REQUESTOR NAME:	**BCOAPO**
INFORMATION REQUEST ROUND NO:	**2**
TO:	**British Columbia Hydro & Power Authority**
DATE:	**December 16, 2016**
PROJECT NO:	**3698869**
APPLICATION NAME:	**FISCAL 2017 TO FISCAL 2019 REVENUE REQUIREMENTS APPLICATION**

69.0 Reference: BCUC 1.4.4
CEC 1.5.3

69.1 Please confirm that the historical values reported in BCUC 1.4.4 are not "weather normalized".

69.2 Are the historical weather normalized residential use per account values reported in CEA 1.5.3 comparable to the forecast values reported in BCUC 1.4.4?

69.3 In BCUC 1.4.4, what accounts for the forecast increase in Light Industrial and Commercial Use per Account for F2017 and the subsequent decreases in F2018 and F2019? Is it the fact that the F2016 values are not weather normalized?

70.0 Reference: BCUC 1.13.1 and 1.13.3

70.1 Please indicate where in Schedule A the deferral of the variance in External OATT revenues to the NHDA is shown for F2015 and F2016.

71.0 Reference: BCUC 1.18.5 and 1.19.1

71.1 Please outline the major factors contributing to the variance in F2019 between the average cost per the 2013 IRP and that in the current RRA (per BCUC 1.18.5).

71.2 Which IPP average/unit cost values (those reported in BCUC 1.18.5 or BCUC 1.19.1) are more comparable (in terms of the calculation basis) with the average IPP costs shown for the 2013 IRP?

72.0 Reference: BCUC 1.22.3 and 1.22.4

72.1 Please explain the increase in distribution losses/decrease in transmission losses for the forecast period as compared to the historical period (per BCUC 1.22.3).

72.2 Please provide a schedule that sets out the calculation of the forecast losses for F2017 based on the formulae described in BCUC 1.22.4.

73.0 Reference: CEC 1.49.5

73.1 Do the Management and Professional compensation rate comparisons provided include Executive Positions?

73.2 If not, please provide a similar comparison for Executive positions based on recent salary surveys.

73.3 Please provide a similar comparison for unionized (i.e. IBEW and MoveUp) positions based on recent salary surveys.

74.0 Reference: BCUC 1.40.5

74.1 It is not immediately clear from the response whether, with its reduced involvement with the CEA, BC Hydro will continue to have access to the information required to continue to provide to the BCUC the reports describe in BCUC 1.40.5. Please clarify.

75.0 Reference: BCUC 1.50.3; 1.50.3.1 and 1.51.2

75.1 The response to BCUC 1.50.3 indicates that $19 M in savings was allocated to individual business units. However, the change in the Business Unit Support costs is only $15.7 M (i.e. $6.8 M + $8.9 M). Please reconcile.

75.2 BCUC 1.50.3.1 indicates that the Business Support Unit still holds $4 M in savings. Please explain why the value at line 14 of the table provided in the response is not negative (i.e. indicating additional savings).

75.3 Where is the $4.3 M in company-wide savings referenced at page 5-20 of the Application reflected in the Application?

76.0 Reference: BCUC 1.63.6 and1.63.8

76.1 BCUC 1.63.8 indicates that 60% of Current Service costs are operating costs. Given this percentage, why was the amount of F2016 operating cost variance deferred only $17.2 M (Application, page 7-29) when the total variance was $36.9 M per BCUC 1.63.6? Wouldn't the operating cost portion of the variance be $22.14 M?

77.0 Reference: BCUC 1.73.1 and 1.73.9
BCOAPO 1.36.1 and 1.36.2

77.1 It is noted (BCOAPO 1.36.2) that a number of the deferred/cancelled capital projects have risk ratings of 9.0 or greater. For all capital projects identified in BCOAPO 1.36.1 with a risk score of 9.0 or less, please explain why there projects were chosen to proceed as initially scheduled as opposed to being delayed/cancelled in lieu of the projects that have been delayed/cancelled per BCUC 1.73.1-Attachment 1.

