August 1, 2019

VIA E-FILING

BCPIAC
Public Interest Advocacy Centre

Reply to: Leigha Worth
ED@bcpiac.org
Ph: 604-687-3034
Our File: 7500.120

Patrick Wruck
Commission Secretary
BC Utilities Commission
6th Floor 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck,

Re: British Columbia Hydro and Power Authority F2020 to F2021 Revenue Requirements Application ~ Project No. 1598990
BCOAPO Information Requests No. 2

We represent the BC Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Tenant Resource and Advisory Centre, and Together Against Poverty Society, known collectively in regulatory processes as "BCOAPO et al." ("BCOAPO").

Enclosed please find the BCOAPO's Information Requests No. 2 with respect to the above-noted matter.

If you have any questions, please do not hesitate to contact the undersigned.

Sincerely,
BC PUBLIC INTEREST ADVOCACY CENTRE

Original on file signed by:

For/ Leigha Worth
Executive Director | General Counsel

Encl.

REQUESTOR NAME:	BCOAPO
INFORMATION REQUEST ROUND NO:	2
TO:	BRITISH COLUMBIA HYDRO & POWER AUTHORITY
DATE:	August 1, 2019
PROJECT NO:	1598990
APPLICATION NAME:	BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application

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90.0 Reference: Exhibit B-6, BCOAPO 1.2.1
Energy, Mines and Petroleum Resources Statement
https://archive.news.gov.bc.ca/releases/news_releases_2017-2021/2018EMPR0004-000311.htm

Preamble: On March 1, 2018 the Ministry of Energy, Mines and Petroleum Resources issued the following statement:

For Immediate Release
2018EMPR0004-000311
March 1, 2018

Ministry of Energy, Mines and Petroleum Resources

Government will help low-income families manage electricity costs

VICTORIA – Minister of Energy, Mines and Petroleum Resources Michelle Mungall has issued the following statement on the B.C. Utilities Commission (BCUC) decision on the BC Hydro rate freeze:

"I am disappointed the BCUC turned down BC Hydro's request for a one-year rate freeze, and instead, approved the previous government's rate increase.

"We completely understand the affordability crisis so many families face, and will be taking action quickly to address the need to reduce electricity costs for those who need it most.

"Government will work with BC Hydro and customer groups on a lifeline rate program. The program could mean that people who have demonstrated need would have access to a lower rate for their electricity*. (emphasis added)*

"In addition, starting in May, BC Hydro residential customers who find themselves in an emergency – such as loss of employment, unanticipated medical expenses or pending eviction for example – will be eligible for a grant toward their outstanding BC Hydro bill. The grant is up to $600 and does not need to be repaid.

"Last month, BC Hydro announced enhanced measures to help customers manage higher winter bills, including a winter payment plan, giving customers the option to spread bill

payments over a six-month period, and increased funding for low-income energy-conservation programs.

"To lower electricity costs for B.C. businesses and industries, we are phasing out the provincial sales tax (PST) on electricity. Following the 50% reduction that started on Jan. 1, 2018, government will completely eliminate the PST on non-residential electricity on April 1, 2019. Residential use of electricity is already PST-exempt.

"Eliminating the PST on electricity will translate into savings of more than $150 million annually for B.C. businesses. This will help them create more jobs for British Columbians, expand into new markets, and reinvest in new technologies.

"Our government will also undertake a comprehensive review of BC Hydro to make it work for people. The review will identify changes and cost savings to keep rates low, while ensuring BC Hydro has the resources it needs to continue to provide clean, safe and reliable electricity. We expect to announce the scope and process for the review in the coming weeks.

"We respect the BCUC's work and diligence as British Columbians' independent regulator. Although disappointed with its decision, we understand the commission's concerns and will work to address them, while implementing ways to make life more affordable for B.C. families."

90.1 If as, as the response to BCOAPO 1.2.1 suggests, there are no current plans to implement lifeline rates, please reconcile this with the above Statement issued by the Ministry.

90.2 Please indicate the current status of the joint initiative referenced in the above Statement to develop lifeline rates.

91.0 Reference: Exhibit B-6, AMC 1.2.1

91.1 How has BC Hydro assured itself (and other ratepayers) that the Freshet Rate sales are truly incremental and would not have occurred in the absence of the rate?

92.0 Reference: Exhibit B-6, BCOAPO 1.3.2.1 and 1.3.3

92.1 Please provide a schedule that sets out the performance measure targets and actual results for 2018/19.

92.2 Please explain why expected lower levels of performance in 2018/19 with respect to the Lost Time Injury Frequency performance measure justify reducing the target for 2019/20 to 2021/22.

93.0 Reference: Exhibit B-5, BCUC 1.2.1 and 1.3.1
Exhibit B-6, BCOAPO 1.10.1 and GJOSHE 1.15.1

93.1 Regardless whether or not BC Hydro "categorizes" its costs to distinguish those incurred for export, the response to BCUC 1.3.1 states that "With the amendments, the recovery in rates of expenditures on infrastructure and energy purchases associated with producing power that is surplus to BC Hydro's domestic needs is no longer be prohibited. Accordingly, the BCUC may allow BC Hydro to recover prudently incurred expenditures for export in rates, similar to how the BCUC assesses expenditures for

domestic purposes." Are there any expenditures/costs in the proposed F2020 or F2021 revenue requirements (either capital or OM&A) that are for the purpose of supporting exports?

