability to develop cheaper methods of producing energy and to be introduced gradually to avoid disruption (T. 77). This rate design is seen as a necessary complement to Power Smart (T. 42, 131), rather than competing with it.

Mr. Fussel testified that B.C. Hydro used a 20-year LRIC result to set R2 (T. 2163). This diminishes the impact of short-term fluctuations and made the customer's decision regarding the rate consistent with the time frame of B.C. Hydro's system planning decisions (T. 2681). Only B.C. Hydro can set the calculation of R2, and it intends to publish its projections looking into the future. In order for a customer to make an investment decision, he must choose to acquire electricity from a source other than B.C. Hydro based on a projection of the LRIC. The LRIC is subject to periodic update and involves a discount rate. Dr. Sarikas agreed that the choice of discount rate does impact the LRIC results but he noted the variability in costs occurs in the short-run (T. 2162). However, the Industrial Users remained concerned about what might be a conflict of interest on the part of the Provincial Government as it both sets the discount rate and might be selling the Columbia River Downstream Benefits to B.C. Hydro (T. 2828).

G-67-14

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

FORTISBC INC.

APPLICATION FOR APPROVAL OF STEPPED AND STAND-BY RATES FOR TRANSMISSION [VOLTAGE] CUSTOMERS

DECISION

May 26, 2014

BEFORE:

L.A. O'Hara, Commissioner/Panel Chair
R.D. Revel, Commissioner

of supply, which means that efficient pricing signals are not triggered. For example, BCPSO notes the LRMC of 5.6¢/kWh used for evaluation of DSM programs, is significantly below the 9.223¢/kWh value proposed for the Tier 2 rate by FortisBC. In summary, BCPSO submits that an LRMC based on new resources does not reflect FortisBC's current LRMC of power and is predicated simply on achieving an inclining rate structure that will incent customers to use less electricity. (BCPSO Final Submission, pp. 4-5)

FortisBC does not disagree with the above submissions of BCPSO, but reiterates that the selection of a lower LRMC as suggested by BCPSO would simply result in a rate that is essentially flat, "further reducing the conservation incentive and rendering the rate ineffective." (FortisBC Reply, p. 3)

Commission Determination

The Panel acknowledges the CEA's and Energy Plan's focus on energy efficiency and accepts that an active demand side can be a critical element to an efficient market. An efficient market requires vigorous competition between supply-side and demand-side resources to achieve an efficient, least-cost outcome. Without this, the energy field is left with a one-sided market in which prices are set only by the supply side.

Therefore, the Panel agrees with BCPSO that the key question in determining if a need for the Stepped Rate exists is whether the Stepped Rate promotes efficient customer behaviour rather than merely results in less electricity consumption. For example, a customer may use less electricity by shutting down operations or switching to an alternative fuel, however this may not result in a net benefit overall.

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In determining how any efficiency benefits of the stepped rates should be measured, the Panel has looked to the DSM Regulations for guidance. Section 4 (1.1) specifies that benefits should be measured using the Total Resource Cost test, which measures the benefit from a British Columbia perspective rather than a utility, participant or non-participant perspective. Although it is preferable that the utility itself also benefits (for example, if the Stepped Rate addresses an operational need of FortisBC), section 4 (1.8) of the DSM Regulations does not require this.

The Panel also considers that in measuring BC efficiency benefits there are two broad types of customer behaviours – short term operational decisions (such as whether to take on another order) and long term investment decisions (such as when to replace equipment). The Panel notes that Barrick has explicitly stated that due to the nature of its operations it would be unlikely to initiate any conservation activities and Interfor, who registered as an Intervener, did not make final submissions or asked any information requests.

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FortisBC has already acknowledged that the consultation process did not follow the usual path due to the circumstances, but assured the Panel that there has been ample opportunity for customers to provide input into the rate design. In light of the lack of customer engagement, the Panel finds it difficult to conclude that the FortisBC stepped rate will have efficiency benefits in the absence of adequate evidence on the price responsiveness of FortisBC's Industrial customers.

The Panel also looked at this issue from a theoretical perspective – specifically, whether it could be assumed that FortisBC's Industrial customers are likely to be at least somewhat price sensitive and whether the Panel could assume that there would be a net efficiency benefit from the proposed Stepped Rate. This was addressed by separately considering the effect the proposed Stepped Rate could have on short term and long term FortisBC customer operational and investment decisions.

For short term customer operational decisions, the Panel agrees with BCPSO and FortisBC that there is a short term surplus in the electricity market at the moment and wholesale prices are expected to be significantly below the proposed Tier 2 energy rate of 9.223¢/kWh. While the Panel does not consider that a rate which over-signals incremental costs at the margin is necessarily inefficient (customers may not over-consume electricity as a result), it does indicate that, at least in the short term, any benefit of introducing the proposed Stepped Rate to improve customer operational decisions would likely be significantly reduced.