78.0 Reference: BCUC 1.74.3

78.1 It would appear that one of the two generating units at the Shuswap Facility is not being used and that none of the generating equipment at Alouette or Elko is being used. Please explain more fully why these generation assets should be considered used and useful and included in rate base?

79.0 Reference: BCUC 1.73.6, 1.76.1 and 1.76.2

79.1 The response to BCUC 1.73.6 refers to "the reliability levels that our customers expect". What does BC Hydro consider to be the "reliability levels that customers expect", how was this "expectation" determined and how do the expected reliability levels relate to current reliability levels?

79.2 How long will it be before BC Hydro can determine if it can allow the Transmission and Distribution portfolio asset health to be lowered while still providing the reliability levels that customers expect? Will this information be available in time to inform BC Hydro's next Revenue Requirements Application?

80.0 Reference: BCUC 1.86.5 and 1.87.5

80.1 Please indicate whether BC Hydro considers the Ladore Spillway Seismic Upgrade and/or the Strathcona Upgrade Discharge to be an "extension" such that a CPCN Application would be required under the current Capital Project Filing Guidelines if the expenditure threshold was exceeded.

81.0 Reference: BCUC 1.87.4

81.1 BC Hydro indicates that the various Strathcona Dam-related projects have different drivers and should be considered separately. Will the particular scope or approach established for any of the projects have an impact on how the other projects are carried out and/or their costs? If so, please indicate the nature of any such inter-relationships.

82.0 Reference: BCUC 1.88.3

82.1 Will the upgrades to Units 5 and 6 result in additional MWs and/or GWhs/year? If so, was an assessment as to the cost/benefit of achieving this incremental output undertaken?

83.0 Reference: BCUC 1.101.3 and 1.101.4

83.1 Does the transmission alternative chosen for the West Kelowna Transmission project affect the scope or spending requirements for the second 138 kV line position at the Westbank Substation? If yes, please explain how.

84.0 Reference: BCUC 1.103.5

84.1 In the current Application are there interest costs being expensed related to borrowings used to purchase land that has yet to be developed? If yes, what are the amounts for F2017, F2018 and F2019?

84.2 Why should these amounts be charged to rate payers if the land is not used and useful?

85.0 Reference: BCUC 1.105.1 and 1.105.1.1

85.1 Please detail what the difference in customer cost responsibility is if a non-Liquified Natural Gas industrial project is the driver for the required upgrades as opposed to if a Liquified Natural Gas project is the driver.

85.2 How is the determination made as to what projects are the "driver"?

86.0 Reference: BCUC 1.120.1 and 1.122.1

86.1 Given that the Mica GIS project is not exempt (per BCUC 1.120.1), why didn't BC Hydro re-apply for approval of the project after the Mica Unit 5 and Unit 6 project was approved by the BC Hydro Board of Directors?

87.0 Reference: BCUC 1.123.1 and 1.123.3
Zone II 1.6.2

87.1 The responses to BCUC 1.123.1 and Zone II 1.6.2 set out two significantly different sets of values for the authorized and actual SMI costs. Please reconcile the two responses.

87.2 BCUC 1.123.1 indicates that the difference between the authorized and actual amounts was not due to a change in scope. However Zone II 1.6.2 indicates a number of "scope changes" that impacted costs. Please reconcile.

87.3 Please provide a schedule that sets out the timing of the capital additions as originally planned (totaling $782 M) versus the timing of the actual capital additions (totaling $696.6 M).

88.0 Reference: BCUC 1.124.5

88.1 The response shows that after F2020 a portion of the DARR in each year is applied to Revenues. Does this mean that these amounts will be treated as revenues and hence (implicitly) contribute to the clearing of the Rate Smoothing account.

