British Columbia Utilities Commission

Laurel Ross
Acting Commission Secretary

Commission.Secretary@bcuc.com
Website: www.bcuc.com

Sixth Floor, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
TEL: (604) 660-4700
BC Toll Free: 1-800-663-1385
FAX: (604) 660-1102

Log No. 51126

VIA EFILING

May 30, 2016

BC HYDRO
2015 RATE DESIGN **EXHIBIT A-30**

Mr. Chris Weafer
Owen Bird
Barristers & Solicitors
PO Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC V7X 1J5

Dear Mr. Weafer:

Re: British Columbia Hydro and Power Authority
Project No. 3698781/G-156-15
2015 Rate Design Application Module 1
British Columbia Utilities Commission Information Request to
Commercial Energy Consumers Association of British Columbia

Further to your May 9, 2016 filing of intervener evidence, enclosed please find Commission Information Request No. 1.

In accordance with the amended Regulatory Timetable established in Order G-50-16, please file your responses electronically with the Commission by Wednesday, June 22, 2016.

Yours truly,

Original signed by:

Laurel Ross

EC/cms
Enclosure

British Columbia Utilities Commission
INFORMATION REQUEST NO. 1 TO THE
COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

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

TABLE OF CONTENTS

A. INTERRUPTIBLE RATE – PURPOSE

1.0 Reference: Exhibit C1-10, Section 3, pp. 23; Section 9, p. 40; Exhibit B-1, p. 1-23; Order G-50-16; Streamlined Review Process Transcript Volume 2, pp. 332-334
Regulatory considerations

On page 23 CEC states:

> A Non-Firm Interruptible Rate and Demand Response Program Pilots are proposed at this time to coincide with the current BC Hydro Rate Design (RDA) proceeding. BC Hydro planned to address voluntary Residential and General Service options in Module 2 of the RDA, as it considered it imperative that issues with the default rates were addressed prior to optional rates. In this way, Module 1 was to lay the foundation for Module 2.
>
> The establishment of a pilot project at this time could permit development activities to be completed prior to or in conjunction with the evaluation of Module 2, ensuring that the program details and/or results are available for examination and approval during Module 2. Delaying the Pilot project could result in several years delay for its implementation if development activities are not initiated until after a Module 2 Decision is rendered.

On page 40 CEC summarizes:

> Non-firm interruptible rates, and/or Demand Response/Load Curtailment Programs are valuable offerings that should be explored and made available to Large General Service and Medium3 General Service Customers… Commercial LGS and MGS customers are asking BC Hydro and the BC Utility Commission to assist them in managing their cost structures and their competitiveness through initiation of pilot programs such as those proposed in this paper. Their request is that mitigation of future cost pressures begin as soon as possible.

At the SRP, on pages 333-334 of transcript volume 2, counsel for CEC says that CEC is urging "a current and ongoing discussion to see where there could be mitigations for incentive type rates as the IRP contemplates.", and "also that we can have the opportunity to tie in Module 1 discussion to Module 2 where the commercial rates may cross over between the two. Or as I said in my opening comments, there should be regulatory efficiency through doing that and hopefully a benefit to all involved."

On page 1-23 of Exhibit B-1, BC Hydro explains:

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

Order G-50-16 amended the Regulatory Timetable to provide for an Oral Hearing in August 2016.

1.1 Is the main purpose of CEC's Evidence to make a case and to tie Module 1 to Module 2? If not, please explain what the main purpose is of CEC's Evidence being provided in Module 1.

1.2 Please elaborate on how CEC's proposal for a pilot project could be established at this time and the results be made available in time for Module 2. In your response, please provide a detailed timeline.

1.3 Does CEC agree with BC Hydro that a load curtailment pilot is a program within the definition of a "demand-side measure" as per section 1 of the *Clean Energy Act* and is not defined as a "rate" or "service"?[1] If CEC does not agree, please provide your reasons for including this proposal in the current Rate Design Application.