93.1.1 If yes, please indicate what they are and where they are included.

93.2 Given the response to GJOSHE 1.15.1, is it reasonable to conclude that, in the short-term, DSM related expenditures are justified primarily on the basis that they will support increased exports?

93.2.1 If not, why not?

94.0 Reference: Exhibit B-5, BCUC 1.173.1

94.1 Please provide a copy of or a link to "BC Hydro's Report on Demand-Side Management Activities for fiscal 2018".

94.2 Does the 5,301 GWh in Row A represent the persisting savings in F2021 from DSM programs initiatives undertaken in F2008 to F2018?

94.2.1 If not, what does it represent and why it the appropriate value to use in the calculation?

94.3 Does the 1,799 GWh in Row B represent the persisting savings in F2021 from DSM programs initiatives planned for F2019 to F2021?

94.3.1 If not, what does it represent and why it the appropriate value to use in the calculation?

94.4 Is the 58,735 GWh in Row E the actual Total Gross System Requirements for F2008 or a weather normalized actual value?

94.4.1 If the former, how would the calculation change if the weather normalized actual value for F2018 was used?

95.0 Reference: Exhibit B-6, CEC 1.4.1 & 1.43.4 and INCE 1.1.1

95.1 The response to CEC 1.4.1 states that:
"The success of our capital planning process as a whole over time is best assessed through the information provided in BC Hydro's Service Plan. The Service Plan contains performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor which provide an indication of the impact of capital investment on system performance over time."
However, the response to INCE 1.1.1 states:
"The BC Hydro system is highly complex and dynamic and it is difficult to make a direct link between the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics and investments in the system. These metrics are influenced by factors beyond capital and maintenance investment including operational procedures and uncontrollable events".

Please reconcile the proposed use of performance measures such as SAIDI, SAIFI and Key Generating Facility Forced Outage Factor evaluate

the success of BC Hydro's capital planning process with the response to INCE 1.1.1 which suggests that there is no direct link between the two.

95.2 Is there a difference between: i) measuring the success of the capital planning process (i.e., to what extent does the capital planning process appropriately identify the required expenditures to meet BC Hydro's planning objectives or put, another way, is the proposed capital plan the appropriate capital plan) and ii) measuring the success in implementing a given capital plan.

95.2.1 If, in BC Hydro's view, there is no difference – please explain why.

95.2.2 If there is a difference, are the SAIDI, SAIFI and Generation Facility Forced Outage Factor performance metrics measuring the success of the capital planning process?

95.2.3 If there is a difference, what performance metrics does BC Hydro use to measure its success in implementing a given capital plan?

96.0 Reference: Exhibit B-5, BCUC 1.5.1 and 1.10.1
Exhibit B-1, pages 3-27 to 3-30

96.1 Please provide a schedule that sets out the forecast LNG load for the test period based on the 2016 Load Forecast.

96.2 With respect to the load forecast for large industrial customers, why is the proposed approach expected to improve the forecast accuracy for specific segments and for which specific segments is this expected to occur (per Exhibit B-1, page 3-29)?

96.3 With respect to the October 2018 residential and commercial load forecasts (BCUC 1.5.1, pages 3-5 of 9), why was the calibration period updated to the most recent 10 years instead of using a longer period that also included the original period used as well as the more recent years where actual data is now available?

96.4 With respect to the October 2018 residential and commercial load forecasts (BCUC 1.5.1, pages 3, 5 & 7 of 9), what is the basis for the updated (mainly higher) projection of average efficiency for the various end uses of electricity?

96.5 With respect to the impact of DSM savings (BCUC 1.5.1, page 9 of 9) associated with the 2016 Load Forecast, please provide a schedule that sets out the assumed annual savings in F2016 to F2024 associated with DSM programs implemented in F2016-F2018.

96.6 With respect to the impact of DSM savings (BCUC 1.5.1, page 9 of 9) associated with the 2018 Load Forecast, please provide a schedule that sets out the actual annual savings in F2016 to F2024 associated with DSM programs implemented in F2016-F2018 embedded in the load forecast.

97.0 Reference: Exhibit B-6, BCOAPO 1.18.4.2

97.1 Based on the response to BCOAPO 1.18.4.2 there appears to be no adjustment made to the load forecast to account for the loss of persistence in savings related to DSM activities prior to F2019. Please confirm that this is the case.

97.1.1 If confirmed, what is the impact in the test years of the loss in savings related to DSM activities prior to F2019?

97.1.2 If not confirmed, please explain how the loss in persisting savings related to DSM activities prior to F2019 is accounted for in the load forecast.

98.0 Reference: Exhibit B-6, BCOAPO 1.19.2

98.1 Are there more recent forecasts available from either the Conference Board of Canada or the Ministry of Finance? If so, please expand the schedule provided in response to BCOAPO 1.19.2 to include the more recent forecasts.

99.0 Reference: Exhibit B-6, BCOAPO 1.22.2

99.1 How is the Light Industrial and Commercial Account forecast developed?

99.2 Given that the actual number of Light Industrial and Commercial accounts in F2018 is higher than the May 2016 forecast, please explain why the forecast account numbers for the test years are lower in the current forecast.