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For longer-term customer investment decisions, the Panel is aware that customers may make inefficient investment decisions in response to the existing Flat Rate. However, these concerns are mitigated by FortisBC only having four customers who make up less than 7 percent of FortisBC's total load on the Large Commercial Service Transmission Rate, and by the alternative available to FortisBC of addressing any identified problems through DSM programs.

3.8.1.4 Government Policy on Self-Generation

The *Clean Energy Act* received Royal Assent on June 3, 2010. It advances 16 specific energy objectives to help achieve British Columbia's energy vision, including new measures to promote electricity efficiency and conservation. Efficiency and conservation objectives are, broadly speaking, to "foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean and renewable resources" and "to reduce waste by encouraging the use of waste heat, biogas, and biomass."

Prior to the introduction of the CEA, the provincial government's emphasis on the promotion of energy efficiency was articulated in both the 2002 and 2007 Energy Plans. Within the 2007 Energy Plan, are two relevant policies: Policy Action #4: Explore with BC utilities new rate structures that encourage energy efficiency and conservation, and Policy Action #21: Ensure clean or renewable electricity generation continues to account for at least 90 percent of total generation.

The 2007 Energy Plan also states: "Government's goal is to encourage a diverse mix of resources that represent a variety of technologies;" and "To close [the] electricity gap will require an innovative electricity industry and the real commitment of all British Columbian's to conservation and energy efficiency." (2007 Energy Plan, pp. 9, 26)

The Celgar pulp mill utilizes wood waste, forest-based biomass and organic material to generate clean Bioenergy. Minister of Energy Bill Bennett is quoted: "I believe that renewable energy like this, its generation and the technology and knowledge around it, is a key to a prosperous future for British Columbia." (BC Hydro News Release, November 12, 2010)

Commission Panel Discussion

The Panel acknowledges that the Government's objective is the promotion of energy conservation and efficiency, including self-generation in the entire Province.

Therefore, the Panel considers that the Stand-by Rate should result in efficient customer investment and consumption decisions – specifically, efficient investment in, and operation of, distributed generation by utility customers and efficient investment in, and operation of, assets

withstand or tolerate lower than usual reliability, then non-firm service should be available to serve that load. If the customer is not able or willing to tolerate periodic and possibly frequent interruptions or curtailments, then the load should be considered to be firm, and firm service should be available. In either case, the service should match the customers' requirements as nearly as practicable." (Exhibit C2-6, p. 7)

Celgar also explained that it "has load shedding relays in place, although they are not currently programmed to respond to system supply constraints. The infrastructure is in place to allow the load shedding relays to be armed when FortisBC designates that non-firm backup is unavailable." (Exhibit C2-9, BCUC 1.9.3)

Commission Determination

The Panel agrees with Celgar that its Electricity Supply Brokerage Agreement effectively set out the terms by which FortisBC was to provide stand-by service to Celgar including a distinction between firm and interruptible service.

However, the Panel is persuaded by FortisBC's argument that its situation is different now and that there would be no benefit to FortisBC to provide non-firm service. If, for planning purposes, the costs are the same and the difference between firm and non-firm service would be in name only and no cost savings would result, then the Panel is in agreement that all service should be firm service. The Panel agrees with Celgar's expert witness that ideally the type of service that should be offered by FortisBC should match the customer's requirements as nearly as practicable; however, the Panel concludes that offering non-firm service is not practicable in this case.

The Panel finds that FortisBC does not have to provide non-firm service given there are no benefits to FortisBC of doing so even if it is what the customer is requesting. The Panel therefore determines that offering only firm service does not make the proposed Stand-by Rate, on this basis alone, unjust, unreasonable, unduly preferential or unduly discriminatory.

However, in the Panel's view good rate design gives customers a strong incentive to use electric service more efficiently, to minimize the costs they impose on the system, and to avoid charges when service is not taken.

G-124-08

IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

RESIDENTIAL INCLINING BLOCK RATE APPLICATION

REASONS FOR DECISION TO ORDER G-124-08

September 24, 2008

Before:

Anthony J. Pullman, Panel Chair & Commissioner
Robert J. Milbourne, Commissioner
Liisa A. O'Hara, Commissioner

BC Hydro stated that it did not rely on a long-run incremental cost study prepared for it by E3 and dated December 1, 2004 which was entered in evidence in the 2007 RDA, on the grounds that it was out-of-date (Exhibit B-7, BCOAPO 2.44.1). It filed a study by E3 concerning the use of marginal costs in ratemaking which stated: "Crucially, marginal costs can vary widely according to location and time..." Marginal capacity cost of transmission or distribution may be low in locations where there is always available capacity, and high in other locations where capacity is often constrained (Exhibit B-28, Undertaking 23, p. 5).