B. INTERRUPTIBLE RATE - NEED

2.0 Reference: Exhibit C1-10, Section 2, pp. 6-9; Exhibit B-17, p. 8; Table 4; FortisBC Inc. Application for Approval of Stepped and Stand-by Rates Decision, p. 47 Rationale

On page 6 of CEC's evidence CEC says: "If BC Hydro customers can operate in a way that will reliably enable them to stay off the BC Hydro hydroelectric system peak then there will be an economic case for BC Hydro to design a rate which does not require a full demand charge component to charge for the electric system capacity which would be required to deliver electricity on the coincident electric system peak."

On page 7 of CEC's evidence CEC explains: "The BC Hydro system peak is typically in the range of about 9500 MW and could last over a period of a few days to a week or two. To the extent that customer load that may otherwise be on the peak could be moved off the coincident electric system peak this would enable BC Hydro to defer adding capacity in the future to the serve such load at the peak."

On page 9 of CEC's evidence CEC states: "The transmission system costs are substantially driven by needing to have the capacity to serve BC Hydro hydroelectric system coincident peak demand as well. Incremental additions to the transmission system can be avoided, if the demand is kept off the coincident electric system peak. However the distribution system costs must be adequate to deliver service to meet the local customer peak demand requirements. So distribution cost responsibility falls more directly to the customer."

In Exhibit B-17, BC Hydro explains: "Consistent with the 2013 IRP, the capacity [Load Resource Balance (LRB)] outlook in this document continues to show a need to acquire additional capacity resources over and above the other resource acquisitions in the plan. BC Hydro continues to base the [Long-run Marginal Cost (LRMC)] for capacity resources on Revelstoke Unit 6 which is the most cost effective generation capacity resource on a unit cost basis (Unit Capacity Cost of $50 to $55/kW-year).The updated capacity LRB outlook in this document shows that the expected need for Revelstoke Unit 6 has been advanced to F2026 from F2030 in the 2013 IRP. At the same time, Revelstoke Unit 6 continues to be a contingency resource for capacity needs prior to Site C, requiring its earliest in service date (now estimated at F2022) to be maintained."

In Table 4 of Exhibit B-17, BC Hydro shows its capacity after planned resources from F2017 to F2025 (i.e. prior to the addition of REV6) ranging from 13,122 MW to 13,881 MW. If a 14% spinning reserve is removed, this would leave an effective load carrying capability ranging from 11,313 MW to 11,959 MW. BC Hydro also provides its forecast demand and demand side management. The result is a range of potential capacity to peak demand surpluses/deficits ranging between 1,450 MW in surplus to 2,300 MW in deficit between F2017 and F2025 (i.e. before REV6).

[1] Exhibit B-1, p. 2-44.

On page 47 of the FortisBC Inc. Application for Approval of Stepped and Stand-by Rates Decision dated May 26, 2014, that Panel explained: “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.”

2.1 Please confirm, or otherwise explain, that BC Hydro’s capacity between F2017 and F2025 is expected to be in excess of its system peak demand.

2.2 Please explain the purpose of a 14% spinning reserve. Are there any other capacity/demand reserves/contingencies built into BC Hydro’s estimates?

2.3 Please describe the value to BC Hydro of providing a new non-firm rate to commercial class customers prior to the point at which BC Hydro would have a need for new capacity.

2.4 Would CEC’s proposals provide more value to BC Hydro if the proposals were based on a need to alleviate a local or regional constraint? Please explain.

2.4.1 Similarly, does CEC know of any constrained areas where commercial class customers are located? Please elaborate.

2.5 Are CEC’s proposals for an interruptible rate, a demand response/load curtailment program, and/or Time of Use rate for commercial class customers considered part of BC Hydro’s current planned resources, or would they be considered over and above the current planned resources? Please explain.

C. INTERRUPTIBLE RATE - OPPORTUNITY

3.0 Reference: Exhibit C1-10, Section 2.1, p. 8
Available peak capacity reductions

On page 8 CEC states:

> Staying off the BC Hydro peak could involve approximately 5 days of interruption typically no more than twice per year to offset the first increment of about 750 MW of peak and up to 10 days of interruption to offset the next 250 MW of interruption simply based on the daily analysis of the peak occurrences provided by BC Hydro.
>
> As can be seen from the BC Hydro hydroelectric system load profile for a peak day there is considerable room overnight (11:00 pm to 7:00 am) for use of the system capacity without contributing to the peak. This timing makes available approximately 3,000 MW of capacity. Further the main peak occurs between the hours of 5:00 pm and 10:00 pm. This would enable BC Hydro to access approximately 500 MW of capacity to the extent that customers avoid electricity use on the coincident peak days between those hours. Finding customers able to commit to being off peak on a consistent and reliable basis would enable BC Hydro to avoid planning for, building and committing capacity for use by those customers.