99.3 How is the Large Industrial Account forecast developed?

100.0 Reference: Exhibit B-6, BCSEA 1.5.3

100.1 The referenced excel file does not appear to be attached to the response. Please provide.

101.0 Reference: Exhibit B-6, GJOSHE 1.10.1

101.1 How is the distribution substation peak demand forecast for each substation developed?

101.1 How does BC Hydro ensure that its system peak demand (which is developed by a coincident summation of the distribution substation forecast and transmission peak demands) is consistent with the total system energy forecast?

102.0 Reference: Exhibit B-6, INCE 1.8.5

Preamble: The response states "For the residential and commercial sectors, the model sales projections (i.e., before DSM) are based on our SAE forecasting models that utilize the U.S. Energy Information Administration (EIA) forecast of stock average efficiency of end use of electricity".

102.1 How does BC Hydro ensure that between the efficiency improvements assumed in the SAE forecasting models and the incremental DSM savings that are subsequently removed from the forecast there is no "double counting" of future efficiency savings?

103.0 Reference: Exhibit B-5, BCUC 1.15.1.1

103.1 Do the values in Table 1 of the response (totaling $1.3 M) represent the difference in the costs for referenced EPAs as between the costs in the F2019 Plan (per the F2019 RRA) and the costs in F2021 per the current RRA?

103.1.1 If not, what do the values represent?

103.2 What would be the difference in total costs in F2021 for these EPAs as between: i) the costs assuming they were renewed on the same terms as the initial agreements and ii) the renewal assumptions used in the Application? (Note: If there is also a change in volumes, please also indicate the change in volumes assumed and the difference in $/MWh)

104.0 Reference: Exhibit B-5, BCUC 1.15.1, 1.15.2 and 1.15.2.1
BC Hydro's EPA Renewal Application (Sechelt Creek Hydro, Brown Lake Hydro, and Walden North Hydro), Exhibit B-5, BCUC 1.8.4

Preamble: In response to BCUC 1.8.4 from the proceeding dealing with BC Hydro's EPA Renewal Application, BC Hydro states:
'BC Hydro's LRB shows it will not need to acquire new energy resources for many years to come. Given potential policy changes that may affect BC Hydro arising from ongoing government review and other energy related policies, on top of technology cost uncertainty in the long term, BC Hydro recently adopted the use of market price as a conservative interim assumption for evaluating energy during surplus and deficit periods.'
The response to BCUC 1.15.2.1 in the current proceeding indicates that this "conservative interim assumption" was used in the case of the two run of the river EPAs due to expire during the test period. However, the response also indicates that this "conservative interim assumption" was not adopted for facilities eligible for the Biomass Energy Program or facilities with other benefits.

104.1 Why was the "conservative interim assumption" not adopted for facilities eligible for the Biomass Energy Program?

104.1.1 What approach was used for these facilities?

104.2 With respect to Table 1 in BCUC 1.15.1, please indicate for which EPAs: i) the original contract expired prior to the test period and new contract has been concluded, ii) the original contract expired prior to the test period but new contract has yet to be concluded, and iii) the original contract will expire during the test period. (Note: Based on the response to BCUC 1.15.2.1 there should be two run of the river and six biomass EPAs in the third category).

104.2.1 Does the "conservative interim assumption" for evaluating energy during surplus and deficit periods apply to all EPAs in categories (ii) and (iii)? If not, why not?

104.3 What types of "other benefits" (per BCUC 1.15.2.1) would preclude the use of the "conservative interim assumption"?

105.0 Reference: Exhibit B-5, BCUC 1.17.1

105.1 Does the $17.3 in "cost savings" reflect just the costs attributed in the F2019 RRA to the three terminated EPAs, the one EPA that was not renewed and the cogeneration project that is not proceeding or is it also net of the opportunity value of the energy (e.g., as surplus power sales in the export market) associated with these projects?

105.2 If the opportunity value of the energy is not included, by how much would allowing for it reduce the "cost savings"?

106.0 Reference: Exhibit B-5, BCUC 1.21.1 and 1.21.2

106.1 The response indicates that the reduced availability of natural gas (due to the pipeline rupture) created the potential for increased electrical heating load due to fuel switching. However, it also notes that this potential increase was not included in the load forecast for the test period. Will this potential increase be included in the load forecast update scheduled for October 2019?

106.1.1 If not, why not?

106.2 Will the Cost of Energy forecast be updated in conjunction with the updated load forecast?

106.2.1 If not, why not?

107.0 Reference: Exhibit B-6, BCSEA 1.14.1
Exhibit B-5, BCUC 1.15.2.1

107.1 For the seven expected new EPAs referenced in the response to BCSEA 1.14.1, have the agreements for each of the projects been finalized?

107.1.1 If all of the agreements have not been finalized, what approach is being used by BC Hydro to evaluate the EPAs?

107.1.2 If the "conservative interim assumption" described in BCUC 1.15.2.1 is not being used to evaluate the projects, please explain why.

108.0 Reference: Exhibit B-6, CEABC 1.6.4

108.1 It is noted that out of the last 10 years there were four where overall purchases (market purchases and net purchases from Powerex) exceeded surplus sales. In each case, please explain why and, in particular, whether it was a function of "need" (i.e., shortfall in domestic supply) or "economics" (i.e., purchases were cheaper than available domestic supply).