BC Hydro stated that its best current estimate of the cost of new energy supply at the plant gate, grossed-up for losses, is 8.27 cents/kWh. This estimate excludes any incremental delivery costs of either transmission or distribution and comprises the weighted average levelized price from the 2006 CFT of 7.36 cents/kWh (which is the Tier-2 price for RS 1823), and the effect of grossing up for losses (Exhibit B-3, BCOAPO 1.3.3).

BC Hydro stated that making its current flat rate structure more efficient requires bringing the marginal energy rate closer to, but not greater than, the long-run marginal cost of new energy supply. Assessing any particular rate design against this principle requires the establishment of a marginal rate "ceiling" - the rate that should not be exceeded by the marginal rate. If BC Hydro's residential tariff provided for the recovery of residential fixed delivery and customer costs through a mechanism other than the energy charges (the Step-1 rate and Step-2 rate in BC Hydro's proposal) then establishing the marginal rate "ceiling" would be a simple matter: the "ceiling" would be the long-run cost of new energy supply.

However, BC Hydro stated that under its residential tariff structure the Basic Charge collects only about six percent of the total residential cost of service, and does not recover the residential fixed delivery and customer costs, which have to be recovered through the energy charge (there being no demand charge). BC Hydro stated that this means that a "ceiling" rate that was based only on the long-run cost of new energy supply would be set at an artificially low amount, resulting in a less efficient pricing structure than one which acknowledged that the energy charges were being used to recover more than simply energy costs. BC Hydro estimated that about three to four cents/kWh

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of the current flat energy charge recovers the residential fixed delivery and customer costs and stated that these costs ought to be added to the marginal cost of new energy supply for the purpose of establishing the marginal rate ceiling i.e. the rate which the Step-2 rate should not exceed (Exhibit B-7, BCOAPO 2.44.1).

CEC and Terasen accept the principle that Step-2 should be priced at the long range marginal cost of new supply (CEC Argument, p. 12; Terasen Argument, para 13).

BCOAPO submits that BC Hydro has offered no evidence to support its assertion that the long term cost of resource smart projects or acquisitions from IPP projects is the marginal cost associated with marginal changes in the load. BCOAPO notes that until 2016 BC Hydro's long term supply acquisitions are largely being driven by the need to achieve the self-sufficiency goals set out in the 2007 Energy Plan and that domestic demand in the same period will be static, and submits that, since acquisition requirements and their timing appear to be relatively insensitive to marginal changes in demand, a price reflecting these acquisition costs does not equal BC Hydro's marginal cost due to a change demand. The price signal in the current flat residential rate is closer to the marginal cost consequences of marginal consumption changes than the Step-2 price signal being proposed for RIB (BCOAPO Argument, pp. 43-44). BCOAPO submits that a "long run spot market forecast represents a reasonable estimate of BC Hydro's long run marginal cost due to a marginal change in load , at least between now and 2016" (BCOAPO Argument, p. 47).

In Reply BC Hydro submits that "BCOAPO ['s] argument in this section is utterly unsupported by any evidence from any witness qualified to opine on these matters" and cites Dr. Orans' testimony as to why the short-run cost of new supply is "a very confusing signal with lots of noise in it (T4:627-28)", and using the long-run full cost brings rate stability (BC Hydro Reply, p. 6).

BC Hydro submits that statements made by BCOAPO in this regard should not be given any weight.

British Columbia
Utilities Commission

IN THE MATTER OF

British Columbia Hydro and Power Authority
2015 Rate Design Application

REASONS FOR DECISION
Transmission Service Freshet Rate Pilot

February 9, 2016

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

1. The uncertainty of whether or not customers will have incremental load increases during preschedule trading. BC Hydro states that for the upcoming trial period, incremental industrial load under the freshet rate pilot are not expected to have a material impact on marketing or operational flexibility.[17]

2. Potential differences between the day ahead prescheduled market as relied upon for the freshet rate and the real time market. BC Hydro explained that any such differences are likely symmetric and thus can be expected to net out close to zero. Given the relatively small volumes ranging from 5 aMW to 30 aMW, BC Hydro does not consider this risk to be material.[18]

3. The potential for tie line constraints to limit the ability to import from the U.S. market. This may result in storage energy, which may have been used during a higher value period being used instead to supply incremental freshet load. BC Hydro states that while tie line limitations can occur during the freshet period, it does not consider them to be an issue as long as major system spills are neither anticipated nor occurring. BC Hydro states it will monitor tie constraints impact as part of the freshet pilot.[19]