Also on page 8 CEC provides a chart titled “BC Hydro Resource Planning Presentation, 2005” whose subheading suggests the chart data are the Peak Day electric load profile of the BC Hydro electric system.

3.1 Is there reason to believe that BC Hydro's Peak Day electric load profile has changed since 2005? Please elaborate.

3.2 Please further explain how CEC derives the 5 and 10 day capacity estimates and the 3,000 MW capacity estimate.

3.3 Are these the same estimates used by BC Hydro to support its Transmission load curtailment pilot? If they are different, please explain why.

3.4 What is CEC's understanding of BC Hydro's position regarding the potential capacity reductions available in the above quote?

4.0 Reference: Exhibit C1-10, Section 2.4.1, pp. 11, 13; Section 8.2, p. 39
Greenhouses

On page 11 CEC states: "The total area for greenhouses in BC is 3,313,186 m^2, which is equivalent to 818 acres. Of these the total in the lower mainland is 3,161,262 m^2 or 781 acres. The total acreage of the greenhouses that in a survey reported having lights is 685,407 m^2 or 169 acres and their combined area under lights is 223,707 m^2 or 55 acres. The 55 acres of lighting would likely involve approximately 27 MW of load."

On page 13 CEC states:

> The potential for growers to enhance production through increased lighting is particularly relevant because it potentially represents offsetting revenue for BC Hydro to replace the revenue reduction in demand charges with additional energy sale. Increased productivity for the greenhouse growers can create benefits for the overall industry and province.
>
> Greenhouse growers have the ability to manage their lighting load. The optimum period of time for plants to receive lighting is about 18 hours during the period where lighting is being used extensively, after which the plants need to rest. The plants can for periods of time get by with about 8 hours of lighting without significant damage to the plant yields and the overall productivity of the plants. For short periods the plants can get by without lighting. The timing of when lighting is diminished is more critical in an early stage of the plant growth and production cycles. Also if the growers have some advance warning time for a lighting outage they would be able to prepare the plants to be better able to withstand the lack of light."

And, on page 39 CEC states: "This additional usage of electrical energy will provide a revenue increase which will offset the reduced revenue from demand charges and in the pilot it would be useful to determine the extent and value of this revenue offset to the commercial class."

4.1 Please provide the source for the above statements.

4.2 Please provide the derivation of the 27 MW, including the basis for the total area of greenhouses, the amount of the area that is in the Lower Mainland, the amount that have lights and how that number of acres results in 27 MW of demand.

4.3 Of the 27 MW, how much would be attributed to large general service (LGS) customers and how much to medium general service (MGS) customers?

4.4 Of the greenhouses' demand, how much currently coincides with BC Hydro's peak demand? Please explain and provide evidence.

4.5 Do greenhouses have specific distinguishing features that warrant specific rate treatment? That is, should they have a rate all of their own? For example, are they naturally interruptible due to onsite back-up generation or do they typically have low load factors? Please elaborate.

4.6 Please elaborate on how managing greenhouse demand to avoid demand during the coincidental peak would create the opportunity for growers to enhance production through increased lighting.

4.7 How much additional energy must be sold to offset the revenue lost due to the proposed reduced demand charges for MGS and LGS greenhouses? How does this compare to the amount of energy currently being purchased?

5.0 Reference: Exhibit C1-10, Section 2.4.3, pp. 15, 17; Appendix 1
Flood pumping agencies

On page 15 CEC states: "There is approximately 3.2 MW of MGS customer demand and 18.5 MW of LGS customer demand."

