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Our File: 14-3364
Date: November 17, 2015

VIA E-MAIL

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

Attention: Erica Hamilton, Commission Secretary

Dear Sirs/Mesdames:

Re: BC Hydro 2015 Rate Design Application (RDA)
Association of Major Power Customers (AMPC) Information Request No. 1 to BC Hydro

We are legal counsel to AMPC in this matter. Further to the Regulatory Timetable set out in Order G-166-15, enclosed please find AMPC's Information Request No. 1 to BC Hydro.

Please contact the writer if you have any questions.

Yours truly,

Bull, Housser & Tupper LLP

Matthew D. Keen

ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC)
INFORMATION REQUEST NO. 1
TO BC HYDRO

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

TABLE OF CONTENTS

A. COST OF SERVICE GENERAL

1.0 References:

Exhibit B-1, Application, Section 3.5, p. 3-7.

Exhibit B-1, Application, Appendix C-2A, Final Report – 2013 Cost of Service Methodology Review, p. 4 of 439.

Exhibit B-1, Application, Appendix C-2B, October 7, 2014 Workshop No. 4, Cost of Service (COS) Methodology – BC Hydro Summary and Consideration of Participant Feedback, p. 110 of 205.

On p. 3-7, BC Hydro indicates that its consultants ”reviewed BC Hydro’s COS analyses, models, spreadsheets used in ratemaking processes, and also undertook discussions with relevant BC Hydro business units whose costs impact the COS study”. BC Hydro’s consultants also reviewed “COS methodologies used by nine electric utilities in ten jurisdictions”.

At p. 110 of Appendix C-2B, BC Hydro further notes that it “proposes methodology changes to certain directives from the 2007 RDA Decision relating to DSM functionalization, BC Hydro Heritage hydroelectric Generation classification, IPP contract classification, Distribution classification and allocation, and Customer Care classification” on the basis of “recommendations from BC Hydro’s COS consultants, Cuthbert Consulting Inc. and NewGen Strategies and Solutions, LLC”.

1.1 Please provide all studies and supporting documentation provided by the SAIC/Leidos/NewGen/Cuthbert Consultants pertaining to the demand and energy classification of generating and transmission assets (Heritage hydro, thermal and contracted IPPs) and IT and metering costs in preparation for the RDA and workshops on Fully Allocated Cost of Service Studies <u>that are not currently on the record.</u>

2.0 Reference: Exhibit B-1, Application, Appendix C-2C, Draft F2016 Cost of Service (COS) Model, Tables 1 and 2, pp. 4 and 6 of 79.

In Table 1, BC Hydro provides the F2016 COS results using both BC Hydro’s proposed methodology and the same methodology used in its F2013 COS study, which used the 2007 RDA decision as its base.

In Table 2, BC Hydro then provides the impact of methodological changes by various classifications to the Residential revenue-to-cost (R/C) ratio, but does not provide the impact of changes for other rate classes.

2.1 With respect to the R/C ratios provided in Table 1 and Table 2 of the Draft F2016 COS Model (pages 4 to 6 of 79 of Appendix C-2C) please itemize the impact of each method change between the F2013 method using the 2007 RDA Decision (column B) and the proposed method (column A) on the 2016 R/C ratios for each rate class (i.e. provide equivalent information for each rate class to that provided for the Residential rate class in Table 2 of Appendix C-2C).

B. HERITAGE HYDRO

3.0 References:

Exhibit B-1, Application, Section 3.7.1, p. 3-24.

Exhibit B-1, Application, Appendix C-2A, Workshop 2 Strawman Proposal, p. 248 of 439.

Exhibit B-1, Application, Appendix C-2B, Workshop 4 Discussion Guide, Section 4, pp. 66-67 of 205.

At p. 3-24, BC Hydro indicates that in the application it “uses a system load factor approach to classify Generation, resulting in a 55 per cent energy/45 per cent demand split”.

