British Columbia Utilities Commission

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VIA EFILE
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December 14, 2016

BC HYDRO F2017–F2019
REVENUE REQUIREMENTS EXHIBIT A-14

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

Dear Mr. James:

Re: British Columbia Hydro and Power Authority
Project No. 3698869 / Order G-40-16
F2017 to F2019 Revenue Requirements Application

Further to your July 28, 2016 filing regarding the above noted application, enclosed please find Commission Information Request No. 2. In accordance with the regulatory timetable set out in Order G-144-16, please file your responses no later than Monday, January 23, 2017.

Yours truly,

Original signed by:

Laurel Ross

CMM/kbb
Enclosure

BC Hydro and Power Authority
F2017–F2019 Revenue Requirements Application

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A. CHAPTER 1 – APPLICATION OVERVIEW

193.0 Reference: APPLICATION OVERVIEW
Exhibit B-1-1, Chapter 5, pp. 5-6 & 5-7
Reports reviewed by management

193.1 In the Application and throughout the IR responses BC Hydro has provided information regarding managements' role, however little was provide related to specific controls and processes. Please explain the specific nature and design of the controls and processes in place for efficiently managing (i) the preparation, (ii) approval and (iii) oversight of each of the following:

- Workforce Plan including the Workforce Optimization initiative and the Work Smart initiative;
- Base-budget review;
- Top down and bottom planning for operating costs;
- Debt management strategy;
- Load forecasting methodology;
- Ten Year Capital Forecast;
- Technology Group Five Year Strategic Plan; and
- Capital Investment Framework.

193.2 Please explain the specific nature and design of the controls and processes in place to ensure that operating costs are well managed to keep customer rate increases to the minimum that is necessary to continue to provide safe and reliable service?

193.3 What processes are in place to ensure that the controls and processes are properly designed and operating efficiently?

194.0 Reference: APPLICATION OVERVIEW
Exhibit B-10, BCOAPO 1.63.1; Exhibit B-10, CEC 1.4.1
Operating costs as a performance measure

In response to BCOAPO IR 1.63.1 and CEC IR 1.4.1 BC Hydro explains that the "operating costs" performance measure was removed in the BC Hydro's Current Service Plan for consistency with the Guidelines for Crown Corporation Service Plans from the Crown Agencies Resource Office of the Ministry of Finance dated November 2014 regarding recommended number of goals and performance measures for Crowns.

BC Hydro states:

> **Several of the metrics that have been removed from the Service Plan continue to be tracked and reported elsewhere. For example, the achievement of our operating cost budget and our net income target form part of our regular financial reporting. Similarly, carbon neutral program emissions are reported to the Province under the B.C. Carbon Neutral Government Regulation.**

194.1 What are BC Hydro's key determining factors in decided which performance measures take priority over others in its Current Service Plan? If BC Hydro continues to track and report elsewhere the metrics that were removed, why not leave them in the Current Service Plan?

194.2 Would BC Hydro agree that tracking changes in operating costs/customer and operating costs/unit sales are standard Performance Measure used by most corporations?

194.2.1 If not, please explain.

194.2.2 If yes, please include these statistics from F2012 through projected F2019 in support of BC Hydro's operating cost projections.

B. CHAPTER 3– LOAD AND REVENUE FORECAST

195.0 Reference: Load and Revenue Forecast
Exhibit B-9, BCUC IR 4.7; Exhibit B-10, CEC IR 24.1
Uses for the Load Forecast approved in the RRA

In response to BCUC IR 4.7 BC Hydro stated that:

> The May 2016 Load Forecast is BC Hydro's annual load forecast and its timing of its preparation was chosen to support the Application. The load forecast presented in the Application will also be used internally for many purposes such as load resource balance planning, monthly energy studies, long term transmission planning studies, and demand-side management planning.
>
> BC Hydro is using the May 2016 Load Forecast to support our September 15, 2016 Application to the British Columbia Utilities Commission for two Electricity Purchase Agreement renewals with two IPPs, Akolkolex and Soo River. The May 2016 Load Forecast may also be used to support other filings such as for future Electricity Purchase Agreements.

195.1 Please confirm, or explain otherwise, that the load forecast approval sought in this Application is limited to the forecast for F2017, F2018 and F2019.

195.1.1 Please confirm, or explain otherwise, that the longer term forecast presented in the Application beyond F2019 is for information only, and will be updated in the 2018 Integrated Resource Plan.

195.2 Please confirm, or explain otherwise, that the load forecast to be approved by the Commission as part of this Application will not be used for any internal or external purposes other than those disclosed in response to BCUC IR 4.7.

195.3 If the Commission were to direct adjustments to the load forecast (either higher or lower) for rate setting purposes, would BC Hydro use the Commission approved load forecast for internal purposes or would it continue to use the load forecast as presented in the Application?

195.4 Please explain in detail to what extent, if any, the test period load forecast to be approved as part of this Application, is of relevance to EPA renewals.

196.0 Reference: LOAD AND REVENUE FORECAST
Exhibit B-9, BCUC IR 9.1
Savings from reduced theft – grow-ops

BC Hydro stated in response to BCUC IR 9.1 that "the reduction in theft from grow-ops has resulted in both increased revenue and reduced consumption. This has been established through our Revenue Assurance field inspections, which in fiscal 2016 found that only 2 per cent of the grow-op sites that we inspected were engaged in theft of electricity."

The table included in BC Hydro's response to BCUC IR 9.1 shows that the percent of grow-op theft for F2016 is 18 percent.

196.1 Please reconcile the percentage of theft from grow-op sights as referenced in the preamble.

196.2 Please explain which percentage (2 percent or 18 percent), or some other percentage, has been used to determine the incremental theft reduction to the test period load forecast.

197.0 Reference: Load and Revenue Forecast
Exhibit B-9, BCUC IR 2.1 and 177.1; Exhibit B-10, CEC IR 14.2, AMPC IR 9.3 series
Load forecast update
Residential, Light Industrial & Commercial, Large Industrial

BCUC IR 2.1 explains the load forecast methodology for residential, commercial, light industrial, and large industrial customer classes as follows:

> Residential Sales
>
> The total residential sales forecast is the sum of the sales for each of BC Hydro's major service regions (Lower Mainland, Vancouver Island, South and North). In each region, the residential sales forecast is calculated as:
>
> Average use per account x total ending number of accounts + electric vehicle sales + estimates to adjust for overlap in codes and standards
>
> Commercial Sales
>
> The total commercial distribution sales forecast is calculated as:
>
> Total regional sales from the commercial SAE models + electric vehicle load + estimates to adjust for overlap in codes and standards
>
> Light Industrial Sales
>
> The sales for light industrial sector is the sum of sales for coal, wood, oil and gas and other industrial loads connected at the distribution level. For further details regarding light industrial sales are provided in Section 3.2.1.3 of the Application.
>
> Large Industrial Sales
>
> The sales forecast for the large industrial sector is developed on account by account basis with a general forecasting equation for each account which is:
>
> Production X intensity X probability weighting

BC Hydro stated in response to CEC IR 14.2 that "We have not adjusted our May 2016 Load Forecast to reflect policies that have been identified in the City of Vancouver's Renewable City Strategy or the Province's Climate Leadership Plan. The Renewable City Strategy includes policy actions that increase the use and supply of renewable energy. To the extent this renewable supply is delivered in the form of electricity supplied by BC Hydro, we would anticipate an increase in overall electricity demand..."

BC Hydro stated in response to BCUC IR 177.1 that "low-carbon electrification could potentially reduce rates through the collection of increased revenue driven by load growth as customers switch to clean electricity in place of other forms of energy such as gasoline, natural gas, and diesel."

In response to AMPC IR 9.3 series, BC Hydro explains that a number of recent developments are "not expected to have an impact on the load forecast over the test period."

197.1 Please elaborate on the timing of the implementation of low-carbon electrification programs.

197.2 Given the recent developments since the forecast was completed, please explain whether BC Hydro has consulted its Large Industrial customers and/or key account managers for an update on the anticipated large industrial load for the F2017–F2019 test period. If yes, please provide a description of any findings or updates. If not, please explain why not.

197.3 Please update the May 2016 forecast by incorporating information from the 2016 historical data, new government policies, low-carbon electrification programs, impact of the Nicola Valley mill closure, and any other new information for Residential, Light Industrial & Commercial and Large Industrial customers.

197.3.1 Please explain and provide a summary table of how each adjustment impacts the forecast for each customer class.

197.3.2 In the updated load forecast provided, were there any known factors that BC Hydro decided not to reflect? If yes, please explain why they were not included.

197.4 Please provide an update to the load resource balance as presented in Tables 3-6 through 3-9 of the Application with the updated load forecast information provided in response to the IR above.

197.4.1 Based on the updated load resource balance provided above, please explain whether this impacts (i) the need for the capacity Demand Side Management (DSM) program during the F2017–F2019 test period and (ii) BC Hydro's IPP renewal strategy.

198.0 Reference: LOAD AND REVENUE FORECAST
Exhibit B-9, BCUC IR 2.1, 2.2
Adjustment for overlap for codes and standards
Residential and Commercial customers

BCUC stated in response to BCUC IR 2.1: "Adjustments for overlap for codes and standards is an estimate of savings from BC Hydro's demand-side management plan that are already reflected in the average efficiency forecast from the U.S. Energy Information Administration"

198.1 For Residential and Commercial customers, please elaborate on how BC Hydro determines the magnitude of the adjustments for overlap of energy savings between codes and standards and DSM savings, which aspect of the forecast is the adjustment applied to, and how BC Hydro verifies whether the adjustment applied has been accurate based on past experience.

199.0 Reference: LOAD AND REVENUE FORECAST
Exhibit B-9, BCUC IR 4.4; Exhibit B-10, CEA IR 5.3
Residential & Light Industrial &Commercial Customers

BC Hydro stated in response to CEA IR 5.3 that "there is a historical downward trend in the residential use per account due to various factors such as impacts of demand-side management."

In response to BCUC IR 4.4, BC Hydro presented the 10 year historical data, and test year forecast, of the use per account (UPA) and customer count for residential and light industrial & commercial customer classes.

199.1 For both the Residential and Light Industrial & Commercial customer classes, please expand the data table to include the forecast UPA and customer count over the 10 year period, and also calculate the variance between forecast and actual in both absolute terms and on a percentage basis. Please also provide a graph showing the 10-year historical forecast, actual and the F2017 to F2019 forecast.

199.2 Please explain the forecast increase in UPA in F2017 given the actual F2016 UPA for Residential and Light Industrial & Commercial classes.

199.3 Please provide the detailed calculation for the Residential load forecast by populating the table set out below:

Residential Load Forecast					
	Average Use Per Account	Ending Number of Accounts	Electric Vehicle Sales	Adj for Codes & Std	Load Forecast
F2017					
F2018					
F2019					

199.3.1 Please provide a similar calculation for the test period relating to Commercial sales.

200.0 Reference: LOAD AND REVENUE FORECAST
Exhibit B-1, page 3-16, Table 3-3, Exhibit B-9, BCUC IR 4.3, 6.1
Large Industrial Load forecasts

The response to BCUC IR 4.2 shows that over the past five years, the actual load for Large Industrial customers has consistently been less than the forecast by an average of 9.3 percent.

In response to BCOAPO IR 17.1, BC Hydro stated that "The time between February and May 2016 was sufficient for BC Hydro to update its large industrial sector forecast, [Large Industrial Load forecast] but insufficient time to allow for an update of the economic projection using the industrial sector forecast as inputs."

200.1 Please explain whether economic projection is an input into the Large Industrial load forecast. If yes, please explain whether there is circular relationship with the industrial sector forecast being both the input and the output of the Large Industrial load forecast. If there is does this pose an issue?

200.2 Please explain whether BC Hydro is investigating methods to improve the accuracy of its Large Industrial forecast.

200.3 If BC Hydro had used the forecasts compiled by the customers and Key Account Managers before adjustments by BC Hydro's industry experts, would the Large Industrial forecasts have been more accurate over the past 5 years? Please show the results.

200.4 On the basis of the information provided in Table 3-3 please fill out the following table and provide an explanation for any variances.

Large Industrial Sales Forecast									
	Oil and Gas			Coal and Metal Mining			Forestry		
	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance
F2009									
F2010									
F2011									
F2012									
F2013									
F2014									
F2015									
F2016									

201.0 Reference: LOAD AND REVENUE FORECAST
Exhibit B-1-1, Appendix A, schedule 14, line 7
FortisBC

201.1 It appears that in recent years, the accuracy of the load forecast for sales to FortisBC has improved dramatically.

202.0 Reference: LOAD AND REVENUE FORECAST
Exhibit B-9, BCUC IR 4.2, BCUC IR 4.3, BCUC IR 4.6, BCUC IR 13.2
Impacts on the revenue requirement as a result to a change in the load forecast

202.1 In response to BCUC IR 4.6 BC Hydro provided a table showing the impact to the revenue requirements due to an overall reduction in the load forecast of 3 percent and 5 percent. Please update the table to show what the impacts would result in the case of a 4 percent overall reduction.

202.1.1 Under the assumption that the load forecast is reduced by (a) 3 percent (b) 4 percent and (c) 5 percent, what would the following be in each of the test periods?

i. Forecast additions to the Rate Smoothing regulatory account;
ii. Rate increase without consideration of a rate cap (no transfers to the rate smoothing account); and
iii. Change to the Cost of Energy forecast.

The table below summarizes the data provided in response to BCUC IR 4.2 and 4.3 which shows that on average the approved Residential and Large Industrial load forecasts have been higher than actual load.

Percent variance between load forecast approved and actual

Reference		Residential	Large Industiral	All
BCUC IR 4.2	Average for the last five years	-3.9%	-9.3%	-4.1%
BCUC IR 4.3	Average for the last seven years	-1.9%	-9.6%	-3.9%
BCUC IR 4.3	Average for the last eight years	-1.0%	-8.8%	-3.3%

202.2 Under these three scenarios: (a) Residential load is reduced by 3.9 percent and Large Industrial load is reduced by 9.3 percent, (b) Residential load is reduced by 1.9 percent and Large Industrial load is reduced by 9.6 percent and (c) Residential load is reduced by 1.0 percent and Large Industrial load is reduced by 8.8 percent, in each of F2017 – F2019, what would be the:

i. Reduction in revenues as calculated in response to BCUC IR 4.6;
ii. Forecast additions to the Rate Smoothing regulatory account;
iii. Rate increase without consideration of a rate cap (no transfers to the rate smoothing account); and
iv. Change to the Cost of Energy forecast.

202.3 In response to BCUC IR 13.2 BC Hydro confirmed that in the five year period between F2012 and F2016, $852.8 million has been added to the NHDA as a result of load forecast variance. Please quantify the amount of the $852.8 million variance that is due to (i) Residential load variance and (ii) Large Industrial load variances.

202.3.1 Was there an offsetting Cost of Energy variance in the same five year period? If yes, please quantify. If not, please explain.

203.0 Reference: LOAD AND REVENUE FORECAST
Exhibit B-1-1, Appendix A, schedule 14; Exhibit B-9, BCUC IR 7.2
Revenue forecast

203.1 Please explain how the Average Revenues $/MWh set out in lines 27-35 of Appendix A, schedule 14 have been derived? Please provide a more detailed explanation for the calculation relating to Residential, Light Industrial & Commercial and Large Industrial customers.

203.2 BC Hydro states that there is new eDrive Rate for LNG facilities. Will BC Hydro be filing this rate with the Commission for approval? If so, when? If not, please explain.

C. CHAPTER 4 – COST OF ENERGY

204.0 Reference: COST OF ENERGY
Exhibit B-9, BCUC IR 15.1; Exhibit B-10, FBC IR 1.1; heritage contract
Energy model

BC Hydro stated in response to FBC IR 1.1 that "BC Hydro optimizes its supply portfolio by maximizing consolidated net revenues."

204.1 Please explain whether maximizing the consolidated net revenue is equivalent to minimizing BC Hydro's revenue requirement over the same time period, resulting in a minimized amount to be recovered from ratepayers.

205.0 Reference: COST OF ENERGY
Exhibit B-9, BCUC IR 15.3; Exhibit B-10, BCOAPO IR 26.1
Energy model

BC Hydro stated in response to BCUC IR 15.3 that "Regardless of the surplus or deficit in system energy, BC Hydro will shape generation into the highest priced periods available, given the flexibility of the system… BC Hydro, through its subsidiary Powerex, will then sell its surplus energy at times and in geographical markets that provide the highest value."

In response to BCOAPO IR 26.1, BC Hydro presents that the heritage unit cost ($/MWh) of market electricity purchases and surplus sales for RRA 2016, Actual 2016, and Forecast F2017 through F2019.