On page 15 CEC also states "The evidence shows that the flood pumping requirements can fall very near to or on the BC Hydro peak demand because the rainfall in this case, November 30th, preceded the cold snap." And on page 17 explains: "If the flood pumping agencies can opt for a non-firm interruptible rate they could arrange to be off the BC Hydro hydroelectric system coincident peak and could avoid cause a need for capacity investment."

In Appendix 1 the BC Flood Pumping Coalition explains: "Historically, BC-FPC member municipalities and improvement districts have rarely pumped at full capacity during BC Hydro coincident peak days. When this is required, super-peak periods could be avoided by pumping with increased demand during Low Load Hours if the penalties for doing this were removed. An interruptible rate which eliminates demand charges and the Monthly Minimum Charge would provide a powerful incentive to avoid pumping during super peak periods."

5.1 Please further explain how a flood pumping agency would be able to guarantee to be off peak if a significant rainfall event occurred at or near a BC Hydro peak demand event?

5.2 Is there a risk to the public if flood pumping were interrupted? Please elaborate.

5.3 Please explain how the 3.2 MW and 18.5 MW were derived and provide that source information.

5.4 How probable is it that a heavy rainfall event will occur (i.e. flood pumping is required), and that event is immediately followed by a peak demand event (e.g. one of the coldest days of the year) wherein flood pumping is still required during that peak event, but at the same time that pumping can be deferred to off peak times? Please elaborate and provide evidence.

5.5 Would flood pumping authorities be expected to consume more energy if the demand charges were lower? Please explain.

5.6 Do flood pumping agencies have specific distinguishing features that warrant specific rate treatment? That is, should they have a rate all of their own? For example, are they naturally interruptible due to onsite back-up generation or do they typically have low load factors? Please elaborate.

6.0 Reference: Exhibit C1-10, Section 2.4.3, p. 20
Forestry manufacturing

CEC states "Key companies in the forestry sector have expressed interest in the initiative to explore options for dealing with their problems with the demand charge structure and costs and would like to explore participation in a pilot initiative with regard to a non-firm interruptible service."

6.1 What "problems" are the Forestry companies having with the demand charges? Do they have poor load factors or seasonal manufacturing? Please elaborate.

6.2 Similar to greenhouses and flood pumping agencies, please provide an estimate of the magnitude of forestry manufacturing LGS and MGS demands, respectively.

6.3 Please provide data that shows a correlation between forestry companies' demand and BC Hydro's system peak.

6.4 Do forestry companies have specific distinguishing features that warrant specific rate treatment? That is, should they have a rate all of their own? For example, are they naturally interruptible due to onsite back-up diesel generation or do they typically have low load factors? Please elaborate.

7.0 Reference: Exhibit C1-10, Section 2.6, p. 22
Uptake potential

CEC states "If greenhouses with existing lighting were to participate there could be up to about 25 MW that might participate and if these greenhouses were to find the rate attractive they may seek to expand the use of lighting, which could take them up toward 80 MW of participating capacity. The ultimate limit would come from the market competition once the winter produce pricing responded to sufficient Canadian supply versus import supply to meet the market requirements at a reasonable price."

And "Uptake potential for flood pumping could be likely be a total conversion with the right rate structure."

And "Uptake potential for forestry and others with some flexibility and the right rate structure would likely see significant meaningful conversion based on preliminary conversations with some of these other sector groups."

7.1 Please further explain what the "right rate structure" entails.

7.2 Please further explain how CEC came to its estimates of customer uptake for the above three categories of customers.

7.3 Please describe how and to what extent the demand charges, energy charges and minimum charges may impact these customers' cost and the potential uptake.

7.4 Would any potential customers be prepared to make capital investments during a "pilot" program?

D. INTERRUPTIBLE RATE - BENEFITS

8.0 Reference: Exhibit C1-10, Section 8, p. 36
Key benefits

CEC states "The benefit of an interruptible non-firm service rate would be a reduction in the BC Hydro peak demand. BC Hydro is planning for additional capacity to be added to the hydroelectric system, which would involve the addition of the 6th unit at the Revelstoke Generating Station. This capacity is anticipated to cost approximately $50/kW -year or $50,000/MW -year. The Revelstoke GS capacity may be required for contingency planning as early as 2021 or 2031 in the base plan."