At. p. 66 of 205 of Appendix C-2B, BC Hydro indicates it “believes…a load factor approach, is most appropriate…compared to a capacity factor approach weighted by book value”. BC Hydro provides four reasons: (1) “[h]ydroelectric capacity…is not used exclusively to meet peak loads in the winter season” but is “also used to optimize the hydroelectric system and earn trade income for all ratepayers; (2) “there is reduced variability with the load factor approach”, whereas the “capacity factor calculation can be variable year over year because of the addition of hydroelectric generating capacity, and (3) “[l]oad factor reflects actual retail usage of resources while the capacity factor reflects what resources are available to be used”, and that assigning “costs based on actual usage…is more appropriate”, and (4) “the load factor approach has jurisdictional support”.

At p. 67 of 205 of Appendix C-2B, BC Hydro provides Table 5, which shows the R/C ratio impact of its preferred load factor approach:

Table 5 Hydroelectric Classification R/C Ratio Analysis

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

3.1 Please confirm that all generators subject to dispatch provide both capacity and energy on the system. If not confirmed, please fully explain your response.

3.2 Please confirm that recent generation additions at Revelstoke and Mica provide both additional energy and capacity for the system. If not confirmed, please fully explain your response.

3.3 Please confirm that there is no standard and commonly used allocation between capacity and energy delivered by generators. If not confirmed, please fully explain your response.

3.4 Please provide examples of any jurisdictions that BC Hydro or its consultants are familiar with that use the capacity factor approach to classify generation assets.

3.5 Please provide examples of any jurisdictions that BC Hydro or its consultants are aware of that use the value of capacity approach to classify generation assets.

3.6 Please provide examples of any jurisdictions that BC Hydro or its consultants are aware of that classify hydraulic generation assets as more than 40% energy-related.

3.7 Please confirm that, since 2007, BC Hydro has seen an increase in the proportion of non-dispatchable generation on its system. If possible, please quantify this effect. If not confirmed, please fully explain your response.

3.8 Please confirm that BC Hydro's system is transitioning from an energy constrained system to a capacity constrained system. If not confirmed, please fully explain your response.

3.9 Please confirm that BC Hydro uses multi-year averages for stability purposes when calculating metrics used for rate design and cost allocation decisions, and provide examples. If not confirmed, please fully explain your response.

3.10 Please confirm that "Option 3" in Table 5 at p. 67 of Appendix C-2B of Exhibit B-1 reflects "Sensitivity 1" on page 3-24 of Exhibit B-1. If not confirmed, please provide a revised version of Table 5 showing the same analysis for Sensitivity 1.

3.11 Please recalculate the 2016-2019 revenue to cost ratios found in Table 5, replacing the heritage hydro generation classification of 55% energy and 45% demand with the previous classification of 45% energy and 55% demand (adding Sensitivity 1 per the response to 3.10 above if required), but applying that classification to all of:

(i) heritage hydro and IPP generation; and

(ii) heritage hydro, IPP and thermal generation.

C. IPP GENERATION

4.0 References:

Exhibit B-1, Application, Section 3.7.3, p. 3-26, Independent Power Producers (IPP)

Exhibit B-1, Application, Appendix C2-A, Attachment 4, pp. 2-3

At p. 3-26, BC Hydro's indicated that its "preferred IPP classification option is the 'Value of Capacity' option which results in a 93 per cent energy and 7 per cent demand classification." The Value of Capacity approach allocates the relative portion of IPP costs to demand "based on the relative portion of capacity benefits from the IPP portfolio over the IPP costs, as preferred for F2016 COS study purposes."

At p. 2-3, BC Hydro indicates that "a Fixed/Variable Approach Classifying IPP purchases on the basis of the fixed and variable components of IPP EPAs will produce counter intuitive results".

4.1 Please provide examples of any jurisdictions that BC Hydro or its consultants are familiar with that use the following approaches to classify generation assets:

(i) fixed/variable;

(ii) modified fixed/variable;

(iii) value of capacity; and

(iv) value of energy.