205.1 Given BC Hydro's energy model and optimization strategy, please explain the larger variance between the unit price of market purchases and surplus sales in the test period forecast than in actual 2016.

206.0 Reference: COST OF ENERGY
Exhibit B-9, BCUC IR 127.2; Application, p. 3-31, Appendix A, Schedule 4, Schedule 14
Heritage resource

BC Hydro stated in response to BCUC IR 127.2 that "Heritage Energy means 49,000 GWh per year less the energy generated for delivery under the Skagit Valley Treaty. BC Hydro is obligated to supply from its generating resources each year the Heritage Energy, or such lesser amount of energy as may be required."

BC Hydro shows in Appendix A of the Application in Schedule 14 line 8, that the forecast load for Seattle City Light is 310 GWh for each year in F2017 to F2019.

The load resource balance presented on page 3-31 of the Application in Table 3-8 shows that the heritage resource for the F2017 to 2019 test period is 48,445GWh, 46,895GWh and 46,014GWh respectively.

206.1 Please reconcile and explain in detail how the amount of heritage energy is calculated. Specifically, please explain why the amount of heritage energy during the F2017 to F2019 test period does not equal to 49,000 GWh less the demand for Seattle City Light.

207.0 Reference: COST OF ENERGY
Exhibit B-9, BCUC IR 17.1, 18.5
IPP volume compared to 2013 IRP

In response to BCUC IR 17.1, BC Hydro stated that "The updated forecast of volume from Electricity Purchase Agreements has increased since the 2013 Integrated Resource Plan to reflect updated expectations for contract attrition, commercial operation dates, renewal timing and energy deliveries."

In response to BCUC IR 18.5, BC Hydro compared the volume and average cost of IPPs for the F2017-2019 test period as presented in the 2013 IRP and in the Application. The tables show that the forecast IPP volume for F2017, F2018 and F2019 are lower in the F2017–F2019 RRA than in the 2013 IRP.

207.1 Please reconcile BC Hydro's statement in response to BCUC IR 17.1 and the information presented in response to BCUC IR 18.5.

208.0 Reference: COST OF ENERGY
Exhibit B-9, BCUC IR 3.1, 18.2
RRA impact on IPP portfolio

In response to BCUC IR 3.1, BC Hydro stated that "Commission decisions on BC Hydro's costs overall or cost of energy specifically, will need to be considered by BC Hydro when it assesses its IPP portfolio."

In response to BCUC IR 18.2, BC Hydro provided information requested in the table included in the IR.

208.1 Please elaborate on how BC Hydro considers the Commission's decision on BC Hydro's cost of energy during the test period (including IPP capital leases) when it assesses its IPP portfolio. Specifically, does BC Hydro view the approved COE (including IPP capital leases) during the test period as a budget cap?

208.2 Please explain whether BC Hydro views the cost ($/MWh) for IPP renewals as presented in response to BCUC IR 18.2 as the target price of its IPP renewals that are reviewed under section 71 of the UCA.

209.0 Reference: COST OF ENERGY
Exhibit B-9, BCUC IR 17.5, 18.5
Forecast cost of IPP renewals

In response to BUC IR 1.17.5 BC Hydro stated "[it] forecasts the cost by applying the price, as determined in accordance with each Electricity Purchase Agreement, to the forecast volumes."

BC Hydro showed in response to BCUC IR 18.5 that the F2019 forecast IPP average cost in the 2013 IRP and in the 2017-2019 RRA is $87.7/MWh and $94.7/MWh, respectively.

209.1 Please explain how BC Hydro forecasts the price of EPA renewals during the test period given that they have not been approved or signed yet.

209.2 Please explain why the forecast average cost of IPPs is higher in the F2017–F2019 RRA than in the 2013 IRP.

209.3 Please explain whether BC Hydro has any EPAs that have "evergreen" provisions, i.e., the initial contract term ends and the agreement continues on a year to year basis until the agreement is terminated by either party with the required notice.

209.3.1 If yes, please explain how BC Hydro determines the timing to renew or terminate contracts with "evergreen" provisions.

209.3.2 Please explain whether BC Hydro can renew EPAs with evergreen provisions earlier to take advantage of the lower contract price of the EPA renewals to reduce the total levelized COE.

D. CHAPTER 5 – OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS

210.0 Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS
Exhibit B-10, MoveUP IR 7.1
SMI – Completion Report

In response to MoveUP IR 7.1, BC Hydro stated the following:

> BC Hydro will be providing the Smart Metering and Infrastructure Completion Report during this proceeding as Appendix P of this Application. The analysis of savings achieved will be included in the report.

If the review of the Application is limited to a written process, upon filing of the IR No. 2 responses the evidentiary record for the review of the Application will be closed.

210.1 At what point in the review of the Application does BC Hydro anticipate filing the SMI Completion Report?

211.0 Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS
Exhibit B-9, BCUC IR 24.2
Balancing competing interests of increasing maintenance costs and keeping rates low

In response to BCUC IR 24.2 BC Hydro explained "BC Hydro balances the competing interests of devising a suitable maintenance program with the goal to meet the 2013 10 Year Rates Plan by continuing to optimize our Preventive Maintenance standards and by prioritizing Condition Based Maintenance."

211.1 Please elaborate on the Preventative Maintenance standards optimization and the Condition Based Maintenance prioritization processes.

211.2 How many Preventative Maintenance standards does BC Hydro have and how many are reviewed and revised each year? Please comment on any trends.

211.3 How much effort (time and/or dollars) was spent in F2014, F2015 and F2016 and how much effort is forecast to be spent in F2017, F2018 and F2019 revising preventative maintenance standards for each of Transmission, Distribution and Generation? Please comment on any trends.

211.3.1 How does the magnitude of BC Hydro's spending on revising Preventative Maintenance standards compare to the benefits it receives from this work? Are there opportunities to become more efficient at preventative maintenance? Please elaborate.

211.4 Similarly, how much effort was spent in F2014, F2015 and F2016 and how much is forecast to be spent in F2017, F2018 and F2019 prioritizing Condition Based Maintenance planning and prioritizing? Please elaborate and comment on any trends observed.

212.0 Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS
Exhibit B-9, BCUC IR 33.1, 33.2
Workforce optimization

In response to BCUC IR 33.1 BC Hydro stated:

> **The 170 FTEs described on page 5-16 of the Application account for the FTEs approved under the Workforce Optimization Program and included in the Application at the time that budget targets were finalized in October 2015. As Workforce Optimization is an ongoing Program, the number of positions identified for conversion between fiscal 2016 to fiscal 2019, as described on page 3 of Appendix F, includes additional FTEs identified under the Workforce Optimization Program as at December 2015.**

In response to BCUC IR 33.2, BC Hydro provided a breakdown of 170 FTEs related to Workforce Optimization into operating, capital and deferred FTEs.

212.1 Please confirm, or explain otherwise, that the table provided in response to BCUC IR 33.2 should total 200 FTEs rather than 170 FTEs to include the 30 "additional FTEs identified under the Workforce Optimization Program as at December 2015" as stated in the response to BCUC IR 33.1.

212.1.1 If confirmed, please update the table provide in response to BCUC IR 33.2 for the revised breakdown of operating, capital and deferred hires in F2017, F2018 and F2019.

213.0 Reference: OPERATING COSTS – INITIATIVES TO IMPROVE OPERATIONS
Exhibit B-9, BCUC IR 32.1, 32.2, 32.4
Work Smart program

In response to BCUC IR 32.1, BC Hydro stated, "Participant feedback indicates that employees are having a positive experience with the Work Smart program."

213.1 Please elaborate on the type of participant feedback that is collected which relates to the Work Smart program. For example, what questions are asked and how are the comments collected and/or summarized?

213.1.1 Please explain how BC Hydro concludes that "employees are having a positive experience."

In response to BCUC IR 32.1 BC Hydro states: "…[it] is and will continue to measure and report upon capacity hours gained, as described in the Application, as the key measure of progress and the outcomes of the Work Smart program."

213.2 Please discuss BC Hydro's methodology for calculating/determining "capacity hours gained" relating to the Work Smart program.

In response to BCUC IR 32.2 BC Hydro reported the following:

Estimated annual value of capacity hours gained by the end of fiscal 2016. **(22,550 capacity hours gained converted to dollars; excludes the value of other benefits)**	**2.0 million**

213.3 Please describe and provide calculations for how BC Hydro's estimated the annual value of capacity hours gained in dollars.

213.3.1 Will BC Hydro continue to estimate the annual value of capacity hours gained in the future and if so how will it do this?

213.3.2 Please confirm, or explain otherwise, that the estimated value of capacity hours gained relates entirely to operating costs.

213.3.2.1 If not, please provide a breakdown of the estimated annual value between operating costs and capital.

In response to BCUC IR 32.4 BC Hydro stated:

> **It is not yet possible to estimate capacity hours gained or other benefits due to Work Smart initiatives in fiscal 2017 to fiscal 2019. Many of the initiatives planned for fiscal 2017 and shown above are underway but capacity hours gained and other benefits are not confirmed until after a project has completed implementation of the future state process. Planning for fiscal 2018 will**

213.4 Please discuss, to the extent possible, what the capital and operating savings would be in each test period year if savings in capacity hours gained are similar to what they were in F2016.

E. CHAPTER 5 – OPERATING COSTS – GROSS AND BASE OPERATING COSTS

214.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-1-1, Section 5.3.1.1, p. 5-10; Exhibit B-9, BCUC IR 26.2
SMI – Supplemental Labour Contracts
Table 5-5

In Table 5-2 on page 5-10 of the Application, BC Hydro provided a table showing that in F2017 there is forecast to be $44.3 million in incremental operating cost, offset by a $22.2 operating cost saving, from Smart Metering and Infrastructure (SMI) sustainment activities.

In response to BCUC IR 26.2, BC Hydro indicates that of the $25.6 million incremental Technology SMI costs (a sub set of costs that make up the $44.3 million) for F2017, $8.3 million is related to Supplemental Labour Contracts. Note 2 in the IR response provide further information related to the Supplemental Labour Contracts as follows:

> **Note 2 – Supplemental Labour Contracts refers to contractors that perform workload coverage, including temporary backfills, temporary duration work, seasonal work or work utilizing expertise not available in the company.**

214.1 Please confirm, or explain otherwise that the costs shown in the table included in response to BCUC IR 26.2 are recorded in lines 1 to 10 of schedule 5S in Appendix A under the same headings as set out in the table attached to the IR.

214.2 Seasonal work aside, please discuss why the $8.3 million cost is forecast to be required in each of the three test period years, specifically providing details on the type of work expected to be completed under Supplemental Labour Contracts.

214.3 From Table 5-2 in the Application, are there any expected incremental operating costs in F2017 related to Supplemental Labour Contracts, other than those included in the $8.3 million from Technology?

214.3.1 If yes, please quantify and explain the type of work anticipated to occur.

214.3.2 Are there any expected offsetting operating costs savings in F2017 related to Supplemental Labour Contracts?

214.3.2.1 If yes, please quantify and explain the type of work anticipated to be eliminated.

215.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 40.1 – 40.6
Canadian Electricity Association membership
Table 5-5

In response to the BCUC IRs 40.1 through 40.6, BC Hydro explained that it now plans to continue being a Canadian Electricity Association Corporate Utility Member, but under reduced scope. It explains that it will continue membership on the Distribution and Power Marketer Councils only. There are also Councils for Generation, Transmission and Customer. BC Hydro explains that the information received from the Canadian Electricity Association will be largely limited to the Councils, and to the committees and programs to which BC Hydro belongs.

BC Hydro elaborated that it currently participates in the Analytics Program through three benchmarking studies. BC Hydro noted this is the only national assessment of reliability and submits it may continue to participate, but does not commit to doing so. BC Hydro explained that system performance is assessed through the Service Continuity Committee and Bulk Electricity System programs and equipment reliability is assessed through the Equipment Reliability Information System Program. BC Hydro explained it currently uses this information for benchmarking and for submission to the Commission in an annual report.

215.1 Please elaborate on why BC Hydro is not part of the Councils for Generation, Transmission and Customer.

215.2 To what level do Hydro Quebec and Manitoba Hydro participate in the Canadian Electricity Association? Which Councils are they on and what committees and programs do they participate in? How does this compare to BC Hydro's proposed participation? Please elaborate.

215.3 Please confirm, or explain otherwise, that under the reduced scope membership BC Hydro will continue to participate in the Analytics Program, in particular, the Service Continuity Committee, the Bulk Electricity, and the Equipment Reliability Information System programs and, subsequently, will be able provide the same quality benchmarking information annually to the Commission.

216.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 35.6
Services – Other (Other)

216.1 For the following four significant services included in 'Services – Other' please provide additional information by completing the table below.

Services - Other																								
$ in millions																								
	A	B	C = B - A	D/A	E	F	G = F - E	G/E	H	I	J = I - H	J/H	K	L	M = L - K	M/K	N	O	P = O - N	P/N	(C+G+J+M+P)/5			
	F2012 Plan	F2012 Actual	$ Variance	% Variance	F2013 Plan	F2013 Actual	$ Variance	% Variance	F2014 Plan	F2014 Actual	$ Variance	% Variance	F2015 Plan	F2015 Actual	$ Variance	% Variance	F2016 Plan	F2016 Actual	$ Variance	% Variance	5 year Avg: $ Variance	2017 Plan	2018 Plan	2019 Plan
DSM Incentives													74.8	53.8	(21.0)	-28%	54.7	73.0	18.3	33%		46.5	91.7	31.1
Travel & Expense-Expense													11.3	0.8	(10.5)	-93%	11.1	0.5	(10.6)	-95%		12.8	12.9	13.0
Supplemental Labour Contracts													17.5	33.5	16.0	91%	17.0	39.7	22.7	134%		22.1	21.4	21.4
Contract Services													197.6	94.5	(103.1)	-52%	197.7	98.3	(99.4)	-50%		199.4	176.0	177.7

216.2 If any of the four services in the table has a "+/- 5 year Avg $ Variance" greater than $10 million please provide an explanation for the variance.

216.3 There appears to be a significant variance between forecast and actual costs in both F2015 and F2016 for each of the four service listed in the table above. Please explain the reason for the

variance in each of those years. If a variance greater than 20 percent occurred in any of the years F2012 through F2014 please provide an explanation for those years as well.

216.3.1 Please discuss what steps BC Hydro has taken in preparing the F2017–F2019 forecast for each of the four services in the table above to limit further significant variances during the test period.

216.4 For Contract Services, please explain what costs were included in the forecast and what costs were included in the actual. Specifically, please address whether the significant variances exist because actual costs are allocated to other cost categories. If so, please provide the other cost categories and the allocated amounts to each.

216.5 Please explain why deferred O&M relating to DSM and First Nations of $96.5 million, $141.5 million and $80.3 million in F2107, F2018 and F2017 respectively are included in Services-Other, which is recovered in Gross O&M on schedule 1, line. Please explain what DSM costs are reported as O&M costs and what costs are captured in the DSM regulatory account.

217.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 35.7, 39.3
Services – Other (Other) – Contractor Services

Capital project dispute resolution

217.1 Please clarify the nature of the $5.0 million plan F2017 'one-time initiative funding for capital project dispute resolution costs' included in Services-Other. What does this cost relate to?

218.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 35.6
Services – Other (Contractors)

218.1 Please provide additional information relating to the breakdown of 'Line Contractor' costs within 'Services – Other' by completing the table below.

Services - Other																								
$ in millions																								
	A	B	C = B - A	D/A	E	F	G = F - E	G/E	H	I	J = I - H	J/H	K	L	M = L - K	M/K	N	O	P = O - N	P/N	(C+G+J+M+P)/5			
	F2012 Plan	F2012 Actual	$ Variance	% Variance	F2013 Plan	F2013 Actual	$ Variance	% Variance	F2014 Plan	F2014 Actual	$ Variance	% Variance	F2015 Plan	F2015 Actual	$ Variance	% Variance	F2016 Plan	F2016 Actual	$ Variance	% Variance	5 year Avg: $ Variance	2017 Plan	2018 Plan	2019 Plan
Line Contractors													19.1	30.1	11.0	58%	17.7	31.9	14.2	80%		17.5	17.3	17.1

218.1.1 Please provide variance explanations for this cost if the 5-year average dollar variance is greater than $10 million.