88.2 Please confirm that this outlook assumes there are no future additions to the Cost of Energy Variance accounts.

89.0 Reference: BCUC 1.128.2 and 1.128.4
BCOAPO 1.39.1 and 1.39.2

89.1 The request at page 7-19 of the Application is that, starting in fiscal 2017, annual negotiation costs related to First Nations be excluded from the calculation of the heritage payment obligation for purposes of deferring variances to the HDA. The response to BCUC 1.128.2 notes that for the period F2007 to F2016 the account captured both negotiation and litigation costs. However, the response to BCOAPO 1.39.1 does not identify "litigation costs" as being included in the request. Please confirm whether the request at page 7-19 includes litigation costs or whether such costs will continue to be capture in the deferral account.

89.2 Do the amounts reported in BCOAPO 1.39.2 include any litigation costs?

90.0 Reference: BCUC 1.134.2 and 1.134.3

90.1 Please provide revised version of the table in BCUC 1.134.3 that includes just the amounts associated with non-heritage assets.

90.2 For the test period, what is the forecast amortization in each year associated capital additions related to non-heritage assets?

91.0 Reference: BCUC 1.141.1 and 1.141.2

91.1 Please explain more fully how the proposed treatment of First Nations negotiation costs for F2017 results in ratepayers being responsible for forecast negotiation costs and BC Hydro bearing the responsibility for any variance between forecast and actual negotiation costs.

92.0 Reference: BCUC 1.129.6 and 1.166.4

92.1 The response to BCUC 1.129.6 indicates that BC Hydro is not at risk for variances from Plan related to external OATT revenues (i.e., the response excludes external OATT revenue per Schedule 15, line 6). However, the response to BCUC 1.166.4 indicates that the variance between forecast and actual external OATT revenues is not deferred to any deferral or regulatory account. Please reconcile these two responses.

93.0 Reference: BCUC 1.156.5

93.1 Please confirm that the load associated with the LNG revenue is included in the Oil & Gas Sector part of the Large Industrial load forecast. If not, where is it captured?

94.0 Reference: BCUC 1.167.4

94.1 Please clarify whether the response under item (ii) was meant to address the situation where the Schedule was rejected on the basis spending levels were too low (as stated) or too high (as the balance of the response appears to suggest).

95.0 Reference: BCUC 1.168.1

95.1 Please revise the updates to Figure 3-1 and 3-2 to include the years F2014-F2016. For DSM Option 2 include the savings forecast to be achieved with approved DSM spending for up to F2016 along with the post F2016 results as included in the 2013 IRP. For the updated DSM results please include the actuals for F2014-F2016 along with the savings to be achieved by the currently proposed DSM Plan.

95.2 Please provide schedules setting out the actual values presented in the updated Figures.

96.0 Reference: BCUC 1.168.3

96.1 The response indicates that over the F2017-F2019 period the spending for Commercial programs will be 25% less than set out in the 2013 IRP but that the savings will be 3% higher. Please indicate how the greater savings are to be achieved with less spending.

96.2 Why was a similar result not possible Residential programs?

96.3 If one were to combine the current proposed spending and savings for Industrial programs and Thermo-Mechanical Pulp how would the totals compare with the 2013 IRP planned spending and savings from Industrial Programs?

96.4 Please provide a second set of schedules comparing the annual expenditures associated with each for F2014-F2024. Note: For the current proposed plan please include the actual spending for F2014-F2016.

97.0 Reference: BCUC 1.170.3; 1.170.3.1 and 1.171.1

97.1 The response to BCUC 1.171.1 states that $102/MWh (F2016$) is the estimated cost for greenfield clean or renewable IPPs. However, pages 3-48 and 3-49 of the Application indicate that BC Hydro expects to be able to acquired EPA renewals at less than $85/MWh (F2013$ or $87/MWh in F2016$). Please explain more fully why the $87/MWh (F2016$) was not used for the period up to F2033 in determining the levelized avoided costs (per BCUC 1.170.3 and revised Appendix X).

98.0 Reference: BCUC 1.171.2

98.1 Please clarify whether the F2017-F2019 columns in the response show the results for: i) currently proposed program activity for F2017-F2019 or ii) the currently proposed activity through to F2024 per Appendix W.