109.0 Reference: Exhibit B-6, CEC 1.16.1
Exhibit B-5, BCUC 1.24.3
Exhibit B-1, pages 4-36 to 4-37

109.1 Is the forecast average market price for F2020 referenced in BCUC 1.24.3 the same as the average forward price for F2020 referenced in CEC 1.16.1?

109.1.1 If not, what is the difference and why?

109.2 What is the most recent average forward price for electricity at Mid-C for fiscal 2020, fiscal 2021, and fiscal 2022?

110.0 Reference: Exhibit B-6, CEC 1.87.1
Exhibit B-1, Appendix A, Schedule 4, Rows 8-11

110.1 It is noted that the market purchases currently forecast for F2019 and planned for F2020 are higher than both historic levels and planned levels for F2021. Please explain why and the extent to which this impacted the forecast/planned energy from heritage and non-heritage sources in those years.

111.0 Reference: Exhibit B-6, INCE 1.7.1
Exhibit B-5, BCUC 1.15.1

111.1 Which of the rows in the Table provided in INCE 1.7.1 include EPA renewals per BCUC 1.15.1?

112.0 Reference: Exhibit B-5, BCUC 1.34.3

Preamble: The response states:
"Business Groups identified significant cost pressures in their respective areas during the fiscal 2020 budgeting cycle. Using the top-down, bottom-up budgeting approach these costs were not funded as the approach did not allow for costs related to these items beyond the existing budget to be funded. These costs had to be accommodated within the Business Group's existing budgets, allowing us to limit our costs increases to $8.5 million and $9.9 million in fiscal 2020 and fiscal 2021 respectively."

112.1 Please clarify what is meant by the "existing budgets" for each Business Group and provide a schedule that sets out the "existing budget" for each Business Group.

112.2 If cost increases for each Business Group had to be accommodated within the existing budgets, why is there any increase in F2020 and F2021?

113.0 Reference: Exhibit B-5, BCUC 1.35.1.1
Exhibit B-1, page 5-21, Table 5-4

113.1 Please explain how the $5.6 M in vacancy factor savings was calculated.

113.2 Please indicate where in Table 5-4 these savings have been included.

114.0 Reference: Exhibit B-5, BCUC 1.35.2

114.1 Why doesn't BC Hydro's new role as Reliability Coordinator lead to an increase in the number of positions (FTEs) required?

115.0 Reference: Exhibit B-5, BCUC 1.38.10
Exhibit B-6, BCOAPO 1.26.3

115.1 Is it the case that in all areas where a Work Smart initiative has led to gains in capacity hours, that there are/will be increases in workload that will "utilize" the capacity hours gained?

115.2 Alternatively, are there not some work areas where the capacity hours gained will exceed the workload increases in F2020 and F2021 such that there could be a need for fewer FTEs? If not, why not?

116.0 Reference: Exhibit B-5, BCUC 1.38.13

116.1 What are the estimated capacity gains in F2020 from the initiatives noted in the response?

116.2 Please explain how initiatives #2 and #3 will lead to gains in capacity hours.

117.0 Reference: Exhibit B-5, BCUC 1.42.7

117.1 What does the bargaining mandate established by the Public Sector Employers' Council for provincial public sector employers, including BC Hydro, represent (i.e., is it guide for public sector employers, is it a maximum, or does it represent something else)?

118.0 Reference: Exhibit B-5, BCUC 1.43.5 and 1.103.1
Exhibit B-1, pages 5-25 & 8-30

118.1 Please provide the overall impact on BC Hydro's revenue requirements for F2020 and F2021 of implementing IFRS 16 separating out the impact associated with EPA and non-EPA leases. Please set out the impact by expense item (i.e., depreciation, OM&A, finance charges, etc.).

119.0 Reference: Exhibit B-5, BCUC 1.49.3
Exhibit B-1, page 5-41 (Table 5-1)

119.1 Please confirm that the $0.8 M in savings associated with Field Service Representatives (i.e., manual metering reading) is not attributable to the full Accenture repatriation as these services were repatriated in F2018.

120.0 Reference: Exhibit B-5, BCUC 1.51.1

120.1 Do all graduating apprentices replace employees that are either retiring/leaving the Corporation?

120.1.1 If not, please explain how trainees graduating from the program lead to a reduction in overall FTEs.

121.0 Reference: Exhibit B-6, AMC 1.3.1 and 1.3.2

121.1 With respect to the table provided in response to AMC 1.3.2, please include a column with the F2019 RRA FTEs.

121.2 With respect to the table provided in response to AMC 1.3.2, why is there no line showing the impact of the Workforce Optimization program?

121.3 What is the reason for increase in Operating FTEs in F2018 and why did the number decline in F2019?

122.0 Reference: Exhibit B-6, AMC 1.3.12

122.1 Is there any true-up (or regulatory account) that addresses/accounts for the difference between forecast and actual project write-offs?

122.1.1 If not, would a regulatory account to address such differences be appropriate?

123.0 Reference: Exhibit B-5, BCUC 1.54.3
Exhibit B-6, BCOAPO 1.7.1

123.1 In making its decision not to prepare USoA financial schedules did BC Hydro consider the value of such schedules in benchmarking exercises such as one performed by the Brattle Group?