8.1 If the timing of the next capacity addition is shifted out to the future, would it be appropriate to discount the savings that an interruptible non-firm generating station (GS) program would provide in the intervening years? If not, why?

9.0 Reference: Exhibit C1-10, Section 2.1, p. 7; Table 4.1
Cost of new and committed capacity

CEC states "Adding capacity at the BC Hydro peak would entail costs for the next increment of potential capacity to be added to the system of $50/kW-year and for later increments of capacity would require capacity additions with a potential cost approaching $100/kW-year."

Table 4.1 on page 8 provides energy production percentages based on time of delivery.

9.1 What is the estimated cost per kW-year to BC Hydro to add new committed capacity resources between F2017 and F2025 (i.e. before REV6)? Can this information be derived/estimated from the data CEC provided in Table 4-1? Please explain.

9.2 Please confirm, or otherwise explain, that BC Hydro provides different energy prices based on the point of delivery and the value it provides to BC Hydro.

9.3 In CEC's opinion, can/should BC Hydro defer its committed capacity additions for the F2017 to F2025 period and instead provide for CEC's proposed commercial class interruptible rate, load curtailment program and/or time-of-use rate? Please explain.

9.4 Please provide the derivation of the $50 and $100/kW-year capacity increments. Please clearly explain the items included and excluded in deriving these estimates, any assumptions, and the accuracy ranges (e.g. capital costs, allowances, contingencies, reserves, O&M, etc.).

9.5 Please provide the source of Table 4.1.

9.6 Please confirm, or otherwise explain, that the data in Table 4.1 are BC Hydro's currently offered energy prices to the point of delivery and are in terms of percent of a base energy price in $/MWh and please further describe the information and terms provided in Table 4.1.

9.6.1 If confirmed, what is the base energy price and provide its source.

E. INTERRUPTIBLE RATE - RISKS

10.0 Reference: Exhibit C1-10, Section 4, pp. 24, 25
Intra-class subsidies

On page 24 CEC provides details of its proposal. CEC proposes an interruptible rate pilot for commercial class customers with a reduced demand charge of $3.92/kW compared to the default rate demand charge of $11.21/kW.

On page 25 CEC explains that "Eligibility for the pilot could provide preference for those customers or customers groups with an ability to make up any lost revenue to the customer class through increased use or expansion of service to ensure a minimal impact on the revenues."

10.1 Please confirm, or otherwise explain, that CEC anticipates that some customers would switch from the default rate to the proposed interruptible rate without increasing their consumption.

10.1.1 If confirmed, please further confirm, or otherwise explain, that the resulting reduction in these customers' bills would have to be made up by the rest of the commercial class customers. Please elaborate.

10.2 Please also discuss whether or not non-participating customers within the commercial rate class should be held harmless. If so, how does CEC propose to ensure this occurs? For example, should the reduced demand charge be set slightly higher to recover distribution related costs? If not, why not?

10.3 What are the risks to non-participants if there is a large uptake for the proposed pilot rate?

10.4 Should the pilot limit that number of customers/amount of uptake? If so, what number/amount and why? If not, why not?

F. INTERRUPTIBLE RATE – COMPARISON TO OTHER RATES

11.0 Reference: Exhibit C1-10, Section 2.5, p. 20; Shore Power Decision, pp. 7, 9
Shore Power

CEC states "Tariff Supplement (TS) 76, and Rate Schedules (RS) 1280 and 1891 provide for non-firm interruptible energy to be available to Shore Power customers, and non-firm interruptible power is not currently available to General Service customers."

The Shore Power rate Decision recognized that ships are in port using the service for only limited periods of time, the ships are not dependent on BC Hydro service in that they can self-generate electricity to meet their needs if this is required, and designing specific rates for shore power service is commonplace for those jurisdictions offering shore power service.[2]

[2] British Columbia Hydro and Power Authority Application for Approval of Shore Power Rate, Rate Schedules 1280, 1891 and Shore Power Service Agreement Electric Tariff Supplement No. 86, Reasons for Decision (Shore Power Decision), p. 7.

11.1 Would the minimization of air pollution in Vancouver and the seasonal nature of the cruise industry also be considered distinguishing factors in the approval of RS 1280 &1891? Please explain.