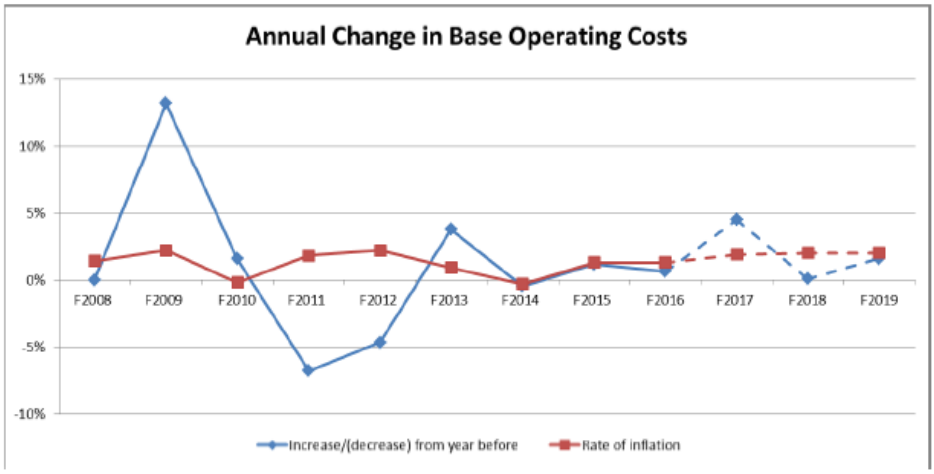
218.2 If Line Contractor costs have "+/- 5 year Avg $ Variance" greater than $10 million please provide an explanation for the variance.

218.3 There appears to be a significant variance between forecast and actual costs in both F2015 and F2016 for Line Contractors. Please explain the reason for the variance in each of those years. If a variance greater than 20 percent occurred in any of the years F2012 through F2014, please provide an explanation for those years as well.

218.3.1 Please discuss what steps BC Hydro has taken in preparing the F2017–F2019 forecast to limit further significant variances during the test period.

219.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 34.4, 38.1; Exhibit B-1-1, Table 5-6, p. 5-24; Exhibit B-1-1, Appendix A, Schedule 5S
Annual change in base operating costs

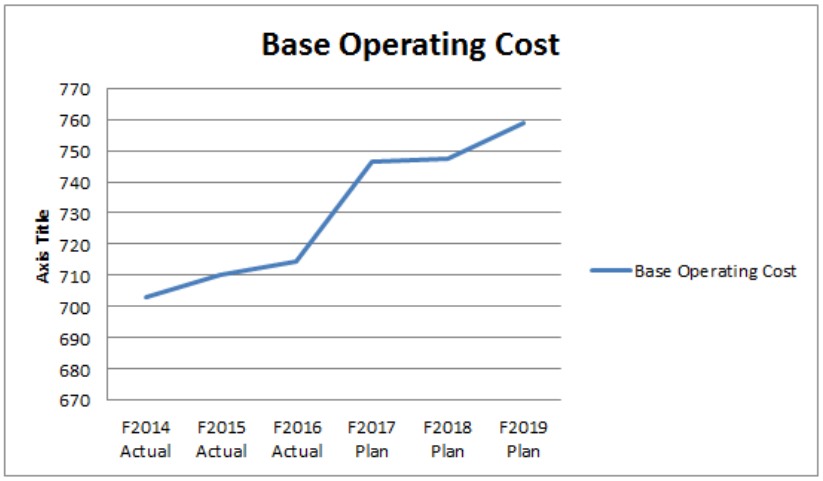
In response to BCUC IR 34.4, BC Hydro provided the following chart showing actual and planned annual change in base operating costs:



219.1 Please reference the data used to prepare the chart provided in response to BCUC IR 34.4 to the schedules provided in Appendix A of the Application.

219.2 Commission staff prepared the following summary and corresponding chart using the first line of the table in BC Hydro's response to BCUC IR 38.1 and Table 5-6 from Exhibit B-1-1. Please confirm, or update as necessary.

	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Reference	Exhibit B-9, BCUC IR 38.1	Exhibit B-9, BCUC IR 38.1	Exhibit B-9, BCUC IR 38.1	Exhibit B-1-1, Table 5-6	Exhibit B-1-1, Table 5-6	Exhibit B-1-1, Table 5-6
Base Operating Cost	703.1	710.1	714.7	746.6	747.2	759
Annual Change in Base Operating Costs		1%	1%	4%	0%	2%



219.3 Please explain why the chart provided in response to BCUC IR 34.4 shows an annual decrease of roughly 5 percent in F2018 compared to the amounts provided in Table 5-6 of Exhibit B-1-1 which shows roughly no change.

219.4 Please chart gross operating costs for F2012 – F2019 based on the sum of lines 1 to 5 in schedule 5S for F2015-F2019 and similar values for F2012-2014.

220.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 36.1, 41.3, 42.1
Gross Operating and Capital Labour cost reconciliation

220.1 Staff prepared the following tables that attempt to reconcile the standard labour rates with the total labour provided in response to BCUC IR 36.1. Please update the table for any errors.

220.1.1 Please explain the reason for the variance highlighted in yellow in each of F2017, F2018 and F2019.

		Reference	Executive	Reference	M and P (excluding Executive)	Reference	MoveUP	Reference	IBEW	Total
2017	Standard labour rates	BCUC IR 1.42.1	$ 240.20	BCUC IR 1.42.1	$ 96.73	BCUC IR 1.42.1	$ 58.89	BCUC IR 1.42.1	$ 73.97	
	Average hrs	BCUC IR 1.41.2	1,684	BCUC IR 1.41.2	1,621	p. 5-25	1,535	p. 5-25	1,461	
	# regular hour operating FTEs	BCUC IR 1.41.3	14	BCUC IR 1.41.3	1,683	BCUC IR 1.41.3	975	BCUC IR 1.41.3	1,139	
	# regular hour capital FTEs	BCUC IR 1.41.3	1	BCUC IR 1.41.3	609	BCUC IR 1.41.3	563	BCUC IR 1.41.3	737	
	Calculated operating labour cost		$5,662,955		$ 263,893,272		$ 88,136,246		$ 123,091,924	$ 480,784,397
	Calculated capital labour cost		$ 404,497		$ 95,490,792		$ 50,893,032		$ 79,647,715	$ 226,436,037
							Plus: cost of overtime hours		BCUC IR 1.36.1	$ 73,600,000
							Calculated labour cost including overtime			$ 780,820,434
							Application labour cost		BCUC IR 1.36.1	$ 795,300,000
										($14,479,566)
2018	Standard labour rates	BCUC IR 1.42.1	$ 244.18	BCUC IR 1.42.1	$ 98.33	BCUC IR 1.42.1	$ 60.10	BCUC IR 1.42.1	$ 75.36	
	Average hrs	BCUC IR 1.41.2	1,684	BCUC IR 1.41.2	1,621	p. 5-25	1,535	p. 5-25	1,461	
	# regular hour operating FTEs		14		1,689		976		1,139	
	# regular hour capital FTEs		1		622		591		737	
	Calculated operating labour cost		$5,756,788		$ 269,214,659		$ 90,039,416		$ 125,404,993	$ 490,415,856
	Calculated capital labour cost		$ 411,199		$ 99,142,402		$ 54,521,819		$ 81,144,408	$ 235,219,828
							Plus: cost of overtime hours		BCUC IR 1.36.1	$ 75,100,000
							Calculated labour cost including overtime			$ 800,735,683
							Application labour cost		BCUC IR 1.36.1	$ 806,500,000
										($5,764,317)
2019	Standard labour rates	BCUC IR 1.42.1	$ 248.44	BCUC IR 1.42.1	$ 100.05	BCUC IR 1.42.1	$ 61.40	BCUC IR 1.42.1	$ 76.85	
	Average hrs	BCUC IR 1.41.2	1,684	BCUC IR 1.41.2	1,621	p. 5-25	1,535	p. 5-25	1,461	
	# regular hour operating FTEs		14		1,694		974		1,139	
	# regular hour capital FTEs		1		624		603		737	
	Calculated operating labour cost		$5,857,221		$ 274,734,699		$ 91,798,526		$ 127,884,471	$ 500,274,917
	Calculated capital labour cost		$ 418,373		$ 101,200,975		$ 56,832,147		$ 82,748,775	$ 241,200,271
							Plus: cost of overtime hours		BCUC IR 1.36.1	$ 77,300,000
							Calculated labour cost including overtime			$ 818,775,188
							Application labour cost		BCUC IR 1.36.1	$ 825,200,000
										($6,424,812)

221.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 36.1
Gross Operating and Capital Labour cost trends

Commission staff prepared the following summary of actual and forecast labour costs for F2012–F2019 using the figures in BC Hydro's response to BCUC IR 36.1:

$ in millions	F2012 Actual		F2013 Actual		F2014 Actual		F2015 Actual		F2016 Actual		F2017 Forecast		F2018 Forecast		F2019 Forecast	
Base labour	533.7	74%	526.6	73%	538.7	72%	531.1	71%	543.1	70%	562.6	71%	579.3	72%	591.8	72%
Year-over-year change			-1%		2%		-1%		2%		4%		3%		2%	
Other benefits	54.7	8%	53.1	7%	54.3	7%	61.6	8%	55.1	7%	62.0	8%	63.8	8%	66.4	8%
Year-over-year change			-3%		2%		13%		-11%		13%		3%		4%	
Current service - pension	69.3	10%	81.8	11%	94.9	13%	89.8	12%	113.4	15%	97.1	12%	88.3	11%	89.7	11%
Year-over-year change			18%		16%		-5%		26%		-14%		-9%		2%	
Overtime labour	59.7	8%	57.4	8%	62.0	8%	69.2	9%	69.2	9%	73.6	9%	75.1	9%	77.3	9%
Year-over-year change			-4%		8%		12%		0%		6%		2%		3%	
Total labour	717.4	100%	718.9	100%	749.9	100%	751.7	100%	780.8	100%	795.3	100%	806.5	100%	825.2	100%
$ change			1.5		31.0		1.8		29.1		14.5		11.2		18.7	
Year-over-year change			0%		4%		0%		4%		2%		1%		2%	

221.1 Please confirm that the labour cost summary prepared by Commission staff above is correct. If not, please amend and provide a corrected summary.

221.2 Please provide a rationale for the 13 percent increase in Other Benefits in actual F2015 and forecast F2017.

221.2.1 Please discuss what actions BC Hydro is taking to control costs in Other Benefits.

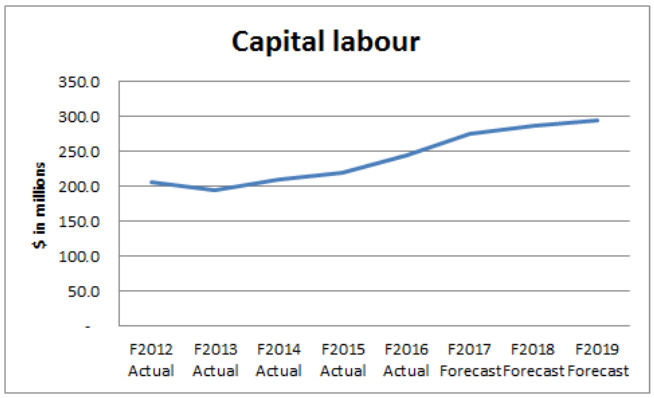
221.3 Please discuss the reasons for the upwards trend in Overtime Labour from F2012–F2019. Please include in your discussion (i) the reasons for a 12 percent increase in F2015 and (i) the rationale for the forecast 6 percent increase in F2017 and (iii) the reason the F2015 increased level was maintained in F2016.

221.3.1 Please explain how, if at all, the increases are connected to the increases in standard labour rates.

222.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 36.1
Capital Labour cost trends

Commission staff prepared the following table and graph of actual F2012–F2016 and forecast F2017–F2019 capital labour costs using BC Hydro's response to BCUC IR 36.1:

	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Forecast	F2018 Forecast	F2019 Forecast
Capital labour	205.8	192.8	208.9	218.8	243.6	274.0	285.3	293.8
Year-over-year change		-6%	8%	5%	11%	12%	4%	3%



222.1 Please confirm that the Capital Labour cost table prepared by Commission staff above is correct. If not, please amend and provide a corrected table and graph.

222.2 Please explain the Capital Labour actual 11 percent increase in F2016 and the forecast increase in F2017.

222.3 Please provide a chart, similar to the one provided above that charts out Capital Labour as a percentage of capital spending for F2012 through F2019.

223.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 36.1
Base Labour cost variances

Commission staff prepared the following table using BC Hydro's response to BCUC IR 36.1:

$ in millions	F2012 Actual	F2012 Plan	F2012 $ Variance	F2012 % Variance	F2013 Actual	F2013 Plan	F2013 $ Variance	F2013 % Variance	F2014 Plan	F2014 $ Variance	F2014 % Variance	F2015 Actual	F2015 Plan	F2015 $ Variance	F2015 % Variance	F2016 Actual	F2016 Plan	F2016 $ Variance	F2016 % Variance	F2017 Forecast	F2018 Forecast	F2019 Forecast
Base labour	533.7	562.4	(28.7)	-5%	526.6	556.3	(29.7)	-5%	536.6	2.1	0%	531.1	545.0	(13.9)	-3%	543.1	549.4	(6.3)	-1%	562.6	579.3	591.8

223.1 Please confirm if the table above prepared by Commission staff is correct. If not, please amend and provide a corrected table.

223.2 Please explain the reason for the variance in Base Labour in F2012, F2013 and 20105. Please discuss what changes to BC Hydro's processes and procedures occurred to allow a more accurate forecast of Base Labour in F2014 compared F2012 and F2013.

223.3 Please discuss the steps BC Hydro has taken in preparing the F2017–F2019 Base Labour forecasts to ensure it is accurate.

223.4 In the table provided in response to BCUC IR 36.1 Deferred Labour + Operating Labour agrees to the total Labour (excl Non-Current PEB) in schedule 5S, line 1 for each of year in the test period. Given that the total Labour in schedule 5S is included in calculation Gross O&M in schedule 1, line 2, please explain why Gross O&M includes deferred labour.

224.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 34.8, 36.1, 41.4, 41.4.1
Overtime labour costs

Commission staff prepared the following summary based on BC Hydro's response to BCUC IR 36.1:

$ in millions	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Forecast	F2018 Forecast	F2019 Forecast
Overtime labour	59.7	57.4	62.0	69.2	69.2	73.6	75.1	77.3
Year-over-year change		-4%	8%	12%	0%	6%	2%	3%

224.1 Please confirm if the table above is correct. If not, please amend and provide a corrected table.

224.2 Please explain if the actual F2016 overtime costs are $69.2 million as provided in response to BCUC IR 36.1 or $72.0 million as provided in response to BCUC IR 41.4.

Commission staff prepared the following calculation based on BC Hydro response to BCUC IR 41.4 and 41.4.1:

$ million	Reference	F2017 Plan	F2018 Plan	F2019 Plan	Total
Associated cost of overtime hours	BCUC IR 41.4	74	75	77	226
Associated cost if overtime hours were regular hours	BCUC IR 41.4.1	65	66	68	199
Difference		9	9	9	27

224.3 Please confirm if the table above is correct. If not, please amend and provide a corrected table.

224.4 Please confirm that BC Hydro plans to spend an additional $27 million over the test period in overtime costs for the reasons outlined in response to BCUC IR 34.8.

225.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-1-1, Appendix A, schedule 5S, line 6
Eligible Capital Overhead

225.1 Please explain the method that is used to allocate the Eligible Capital Overhead, once established, to the individual capital projects.

226.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, BCUC IR 43.1
Business group operating cost tables by key business unit

226.1 Please provide additional information regarding the gross operating costs of the business groups by completing the tables below and as attached. Please ensure that the sums of the business groups agree to the amounts for BC Hydro as a whole as shown in Exhibit B-1-1, Appendix A, Schedule 5S and as demonstrated in the table below.