98.2 For the F2017-F2019 period, please provide a table similar to Appendix W-Table 10 that shows the derivation of: i) the Net Levelized Modified TRC and ii) the Net Levelized Total Resource Cost for programs in these three years.

98.3 In the case of the Capacity focused DSM, what is the Net Levelized TRC value in $/kW-year associated with the F2017-F2019 Plan?

99.0 Reference: BCUC 1.174.1

99.1 It is noted that BC Hydro has consistently underspent its approved DSM budget for each of the years F2012-F2016. What is/will be different about the F2017-F2019 period such that this will not continue to occur?

100.0 Reference: BCUC 1.175.1 and 1.175.1.1

100.1 It is noted that the response covers the period F2016-F2024. Given that BC Hydro's requesting approval for its proposed F2017-F2019 expenditure schedule, please provide similar tables for the programs proposed for these years.

101.0 Reference: BCUC 1.175.2; 1.175.2.1 and 1.175.2.2

101.1 BCUC 1.175.2.1 specifically referenced the F2017-F2019 period. However, the response references Appendix W which appears to cover program activity from F2016-F2024. Please provide a response that specifically addresses the programs BC Hydro is proposing for the F2017-F2019 period.

101.2 Similarly, if the response to BCUC 1.175.2.2 does not specifically address the DSM spending for programs in F2017-F2019, please provide a response that specifically addresses the measures proposed for this period.

102.0 Reference: BCUC 1.178.1.1

102.1 Is the price elasticity used to determine the impact of the RIB on the load forecast assumed to be a long-run or a short-run price elasticity? Please provide supporting references.

102.2 The response states that the cost effectiveness of the RIB rate is expected to remain positive regardless of the customer cost assumption. Please demonstrate why this is expected to be the case. As part of the response please indicate what the cost effectiveness of the RIB rate would be if a residential customer was assumed to achieve the savings by investing dollars equivalent to 95% of the anticipated bill savings in the home improvement measures (Note: Use the RIB rate design proposed in the recent RDA).

103.0 Reference: BCUC 1.181.1.1 & BCUC 1.181.3
BCOAPO 1.56.1

103.1 The response to BCUC 1.181.1.1 indicates that BC Hydro‘s load curtailment program is testing the ability to meet a 16-hour peak for up to 36 days over the winter and shoulder periods. For how many hours a year would a capacity focused demand-side management program have to offer kW reductions in order to provide the same system benefit as a generation capacity option? Please provide the analysis supporting the response.

103.2 How quickly must a capacity focused demand-side option be able to respond to a capacity shortfall in order to provide the equivalent benefit of a generation capacity option? Will differences in response times be taken into account in the net benefit evaluation?

104.0 Reference: BCUC1.181.3 & 1.182.1

104.1 Both of these responses make reference to the possible role of capacity focused demand-side management in reducing constraints at the local level (regional transmission and/or distribution). Would the number of hours of availability have to increase if a capacity focused demand-side management program was going to be relied on for both generation capacity relief as well as relief for local constraints? If not, why not?

104.2 If yes, by how much would the number of hours of availability have to increase?

105.0 Reference: BCUC 1.183.4

105.1 Please reconcile the statement that "BC Hydro does not generally expect forecast revenues received from different customer segments to change as a result of the introduction of conservation rates" with the fact that BC Hydro explicitly adjusts its load forecast (and hence its forecast revenues) to account for the impact of conservation rates such as the RIB.

106.0 Reference: BCUC 1.184.5 & 1.184.5.1

106.1 Please confirm that Table 1 sets out program results for: i) actual program activity in the years F2013-F2016 vs. ii) planned program activity for the years F2014-F2016, and that the later does not include any program activity post F2016. If not, please re-do on this basis.

106.2 Table 2 in the response to BCUC 1.184.5 covers the forecast period F2016-F2024, whereas the question requested that the forecast be for programs for the period F2017-F2019 (i.e. the period covered by the proposed DSM Expenditure schedule). Please revise Table 2 such that the forecast period values align with proposed F2017-F2019 programs.