123.2 Please explain why BC Hydro considered it appropriate to discontinue preparing USoA financial schedules without the formal approval of the BCUC.

124.0 Reference: Exhibit B-6, BCOAPO 1.32.1

124.1 The response suggests that the Unallocated Funds budget from the F2009 RRA was $8 M (i.e. $15 M less $7 M). Please provide a reference to the previous RRA that demonstrates this is the case.

124.1.1 If this premise is not correct, please explain why and clarify the response to BCOAPO 1.32.1.

125.0 Reference: Exhibit B-6, BCOAPO 1.34.1

Preamble: The response states:
"BC Hydro's maintenance work is planned, on a prioritized basis, within the approved maintenance budget level. Reallocations may be made among the various categories of maintenance (preventative, condition-based, corrective, facilities or engineering) or across the Stations Asset Maintenance and Line Asset Maintenance departments based on maintenance priorities. In the event that there are significant unforeseen risks or events which cannot be accommodated in the existing maintenance budget a request would be made to reallocate funds from elsewhere in BC Hydro".

125.1 For each department, what was the initial "approved maintenance budget level" for F2020 and what was it based on?

125.2 Were there any "reallocations" between departments based on "maintenance priorities"? If so, what are they and why were they required?

125.3 Was there any reallocation of funds from elsewhere in BC Hydro? If so, how much was reallocated, to which departments was it directed and what necessitated the need for the reallocation?

126.0 Reference: Exhibit B-5, BCUC 1.69.3

Preamble: The explanation for the actual F2017 Business Support costs being higher than the F2017 RRA value is that "$11.0 million planned savings from the Transmission, Distribution and Customer Service Efficiency Initiative. The planned savings were held in the Business Unit Support KBU and were not allocated to the individual KBUs; however, the actual savings were achieved in the individual KBUs." Similar observations apply for F2018 (actual) and F2019 (forecast). Please explain why there is no overall (equivalent) reduction in the actual (vs. plan) costs for the other KBUs in these years.

126.1 What were the actual savings achieved in each of F2017, F2018 and F2019?

126.2 Based on the response to BCUC 1.69.3, one would expect to see the annual total actual/currently forecast costs for the other departments to be less than the RRA values in each of the years F2017-F2019 based on achieved savings. However, this is not the case. Please explain why.

127.0 Reference: Exhibit B-6, BCOAPO 1.42.2

127.1 The forecast spending on Generation Station Maintenance increases by 10% in F2020 (over F2019 Forecast). What are the specific reasons for the increase?

127.2 Why is a similar level of spending on Generation Station Maintenance required in F2021?

127.3 The forecast spending on Substations Maintenance increases by 30% in F2020 (over F2019 Forecast). What are the specific reasons for the increase?

127.4 Why is a similar level of spending on Substations Maintenance required in F2021?

128.0 Reference: Exhibit B-5, BCUC 1.85.3
BC Hydro's MRS RC Registration Application, Exhibit B-1, page 2-4

128.1 BC Hydro's MRS RC Registration Filing indicates that BC Hydro's PEAK membership fees are in the order of $4 M annually. Which KBU's budget for F2019 includes these membership fees?

128.2 Please demonstrate that the KBU's budget for F2020 has been reduced to reflect the fact BC Hydro will no longer be required to pay these membership fees.

129.0 Reference: Exhibit B-6, CEC 1.52.1 to 1.52.5

129.1 How does BC Hydro measure the performance of its Revenue Assurance Program?

129.2 What has been the program's performance for the last 3 years?

129.3 With respect to CEC 1.52.3, what was the total amount recovered in each of F2017, F2018 and F2019 that is directly attributable to the Revenue Assurance Program? Please report separately recoveries related to grow-ops versus other thefts.

129.4 For each of the years F2017-F2019, what was the total cost of the Revenue Assurance Program?

129.5 With respect to CEC 1.52.4, what is the basis for the 5% and 60% figures?

130.0 Reference: Exhibit B-5, BCUC 1.107.1

130.1 For each project with a positive variance of 10% or more, please explain why actual costs were higher than expected costs.

131.0 Reference: Exhibit B-5, BCUC 1.110.1
Exhibit B-1, Appendix H, page 15

Preamble: The response states in part:
"During the annual capital planning cycle in 2018 to develop the fiscal 2020 to fiscal 2024 Capital Plan, any ex-plan projects already approved and not reflected in the prior capital plan (i.e., the capital plan developed in 2017) were incorporated into the capital plan. Based on updated information for all projects within the capital plan including these ex-plan projects, the prioritization process was used to reduce the fiscal 2020 to fiscal 2024 Capital Plan to the previously approved targets for that period.

131.1 Please provide a schedule that sets out: i) the previously approved targets for the period and ii) the forecast capital spending based on updated information for all projects within the capital plan including the ex-plan projects prior to the use of the prioritization process to reduce the F2020 to F2024 Capital Plan to the previously approved targets for the period.

131.2 Please indicate which projects were impacted by the prioritization process and why the prioritization process deemed that it was appropriate to have their spending for the period reduced/eliminated versus the spending on other projects?

131.3 For those projects that were impacted by the prioritization process, please indicate what their risk scores are per Exhibit B-1, Appendix H, page 15.