4.2 Please confirm that IPP contracts relate to generation assets that are non-dispatchable. If not confirmed, please fully explain your response.

4.3 Please confirm that all delivered generation associated with IPP contacts is compensated regardless of system demand. If not confirmed, please fully explain your response.

4.4 Please confirm that energy delivered by IPPs under long-term contracts does not vary in response to the hourly, daily, weekly, monthly or annual level of customers' aggregate energy consumption.

4.5 Please confirm that once BC Hydro enters into an IPP contract, its costs under the contract are fixed, rather than variable. If not confirmed, please fully explain your response.

4.6 Please confirm that an increased proportion of intermittent and seasonally varying energy sources interconnected to the system and not subject to dispatch by the utility operator places a greater reliance on other sources that can be dispatched to provide capacity. If not confirmed, please fully explain your response.

4.7 Please confirm that the use of net-metering and feed-in tariffs that provide "virtual energy storage" similarly place a greater reliance on sources that can be dispatched to provide capacity. If not confirmed, please fully explain your response.

D. THERMAL GENERATION

5.0 Reference: Exhibit B-1, Application, Section 3.7.2, p. 3-25

At p. 3-25, BC Hydro indicates that there are "three BC Hydro-owned thermal generating stations: Fort Nelson Generating Station (FNG), Prince Rupert Generating Station (PRG) and Burrard Generating Station (Burrard)." BC Hydro proposes the following for classifying these stations:

- FNG – use a load factor approach specific to the Fort Nelson service territory to classify FNG's O&M and capital generation costs. This results in a 74 per cent energy and 26 per cent demand classification. Fuel costs are classified as 100 per cent energy;

- PRG – For simplicity, use the system load factor with no adjustment for IPP supply to classify PRG's O&M and capital generation costs. This results in a 60 per cent energy and 40 per cent demand classification. Fuel costs are classified as 100 per cent energy; and

- Burrard – classify Burrard O&M and capital costs as 100 per cent demand with associated fuel costs treated as 100 per cent energy.

5.1 Please provide examples of classifications used for base-load and peaking thermal generation in other jurisdictions.

5.2 Please explain in detail why thermal generation is not 100% demand related.

5.3 Please confirm that the Burrard, Prince Rupert, and Fort Nelson generation facilities function as transmission, peaking and base load assets, respectively. If not confirmed, please fully explain your response.

E. IT COSTS

6.0 Reference: Exhibit B-1, Application, Section 3.6.5.1, p. 3-17

At p. 3-17, BC Hydro estimated the functional split in IT costs shown in Table 3-2.

Table 3-2 IT Functionalization

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

BC Hydro indicated that its “[c]osts were functionalized according to the main beneficiary of the services – Generation, Transmission, Distribution, etc”, and where possible, “costs were functionalized directly”.

6.1 Please provide the last 10 years of total IT costs for BC Hydro.

6.2 Please provide a detailed breakdown of IT costs by each utility function listed in the cost of service study.

6.3 Please show how each IT cost listed in 6.2 has changed in the function to which it was allocated during the past 10 years.

6.4 Please provide the total of all IT costs related to the implementation, operation or upgrade of "smart meters".

6.5 Please provide any data analyses extracted from "smart meters" and any associated reports generated within BC Hydro or by contractors.

6.6 Please provide the initial business case for "smart meters".

F. TRANSMISSION EXTENSIONS AND TS6

7.0 Reference: Exhibit B-1, Application, Section 1.5.2, p. 1-21

At p. 1-21, BC Hydro indicates that it "confirmed with stakeholders that Transmission extension policy and Distribution extension policy would be the subject of a later module (referred to as Module 2)."

7.1 Please confirm that BC Hydro's view is that tariff supplement number six requires updating. If not confirmed, please fully explain your response.