106.3 Based on preceding results please provide a revised response to BCUC 1.184.5.1.

107.0 Reference: BCUC 1.186.1

107.1 Please confirm that the source of the BC Hydro data is Tables 9 and 10 from Appendix W.

107.2 Please confirm whether Appendix W reports the results for BC Hydro's proposed F2017 to F2019 programs or for programs implemented over some other period.

107.3 Please clarify the period of program activity covered by the FBC values.

108.0 Reference: AMPC 1.6.1

108.1 With respect to the Commercial and Residential SAE Use models (pages 5 - 14 of the response), please indicate what the "dependent variable" is in each case.

108.2 Please provide a definition of each of the non-binary variables used in the Residential and Commercial equations.

108.3 Pages 2 and 3 of the response set out the Residential and Commercial SAE Model Drivers. However, none of the "drivers" shown are actually used as explanatory variables in the model equations. Please explain how these drivers impact the model and the forecasts.

109.0 Reference: AMPC 1.7.1 – 1.7.3

109.1 Please explain the relationship between the Residential SAE Models set out in AMPC 1.6.1 and the EIA residential models described in AMPC 1.7.1.

109.2 None of the penetration/fuel share information provided in AMPC 1.7.1 or 1.7.2 appears to be either an input to or an output of the Residential SAE models. Please explain how the forecasts in AMPC 1.7.1 and 1.7.2 are developed and used for purposes of forecasting Residential energy use.

110.0 Reference: AMPC 1.6.1 & 1.8.2

110.1 The response to AMPC 1.8.2 states that the commercial SAE Models use a forecast of space and water heating shares. However, the commercial SAE models provided in AMPC 1.6.1 do not appear to use either of these variables. Please reconcile.

111.0 BCOAPO 1.5.1 & 1.36.2

111.1 For those capital projects less than or equal to $5 M, please indicate the total related reduction in capital expenditures over the F2017-F2019 period broken down as between the categories in Table 6-5 (Application page 6-16) and, for each category, indicate the proportion that has been delayed versus cancelled.

112.0 Reference: BCOAPO 1.18.1

112.1 Please explain why the actual Residential and Commercial Light Industrial sales reported in this response for F2016 do not match those in Table 3-2 of the Application. For example, for Residential the values are 17,269 GWh and 17,331 GWh respectively.

113.0 Reference: BCOAPO 1.21.3

113.1 Please explain more fully how the referenced BCUC Decision supports treating VAR and voltage optimization savings as a sales reduction as opposed to losses, since losses also “reduce the energy demand that a public utility must serve” and “have no interaction with customer behaviors and choices”.

114.0 Reference: BCOAPO 1.23.2 & BCUC 1.22.3

114.1 With respect to BCOAPO 1.23.2, what is the difference between columns C and D?

114.2 Please explain why the Firm Sales values reported for F2017-F2019 in the two responses are different.

114.3 Please explain why these values differ from the total Mid Domestic Sales shown in Table 3-2 (Application, page 3-13).

114.4 Please explain why the System Losses reported for F2017-F2019 in the two responses are different.

115.0 Reference: BCOAPO 1.26.1 & 1.27.1

115.1 The year over year pattern for the unit cost of Natural Gas for Thermal Generation shown in BCOAPO 1.26.1 does not match the pattern for forecast

natural gas prices in BCOAPO 1.27.1 (For example, the unit cost is materially lower in F2017 than F2016 but the natural gas price is marginally higher in F2017). Please reconcile the values reported in the two responses.

116.0 Reference: BCOAPO 1.31.2

116.1 With respect to Unavoidable Labour Costs, please break down the increases in Table 5-5 in each year as between that attributable to increases in number of FTE's vs. increases in cost per FTE.

116.2 What was the actual Base Operating Cost for F2016?

116.3 If the actual varies from the F2016 RRA Plan by more than 5%, please re-do the F2017 Plan portion of Table 5-5 using the F2016 actuals as the starting point.