Training, Development and Generation	F2012 RRA	F2013 Actual	F2014 RRA	F2014 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Training and Development							
Generation Operations							
Generation Resource Mgmt							
Generation Asset Mgmt							
Generation Maintenance							
Business Unit Support							
LESS:							
Eligible Capital Overhead							
External Recoveries							
Total Gross Operating Costs including Regulatory Account Additions							
Total Gross Provision & Other							
Total Gross Operating Cost and Provision & Other including Regulatory Account Additions							

Transmission, Distribution and Customer Services	F2012 RRA	F2013 Actual	F2014 RRA	F2014 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Field and Grid Operations							
Asset Management & Grid Eng							
Program & Contract Management							
Customer Service & Distribution Design							
Technology							
Business Unit Support							
LESS:							
Eligible Capital Overhead							
External Recoveries							
Total Gross Operating Costs including Regulatory Account Additions							
Total Gross Provision & Other							
Total Gross Operating Cost and Provision & Other including Regulatory Account Additions							

Capital Infrastructure Project Delivery	F2012 RRA	F2013 Actual	F2014 RRA	F2014 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Project Delivery							
Generation & Transmission Engineering							
Aboriginal Relations							
Environmental Risk Management							
Dam Safety							
Properties							
Business Unit Support							
LESS:							
Eligible Capital Overhead							
External Recoveries							
Total Gross Operating Costs including Regulatory Account Additions							
Total Gross Provision & Other							
Total Gross Operating Cost and Provision & Other including Regulatory Account Additions							

Operations Support	F2012 RRA	F2013 Actual	F2014 RRA	F2014 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Executive							
Finance & Supply Chain							
Corporate Affairs							
Safety, Security, Emergency Mgmt							
Remote Courses							
PP Capital Labor Operating Costs							
Corporate Costs							
LESS:							
Eligible Capital Overhead							
External Recoveries							
Total Gross Operating Costs including Regulatory Account Additions							
Total Gross Provision & Other							
Total Gross Operating Cost and Provision & Other including Regulatory Account Additions							

Consolidated Total	F2012 RRA	F2012 Actual	F2013 RRA	F2014 RRA	F2014 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Training, Development and Generation								
Transmission, Distribution and Customer Services								
Capital Infrastructure Project Delivery								
Operations Support								
Total Gross Operating Costs	1,328.8	1,371.9	1,210.1	1,288.5	1,273.9	1,288.1	1,223.0	
LESS:								
Eligible Capital Overhead	(83.4)	(84.7)	(83.4)	(88.8)	(89.2)	(89.0)	(89.7)	
External Recoveries	(27.7)	(30.3)	(27.8)	(27.1)	(26.2)	(29.2)	(31.8)	
Total Gross Operating Costs including Regulatory Account Additions	1,168.4	1,188.7	1,119.8	1,166.6	1,118.6	1,168.9	1,101.6	
Total Gross Provision & Other	39.4	120.3	29.7	97.3	58.0	61.0	61.7	
Total Gross Operating Cost and Provision & Other including Regulatory Account Additions	1,179.8	1,309.0	1,149.6	1,263.8	1,186.0	1,230.0	1,163.4	

226.1.1 Please provide a rationale, at the key business unit level, for any significant trends, plan-to-actual variances or year-over-year changes which may be interpreted from the data.

227.0 Reference: OPERATING COSTS – GROSS AND BASE OPERATING COSTS
Exhibit B-9, CEC IR 48.5, 48.5.1; BCUC IR 34.10; July 2011 Government Review of BC Hydro (Report) Recommendations
Standard Labour Rates
Salary holdback pay for Directors and Executives

227.1 Please confirm whether "salary holdback pay for Directors and Executives" is included in the "Base Labour" or "Other Benefits" component of total labour costs in BC Hydro's response to BCUC IR 36.1.

227.2 Please provide actual F2012–F2016 and forecast F2017–F2019 "salary holdback pay for Directors and Executives," separating individual and corporate award components.

227.2.1 Please discuss and provide the reasons for any trends or significant increases/decreases in the data provided.

227.3 Please elaborate on the range of possibilities in the "Rating" component of the salary holdback award formula for individual and corporate performance components. What is meant by ratings of "0 to 1"?

In response to CEC IRs 1.48.5 and 1.48.5.1 BC Hydro stated:

> **Individual performance, which accounts for 60 per cent of the calculation, is based on the employee's performance as documented in their performance plan.**

227.4 Please explain how BC Hydro's performance rating system of Needs Improvement, Developing, Fully Performing, High Achiever and Exceptional in employees' performance plans translates into the range of possibilities in the "0 to 1" rating component of the salary holdback award formula.

As referenced in BCUC IR 34.10:

> Recommendation 14 of the Report states "Adjust incentive plans under the Variable Pay program for Management and Professional staff to ensure targets for performance measures are set at a level that is not easily attained to prevent the incentive pay becoming part of base compensation."

227.4.1 Please explain how Recommendation 14 of the Report is reflected in the individual award component of actual and forecast salary holdback pay for Directors and Executives.

227.5 Similar to the chart provided in response to BCUC IR 34.10, please provide a chart for F2012–F2016 to reflect the performance rating distribution of Directors and Executives only by fiscal year.

F. CHAPTER 5 – OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES

228.0 Reference: OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES
Exhibit B-9, BCUC IR 42.1, 42.2
Standard labour rates

In response to BCUC IR 42.1 BC Hydro provided the following F2016 RRA standard labour rates table:

	F2016 RRA			
	MoveUP	IBEW	M and P	Executive
Base pay	39.36	46.59	70.70	170.29
Current service pension costs	6.10	7.64	10.49	25.21
Other benefit costs	5.07	6.34	8.71	20.93
Premiums and allowances	1.75	8.00	2.73	15.04
Gainsharing/results pay	1.38	1.73	-	32.55
Standard Labour Rates	**53.66**	**70.30**	**92.63**	**264.02**

In response to BCUC IR 42.2 BC Hydro provided the following F2016 standard labour rates:

($ per hour)	MoveUp	IBEW	M and P	EXEC
Standard Labour Rates F2016 Plan	55.33	69.90	93.88	270.41

228.1 Please confirm which of the above are the correct F2016 standard labour rates and provide a revised table for BC Hydro's response to either BCUC IR 42.1 or 42.2.

Using the standard labour rates tables provided in response to BCUC IR 42.1, Commission staff calculated the increase/(decrease) in standard labour rate components for F2017 and compared these amounts to the stated increases/(decreases) in revised Table 5-10 in response to BCUC IR 42.2. Commission staff noted differences and summarized these in the table below:

F2017 Plan ($ per hour) - Forecast increases/(decreases)				
		Calculated increase/(decrease) [per BCUC IR 42.1]	Revised Table 5-10 increase/(decrease) [Ref: BCUC IR 42.2]	Correct increase /(decrease)
Base pay	MoveUP	3.45	2.20	
	IBEW	2.21	1.91	
	M and P	2.40	1.43	
	Executive	(4.41)	(8.43)	
Current service pension cost	MoveUP	1.13	1.09	
	IBEW	0.05	0.75	
	M and P	1.26	1.38	
	Executive	1.46	1.49	
Other benefit costs	MoveUP	0.47	0.16	
	IBEW	(0.44)	(0.18)	
	M and P	0.30	(0.08)	
	Executive	(0.49)	(1.61)	
Premium and allowances	MoveUP	0.06	0.03	
	IBEW	1.78	1.53	
	M and P	(0.09)	(0.11)	
	Executive	(11.55)	(12.06)	
Gainsharing/results pay	MoveUP	0.12	0.08	
	IBEW	0.07	0.07	
	M and P	0.23	0.23	
	Executive	(8.83)	(9.60)	

228.2 Please confirm if the table above prepared by Commission staff is correct and populate the table to provide the correct dollar per hour standard labour rate component increases/(decreases) for F2017.

229.0 Reference: OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES Exhibit B-9, BCUC IR 42.1 Standard labour rate changes

Commission staff prepared the following tables using BC Hydro's response to BCUC IR 42.1:

	MoveUP								MoveUP						
	$ per hour								Year-over-year % change						
	2012	2013	2014	2015	2016	2017	2018	2019	2013	2014	2015	2016	2017	2018	2019
Base pay	37.05	37.80	38.56	39.35	39.36	42.81	43.61	44.45	2.0%	2.0%	2.0%	0.0%	8.8%	1.9%	1.9%
Current service pension costs	5.88	6.26	6.49	6.27	6.10	7.23	7.37	7.51	6.5%	3.7%	-3.4%	-2.7%	18.5%	1.9%	1.9%
Other benefit costs	5.31	5.26	5.22	5.02	5.07	5.54	5.77	6.05	-0.9%	-0.8%	-3.8%	1.0%	9.3%	4.2%	4.9%
Premium and allowances	1.83	1.87	1.91	1.75	1.75	1.81	1.82	1.83	2.2%	2.1%	-8.4%	0.0%	3.4%	0.6%	0.5%
Gainsharing/results pay	1.30	1.32	1.35	1.38	1.38	1.50	1.53	1.56	1.5%	2.3%	2.2%	0.0%	8.7%	2.0%	2.0%
Standard Labour Rates	**51.37**	**52.51**	**53.53**	**53.77**	**53.66**	**58.89**	**60.10**	**61.40**	2.2%	1.9%	0.4%	-0.2%	9.7%	2.1%	2.2%

	IBEW								IBEW						
	$ per hour								Year-over-year % change						
	2012	2013	2014	2015	2016	2017	2018	2019	2013	2014	2015	2016	2017	2018	2019
Base pay	44.26	45.24	46.14	46.58	46.59	48.80	49.73	50.69	2.2%	2.0%	1.0%	0.0%	4.7%	1.9%	1.9%
Current service pension costs	7.02	7.48	7.76	7.84	7.64	7.69	7.84	7.99	6.6%	3.7%	1.0%	-2.6%	0.7%	2.0%	1.9%
Other benefit costs	6.34	6.28	6.24	6.29	6.34	5.90	6.14	6.44	-0.9%	-0.6%	0.8%	0.8%	-6.9%	4.1%	4.9%
Premium and allowances	6.99	7.14	7.28	8.00	8.00	9.78	9.82	9.86	2.1%	2.0%	9.9%	0.0%	22.3%	0.4%	0.4%
Gainsharing/results pay	1.55	1.58	1.61	1.73	1.73	1.80	1.83	1.87	1.9%	1.9%	7.5%	0.0%	4.0%	1.7%	2.2%
Standard Labour Rates	**66.16**	**67.72**	**69.03**	**70.44**	**70.30**	**73.97**	**75.36**	**76.85**	2.4%	1.9%	2.0%	-0.2%	5.2%	1.9%	2.0%

	M and P								M and P						
									Year-over-year % change						
	2012	2013	2014	2015	2016	2017	2018	2019	2013	2014	2015	2016	2017	2018	2019
Base pay	62.95	64.21	65.51	67.36	70.70	73.10	74.21	75.32	2.0%	2.0%	2.8%	5.0%	3.4%	1.5%	1.5%
Current service pension costs	9.99	10.64	11.03	10.23	10.49	11.75	11.92	12.11	6.5%	3.7%	-7.3%	2.5%	12.0%	1.4%	1.6%
Other benefit costs	9.02	8.94	8.87	8.20	8.71	9.01	9.34	9.76	-0.9%	-0.8%	-7.6%	6.2%	3.4%	3.7%	4.5%
Premium and allowances	3.93	4.01	4.08	2.73	2.73	2.64	2.63	2.63	2.0%	1.7%	-33.1%	0.0%	-3.3%	-0.4%	0.0%
Gainsharing/results pay	7.37	7.51	7.66	3.35	-	0.23	0.23	0.23	1.9%	2.0%	-56.3%	-100.0%	#DIV/0!	0.0%	0.0%
Standard Labour Rates	**93.26**	**95.31**	**97.15**	**91.87**	**92.63**	**96.73**	**98.33**	**100.05**	2.2%	1.9%	-5.4%	0.8%	4.4%	1.7%	1.7%

229.1 Please confirm if the tables above are correct. If not, please amend and provide corrected tables.

229.2 Please explain the reason for the variation in the Current Service Pension Costs between -

MoveUP, IBEW, and M and P and include an explanation of the differences, if any, in the pension benefits provided to each group of employees.

229.2.1 Please explain why the F2017 Current Service Pension Costs are forecast to increase by 18.5 percent and 12 percent for MoveUP and M and P respectively, but only 0.7 percent for IBEW.

229.3 Please provide explanations for the following standard labour rate changes which are highlighted in red font in the tables above:

i. F2017 MoveUP base pay increase of 8.8 percent

ii. F2017 MoveUP other benefits cost increase of 9.3 percent

iii. F2017 MoveUP gainsharing/results pay increase of 8.7 percent

iv. F2015 IBEW premium and allowances increase of 9.9 percent

v. F2015 IBEW gainsharing/results pay increase of 7.5 percent

vi. F2017 IBEW base pay increase of 4.7 percent

vii. F2017 IBEW premium and allowances increase of 22.3 percent

viii. F2017 IBEW gainsharing/results pay increase of 4.0 percent

ix. F2016 M and P base pay increase of 5.0 percent

x. F2016 M and P other benefits cost increase of 6.2 percent

G. CHAPTER 5 – OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION BUSINESS GROUP

230.0 Reference: OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION
Exhibit B-9, BCUC IR 45.6 – 45.7; 48.1, Attachment 1, p. 13
Reliability indices – Availability Factor and Forced Outage Factor

In response to BCUC IR 45.6 and 45.7, BC Hydro explained that both generator Availability Factor and Forced Outage Factor are time based and not related to generator capacity.

In response to BCUC IR 48.1, BC Hydro provided an audit report. In that report, the author explains: "Recently, BC Hydro's most comparative utility withdrew participation from [Canadian Electricity Association] benchmarking. Management is working with NERC (North American Electric Reliability Corporation) GADS (Generating Availability Data System) information on a trial basis for more relevant benchmarking data."

230.1 Please provide the equations and R-squared for each line provided in responses to BCUC IR 45.6 and 45.7. What does each of these R-squared measures say about how well these linear models fit this data? Can any conclusions be drawn?

230.2 Which utility withdrew from Canadian Electricity Association benchmarking and are any reasons known?

230.3 Are there more applicable generator availability factors and /or forced outage factors like benchmarks that have been normalized based on generating unit capacity? If so, please provide information on these measures and on BC Hydro's corresponding performance. Please comment on any trends observed.

230.4 At what value would BC Hydro consider Forced Outage Factor and Availability Factor unacceptable and why?

230.5 If the Commission determined that service was becoming inadequate (re: Forced Outage Factor

and Availability Factor), what would BC Hydro do to improve reliability? For example, would it add more maintenance and/or would it primarily be achieved through additional sustainment or other capital? Please explain.

230.6 Are BC Hydro's Forced Outage Factor and Availability Factor results audited? If so, how and by which department or group? Please provide the findings and recommendations of the most recent audit. If not, why not?

231.0 Reference: OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION
Exhibit B-9, BCUC IR 48.1
Managing the life cycle of generation assets
Generation equipment maintenance and capital investment

The audit report provided as Attachment 1 to the response to BCUC IR 48.1 explained that BC Hydro had no process to regularly update/revise its Equipment Health Ratings methodologies. In addition it noted that the methodologies do not incorporate statistical techniques and incorporating these may lead to a more accurate representation of asset health. Generation responded to these recommendations by stating it will add a requirement to each EHR methodology that it be reviewed for applicability at least once every four years by March 31, 2015 and it will continue to monitor statistical analysis work that is being done in the hydro-electric industry and apply such methods when determined to be beneficial.

The audit report also recommended that risk thresholds be introduced across the business objectives (safety, reliability, etc…) in capital investment planning. In response, Generation explained it is not proposing to introduce risk thresholds, given the level of rigor provided by the current processes. The audit further recommended that BC Hydro consider post project risk to determine the amount of risk reduction achieved by a particular solution alternative. Generation responded that it is not proposing any further change at this time given this approach has been tried in the past. However, additional software modules may be available in F2016 and Generation will consider at that time incorporating post-project risk to communicate deferral risk associated with projects or portfolios of projects.

However, in response to BCUC IR 48.1 BC Hydro explained that it has implemented all the Audit Report recommendations.

The report also notes that improvement opportunities relate to asset health assessments and methodology reviews, and there is a backlog of EHR assessments.

231.1 Please provide comment on BC Hydro's progress in clearing the backlog of EHR ratings.

231.2 Could clearing the backlog result in higher maintenance or capital spending than forecast (e.g. an inspection is overdue and is required to perform a EHR assessment, the inspection finds that repairs or replacement is needed, without the inspection it would not have been known that the repairs or replacement would have been needed)? Please elaborate.

231.3 Please provide the EHR assessment dates for the EHR ratings provided in Appendix R. Please comment on any observations regarding the assessment dates.

231.4 Please confirm and explain how BC Hydro has or is incorporating statistical techniques in its EHR methodologies. If not confirmed, please explain why this recommendation is not being incorporated.

231.5 How many EHR methodologies are there? How many has BC Hydro reviewed since this Audit Report? What is the review plan for the test period? Please elaborate.

231.6 Please confirm, or otherwise explain, that BC Hydro did not implement all the Audit Report recommendations, but did implement all the Audit Report recommendations that it accepted.

231.7 Please provide an update on the incorporation of post-project risk.

232.0 Reference: OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION
Exhibit B-9, BCUC IR 48.4
Managing the life cycle of generation assets
Generation major equipment failures

In response to BCUC IR 48.4, BC Hydro listed several major equipment failures.