7.2 Please confirm that tariff supplement number six will continue to govern any 2015 and 2016 transmission extension applications. If not confirmed, please fully explain your response.

G. BONBRIGHT CRITERIA WEIGHTING AND LRMC

8.0 References:

Exhibit B-1, Application, Section 2.3.2.2, p. 2-46 and p. 2-52

Exhibit B-1, Application, Section 2.4.1, p. 2-56

At p. 2-46, BC Hydro discusses the concept of long run marginal cost as follows:

LRMC can be defined as the change in the long-run total cost resulting from a change in the quantity of output produced. In short, LRMC represents the price of the most cost-effective way of satisfying incremental customer demand where existing resources are insufficient to meet that demand. The standard economic technique used to determine LRMC is to calculate the minimum present-day view of the cost of meeting a permanent increment (or decrement) of demand in which all capital and operating production inputs can be considered variable.

BC Hydro then describes at p. 2-52 that its "energy LRMC outlook is as follows: $85/MWh-$100/MWh from F2017 to about F2030."

Finally, at p. 2-56, BC Hydro lists the four categories of Bonbright criteria it applied in stakeholder engagement: (1) Economic efficiency; (2) Fairness; (3) Practicality; and (4) Stability.

8.1 Please confirm that the long run marginal cost for electricity (LRMC) reflects the long-term projected cost to satisfy incremental customer electricity demand. If not confirmed, please fully explain your response.

8.2 Please confirm that the LRMC is a projection that is a function of a number of external factors including legislation, technology, and market conditions. If not confirmed, please fully explain your response.

8.3 Please confirm that because LRMC is a function of a number of external factors, there is uncertainty in determining the projected LRMC. If not confirmed, please fully explain your response.

8.4 Please confirm that as a result of the uncertainty in determining LRMC, any determination of LRMC must be viewed as a range of potential LRMCs that reflect the uncertainty that goes into the LRMC determination. If not confirmed, please fully explain your response.

8.5 Please confirm that BC Hydro's energy LRMC outlook of $85-$100 per MWh for F2017 to F2030 (RDA, p. 2-52) reflects such a range. If not confirmed, please fully explain your response.

8.6 Please confirm that because of the external factors that influence LRMC, the LRMC may fall outside BC Hydro's projected $85-$100 range in F2017 to F2030. If not confirmed, please fully explain your response.

8.7 Please confirm that the short run marginal cost for electricity (SRMC) can be less than the long run marginal cost. If not confirmed, please fully explain your response.

8.8 Please confirm that the SRMC can be less than the average cost of electricity. If confirmed, please estimate the SRMC for 2015. If not confirmed, please fully explain your response.

H. TRANSMISSION SERVICE RATE CLASS

9.0 Reference: Exhibit B-1, Application, Section 4.4, p. 4-18 and p. 4-22.

At p. 4-18, BC Hydro indicates it "developed a graph showing coincident factor and load factor that illustrated FortisBC and New Westminster as having load profiles that are relatively unique when compared to Transmission Service customers."

BC Hydro further notes at p. 4-22 that it "proposes to address the issue of creating separate rate classes for FortisBC and New Westminster as part of its F2019 COS". BC Hydro "agrees with New Westminster that the potential impacts of creating separate rate classes for FortisBC and New Westminster can be better understood at the time of the F2019 COS".

9.1 Please confirm that each of the following are currently included in the Transmission Service rate class:

i. New Westminster;
ii. FortisBC;
iii. UBC;
iv. SFU; and
v. YVR.

If not confirmed, please fully explain your response.

9.2 Please confirm that each of the following are not industrial customers:

i. New Westminster;
ii. FortisBC;
iii. UBC;
iv. SFU; and
v. YVR .

If not confirmed, please fully explain your response.

9.3 Please confirm that each of the following are better characterized as "wholesalers" to either residential, SGS or MGS customers than characterized as industrial customers:

i. New Westminster; and
ii. FortisBC.