117.0 Reference: BCOAPO 1.52.1
BCUC 1.162.3

117.1 If practical, please provide a map or some other graphic illustrating where the Generation Transmission Lines are located.

118.0 Reference: BCOAPO 1.61.1

118.1 Please explain why the target savings for F2018 (700 GWh) are significantly less than the incremental F2018 Plan savings (798 GWh).

119.0 Reference: BCOAPO 1.65.1

119.1 Please confirm that the response to CEC 1.5.3 does not show the effect of the weather being warmer than "normal" as the two values being compared in column C are both weather normalized values.

119.2 Please provide a schedule that compares the actual sales by sector from the F2015-F2016 RRA with the actual weather normalized values for each year.

120.0 Reference: BCSEA 1.2.9.1 and 1.33.1

120.1 Throughout the Application and IR responses reference is made to:

i. The 2013 IRP DSM Plan (per BCUC 1.168.1)

ii. Changes to the 2013 IRP DSM Plan per the F2015-F2016 RRA and Order G-48-14 (per Application, page 10-4)

iii. An Updated 2013 IRP DSM Plan (per BCSEA 1.2.9.1 and 1.3.5)

Please provide a series of schedules that compare the following for the above three DSM Plan variations, as well as the currently proposed DSM Plan for the period F2014-F2014:

- Incremental DSM savings (GWh) each year due to new program activity

- Cumulative DSM savings (GWh) with F2014 as the starting/first year
- Annual DSM expenditures.

Note: Please include actual values in the schedules where appropriate (e.g. F2014-F2016 actuals when reporting the current DSM proposal).

121.0 Reference: BCSEA 1.3.2 & 1.3.6

121.1 What programs were modified/eliminated specifically as a result of not passing the Utility Cost Test using the BC-border sell price?

122.0 Reference: BCSEA 1.3.5

122.1 Please confirm that the table provided in the response compares the cost effectiveness for the F2017-F2019 programs, as requested in the original question.

122.2 If not, please provide a revised response that specifically addresses the result of the program activity for this three year period.

123.0 Reference: BCSEA 1.7.1

123.1 What are the programs contributing to the 10-30 GWh of missed opportunities?

124.0 Reference: BCSEA 1.16.1

124.1 With respect to the first tab (Acquired Energy) of the Attachment provided, please indicate what the annual values for each program represent.

124.2 Why are these values different than either the cumulative or the incremental savings values for F2016-F2019 reported in BCOAPO 1.61.1 or those set out in Table 1 of Appendix W?

124.3 If the difference is simply the fact that the values in BCSEA 1.16.1 are present valued to F2016, why don't the F2016 values match?

125.0 Reference: BCSEA 1.20.2

125.1 Given there may be some overlap between the customers participating in each program, what is the total number of Low Income customers that are expected to participate in these programs in F2017, F2018 and F2019?

126.0 Reference: BCSEA 1.20.4

126.1 Why do these values differ from those set out in Table 1 of Appendix W?

127.0 Reference: BCSEA 1.21.2

127.1 How does BC Hydro determine and verify the savings actually achieved from the Residential Behaviour Program?

128.0 Reference: BCSEA 1.25.2 & 1.25.5

128.1 What is the net levelized utility cost for each program and for the Plan overall for program activity in the F2017-F2019 period for which approval of the expenditures is being requested (as opposed to F2016-F2024)?

129.0 Reference: BCSEA 1.33.1

129.1 Please explain the difference between the annual savings from the F2017-F2019 Plan as shown in BCSEA 1.33.1 and the incremental energy savings reported in BCOAPO 1.61.1.

129.2 Please provide the incremental energy savings (GWh) from new activity only for the updated 2013 IRP for F2017-F2019 (similar to BCOAPO 1.61.1). Are these values equivalent to those in BCSEA 1.33.1?

If not, why not?