232.1 Has BC Hydro noticed any systemic/repetitious failures? For example, there were two brushgear failures on GMS Unit 8 and there were two turbine bearing failures. If so, what corrective actions is BC Hydro taking across the fleet to address these issues?

233.0 Reference: OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION
Exhibit B-1-1, p. 6-21; Exhibit B-9, BCUC IR 48.5, 48.5.1, 48.5.7, 74.6
Managing the life cycle of generation assets
Generation asset management – Available Energy facilities

On page 6-21 of the Application, BC Hydro explains that "… Alouette and Elko generating stations and Shuswap Unit 1 have been forced out of service due to unsatisfactory equipment conditions and will remain out of service for an extended period."

In response to BCUC IR 48.5 and 48.5.1, BC Hydro explained that the investment strategy for the Available Energy facilities has been consistent for over 10 years and that this strategy is consistent with the Generation Strategic Asset Management Plan, which recognizes the need to prioritize investments that provide the greatest overall benefit. BC Hydro submitted the strategy is not part of a policy decision.

In response to BCUC IR 48.5.7 BC Hydro provided PowerPoint slides for the Falls River strategy. It noted there is opportunity to redevelop the facility to ~16 – 25MW of winter capacity and notes the North Coast supply strategy due to regional growth and minimizing gas.

In response to BCUC IR 74.6, BC Hydro explained "In evaluating the energy and capacity benefits of a particular investment or of demand-side management and Electricity Purchase Agreement renewals, BC Hydro uses the reference price to test the cost effectiveness of different resources."

233.1 Please explain BC Hydro's review and approval process for the adoption of the Available Energy facilities investment strategy. When was that decision made? Who approved the strategy? What are the criteria and key measures for its continued adoption of this strategy? Please explain.

233.2 Does BC Hydro consider leasing and/or selling any of the Available Energy facilities, or Alouette, before or after redevelopment an option? If so, why? If not, why not?

233.3 Is there additional value to Falls River's output due to its inflow pattern and location? Would a positive LNG plant decision for the North Coast area expedite a Falls River redevelopment decision? Please elaborate.

234.0 Reference: OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION BUSINESS GROUP
Exhibit B-9, BCUC IR 49.1, BCUC IR 49.2, BCUC IR 49.3
Mandatory reliability standards (MRS)

In response to BCUC IR 49.2, BC Hydro indicated that the MRS related Operations Generations actuals for F2015 and F2016 was $0 and $225,000 respectively. In BCUC IR 49.3, BC Hydro provided forecasts for MRS related Operations Generations during the test period.

234.1 Please describe Operations Generations and how the activities related to MRS. Does it refer to the Generation Operations key business unit under the Training, Development and Generation business group?

234.2 Please discuss why the MRS related Operations Generations actual in F2015 was $0.

In response to BCUC IR 49.1, BC Hydro stated the following:

> BC Hydro has reviewed the Assessment Report 7, 8 and 9 costs, however we are not able to populate the table as requested in this information request. The majority of the Mandatory Reliability Standards operating costs pertaining to Operations Standards are absorbed into existing budgets and not tracked separately. BC Hydro has not established charge codes for each individual item and therefore its review is based on individuals estimates of time allocated per task. On a go forward basis, BC Hydro is looking into establishing ways to track costs.

Further, in reference to the summary table prepared by BCUC in BCUC IR 49.1, BC Hydro stated that the actual incremental and ongoing costs resulting from Assessment Report 8 and 9 are "still in the estimate stage and the costs provided in the table are reasonable." The table indicates the annual ongoing costs as $132,000 as per Assessment Report No. 9, and $7,757,100 as per Assessment Report No. 8, which is a total of $7,889,100 annual ongoing costs.

The table BC Hydro provided in response to BCUC IR 49.3 shows the forecast operating costs for the test period for MRS (not including MRS operating costs pertaining to Operations Standards) and Critical Infrastructure Protection (CIP). Below are the totals expected for each year in the test period:

Table 1: MRS and CIP Grand Total Calculated from BC Hydro Response to BCUC IR 49.3

	F2017	F2018	F2019
MRS Total	1,310,000	1,199,000	1,128,000
CIP Total	1,589,000	1,994,000	2,144,000
Grand Total	**2,899,000**	**3,193,000**	**3,272,000**

234.3 Please confirm that the roughly $7.9 million of annual ongoing costs will be fully or mostly actualized during the test period.

234.3.1 If confirmed, please discuss for each year in the test period how the Grand Total shown in the table above compares to the approximately $7.9 million of annual ongoing costs from the Assessment Reports #8 and #9.

234.3.1.1 Specifically address if the Grand Totals calculated above: Are a subset of the approximately $7.9 million of annual ongoing costs, and the remaining $5 million pertain to Operations Standards which are expected to be absorbed into the existing budgets; or are these costs in addition to the roughly $7.9 million of annual ongoing costs? If yes, would it be fair to conclude that all the approximately $7.9 million relates to Operations Standards which is expected to be absorbed into existing budgets.

234.3.2 If not confirmed, please estimate by when BC Hydro anticipates the roughly $7.9 million of annual ongoing costs will be fully or mostly actualized.

234.4 Please confirm that the CIP Total includes the CIP Operations Standards. If not confirmed, please discuss.

234.5 Please discuss in more detail the tools that BC Hydro is looking to implement to track actual costs, the key data it will track and the timeline by which BC Hydro expects to have the tools operational by.

235.0 Reference: OPERATING COSTS – TRAINING, DEVELOPMENT AND GENERATION
Exhibit B-1-1, Appendix N; Exhibit B-9, BCUC IR 46.1–46.3, 61.2
Safety

235.1 Are any of BC Hydro's workforce and public safety performance metrics audited? If so, how? Please provide the findings and recommendations of the most recent audit. If not, why not?

H. CHAPTER 5 – OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER SERVICE BUSINESS GROUP

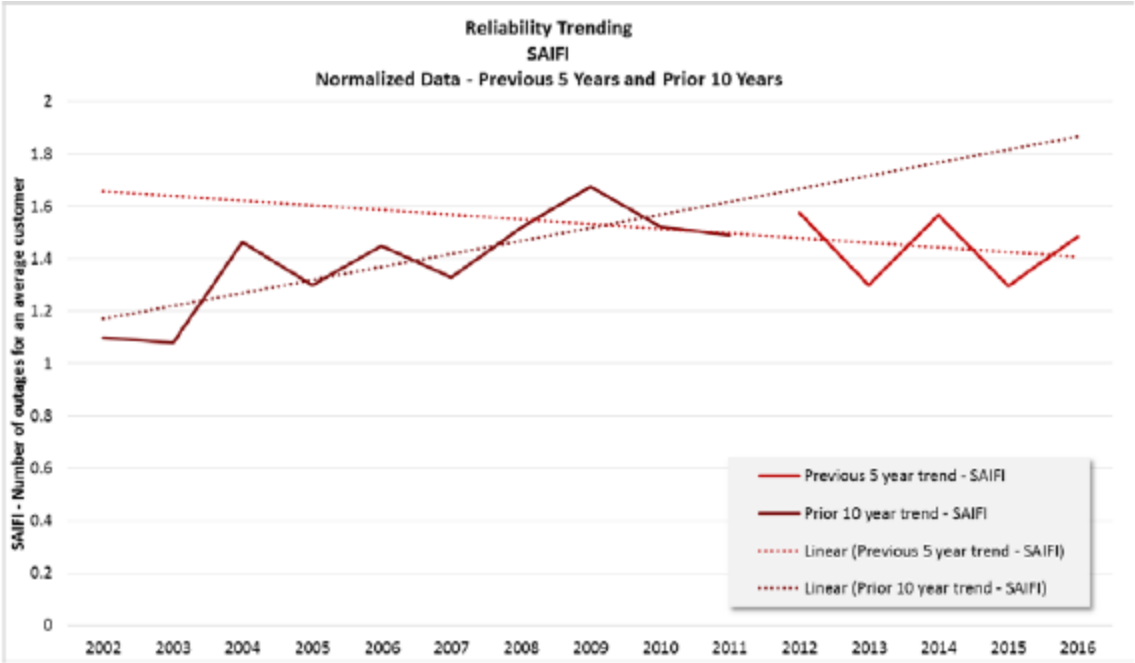
236.0 Reference: OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER SERVICE
Exhibit B-9, BCUC IR 45; Exhibit B-10, CEC IR 1.3.3.1
Reliability indices – SAIDI, SAIFI and %ASAI

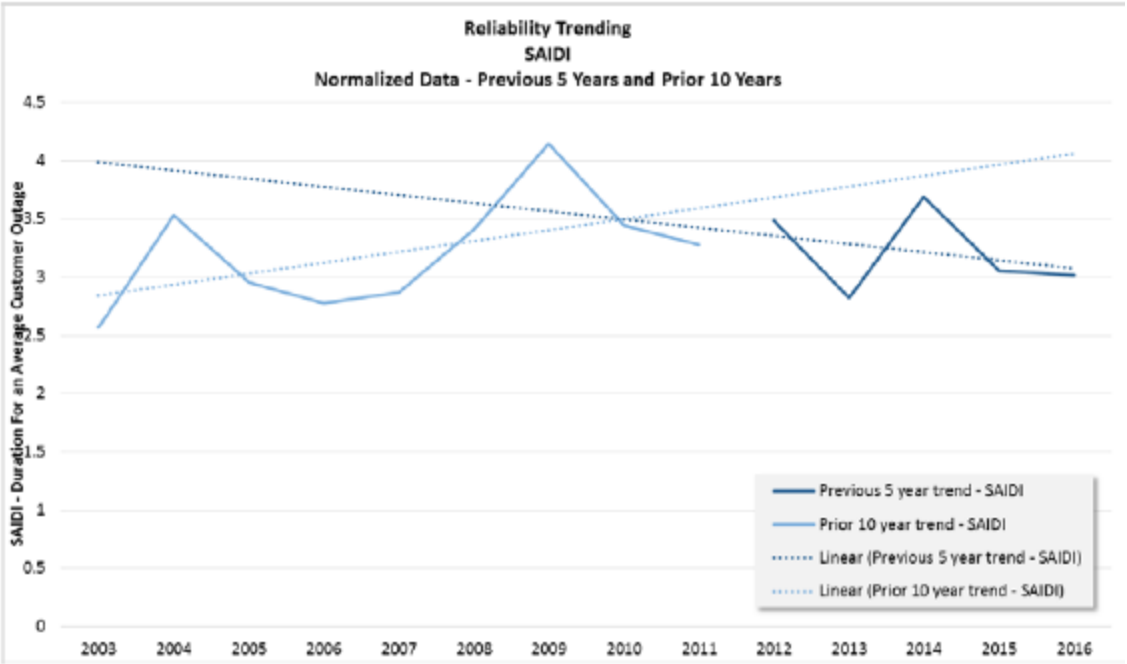
The SAIDI and SAIFI performance measures provided to the Government in Appendix E and those provided in Appendix N use BC Hydro's Major Event Day definition normalization method, whereas the measures provided to the Commission in the annual report use the IEEE Beta 2.5 Major Event Day definition normalization method (IEEE).

Using BC Hydro's definition and normalizing the SAIDI and SAIFI metrics on full-year actuals for F2016, BC Hydro's results were 1.48 and 3.01 (Appendix N, Table N-1), respectively, whereas using the IEEE definition the results were 1.60 and 3.42, respectively (Appendix U, Table 3). No Canadian Electricity Association benchmarks for overall system data normalized using the IEEE method were provided for F2016 or any other year.

BC Hydro explained that the IEEE method and BC Hydro's method share the common purpose to better reveal trends in reliability performance that would be obscured by major events. The IEEE method is most markedly different from the BC Hydro method in the choice of Major Event Day Threshold.

BC Hydro submitted that the upward trend in SAIDI and SAIFI in Appendix U is attributed to the fact that these metrics are based on all-events non-normalized data. Over the period of F2003 to F2016, BC Hydro submitted it has experienced upward trends in the outage impacts related to uncontrollable major events, but when considering normalized data, it submits the trend is improving. It provides the following graphs in support:





In response to CEC IR 1.3.3.1 BC Hydro provided further normalized BC Hydro SAIDI and SAIFI data, as well as SAIDI and SAIFI data for a Canadian Electricity Association Canadian Composite excluding Most Prominent Events.

BC Hydro also submitted that a sub-group of select utilities within the Canadian Electricity Association community with characteristics closer to BC Hydro's provides a better direct comparison than with the Canadian Electricity Association averages. A more appropriate comparison is with Hydro Quebec, Manitoba Hydro, and SaskPower.

Similarly, BC Hydro explains that the %ASAI was low in F2016 due to a major storm event and the System Resiliency Initiative invested $11 million in operating expenditures and almost $200 million in capital expenditures over five years to improve reliability in communities that are the most vulnerable to outages or longer outage durations caused by storms.

236.1 If available, please provide the Canadian Electricity Association's SAIDI and SAIFI benchmarks for overall systems normalized using the IEEE method for F2014, F2015 and F2016. Please compared BC Hydro's SAIDI and SAIFI overall system normalized using the IEEE method for these years to those Canadian Electricity Association benchmarks. Please also discuss any trends observed.

236.2 Please confirm, or otherwise explain, that BC Hydro's Major Event Day definition typically removes more customer interruptions and customer hours lost from the SAIDI and SAIFI calculations, and consequently provides the appearance of better SAIDI and SAIFI results as compared to using the IEEE definition.

236.3 Please confirm, or otherwise explain, if the data provided in the charts in the preamble use the BC Hydro Major Event Day definition.

236.4 Do any of Hydro Quebec, Manitoba Hydro and/or SaskPower use the BC Hydro Major Event Day definition? Do any use the IEEE definition? Do any have their own definition? Please elaborate.

236.5 For the four linear models shown in the preamble please provide the four equations and R-squared measures. What do the R-squared measures say about how well each of these linear models fit the data? Can any conclusions be drawn? Please elaborate.

236.6 Please produce the same charts and linear models included in the preamble but using the IEEE method. Please provide the linear equations and R-squared measures for each of these new four lines. Please discuss any variances and trends observed. What do the R-squared measures say about how well the linear models fit this data? Can any conclusions be drawn? Please elaborate.

236.7 Please provide linear fit models for both the data provided in the charts included in the preamble but for the entire time period shown, for both IEEE and BCH methods. What does each of these R-squared measures say about how well these linear models fit this data? Can any conclusions be drawn? Please elaborate.

236.8 Please provide linear fit models for the Appendix U Distribution and Transmission SAIDI and SAIFI data for the entire time periods provided. Please provide the equations and R-squared measures for each linear model. What does each of these R-squared measures say about how well these linear models fit this data? Can any conclusions be drawn? Please discuss any trends observed.

236.9 Please describe controllable events that affect reliability.

236.10 Which of the above performance measures and models conveys the best information regarding reliability trends to BCH transmission and distribution customers? Please explain why. What are these trends?

236.11 Are BC Hydro's SAIDI, SAIFI and %ASAI results audited? If so, how and by which department or group? Please provide the findings and recommendations of the most recent audit. If not, why not?

236.12 Please elaborate on the System Resiliency Initiative. Are there any plans to continue pursuing this initiative or similar actions?

236.13 At what values would BC Hydro consider SAIDI, SAIFI, and %ASAI unacceptable and why? Please also indicate which data scope and normalization method should be used.

236.14 If the Commission determined that service was becoming inadequate (re: SAIDI, SAIFI and %ASAI), what would BC Hydro do to improve reliability? For example, would it add more maintenance and/or would it primarily be achieved through additional sustainment or other capital expenditures? Please elaborate.

237.0 Reference: OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER SERVICE
Exhibit B-9; BCUC IR 53.3
Transmission and distribution - asset management

In response to BCUC IR 53.3, BC Hydro provided the results of a Black and Veatch T&D asset management assessment, Gap Analysis Report and noted it "assessed the identified gaps and has since addressed all but one of the gaps that were deemed of value to address." In the report, certain identified high priority gaps were noted as not included in the scope of the Transmission and Distribution Transformation project. For example, the need for the Asset Management Framework to be approved by senior management and the need to develop a T&D Asset Management Policy with review and approval by senior management. Black and Veatch note that they believe that BC Hydro will obtain the most benefit in improving its asset management efficiency and effectiveness by implementing improvements to close these specific gaps.

237.1 Please identify which gaps were deemed not of value to address. Please explain why.

237.2 Please provide the specific gap that has not been address and explain why.

237.3 Please discuss some of the steps BC Hydro has taken to improve the asset management efficiency and effectiveness since the issuance of the Gap Analysis Report.