4. The potential for load shifting. Load shifting occurs in those instances where customers are able to reduce RS 1823 energy in the non-freshet months and increase it during the freshet months. BC Hydro states that although shifting is a complex issue and there may be some negative impacts on non-participating customers, shifting loads from non-freshet to freshet periods should be eligible for the freshet pilot as long as there is incremental consumption during freshet. The primary risk of shifting is the loss by non-participating customers in the event the load reduction during the non-freshet period results in reduced revenue that is greater than offsetting export revenues. The potential financial impact was discussed during the SRP where BC Hydro acknowledged that a reduction in Tier 2 energy would result in a revenue loss of $85 an hour with an offsetting gain in the export market of $30 to $35 a megawatt hour if in the winter.[20]

BC Hydro considers the financial impact of the load shifting risk during the freshet pilot to be small. It states that based on the take-up range of 5 aMW to 30 aMW, the impact on non-participating ratepayers could range between $200,000 and $4.3 million. In addition, BC Hydro points out that the risk is much less "because the most likely users of the rate (chemical producers and some large forestry producers) are consuming, on average, very close to 90 percent of their respective Customer Base Lines (CBL) and would be at risk of a downward adjustment in their RS 1823 CBL if they shifted any more than ~1 to ~3 percent of their load into the freshet period."[21]

BC Hydro outlined two scenarios where shifting could benefit non-participating customers. The first of these relates to the potential for the shifted amounts to be reflected as a reduction in its long-term load forecast. This could result in a long run marginal cost reduction that exceeds the RS 1823 revenue reduction. BC Hydro acknowledges that this is unlikely in the short term given that the freshet rate is a two-year pilot and any changes in customer behaviour are not likely to be reflected in the long-term load forecast. A second benefit could be where the load reduction in non-freshet months is in the winter and "there could be capacity benefits to BC Hydro and/or higher value (relative to other non-freshet periods) from additional energy not being

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[17] Exhibit B-1, p. 7-38; Exhibit B-5, BCOAPO IR 1.170.1.
[18] Exhibit B-5, BCOAPO 1.170.1.
[19] Exhibit B-1, p. 7-38; Exhibit B-5, BCOAPO 1.170.1; T2:253.
[20] Exhibit B-1, p. 7-42; Exhibit B-1, Appendix C-5B, p. 35; T2:206 and 253
[21] Exhibit B-1, p. 7-42; Appendix C-5B, W.S. #10, pp. 35-37.

consumed." BC Hydro states that the impact of shifting is difficult to identify but it will be considered in evaluating the freshet rate pilot.[22]

Another potential area of risk is that of natural growth in consumption due to business expansion. This was explored to a degree within the SRP where Commission staff queried whether the recent Canadian dollar slide may be expected to result in increased production by pulp and paper companies. BC Hydro acknowledged "that there is an opportunity that potentially customers selling their goods into the states, they may be increasing production."[23] A pulp and paper industry representative from AMPC (i.e. Catalyst Paper) observed that "[p]redicting paper prices is a mug's game. Paper markets around North America are dropping 10 percent year over year."[24]

3.3.2 Need for the freshet rate pilot project

CEBC questioned whether there is a freshet problem and whether there is a need for a freshet rate pilot. In the SRP it posed a number of questions to BC Hydro with respect to the informational graphs presented by BC Hydro to demonstrate the surplus that exists during the freshet period. CEBC questioned whether these graphs actually demonstrated there was a significant surplus over the freshet period as claimed. Specifically, CEBC asked how many gigawatt hours of surplus electricity there is for customers to take. BC Hydro was unable to answer the question in precise terms due to the information presented being in monthly averages. However, it pointed out that in an average water year it can be expected that a surplus would exist for half the time resulting in exporting or spilling and for the other half the time there would be no surplus as water levels would be below the monthly average.[25]

CEBC maintained that the surplus is a very small amount and estimates it to be around 50 average megawatts translating to about 36 gigawatt hours a year. It submits that when this is viewed in the context of BC Hydro's delivery of 54 to 55,000 gigawatt hours, "it's essentially not much more than a rounding error." CEBC asserted that there is no freshet problem and no need for a tariff solution. A more appropriate solution would be to have BC Hydro enter into contracts with industrials willing to purchase any surplus amounts during freshet.[26]

Commission staff also questioned the information on BC Hydro's graphs and what they demonstrated. One question with reference to the graph on page 2 of Exhibit B-12 asked BC Hydro to "confirm that the potential freshet period energy oversupply is, on average, expected to be the very small area between the implied minimum generation average line, the red line, and the average load line, the black line?" BC Hydro responded that:

> the graph was intended to show was for a monthly average what the average load would be against the average minimum generation. So it would be for that—yeah, the difference between those two, that small areas, would be on an average basis if you did it for the month when you'd be in a force generation period. What the graph isn't showing is how that would change within the month or how it would differ between the high load hour period and the low load hour period.[27]

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[22] Exhibit B-1, p. 7-42.
[23] T2:307.
[24] T2:306–307.
[25] T2:336; T2:217–220
[26] T2:336–337.
[27] T2:293.