132.0 Reference: Exhibit B-5, BCUC 1.110.1

Preamble: The response states in part:
"Three ex-plan projects related to transmission system upgrades for the Liquefied Natural Gas and Oil and Gas sectors in the North Coast and Peace regions have been initiated since the fiscal 2020 to fiscal 2024 Capital Plan was finalized. These additional investments and the related increase in unplanned future amortization will be offset by the expected increase in future revenue related to these projects."

132.1 With reference to Exhibit B-1, Appendices I and J, please indicate which three projects the response is referring to.

132.2 Do any of these three projects impact the revenue requirements in the test years?

132.2.1 If yes please indicate which projects impact the revenue requirements for F2020 and F2021 and what the impact is.

132.2.2 If yes, are there additional revenues from the projects in F2020 and F2021 sufficient to offset these impacts?

133.0 Reference: Exhibit B-5, BCUC 1.133.1

133.1 With respect to the W.A.C. Bennett Dam Rip-Rap Upgrade (G000623), please confirm that the total capital additions are anticipated to be under the forecasted expected amount (per BCUC 1.107.1). If not, please explain.

133.2 With respect to the DVES: New DGR Strategic Property Purchase (900222), please explain the purpose of the purchase and why it was still considered prudent when the actual cost was almost double the original forecast.

133.3 With respect to Transmission Project and Programs less than $5 M, the total actual capital additions in F2017 and F2018 are more than 60%

higher ($519.2 M vs. $324.4 M) than the RRA values. Please provide an explanation for this significant variance.

134.0 Reference: Exhibit B-6, CEABC 1.13.2
Exhibit B-1, Appendix H, page 2

134.1 It is noted that for none of the five examples provided is there any reference to how the results of the project's assessment based on BC Hydro's enterprise framework for capital prioritization (per Exhibit B-1, Appendix H, page 2). Were each of the projects assessed and scored in accordance with the framework?

134.1.1 If yes, what were the results and how, if at all, did these results inform the decision making?

134.1.2 If not, why not?

135.0 Reference: Exhibit B-5, BCUC 1.108.3 and 1.108.5
Exhibit B-6, CEC 1.89.1
Exhibit B-1, Appendix C, page 29

135.1 The response to BCUC 1.108.3 states that "The Current Capital Plan contains only high-level investment projections for fiscal 2025 to fiscal 2029 and cannot be split between growth and sustain". However, in Appendix C (page 29) BC Hydro provides a breakdown of the reduction in capital spending and specifically separates out sustainment-related spending. Please reconcile the response to BCUC 1.108.3 with the detail provided in Appendix C.

135.2 How did BC Hydro establish that the sustainment-related capital expenditures could be reduced by $1.6 B over the ten-year period F2020 to F2029?

135.2.1 What degree of confidence does BC Hydro have in this reduced spending projection given that it is based only on "high level investment projections" (per CEC 1.89.1) and the detailed planning is yet to be undertaken?

136.0 Reference: Exhibit B-5, BCUC 1.135.3
Exhibit B-1, page 7-36

136.1 Please confirm that the Amortization of Capital Additions Regulatory Account means the customer (eventually) only pay for the actual amortization of assets incurred after the capital additions are recorded and amortization commences on the assets.

136.1.1 If not confirmed, please explain why.

137.0 Reference: Exhibit B-1, Pages 6-50 to 6-51 and Appendix O, pages 62-63

137.1 For purposes of forecasting growth-related transmission capital expenditures are BC Hydro's assumptions regarding the start-up dates for new customers the same as those used for load forecasting purposes (i.e., F2019 to F2021 only includes the start-up of "high likelihood

projects" that are included in the load forecast for those years through its new binary assessment process)?

137.1.1 If not, what assumptions are made regarding the in-service/start-up dates for new customer for purposes of the forecast capital expenditures and asset in-service dates used in the Application?

137.1.2 If there is any inconsistency between the assumptions made for load forecast purposes and capital planning purposes are rate-payers eventually held "whole" via BC Hydro's regulatory accounts and, if yes, how?

138.0 Reference: Exhibit B-1, Appendix J, pages 71-72

138.1 Under Issues Being Addressed, please explain the basis for the 2028 and 2021 dates referenced in the discussion (i.e., why is the ability to supply load under normal conditions exceeded in 2021 but the system is able to maintain supply to all customers until 2028?).

139.0 Reference: Exhibit B-5, BCUC 1.119.2

139.1 Please provide a schedule of key milestones for the PRES Project that demonstrates the project will be in service no later than December 31, 2022**.**

140.0 Reference: Exhibit B-5, BCUC 1.121.4.1

140.1 Absent the thermal upgrades, is there/will there be sufficient load in the Peace region to utilize all of the available energy that cannot be transferred to domestic load centers outside the region or export markets?

140.1.1 If not, what is the likely surplus energy in future years that will be "lost"?

141.0 Reference: Exhibit B-5, BCUC 1.122.1.1 and 1.122.2
Exhibit B-1, page 5F-38
Exhibit B-1, Appendix A, pages 66 & 67

141.1 With respect to Appendix A, Schedules 10 & 11, what are the actual (F2017 & F2018), the forecast F2019 and the planned F2020 and F2021 end of year values for i) net assets in-service related to EV charging stations owned by BC Hydro and ii) net contributions related to EV charging stations owned by BC Hydro?