237.4 Please confirm, or otherwise explain, if the T&D Asset Management Framework has been approved by senior management.

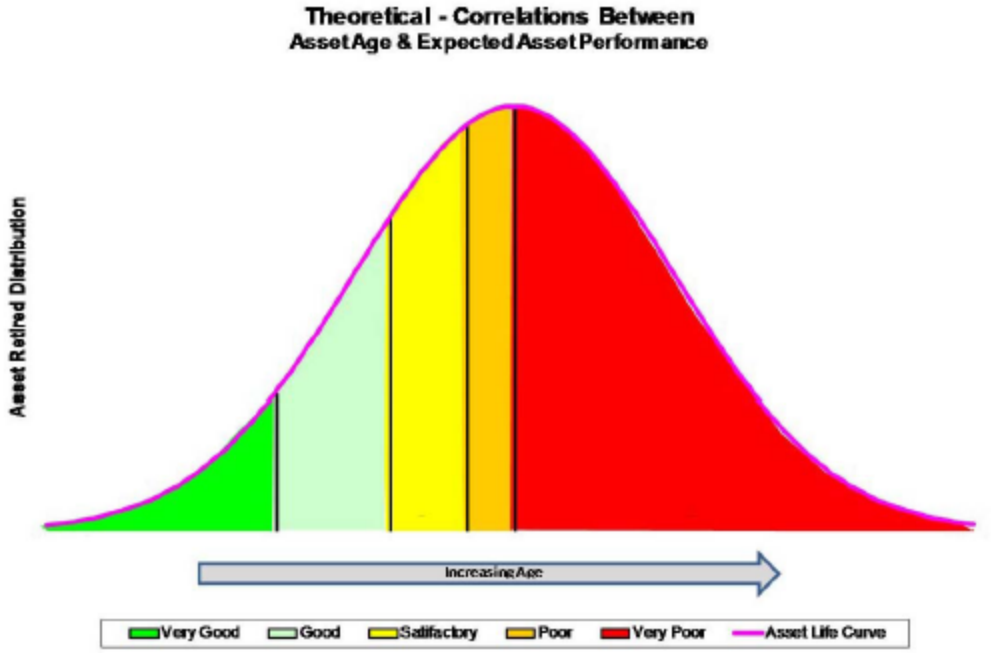
237.5 Similarly, please confirm, or otherwise explain, if a T&D Asset Management Policy has been developed and has been reviewed and approved by senior management.

237.6 If not approved by senior management, who approves these?

238.0 Reference: OPERATING COSTS – TRANSMISSION, DISTRIBUTION AND CUSTOMER SERVICE
Exhibit B-9; BCUC IR 53.8
Transmission and distribution – Asset Health Index

In response to BCUC IR 53.8, BC Hydro provided another Black and Veatch report. This report is a benchmarking assessment of BC Hydro's Asset Health Index to other utilities. On page 59 of that report, Black & Veatch provide the following chart:

Asset Expected Health



Expected Health of Asset over Time, Correlated with Age

In response to BCUC IR 53.8, BC Hydro provides Asset Health Index distributions by each asset class. Two representative asset class examples are provided below:

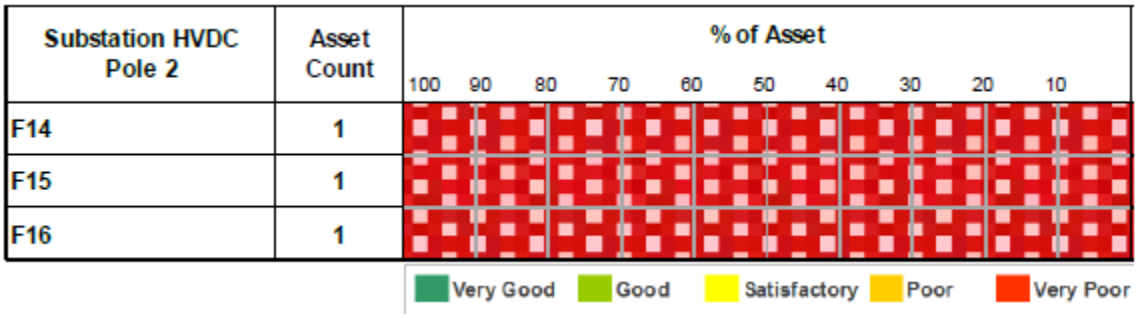
Transmission Metal Structures	Asset Count	% of Asset (100 90 80 70 60 50 40 30 20 10)
F14	22,065	
F15	22,767	
F16	23,084	

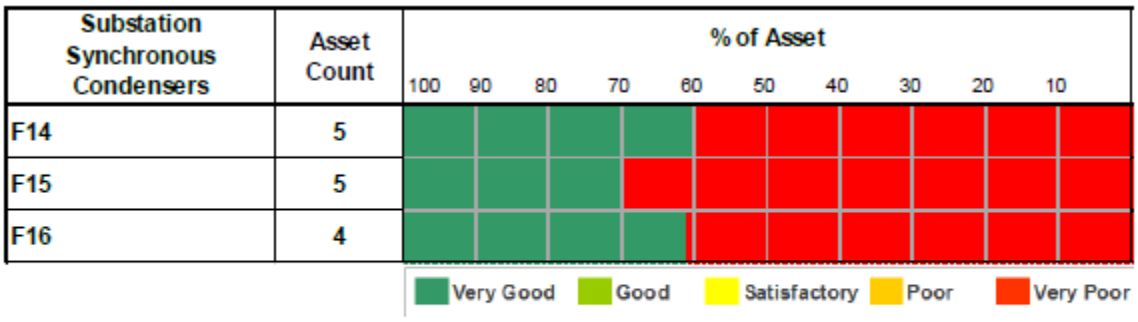
Very Good | Good | Satisfactory | Poor | Very Poor

Substation Transformer	Asset Count	% of Asset (100 90 80 70 60 50 40 30 20 10)
F14	1,076	
F15	1,115	
F16	1,138	

Very Good | Good | Satisfactory | Poor | Very Poor

BC Hydro also provides the following AHI distributions for Substation HVDC Pole 2 and Substation Synchronous Condenser:





Substation Synchronous Condensers - The assets in this class are undergoing significant investment in the Fiscal 2017 to Fiscal 2019 period to address the assets with "Very Poor" rating.

238.1 Please compare the Asset Health Index distributions by asset class to the expected health of assets over time, correlated with age. Overall, in general, does it appear that BC Hydro's T&D assets are in much better condition than the expected health of T&D assets over time, correlated with age? If so, why? If not, why not? Please explain.

238.2 Please elaborate on the AHI for Substation HVDC Pole 2.

238.3 Please describe the significant investments in synchronous condensers planned F2017 to F2019, and provide the forecast costs involved.

I. CHAPTER 5 – OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY BUSINESS GROUP

239.0 Reference: OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY BUSINESS GROUP
Exhibit B-9, BCUC IR 36.1
Business unit support costs

239.1 Please explain the nature of/circumstances behind the $7.1 million "First Nation community payment" on line 4 of the breakdown of Business Unit Support costs in response to BCUC IR 36.1. Please confirm that this one a one-time cost only.

240.0 Reference: OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY
Exhibit B-9, BCUC IR 55
Budget to actual costs

In response to BCUC IR 55, BC Hydro showed that the $3.94 billion from F2011 to F2015 only includes Generation and Transmission projects over $100,000 and the $6.49 billion from F2012 to F2016 only includes Generation, Transmission, Smart Metering and Infrastructure, and Properties projects. BC Hydro also notes that these measures exclude capital programs.

240.1 Please provide budget to actual cost comparisons for both the F2011 to F2015 period and the F2012 to F2016 period using 1) all BC Hydro projects over $100,000 and 2) using all BC Hydro projects over $100,000 plus all capital programs. Please comment on any observations.

241.0 Reference: OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY
Exhibit B-9, BCUC IR 58.2
Dam safety

In response to BCUC IR 58.2 BC Hydro provided the summary and conclusion from an internal audit and provides a link to the internal audit report. The internal audit found that key Dam Safety Program activities are being well executed with some areas for improvement and, notably, the Vulnerability Index ranking process. On page 8 of the audit report, it described the following:

> **Vulnerability Index (VI)**
>
> - The VI provides a relative measure of the gap magnitude between performance capability and normal expectation of the dam feature, under best Dam Safety practices. However, some limitations exist in the VI rating process such as:
> - VI inputs may not be rated consistently depending on the initiator of the input and their level of understanding of the process.
> - System deficiencies (operational, procedural, management) are not included in the VI assessment process.
> - The VI is quantified based on the sum of individual deficiencies at a dam and not on an overall dam basis, which may lead to over estimation of the overall dam vulnerability.

241.1 Please elaborate on BC Hydro's progress on the areas for improvement noted in the audit report including the Vulnerability Index ranking/rating process.

241.2 Would improvements in the ranking/rating process be expected to lead to more optimized dam safety maintenance and capital spending by better prioritizing risk reduction projects? Please elaborate.

242.0 Reference: OPERATING COSTS – CAPITAL INFRASTRUCTURE PROJECT DELIVERY
Exhibit B-9, BCUC IR 59.3
Physical and cyber security

In response to BCUC IR 59.3, BC Hydro explained that "It would be correct to say that there are more projects than funds available; however, BC Hydro manages within the 2013 10 Year Rates Plan to mitigate pressure on rates."

242.1 Are there physical and cyber security projects that have a positive value or result in risk reduction at low cost that are not being pursued because of the limited funds being made available?. Please elaborate.

J. CHAPTER 5 – OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES

243.0 Reference: OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES
Exhibit B-9, BCUC 41.3
Overtime hour FTEs

243.1 Please explain what distinguishes an overtime hour FTE from a regular hour FTE.

243.1.1 Please clarify whether standard labour rates for an overtime hour FTE are the same as standard labour rates for a regular hour FTE.

244.0 Reference: OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES
Exhibit B-10, Zone II IR 1.1
FTE'S

244.1 In the table provided in the response to Zone II IR 1.1 does the row titled MWh Sales include MWh sales that were deferred to the HDA and/or the NHDA?

244.1.1 If yes, please update the table provided in the response to Zone II IR 1.1 to include an additional row titled 'MWh Sales excluding deferrals'.

244.1.2 Please update the table to include Forecast Customers – Year End during the test period.

244.1.3 Please update the table to include total labour costs for (i) FTE's O&M total labour costs (excluding non-current PEB, (iii) Services – ABSU from schedule 5S, line 2, and (iv)contractor costs included in Services-Other, schedule 5S, line 3.

244.1.3.1 Please confirm, or explain otherwise that these costs represent BC Hydro's total labour and contractor costs (excluding those capitalized).

244.1.4 Do the Base Labour costs include both O&M and Capitalized FTE's? If yes, please update the table to exclude capitalized FTE's and provide the information for O&M (i) Base Labour (excluding Non-Current PEB) and (ii) Benefits.

244.2 The table below has been adapted from the table included in response to Zone II IR 1.1. Please confirm that the information provided is accurate or update as necessary.

Statistic Category	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
FTEs - Total (including overtime)	6,388	6,208	6,303	6,312	6,234	6,296	6,344	6,365
Base Labour	593,380,526	583,985,635	600,706,223	600,309,461	612,264,615	636,165,743	654,373,196	669,119,012
Benefits	123,913,442	134,876,028	149,159,689	151,397,027	168,503,380	159,090,401	152,130,576	156,126,404
Total	717,293,967	718,861,663	749,865,913	751,706,488	780,767,995	795,256,144	806,503,772	825,245,416
Average Employee (FTE) Cost per Year - Base Labour	92,894	94,066	95,300	95,104	98,219	101,044	103,144	105,120
Average Employee (FTE) Cost per Year - Benefits	19,399	21,725	23,664	23,985	27,031	25,269	23,979	24,528
Average Employee (FTE) Cost per Year - Total	112,293	115,791	118,964	119,089	125,250	126,312	127,123	129,648

244.2.1 Please explain why there was a significant increase in Average Employee (FTE) Cost per Year – Benefits in F2016. Please explain why they are forecast to decrease in F2017 and F2018 as compared to F2016 and then increase slightly in F2019.

244.3 Please explain why the Average Employee (FTE) Cost per Year – Total increase by 15.5 percent between F2012 and F2019.

In response to Zone II IR 1.1 BC Hydro provided the following information:

	Actual										Plan		
Statistic Category	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
O&M Cost per MWh	$ 11.26	$ 11.18	$ 12.50	$ 15.04	$ 17.51	$ 17.29	$ 16.88	$ 16.46	$ 19.36	$ 19.73	$ 20.36	$ 22.57	$ 22.78

244.4 It appears that the O&M Cost per MWh is forecast to increase by 32 percent between F2012 and F2019, or 4.5 percent a year. Please explain, at a high level, the reason for an annual 4.5 percent increase.

245.0 Reference: OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES
Exhibit B-10, Zone II IR 1.1
Distribution system statistics

245.1 Please clarify what the unit of measure is in response to Zone II IR 1.1 with respect to Distribution km per FTE and Distribution & Transmission km per FTE. For clarity, does "12" mean

12 distribution km per FTE, or a larger multiple?

245.2 Please explain why Distribution km per FTE and Distribution & Transmission km per FTE information could not be provided for F2017-F2019 plan.

245.3 Please explain why Distribution km per FTE and Distribution & Transmission km per FTE remained constant from F2009–F2012 but declined from F2007 and F2008.

245.4 Please discuss which, if any, of the measures in the table provided in Zone II IR 1.1 are used by BC Hydro for measuring employee productivity in distribution and transmission.

245.4.1 What does BC Hydro use as a benchmark for these measures and why? If these measures are not benchmarked, please explain why not.

245.4.2 Please discuss BC Hydro's performance against the relevant benchmark for these measures. If performance is below benchmark, please address what steps BC Hydro is taking to improve performance.

245.5 What other productivity or benchmarking measures (not identified in Zone II IR 1.1) does BC Hydro use in distribution and transmission? For example: number of engineers in Transmission per circuit km of Transmission, per station, and/or per asset $.

245.5.1 Please provide the results of these productivity or benchmarking measures annually for F2014–F2016 and forecast for F2017–F2019, and discuss any significant results.

246.0 Reference: OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES
Exhibit B-9, BCUC IR 41.3
Employee headcount

246.1 In the same format as the tables provided in response to BCUC IR 41.3, please provide annual employee headcount information for plan and actual F2012–F2016, and forecast F2017–2019.

247.0 Reference: OPERATING COSTS – FULL TIME EQUIVALENTS AND STANDARD LABOUR RATES
Exhibit B-1-1, Section 5.3.1.1, p. 5-10; Exhibit B-9, BCUC IR 27.1, BCUC IR 28.3
SMI – Full time equivalents (FTEs)

In Table 5-2 on page 5-10 of the Application and in response to BCUC IR 27.1, BC Hydro provided a breakdown of FTEs by key business units requiring SMI sustainment activities. BC Hydro indicated that of the total 51 FTEs required in each year of the test period, 25 are for Technology and 23 are for Field and Grid Operations.

In response to BCUC IR 28.3, BC Hydro stated that effective October 1, 2016 it "took back responsibility for manual meter reading from Accenture Business Services for Utilities (ABSU)" and also "restructured the meter reading function to improve productivity by realigning the FTEs and locations of Field Service Representatives."

247.1 Please confirm, or explain otherwise, that taking back responsibility for meter reading contributes to the increase in FTEs for SMI sustainment activities.

247.1.1 If not confirmed, please indicate how many FTEs contribute to the increase of 51 FTEs in each year of the test period.

247.1.2 Please specify which key business unit(s) the FTEs were added to.

247.2 Please provide details regarding the need for the increase in FTEs in the Field and Grid Operations key business unit.

247.3 Now that the SMI project is complete, please quantify the decrease in FTEs in each key business unit in each of the test years as a result of the SMI program. Please describe the job function

where any decrease is forecast to occur.