130.0 Reference: CEA 1.13.1

130.1 When constructed, will part or all of the new/upgraded transmission facilities required to deliver the energy and capacity provided by Site C be considered as Generation-Related Transmission Assets (GRTA)?

131.0 Reference: CEC 1.15.5

131.1 Please explain why there is a difference in the actual housing starts for 2005-2014 as reported by Fairholm and CMHC. One would expect the actual values to be known and the same for both.

132.0 Reference: CEC 1.59.1

132.1 When will the SMI Program Completion and Evaluation Report be filed?

133.0 Reference: CEC 1.62.1

133.1 What are the customer contributions/payments associated with the $15 M in customer initiated projects?

134.0 Reference: CEC 1.102.2

134.1 How does BC Hydro determine the demand reduction achieved by each customer during a curtailment event?

135.0 Reference: CEC 1.108.4

135.1 Would the addition of the savings reported in CEC 1.108.4 and those shown in Table 1 of Appendix W yield the total (actual and expected) cumulative savings starting in 1989 through to F2024 or is there some overlap between the two tables?

136.0 Reference: CEC 1.116.1

136.1 What improvements/changes will the customer see as a result of the Enterprise Billing Infrastructure program?

137.0 Reference: CEC 1.116.1; 1.116.3; and 1.116.4

137.1 The response to CEC 1.116.3 states that the costs and benefits have been identified for each of the projects noted in CEC 1.116.1. However, CEC 1.116.4 states that the net financial benefits of the Enterprise Billing Infrastructure Project are not yet quantified. Please reconcile these two statements and indicate if there are any other projects noted in CEC 1.116.1 for which the net financial benefits have not yet been determined.

137.2 Please provide the Identification Phase business case for the Enterprise Billing Infrastructure Project (per CEC 1.116.4).

138.0 Reference: CEC 1.119.3; 1.119.4; and 1.119.5

138.1 Similarly, CEC 1.119.4 states that BC Hydro has assessed the benefits and costs for each of the projects noted in CEC 1.119.3. However, CEC 1.119.5 notes that for the three largest projects it has not yet quantified their financial benefits. For how many of the other projects noted in CEC 1.119.3 has BC Hydro not yet quantified the financial benefits?

139.0 Reference: CEC 1.114.3
Application, page 6-108, Table 6-20

139.1 Please identify any projects with a total cost of more than $2 M that contributed to the actual IT capital additions in F2015 and F2016 per Table 6-20.

139.2 For the three cost projects with the largest capital additions in F2015-F2016, please provide the Implementation Phase business cases (per CEC 1.114.3).

140.0 Reference: MoveUP 1.8.6

140.1 Please indicate what would be included in “accounting adjustments”.

141.0 Reference: MoveUP 1.9.1 and 1.9.3.3

141.1 The response to MoveUP 1.9.1 suggests that a range of forecasts was not developed for LNG load. However MoveUP 1.9.3.1 describes how high and low sales forecasts were developed for LNG-dependent producers. Please reconcile these two responses.

142.0 Reference: MoveUP 1.11.5

142.1 Is the recovery from all customers specified by the Order in Council that authorized the Regulatory Account?

143.0 Reference: CEC 1.108.4
SWF 1.3.6

143.1 Do the values in response to SWF 1.3.6 represent: i) the incremental savings from new program activity in the fiscal year or ii) incremental savings overall, taking into account both new program activity and the loss of persistence in savings from previous years' programs?

143.2 CEC 108.4 shows an increase in F2008 (over F2007) of 437 GWh which is greater than the incremental savings reported in SWF 1.3.6 (302 GWh). Please explain how the values in the two responses are related and can be reconciled.

144.0 Reference: Zone II 1.6.3

144.1 Please explain the basis for the negative values for Voltage Optimization – Commercial Customer Sites and Voluntary TOU Rates in the Business Case (to 2016) column.

144.2 Please explain why the actual Theft Detection Benefits to F2016 are virtually the same as in the Business Case when the current Energy Reference Price is materially less than that used in the Business Case.