If not confirmed, please fully explain your response.

9.4 Please confirm BC Hydro has previously included a separate rate class for wholesale customers in cost of service studies. If not confirmed, please fully explain your response.

9.5 Please confirm BC Hydro has the necessary data to prepare a cost of service study with wholesale customers as a separate rate class from other transmission level customers. If not confirmed, please fully explain your response.

9.6 Please confirm that UBC, SFU and YVR are being retained in the transmission rate class because their coincidence and load factor profiles resemble industrial customers, as shown in Figure 7 on page 61 of the Workshop 5 Consideration Memo at Appendix C-5A. If not confirmed, please fully explain your response.

9.7 Please confirm that price elasticity for electricity reflects responsiveness of the quantity of electric demanded by a customer in response to changes in electricity price. If not confirmed, please fully explain your response.

9.8 Please confirm that a price elastic electricity customer will have a greater than a 1% decrease in quantity demanded for each 1% increase in price. If not confirmed, please fully explain your response.

9.9 Please confirm that a price inelastic customer will have less than a 1% decrease in quantity demanded for each 1% increase in price. If not confirmed, please fully explain your response.

9.10 Please confirm that industrial customers are typically price elastic. If not confirmed, please fully explain your response.

9.11 Please confirm that each of the following customer types are typically price inelastic.

i. residential customers;
ii. SGS customers; and
iii. MGS customers.

If not confirmed, please fully explain your response.

9.12 Please provide the number of industrial customers that have ceased normal service under the Transmission Service rate class due to shut downs or for any other reason in 2015, and the associated aggregate load those customers represented before ceasing normal service.

9.13 Is BC Hydro aware of any other utilities that include wholesale-type customers like New Westminster and FortisBC the same rate class as industrial customers. If so, please list all example BC Hydro is aware of, including the type of customer and the rate class they are included in.

9.14 Please confirm that most utilities serve wholesale customers such as municipalities on a different rate schedule than industrial customers. If not confirmed, please fully explain your response.

I. CUSTOMER BASELINE LOADS

10.0 References:

Exhibit B-1, Application, Appendix C-2C, Schedule 1.0, p. 11 of 79.

Exhibit B-1, Application, Appendix C-2C, Schedule 5.0, p. 22 of 79.

Exhibit B-1, Application, Appendix C-2C, Schedule 5.1, p. 23 of 79.

In Schedule 1.0, BC Hydro lists its planned costs that make up its revenue requirement.

In Schedule 5.0, BC Hydro provides its energy allocators for F10-F14, F16, and F13.

In Schedule 5.1, BC Hydro provides its demand allocators for F10-F14 and F13.

10.1 Please confirm if the “Energy @ Customer Meter” figures used in Schedule 5.0 of the Cost of Service Study reflect the full customer baseline load (CBL) energy of all transmission customers. If not, please provide the values that would be included in Schedule 5.0 if showing the full Energy @ the Customer Meter reflecting the full CBL energy for all transmission customers (i.e., assuming all CBL was being used) including a description of any necessary estimates or assumptions.

10.2 Please discuss if there would be any revisions necessary to the Demand Allocators (Schedule 5.1) if the Schedule 5.0 was adjusted to reflect the full CBL of transmission customers (i.e., to ensure consistency between CBL energy and peak loads). If so, please provide a version of schedule 5.1 reflecting this assumption, including any estimates and assumptions necessary.

10.3 Please discuss how the Planned Costs provided in schedule 1.0 of Appendix C-2C would change if BC Hydro were required (a) to serve the full CBL energy of all Transmission customers, and (b) to credit back to the Transmission class all costs incurred by Hydro (via foregone revenue) to acquire all assumed unused CBL energy at the Tier 2 rate (classified and allocated consistent with the treatment for IPP power acquisition). Please provide a revised version of Schedule 1.0 reflecting this assumption and a description of any estimates or assumptions used in preparing the analysis.