141.1.1 Also, for each schedule, in which row are the values reported?

141.2 For each year, how many charging stations does this represent?

141.3 Please explain the difference between the 56 fast charging stations owned by BC Hydro (per Exhibit B-1, page 5F-38) and the 30 fast charging stations referenced in the response to BCUC 1.122.1.1.

142.0 Reference: Exhibit B-5, BCUC 1.134.1

142.1 Does the Application's capital expenditure forecast include the spending initially anticipated for the second property purchase?

142.1.1 If yes, how much was the anticipated spending and where is it reflected in the Application?

143.0 Reference: Exhibit B-5, BCUC 1.148.3 & 1.148.4

143.1 Please provide a comparative analysis similar to that in BCUC 1.148.3 that compares: i) the current Application vs. ii) the results from using the DARR table mechanism approved by the BCUC in its Decision on BC Hydro's Fiscal 2009 - Fiscal 2010 Revenue Requirements Application.

144.0 Reference: Exhibit B-5, BCUS 1.150.4

144.1 Please explain why the fact the low-carbon electrification projects BC Hydro has undertaken and the BC Hydro LCE Program fall within one (or more) class of prescribed undertakings defined under the Greenhouse Gas Reduction precludes them from falling within the definition of "demand side measure" in accordance with section 1 of the *Clean Energy Act*.

145.0 Reference: Exhibit B-5, BCUC 1.150.5

145.1 With respect to Table 10-14, the response states that the values represent the average measure life of the DSM expenditures proposed for the test period only. What is the difference/distinction between the 2-year and the 10-year values?

145.2 In each of the test years (F2020 and F2021) how much of the amortization of the DSM regulatory account is attributable to the DSM expenditures proposed for the test period?

146.0 Reference: Exhibit B-5, BCUC 1.158.10
Exhibit B-6, CEC 1.75.1 to 1.75.5

146.1 CEC 1.75.3 indicates that business cases are developed for individual conversion projects. Were all the conversion projects that BC Hydro has undertaken and will be undertaking during the test period cost effective?

146.1.1 If not, what is the basis for approving/initiating those that weren't?

147.0 Reference: Exhibit B-5, BCUC 1.161.1

147.1 The response states that "BC Hydro did not forecast project write-offs in prior test periods". In prior years, how were actual project write-offs treated (i.e., were they written off against net income and effectively paid for by the shareholder)?

147.2 Under the current plan, how will the difference between the forecast and actual write-offs be treated?

148.0 Reference: Exhibit B-6, BCOAPO 1.72.1

148.1 Apart from Finance charges, what other elements of BC Hydro's revenue requirement would be impacted by a change in the USD$/CAD$ exchange rate?

148.1.1 For these other elements of the revenue requirement would a lower exchange rate generally increase or decrease the test years' revenue requirements?

149.0 Reference: Exhibit B-5, BCUC 1.163.2 and 1.164.1

149.1 With respect to the table provided in the response to BCUC 1.163.2, please revise by adding two additional columns that set out for each row the amounts forecast to be paid in F2020 and F2021 by domestic customers and recovered through BC Hydro's bundled sales rates.

150.0 Reference: Exhibit B-5, BCUC 1.172.1
Exhibit B-1, pages 10-33 – 10-34

150.1 Please provide a detailed listing of what were considered to be portfolio-level costs prior to the March 2017 changes to the Demand-Side Measures Regulation.

150.1.1 How, if at all, did what could be considered portfolio level costs change as a result of the 2017 changes to the Regulation?

150.1 BCUC 1.172.1 states that the Demand-Side Measures Regulation "does not endorse the attribution of portfolio-level costs to individual programs"**.** Does the Regulation preclude the attribution of portfolio-level costs to individual programs?

150.1.1 If yes, please indicate specifically where in Regulation this is addressed.

150.1.2 Also, if yes, does it preclude jut the attribution certain types of portfolio-level costs or all portfolio-level costs?

151.0 Reference: Exhibit B-1, Appendix X, page 7 of 8 (Table A-7)

151.1 Do the results reported for the Modified Total Resource Cost Test and the Total Resource Cost Test excluding NEBs for the individual DSM Programs include avoided capacity costs where appropriate?

151.1.1 If not why, given Section 4 (1.1) (b) of the DSM Regulation which states "the avoided electricity cost, if any, respecting a demand-side measure, <u>in addition to the avoided capacity cost</u>, is…"? (emphasis added)

151.2 Footnote #2 states that "Capacity focused DSM is not included in the cost-effectiveness calculations". Does this mean that neither the cost of

Capacity Focused DSM activities (per Table A-1) nor the capacity savings from these activities are include in the benefit cost ratios reported for the Portfolio Total?

151.2.1 If not, what does it mean?

151.2.2 Why was capacity focused DSM excluded from the cost effectiveness calculations?

151.2.3 What would be the benefit cost ratios for the Portfolio Total if capacity focused DSM was included?

152.0 Reference: Exhibit B-5, BCUC 1.175.1, 1.175.2 and 1.175.3

152.1 With respect to Table A-7, for purposes of determining the values for the TRC Test excluding NEBs – was the 40% adjustment required for certain DSM programs per Section 4 (2) also excluded?