11.2 Is the Shore Power rate being offered to incent new consumption? How does this compare to CEC's proposal? Please elaborate.

12.0 Reference: Exhibit B-1, Section 5.3; Rate Schedules 1205, 1206, 1207; Freshet Rate Decision, p. 4; Freshet Rate SRP, Transcript Volume 2, p. 332
General Service Dual Fuel and Freshet Rate Pilot

In Exhibit B-1 BC Hydro provides its concerns with the Residential Dual Fuel Interruptible (E-plus) Rate and explains its current proposal. BC Hydro has similar General Service Dual Fuel closed rates. BC Hydro is also currently offering a pilot to RS 1823 (Freshet Rate Pilot) customers which provides a lower rate during the Freshet Period to incent incremental consumption.[3]

By Order G-17-16, the Commission directed BC Hydro to file three evaluation reports on the Freshet Rate for transmission stepped rate service customers. The evaluation criteria are listed in section 7.3.4.6 of that application with additional criteria listed in that order. At the streamlined review process (SRP) for that application, counsel for CEC indicated that "…there will be significant commercial load which will be able to take advantage of a freshet rate. And right now, the demand charge structure limits some commercial customers' demand, particularly where there is variable demand in a month. Also there is suppression of load because of the demand charge."

12.1 Please compare the E-plus Rate and the Freshet Rate Pilot to CEC's proposal. How are they consistent? How are they inconsistent?

12.2 Does the CEC believe that its case could benefit from the evaluation reports on the transmission service rate (TSR) freshet rate?

12.3 The third and final evaluation report for the freshet rate for TSR customers is due in 2018. Does CEC consider it a reasonable time frame to design a pilot for MGS and LGS customers at or around 2018?

G. INTERRUPTIBLE RATE - EXECUTION

13.0 Reference: Exhibit C1-10, Section 4, p. 25
Migration

On page 25 CEC explains: "Taking service or partial service under the non-firm or interruptible tariff should not preclude a customer from migrating to a firm service in the future, with an appropriate planning period to enable BC Hydro to ensure that capacity will be available on the peak to serve the customer load. Migration to firm service could be provided only when capacity is available."

[3] British Columbia Hydro and Power Authority 2015 Rate Design Application, Reasons for Decision Transmission Service Rate Pilot, dated February 9, 2016 (Freshet Rate Decision), p. 4.

13.1 To meaningfully assist BC Hydro in its firm load forecasts, what re-entry provisions would be required to ensure the Commercial customers opting in to a peak load curtailment program can be counted on to not affect the firm load forecasts of BC Hydro? For example, would those customers wishing to return to firm supply need to give notice of at least as long as the planning horizon for BC Hydro to add generation or transmission capacity? Could this be as long as 5 years or more?

14.0 Reference: Exhibit C1-10, Section 4, pp. 24-28
Interruptible rate structure

On pages 24 to 28 CEC describes the conditions for the interruptible rate structure.

14.1 Please confirm whether these conditions would apply during a pilot program? For example, would the metering conditions apply during the pilot and would all the terms and conditions apply? If not, what would apply?

14.2 Please explain the rationale for the 65% reduction in the LGS demand charge and the 60% reduction in the MGS demand charge.

14.3 What hierarchy would CEC propose for disconnection and why?

14.4 Should the hierarchy of disconnection be considered for setting the appropriate demand charge? Please explain.

15.0 Reference: Exhibit C1-10, Section 2.4, p. 11
Demand charges

On page 11 CEC states:

> Demand charges are currently established at $0/kW up to 35 kW, 5.72/kW between 35 kW and 150 kW and $10.97 per kW for all kW in excess of 150 kW for MGS and LGS customers. Demand Charges are anticipated to rise to $11.21 per kW for LGS customers on the entire demand and for MGS customers to be $4.92 kW for the entire demand. These demand costs are charged to and collected from customers in monthly billings based on the highest demand reached in the month or through a minimum charge, which is set at 50% of the highest demand reached in any one of the 4 months in which peak use on the BC Hydro system may occur.

15.1 Recognizing the much higher demand charges for LGS customers, would it not be reasonable to limit any pilot program to LGS customers only?