K. CHAPTER 5 – OPERATING COSTS – OPERATIONS SUPPORT BUSINESS GROUP

248.0 Reference: OPERATING COSTS – OPERATIONS SUPPORT BUSINESS GROUP
Exhibit B-9, BCUC IR 60.4
Corporate costs

In response to BCUC IR 60.4, BC Hydro provided the following breakdown for corporate costs in the Operations Support business group:

($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
Labour Residual	6.0	18.6	11.8	0.4	-	-	-
Insurance Expense	9.9	9.1	9.9	9.0	9.0	9.0	9.0
Dues & Fees (Including Corporate Memberships)	4.4	4.6	4.4	4.3	4.2	4.2	4.2
Unallocated Funds *	4.9	1.1	10.1	0.1	4.0	5.2	6.5
IFRS Ineligible Capital Overhead	(156.8)	(156.8)	(134.4)	(134.4)	(112.0)	(89.6)	(67.2)
Total Corporate Costs (Excluding Recoveries)	(131.6)	(123.5)	(98.3)	(120.6)	(94.8)	(71.2)	(47.5)
Recoveries	-	(4.4)	-	-	-	-	-
Total Corporate Costs (Net of Recoveries)	(131.6)	(127.9)	(98.3)	(120.6)	(94.8)	(71.2)	(47.5)

248.1 Please explain what the Labour Residual cost on line one of the table above relates to.

248.1.1 Please explain the large variances between forecast and actual Labour Residual costs in F2015 and F2016. Please explain why the actuals in F2015 were $18.6 million and dropped to $0.4 million in F2016. What is the rationale for the nil forecast in F2017 through F2019?

248.2 Please explain the reason for the variance between forecast and actual in F2015 and F2016 relating to Unallocated Funds of $3.8 million and $10.0 million, respectively.

248.2.1 Please discuss if the unallocated funds were not spent and specifically address if the costs of adhoc projects and unanticipated expenses were less than plan.

248.2.2 Please provide a rationale for the 25-30 percent increasing forecast relating to Unallocated Funds during the test period.

L. CHAPTER 6 – CAPITAL EXPENDITURES AND ADDITIONS

249.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 64.1, Attachment 1
Enterprise-wide framework for capital prioritization

In response to BCUC IR 64.1 BC Hydro explained:

> The corporate risk matrix was augmented with supplemental criteria to capture the impacts of a diverse set of investments across BC Hydro. The matrix was also augmented with additional consequence and likelihood levels to provide more differentiation between investments. The augmented corporate risk matrix is referred to as the capital allocation risk matrix.

In Attachment 1 to BCUC IR 64.1 BC Hydro provided its Capital Investment Analysis Guide. BC Hydro noted that "Assessing the negative impact of deferral is the method to be used to support a decision to include a risk-driven investment in the Capital Plan, while assessing the positive impact of proceeding is

the method to be used to support a decision to include a value-driven investment." Appendix 7 to Attachment 1 contains a BC Hydro internal link to the Corporate Capital Allocation Risk Matrix and information on BC Hydro's Enterprise Risk Management.

249.1 Please provide and further discuss the Corporate Capital Allocation Risk Matrix and the Enterprise Risk Management information expected to be contained at the BC Hydro internal link.

249.2 Please explain BC Hydro's process to establish consequence and likelihood levels. For example, does BC Hydro rely on professional judgment and/or reaching general consensus, or does it use previous risk and consequence assessment data? Similarly, what process is used to challenge consequence and likelihood levels? Does BC Hydro undertake any confirmation/validation testing of consequence/likelihood assumptions? How reliable are the methods BC Hydro uses? Please elaborate.

In Attachment 1 to BCUC IR 64.1 BC Hydro explained that for value-driven projects it uses Net Present Value (NPV) divided by the upfront cost to determine a value score for each project. The benefits of value driven projects are estimated based on its hard benefits and 25 percent of its soft benefits.

249.3 In the prioritization process, how are estimates of hard and soft benefits and costs validated or verified? Please elaborate.

In the attachment, BC Hydro also explains that Generation projects are generally risk driven and going forward reliability risk for these projects should be mapped according to the following priority order: EHR, GWh forced out and financial consequence. The Commercial Management (CM) costs and duration of a previous outage should be used to estimate financial severity rather than the current market price or BC Hydro's Reference Price.

249.4 Please elaborate further on why Generation projects are prioritized based in the order of EHR, GWh forced out and financial consequence.

249.5 Please further explain how CM costs are determined and provide a sample calculation. Are CM costs estimates of previous lost opportunity costs? Do CM costs include replacement/repair costs? How are lost opportunity costs determined and validated or verified? Are the CM costs used to determine financial severity forecast costs which have been adjusted based on past CM costs? Please elaborate.

249.6 Why are the CM costs used rather than the current market price or BC Hydro's Reference price?

249.7 Considering BC Hydro's recent update to its load resource balance, would BC Hydro expect the CM costs in the next three years to be higher or lower than in the last 3 years? Please elaborate.

249.8 Please provide the risk and value scores for all evaluated projects included in the most complete Appendix I (please add a new column). For those projects not evaluated on risk or value, please briefly indicate why.

249.9 Please provide the analytical evaluation of the negative impact of deferral of each of the three lowest risk ranked projects for each category provided in Appendix I. Provide only for those projects which have capital additions in the test period, are greater than $5 million for technology projects, or greater than $20 million for all other projects. Please include an explanation of each result, including assumptions and justifications.

249.10 Please provide the analytical evaluation of the positive impact of proceeding of each of the three lowest value ranked projects in each category provided in Appendix I. Include only those projects which have capital additions in the test period and are greater than $5 million for technology projects, or greater than $20 million for all other projects. Please include an explanation of each result, including assumptions and justifications.

In the Capital Investment Analysis Guideline, BC Hydro explains that "Additional guidelines were developed to aid in assessment of transmission reliability risk. The redundancy built into the transmission system limits the exposure to negative consequences if system expansion projects or projects to address asset failures are deferred. To the extent possible, the additional guidelines were aligned with existing metrics and analysis."

249.11 Please confirm, otherwise explain, that the additional guidelines are provided in Attachment 1, Appendices 1 to 6.

The Capital Investment Analysis Guideline also explain: "Transmission growth projects that expand the capability of the system to serve load growth will assess reliability risk using Expected Energy Not Served (EENS)." And "For projects initiated to sustain the existing capability of the system and address asset replacement, an Asset Condition risk assessment criteria was developed. This assessment criterion takes into account how critical an asset is to the functioning of the system, the length of time required to return an asset to service after failure, and the health of the asset."

249.12 For the 3 lowest ranked transmission growth projects greater than $20 million with capital additions in the test period provided in Appendix I, please provide their EENS and elaborate on the results. How do these results compare to other projects taken/not undertaken in the test period?

249.13 For the 3 lowest ranked transmission projects greater than $20 million with capital additions in the test period provided in Appendix I and initiated to sustain the existing capability of the system and address asset replacement, please provide their Asset Condition risk assessments and elaborate on the results. How do these results compare to other projects taken/not undertaken in the test period?

For distribution projects, the guidelines explain that Customer Hours Lost (CHL) and Customer Interruptions (CI) are the reliability criterion considered, if capital work on a feeder or set of feeders is to be deferred. The guidelines also note that other reputational criteria are also used: CEMI-4, which measures the number of customers experiencing 4 or more outages on an annual basis, CELID-6, which measures the number of customers experiencing an outage of 6 hours or longer, and CELID-12, which is the number of customers experiencing an outage of 12 hours or longer, when assessing the safety risk of deferring a project.

249.14 For the 3 lowest ranked distribution projects and transmission projects greater than $5 million with substation distribution assets provided in Appendix I, please provide the negative impact of deferral outside the test period using CHL, CI, CEMI-4, CELID-6 and CELID-12 criterion (where applicable) and elaborate on the results. How do these results compare to other projects taken/not undertaken in the test period?

250.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 65.1, Attachment 2, BCUC IR 66.1
Financial oversight and expenditure authorization policies for capital projects – Approval limits and thresholds

In response to BCUC IR 65.1, BC Hydro noted that it updated the table of Financial Approval Authority Limits to reflect revised limits, updated hyperlinks, and other minor edits in March 2016. BC Hydro also provided the Corporate Policy Statement Financial Approval Process which notes that Board approval is required for Authorization Documents, Contracts, Commitments and Payment Documents greater than $50 million within the Approved Annual Plan and $20 million for ex-plan projects.

In response to BCUC IR 66.1 BC Hydro stated that only financial criteria should be used to trigger a CPCN application and provides its 2010 Capital Project Filing Guidelines which notes: "Rather than focus on

the definition and distinction between projects and programs, BC Hydro will use individual BC Hydro Board approvals as the trigger for capital project filings, irrespective of the characterization of the capital expenditure. When the initial BC Hydro Board approval to proceed with implementation phase funding is sought for any capital expenditure above the threshold, the capital project filing requirement would be triggered."

BC Hydro proposed that: "The expenditure threshold trigger is the authorized cost estimate. The authorized cost estimate is the requested funding for a project, inclusive of all contingencies and reserves, and based on a fixed scope and in-service date. We consider this is the appropriate cost estimate to use as a threshold as the authorized cost estimate is the amount that is reviewed and signed-off by BC Hydro's Board of Directors and is the amount that we have committed to spend."

250.1 Please explain which approval limits were changed in March 2016.

250.2 Please describe what is meant by each of Authorization Documents, Contracts, Commitments and Payment Documents.

250.3 Do individual strategies or capital asset replacement programs, which are estimated to result in expenditures greater than $50 million via prospective contracts or commitments to specific vendors, require Board approval? Please elaborate.

250.4 Please provide and discuss Commission decisions regarding thresholds for CPCN or section 44.2 filings for BC Hydro and BCTC.

250.5 How do Board approval thresholds relate to the Commission approved thresholds and to the thresholds provided in the 2010 Capital Project Filing Guidelines? Please elaborate.

251.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 65.4
Financial oversight and expenditure authorization policies for capital projects – Properties and Fleet

In response to BCUC IR 65.4, BC Hydro explained: "Properties and Fleet capital projects have not been recently audited due to their small size and low risk."

251.1 When were the last Properties and Fleet audits? What were those results? When are the next audits planned?

251.2 Understanding that audits for small low risk projects may not be efficient; could one expect value to be obtained from an audit of these groups' processes? Please elaborate.

252.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 67.1
Capital Additions Forecast

BCUC 67.1 asked: "What are the consequences in the near and long term to deferral accounts and ultimately rates if BC Hydro were to have capital additions 20 percent higher or 20 percent lower than forecast in the test period? Similarly, what is the probability of such a difference in capital additions occurring? Please elaborate." In response BC Hydro assumed that capital additions in the years following the test period would be lower or higher by the corresponding 20 percent.

252.1 Please respond to BCUC IR 67.1 assuming the 20 percent lower or higher capital additions in the test period do not result in lower or higher capital additions post test period.

253.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 72.1, 72.2, 72.3
Generation, transmission, distribution, technology and other capital projects

In response to BCUC IR 72.1, 72.2 and 72.3 BC Hydro explains that it classifies projects to sustain or expand substation Distribution assets as Transmission projects and confirms that substation projects are automatically considered transmission projects no matter what the percentage of the project scope or cost is for transmission assets.

BC Hydro's 2010 Capital Project Filing Guidelines provide a $50 million threshold for distribution projects and a $100 million threshold for transmission projects (including substation distribution asset components).

253.1 Please confirm, otherwise explain, that BC Hydro has no projects in the test period that it classifies as distribution that are greater than $50 million.

253.1.1 Please confirm, otherwise explain, that BC Hydro has never had a project it classified as distribution with an authorized amount greater than $50 million. If not confirmed, please list and describe those projects including authorized dollar amounts.

253.2 Please confirm, otherwise explain, that 6 of the 49 projects listed in Appendix I as transmission projects are substation projects with estimated costs or allowances greater than $50 million: the Horne Payne Substation Upgrade, Northwest Substation Upgrade, Big Bend Substation, Capilano Substation Upgrade, Mainwairing Substation Upgrade and Newell Substation Upgrade.

254.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-1-1, pp. 6-15–6-17; Exhibit B-9, BCUC IR 1.73.1, Attachment 1
Deferred projects

On pages 6-15 to 6-17 of the application BC Hydro explains that it found reductions of $99 million in capital expenditures and $167.2 million in capital additions for Transmission and Distribution in the test period. In response to BCUC IR 1.73.1 BC Hydro provides a list of all the projects greater than $20 million (or $5 million for Technology projects) that were delayed or cancelled in the test period to support the 2013 10 Year Rates Plan. None of these projects were Transmission or Distribution projects.

254.1 Please confirm, otherwise explain, that no Transmission or Distribution projects greater than $20 million were affected by the decision to achieve the $167.2 million in reductions in capital additions the test period.

254.1.1 If confirmed, please explain where the reductions are coming from. For example, are they all program related reductions? Are smaller projects being delayed or cancelled? Please elaborate and provide similar information as Attachment 1 to BCUC IR 1.73.1.

255.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-1, p. 6-21; Exhibit B-9, BCUC IR 74.3-74.5
Out of service generating stations

On page 6-21 BC Hydro explained that "…Alouette and Elko generating stations and Shuswap Unit 1 have been forced out of service due to unsatisfactory equipment conditions and will remain out of service for an extended period."

In response to BCUC IR 74.3 BC Hydro explained that Alouette and Elko facilities are currently being used only to convey water and Shuswap continues to generate electricity from one of the two units and convey water.

In response to BCUC IR 74.4 BC Hydro explained that "Alouette and Elko facilities and Shuswap Unit 1 continue to be accounted for as they have in the past. Assets continue to depreciate at the rates that were recorded at the time the asset was put in-service. The net book value remaining is primarily for dam related assets which are still being used for water conveyance purposes."

255.1 Please provide and comment on the cost, accumulated depreciation, depreciation expense and the net book value for Alouette's non-water conveying assets, Elko's non-water conveying assets and Shuswap's out of service generating assets for F2017, F2018, and F2019.

256.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-1-1, pp. 6-29; Exhibit B-9, BCUC IR 76.2
Asset Health Index – aging asset demographic

On page 6-29 of the Application BC Hydro explains that its level of sustainment expenditures on T&D of $1.1 billion in the test period is below the rate of replacements needed to maintain the condition and average age of these assets.

In response to BCUC IR 76.2 BC Hydro explained: "At our current level of investments for sustaining assets, the number of assets rated Poor or Very Poor is expected to increase and the average age of the assets will continue to rise. This investment strategy will test whether it is possible to allow the Transmission and Distribution portfolio asset health to be lowered and still provide the reliability levels that our customers expect."

256.1 What measures does BC Hydro plan to use and/or report on to measure whether it is providing expected reliability levels? I.e. customer complaints, SAIDI or SAIFI measures.

256.1.1 What level of any of these measures would indicate that asset health has be reduced below expect levels for reliability?

256.2 What is the trigger for BC Hydro to increase its T&D portfolio asset health, presumably through increased spending on sustainment? Would BC Hydro agree that the next RRA would be the appropriate timing to report to the Commission on the effectiveness of its current proposed level of sustainment expenditures on T&D? Please elaborate.

257.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 77.2–77.4
Customer reliability spending

In response to BCUC IR 77.2 through 77.4, BC Hydro explained that its largest reliability initiative is for distribution automation and it plans to spend approximately $64 million on it in the test period. BC Hydro also describes the expected benefits would be a reduction in distribution system trouble events that result in customer outages and their associated customer hours lost.

257.1 Does BC Hydro's distribution automation program meet the threshold for filing a CPCN or section 44.2 applications with the Commission? Why or why not? Please explain.

257.2 Please explain how the proposed spending on the distribution automation program was reviewed and approved. Was the BC Hydro Board involved?

257.3 Please provide BC Hydro's historical annual spend on distribution automation over the past 10 years.

257.4 Has BC Hydro analyzed the effectiveness of its past spending on distribution automation? If so, please provide those results. If not, when does BC Hydro plan to review the benefits of its proposed spending? How will it report the results to the Commission?

257.5 If distribution automation program spending were reduced or increased by 25 percent in the test period, what would BC Hydro anticipate the effects to be? Please elaborate.

258.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-1-1, Appendix J, p. 15; Exhibit B-9, BCUC IR 86.4, 86.6, Attachment 1; Exhibit B-10, CEA 1.16.1
Ladore Spillway Seismic Upgrade and Salmon River diversion projects

Appendix J explains that a dam safety investigation is in progress at Ladore to evaluate the seismic performance of the dam, including the spillway.

In the Ladore Facility Asset Plan, it identifies that the penstocks are in unknown condition with an inspection planned for F17. It notes that this may identify a need for additional maintenance or capital investment. It also notes that the withstand of the water passages are unknown. The plan also notes an assessment of the seismic withstand of the powerhouse is expected in F2017 to F2018.

The plan identifies the seismic upgrades of the spillway are planned for F2014 to F2019, unit 1 redevelopment for F2018 to F2025, unit 2 redevelopment for F2022 to F2026, and dam seismic upgrades for F2025 to F2028.

Ladore has three steel-lined penstocks leading to a two-unit powerhouse. Only two of the penstocks are currently utilized. The Facility Asset Plan notes the third penstock will not be used until a business case supports the viability of a third generator.