152.2 Please clarify the difference between what the benefit cost ratios reported in Table A-7 (Appendix X) and those reported in BCUC 1.175.1 represents.

152.3 With respect to BCUC 1.175.2:

152.3.1 What gives rise to the negative values for Residential-Retail programs?

152.3.2 If the 40% adjustment required for certain DSM programs per Section 4 (2) was excluded for purposes of determining the values for the TRC Test excluding NEBs in Table A-7, provide a revised version of BCUC 1.175.2, where it is excluded.

153.0 Reference: Exhibit B-5, BCUC 1.181.2
Exhibit B-1, Appendix X, Tables A-4 and A-5

153.1 Why is it possible in Tables A-4 and A-5 to attribute incremental energy and capacity savings to Residential Energy Management Activities but not to Commercial and Industrial Energy Management Activities?

153.2 The footnotes to Tables A-4 and A-5 indicate that the Commercial and Industrial Energy Management Activities enable and support energy and capacity savings reported under other programs for these sectors.

153.2.1 Please indicate in what ways the Energy Management Activities related to these sectors enable and support energy and capacity savings reported under other programs.

153.2.2 Doesn't separating these costs out (and not including them as part of the individual DSM program costs) result in the benefit ratios for DSM programs in these sectors being overstated? If not, why not?

153.3 In the case of the Residential sector it is noted that both energy and capacity savings are attributed to Residential Energy Management

Activities. Do Residential Energy Management Activities also serve to enable and support energy and capacity savings reported under for other Residential DSM programs?

153.3.1 If yes, please indicate how.

154.0 Reference: Exhibit B-6, AMPC 1.5.7

154.1 The response confirms that "DSM with a levelized utility cost less than $30 per MWh reduces BC Hydro's overall revenue requirements and overall customer bills". Does DSM with a levelized utility cost less than $30 per MWH reduce the rates paid by all customer classes?

154.1.1 If yes, please explain why.

155.0 Reference: Exhibit B-5, BCUC 1.15.3
Exhibit B-6, AMPC 1.5.9; and INCE 1.2.1

155.1 With respect to AMPC 1.5.9, why was a 15-year period (i.e., 2020-2034) used to calculate the levelized market price when, with committed domestic resources (including Site C), the planning view LRB only shows an energy surplus until fiscal 2027 (per INCE 1.2.1)?The response to AMPC 1.5.9 states that "For the purpose of assessing the TRC under that regulation, the levelized energy LRMC of $105/MWh was used for the duration of the forecast period. Internal decisions on demand side measures are based on the utility cost test at market price, not the LRMC"**.**

155.2.1 Please clarify what is meant by "internal decisions on DSM measures".

155.2.2 In particular, does this mean that the decisions regarding the proposed DSM plan (per Appendix X) are based on the utility cost test at market price?

155.3 Apart from those related to DSM, what other internal decisions affecting the revenue requirement in the test years rely of the value ascribed to BC Hydro's future opportunity cost for energy (e.g., EPA renewals, new EPA agreements, new capital spending commitments, etc.)?

155.3.1 In each case, what has BC Hydro used as the basis for the opportunity cost energy for purposes of establishing the revenue requirement proposed for the test years?

156.0 Reference: Exhibit B-6, BCOAPO 1.81.1.1 and BCSEA 1.51.3

156.1 What impact, if any, does BC Hydro expect the flattening of the Residential tiered energy rate would have on the persistence of the conservation savings that have been attributed to the RIB rate?

157.0 Reference: Exhibit B-6, BCSEA 1.51.2
Exhibit B-1, Appendix X, Tables A-4 and A-5

157.1 The response states "The forecast of TSR energy savings is based on historical and forecast demand-side management projects and incremental self-generation projects at specific TSR customer facilities." How does BC Hydro distinguish between DSM projects and incremental self-generation projects that are attributable to the overall rate level (e.g., would have occurred in the absence of the stepped rate for transmission customers) and projects that can be directly attributed the Transmission Service Rate?

158.0 Reference: Exhibit B-6, BCSEA 1.53.1

158.1 What DSM programs has BC Hydro currently scheduled for evaluation in F2019, F2020 and F2021?

158.2 Based on the plan set out in response to part 1 which DSM programs will not have been subject to an evaluation over the F2017 to F2021 period?

159.0 Reference: Exhibit B-6, CEABC 1.15.1 and 1.15.4; and INCE 1.2.1
Exhibit B-5, BCUC 1.186.2

159.1 In calculating the cost effectiveness of the projects, what assumptions did BC Hydro make regarding future increases in BC Hydro rates for purposes of forecasting the additional revenues that will be earned?

159.2 Why was the time period up to F2031 used for purposes of calculating the GGRR NPV?

159.3 The tables provided in response to CEABC 1.15.1 only provide incremental energy through to F2022. For any of the projects, is there expected to be incremental energy after F2022?

159.3.1 If yes, please provide revised version of CECBC 1.15.1 that shows the incremental energy for all the year impacted.

159.4 If for any of the projects there is expected to be incremental energy after F2026, how was the fact that the planning view LRB with just committed resources shows there is no surplus after this date (per INCE 1.2.1) taken into account?