H. INTERRUPTIBLE RATE - EVALUATION

16.0 Reference: Exhibit C1-10, Section 8.1, p. 36; Section 8.2, p. 39
Success

On page 36 CEC explains: "The benefit of an interruptible non-firm service rate would be a reduction in the BC Hydro peak demand."

And on page 39 CEC explains: “In addition to lowering the costs for participants in a pilot with a non-firm interruptible rate there will be opportunities for expanded use of the existing facilities. This expanded use in the case of greenhouses would provide an opportunity for increased yields and productivity. The additional value for the commercial sector productivity would be a key element to study and research during the pilot to establish the full public interest value in having such a rate.”

16.1 How can the ultimate potential of the program be assessed?

16.2 What does a successful general service interruptible rate look like? For example, is the rate considered successful if there is a high uptake among GS customers? Is it considered successful if BC Hydro’s peak demand lowers and capacity is better managed? Does a successful interruptible rate require substantial incremental consumption to offset revenue lost in demand charges, or is it successful if the rate results in more economically competitive greenhouses? Please elaborate.

16.3 How can success be measured (e.g. Would commercial class customers be required to have agreed upon baselines first, then BC Hydro measure the degree of shifting from their baselines? Would economic output need to be known?)? Please elaborate.

I. LOAD CURTAILMENT PROGRAM AND TIME-OF-USE RATES

17.0 Reference: Exhibit C1-10, Section 2.1, p. 9
Definitions of non-firm interruptible and demand response programs

On page 9 CEC states:

> “From the above analysis it could be appropriate to define a non-firm interruptible rate as one which ensures that the customer does not use energy coincident on the BC Hydro peak days and at the peak time of those peak days.
>
> Additionally, it could be appropriate to define a demand response program which would enable customers to offer capacity use reductions at the coincident peak times in order to reduce BC Hydro's requirements for supplying peak capacity from the system.”

17.1 Would it be appropriate that the demand response program be limited to LGS customers during the initial testing of programs and only include demand response payments when BC Hydro calls on a particular customer to curtail?

18.0 Reference: Exhibit C1-10, Section 2.5, p. 21
Transmission load curtailment pilot

On page 21 CEC states: “Very significant savings opportunities are available to Transmission customers (RS 1823) who are able to reduce their normal load by 5 MW during winter and shoulder seasons when notified in the Load Curtailment Pilot. The Load Curtailment Pilot has just completed Year 1 and is scheduled to commence Year 2 in October 2016.”

18.1 Would it not be appropriate to complete the Transmission Load Curtailment Pilot and evaluate its success before adding a similar program at the General Service level? Please explain.

19.0 Reference: Exhibit C1-10, Appendix 3
BC Hydro load curtailment request for proposal (RFP)

In Appendix 3 of the Application CEC provides the slides from BC Hydro's 2015 Load Curtailment RFP Webinar.

19.1 Would the Performance Test conditions in Section 13.3 of the slides equally apply to a GS Load Curtailment program? If not, why not and what would apply?

19.2 Would the Curtailment Notice provisions also apply to a GS load curtailment program? If not, why and what would apply?

20.0 Reference: Exhibit C1-10, Section 5, p. 30; Section 6, p. 31
Demand response and Time of Use rates

On page 30 CEC states: "A Demand Response Pilot Project should be determined to best suit BC Hydro requirements, whilst offering value to the customer."

On page 31 CEC states: "Time of Use rates would be another suitable option for BC Hydro to offer to General Service customers and should be examined for their potential to free-up BC Hydro capacity."

20.1 If Time of Use (TOU) were to be considered, would it need to be mandatory for all customers in a class? If not, would there be gaming of the rates in a voluntary program?

20.2 Would TOU rates be likely to be more successful for LGS customers compared to MGS customers due to the higher LGS demand charges?

20.3 Please compare the advantages/disadvantages of interruptible rates, a load curtailment program and time-of-use rates. Does CEC have an order of preference? Please explain.

20.4 Please describe how and to what extent the demand charges, energy charges and minimum charges may impact the customers' cost and the potential up-take of a load curtailment program and time-of-use rates.