Upstream from the 47 MW Ladore facility is the 64MW Strathcona facility and downstream is the 126MW John Hart facility. Water flows from the Upper Campbell Reservoir into the Lower Campbell Reservoir via Strathcona and additional water flows into the Lower Campbell Reservoir due to the Salmon River and Quinsam Diversions. The Big Slide Saddle Dam and the Loveland Bay Saddle Dam also impound Lower Campbell Reservoir.

In response to CEA 1.16.1, BC Hydro explained that it "…has decided not to pursue the Salmon River Diversion Canal Refurbishment and Fish Passage Improvement Project (Salmon River diversion). BC Hydro is in discussion with relevant agencies to determine the scope of a decommissioning project. Once an appropriate scope is determined, BC Hydro will file an application to the British Columbia Utilities Commission under section 41 of the Utilities Commission Act for permission to cease operation of the Salmon River diversion."

In response to CEC 1.16.2 BC Hydro explained that "The Salmon River Diversion Canal Refurbishment and Fish Passage Improvement Project had an Implementation Phase Cost Estimate range of $41.1 million to $37.4 million to extend the life of the diversion works by 20 years. BC Hydro has decided to not pursue this project."

In response to BCUC IR 86.4 BC Hydro explained that strategy for Ladore is not full redevelopment.

258.1 Please confirm, otherwise explain, that the dam safety investigation includes the Big Slide Saddle Dam and the Loveland Bay Saddle Dam.

258.2 Please provide the cost estimate (or planning allowance) and approximate timing of the unit 1 redevelopment project.

258.3 Please summarize in a table the findings and recommendations of the most recent condition assessments, including evaluations of the seismic withstand, for each of the penstocks, the water passage components (e.g. power tunnel), the powerhouse, the spillway, the spillway gates and each of the dams.

258.4 Will the dam safety investigation of the seismic performance of the dam(s), the penstock inspection and / or the seismic withstand assessment of the powerhouse / water passages better inform the costs, timing, scope and need for the spillway project and how projects at Ladore may be grouped together and what applications would be filed with the Commission? Please elaborate.

258.5 Similarly, will the outcome of the application for permission to cease operation of the Salmon River diversion, inform the costs, timing, scope and need for the spillway project as well as how projects at Ladore may be grouped together and what applications would be filed with the Commission? Please elaborate.

258.6 Please provide the planning cost allowance, the anticipated benefits and the approximate timing of the Salmon River diversion decommissioning project.

259.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 87.4, 87.6, Attachment 1
Strathcona Upgrade Discharge

In response to BCUC IR 87.4 BC Hydro identified a Spillway Gate Upgrade project that is on hold, pending determination of the Low Level outlet design. In the facility asset plan for Strathcona (Attachment 1 to BCUC IR 87.6) it reserves a planning allowance of $75 million for a Spillway Gate Upgrade project planned for F2015.

259.1 Please confirm the project identified in response to BCUC IR 87.4 and the one included in the facility asset plan are the same.

259.2 Please provide the regulatory history of the Strathcona Spillway Gate Upgrade project.

260.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-1-1, Appendix I
General

260.1 Please confirm, otherwise explain, that BC Hydro plans to inform the Commission in the annual report of any material changes to the scope, schedule and cost projections of all projects listed in Appendix I.

260.2 Please confirm, otherwise explain, that if, after refinement but before construction or the next RRA, BC Hydro foresees any of one these projects potentially exceeding the CPCN or section 44.2 threshold (existing or new), BC Hydro will file applications for these refined projects with the Commission for approval.

260.3 If the Commission were to find that BC Hydro's revenue requirement required reductions, which projects or programs or budgets would BC Hydro propose to cut back and why?

260.4 Please add a column to the most up-to-date Appendix I-A to show the commitments BC Hydro has made in this Application to filing either CPCN or section 44.2 applications with the Commission. Please also indicate the filings not committed to, but anticipated.

261.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 88, 89, 92; BC Hydro 2015 Rate Design Application, Exhibit B-37
Bridge River 2 – Upgrade Units 5, 6, 7 and 8, Cheakamus Unit 1 and Unit 2 Generator Replacement

In response to BCUC IR 88 series of questions BC Hydro explains that water must pass through Bridge River 1 or 2, or Terzaghi. BC Hydro submits that the opportunity to reliably move water through Units 5 and 6 by fiscal 2019, is the primary reason the Units 5 and 6 Upgrade Project is separate from the Units 7 and 8 Upgrade Project.

In response to BCUC IR 89 series of questions BC Hydro explains that the two Cheakamus units will each be uprated from 70MW to 90MW as a result of the Generator Replacement project.

261.1 Please confirm, otherwise explain, that the plan is to upgrade Bridge River Unit 5 one year and Unit 6 the following year. Similarly, please confirm, otherwise explain, that the plan would be to upgrade Unit 7 one year and Unit 8 the following year (i.e. all four units would likely take 4 years/outage cycles to complete).

261.2 Please elaborate on the consequences of high flows at Terzaghi. Has this occurred in the past? What were those consequences?

261.3 Based on expected inflows and storage capability, how many Bridge River 1 and/or 2 units are required to be operational to reliably pass water through the Bridge River system? Please elaborate.

261.4 Please confirm, otherwise explain, the energy and capacity resource balances provided in Exhibit B-37 of the 2015 RDA considered the additional energy and capacity that will be provided by the Bridge River and Cheakamus upgrade projects as committed resources.

261.4.1 Similarly, please confirm, otherwise explain, that the additional energy or capacity that these projects will provide was considered in the 2013 long-term resource plan.

261.5 Please discuss the value of the existing energy and capacity being provided at each of these plants, considering the time of year that they generate, and discuss the value that any additional energy or capacity may provide.

262.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 93.1
Seven Mile Overhaul Units 1 to 3 Turbines

In response to the BCUC IR 93 series of questions, BC Hydro identified replacement as the leading alternative and noted that the $83.0 million was a planning allowance for the refurbishment option.

262.1 Please provide the planning allowance associated with the replacement option.

263.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 94
Burrard

In response to BCUC IR 94 series of questions BC Hydro explained Burrard's operations and costs.

263.1 Please provide the amount of reactive support that is required to be available at Burrard at any given time and discuss why this amount is required.

263.2 Please provide the amount of reactive support that is available from the four synchronous condensers at Burrard and what its limiting factor is.

263.3 Please discuss how many synchronous condensers can currently be operated at the same time with the existing equipment at Burrard.

263.4 If there is a gap between the requirements, the amount of reactive support available and the equipment at Burrard, please explain why, when and how BC Hydro plans to close this gap. Please also include the cost of doing so. Conversely, if there is more reactive support and equipment available, please explain why.

263.5 Please provide the anticipated costs of completing the work to convert Burrard to a synchronous condense only facility as described in response to BCUC IR 1.94.4.

263.6 Have the turbines and related equipment on all four synchronous condensers been removed and scrapped, sold or put in storage? Please elaborate.

264.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 103.5
Projects A and B

In response to BCUC IR 103.5, BC Hydro explained that BC Hydro's net income has been set for the test period and hence is unaffected by rate base. It also notes all land is included in rate base.

264.1 Please explain why land for these projects is included in rate base instead of asset account 'Land Held for Future Use'? What is BC Hydro's understanding of the accounting difference between the two?

264.2 Given that the current construction starts dates are both "TBD" and BC Hydro states that the carrying costs of the land is being expensed until the land is under development, does this equate to BC Hydro holding assets in rate base which are not actively used and useful? Would this also equate to ratepayers paying for assets that are not yet used and useful? Please discuss.

264.3 Will BC Hydro track these land purchases and costs and report on them in the next RRA?

264.4 Please provide the basis for the cost estimates for each proposed land purchase.

264.5 Have alternative land locations been analyzed? Please elaborate.

264.6 Please elaborate on BC Hydro's ability to expropriate land for these projects.

265.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-1-1, Appendix J, p. 57; F2012–F2014 Amended RRA, Appendix J, p. 117;
Exhibit B-6, Appendix I-A – Transmission, line 29; Exhibit B-9, BCUC IR 108
Bid Bend Substation

Appendix I-A shows this project as having an implementation approval of $56.4 million but a current authorized amount of $67 million. It also shows an implementation approval in service date of F2016 but a current forecast in service date of F2018. Appendix J explains: "This project involves construction of a new 60/12 kV, 67 MVA substation in the Big Bend area of South Burnaby to address the load growth of the area." In the F2012–F2014 RRA this project was listed as $33.0 million (+100 percent/-50 percent).

265.1 Please provide and comment on the first approved Big Bend Implementation business case and EAR and any subsequent revisions.

266.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 109.1
Terrace to Kitimat Transmission

In response to BCUC IR 109.1 BC Hydro explained that the 2.5 km 2L103 transmission line replacement is not included in the exemption granted under Ministerial Order M073 2(c).

266.1 Please provide the cost estimate for the non-exempt portion of the project.

266.1.1 If the cost estimate range exceeds $20 million for the non-exempt portion of the project, please provide and comment on the latest business case and EAR and the estimated start date of construction.

267.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-1-1, Appendix J, p. 69; Exhibit B-9, BCUC IR 110
Mainwairing Substation Upgrade

Appendix J explains "This project is to replace the power transformers T1 and T3, the two 12 kV feeder sections and the control building that have reached end of life at Mainwaring Substation."

267.1 Please provide the Facility Area Plan, Facility Asset Plan, relevant Asset Strategy and Substation Load Forecast for this facility.

267.2 Please provide the latest transformer and feeder asset health assessments and control building assessment report.

268.0 Reference: CAPITAL EXPENDITURE ADDITIONS
Exhibit B-9, BCUC IR 111.1
Mandatory reliability standards – Critical Infrastructure Protection version 5 (CIP v5)

In response to BCUC IR 111.1, BC Hydro indicated that:

> **There are multiple components to BC Hydro's NERC CIP v5 work, including compliance requirements for the Transmission & Distribution assets, Grid Operation Control Centers and Generation assets. The investments for these various components of the CIP v5 work are included in the respective capital forecast of the groups responsible for planning the work.**

268.1 Please demonstrate the total capital impact of the NERC CIP v5 work by providing a detailed breakdown of capital expenditure and capital addition forecasts related to all components of the NERC CIP v5 work for F2017 to F2019.

268.1.1 For each line item, please provide a description of the work involved.

269.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-6, Supplemental Appendix I-A – Technology, lines 5, 6, 12, 14; Exhibit B-9, BCUC 114.1, 114.4, 114.6, 114.8, 114.9
Projects over $2 million, Enterprise Billing Infrastructure and Graphic Work Design Tool projects

In response to BCUC IR 114.1, BC Hydro submitted it is applying for approval of its revenue requirements and rates over the test period, which includes recovery of its capital additions related to information technology projects.

Supplemental Appendix I-A shows the Graphic Design Tool (Graphic) project had a current pre-implementation cost estimate of $12.9 million to $23.0 million with capital additions of $15.0 million in F2018, and expenditures of $6.3 million in F2017 and $4.3 million in F2018.

In response to BCUC IR 114.4 BC Hydro explained that the Graphic project was cancelled in October 2016.

In response to BCUC IR 114.6 BC Hydro explained the Enterprise Billing Infrastructure (Billing) project is now in Definition Phase, and the estimated capital cost estimate still remains less than $20 million.

In response to BCUC IR 114.8 BC Hydro explained that "The initiatives to develop energy conservation tools that meet the criteria for demand-side measures as defined in the Clean Energy Act are included in the Fiscal 2017 – Fiscal 2019 Demand-Side Management Plan."

In response to BCUC IR 114.9 BC Hydro described the Energy Insights project is to "Improve the customer experience through the creation of energy insights, aimed at providing proactive notifications to customers about energy consumption patterns with the goal of effecting behavioural change" and the MyHydro EDX is to "Implement a unified, on demand and scheduled data publishing capability for residential and business account holders, via MyHydro."

269.1 Please confirm, otherwise explain, that the projected costs of the cancelled Graphic project have been completely removed from the RRA request, any forecast expenditures or additions, as well as from any budget. That is, this money is not being reallocated. If it is being reallocated, please explain to what and why.

269.2 Please provide the current capital cost estimate of the Billing project, including the accuracy range.

269.3 Please confirm, otherwise explain, that BC Hydro is not seeking recovery of the capital additions related to IT energy conservation tools twice, once in technology projects, once in DSM.

269.4 Similarly, please confirm, otherwise explain, that the proposed Energy Insights project is covered under DSM.

269.5 Please elaborate on the expected functionality of MyHydro EDX. Does this project have any components that relate to energy conservation tools or DSM?

270.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-6, Supplemental Appendix I-A – Properties, lines 1-16
Properties projects

270.1 Please discuss the implications of deferring each of the Properties projects listed in Supplemental Appendix I-A from the test period.

271.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Supplemental Appendix I-A – Other, lines 9, 11, 12, 13; Exhibit B-9, BCUC IR 117
Construction Services/Lower Mainland Transmission Building, Material Classification Facility, Materials Management Facility and Fleet Facility projects

271.1 Is the Fleet Facility also on the Surrey Campus? If yes, are there any savings/efficiencies that could be gained by combining this project with any of the other projects at the Surrey Campus?

271.2 Please provide a plan view drawing or map showing the location of all the current and proposed facility locations on the Surrey Campus.

272.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-1-1, pp. 6-49–6-51, 6-118, 6-119; Exhibit B-6, Appendix I-A – Other, line 18; Exhibit B-9, BCUC IR 118
Fleet/Vehicles/Materials Management

272.1 Please compare BC Hydro's average age per vehicle, number of employees per vehicle, intended age at replacement and intended mileage criteria to FortisBC's.

273.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-6, BCUC IR 1.120.1, Supplemental Appendix I-B, Attachment 1, Table 3
F2015 and F2016 capital additions – Hugh Keenleyside Gate Reliability Upgrade project

In response to BCUC 120.1 BC Hydro provided a revised Appendix I-B, showing projects in-service F15-F16 greater than $20 million, including the Hugh Keenleyside Spillway Gate Reliability Upgrade (HLK) project.

273.1 Please confirm, otherwise explain, that the $90.2 million provided in column S for HLK is a non-IFRS adjusted amount.

273.2 Please confirm, otherwise explain, that the $90.2 million adjusted for IFRS would be $81.3 million (see Attachment 1, Table 3).

273.3 Please confirm, otherwise explain, that the forecast cost at completion adjusted for IFRS is $117.4 million (see Attachment 1, Table 3).

273.4 Please confirm, otherwise explain, that the variance between the IFRS adjusted expected value ($81.3 million) and the IFRS adjusted forecast cost at completion ($117.4 million) is $36.1 million and this would constitute a 44 percent cost variance.

274.0 Reference: CAPITAL EXPENDITURES AND ADDITIONS
Exhibit B-9, BCUC IR 121.5, Attachment 1, pp. 10, 22
GM Shrum (GMS) G1-5 Capacity Increase project

On page 10 of the GMS Facility Asset Plan it lists a G1-G5 Capacity Increase project for $78.9 million in the Implementation phase. On page 22 it explains that the Unit 1 to 5 Capacity Increase project is currently underway with phased in-service dates anticipated to be F2024 through F2028. Units 1 to 5 circuit breaker replacement is identified as scope within the Capacity Increase project.

274.1 Please elaborate on the scope, need, alternatives, costs and timing of the G1-G5 Capacity Increase project.

M. CHAPTER 7 – DEFERRAL AND OTHER REGULATORY ACCOUNTS – DEFERRAL ACCOUNTS

275.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – GENERAL
Exhibit B-10, Zone II, IR 3.5; Exhibit B-9, BCUC IR 129.6
Variance not captured in deferral accounts

275.1 In response to Zone II IR 3.5 BC Hydro provides a table. Please explain why there is a favorable/unfavorable variance related to amortization of deferred provisions and amortization of CPI costs. Specifically, please explain why a variance related to the difference between the forecast amortization of a regulatory account and the actual amortization of the regulatory account would be an adjustment to net income and not a regulatory account addition.

275.1.1 Subsequent to Commission approval of the amortization of a regulatory account, please explain why the actuals would differ from the forecast.

275.2 Please cross reference the table provided in response to BCUC IR 129.6 with the table provided in response to Zone II IR 3.5.

275.3 In the table provided in response to BCUC IR 129.6, BC Hydro stated that it is at risk for any variance in DSM and FRSR amortization. Given that DSM and FRSR costs are captured in regulatory accounts, please explain why the amortization variance is not captured in the respective regulatory account.

275.4 Please compare the table provided in BCUC IR 129.6 with the table provided BCUC IR 1.10.5 in the F2012-F2014 BC Hydro RRA and explain why Forecast Item are different.

276.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – GENERAL
Exhibit B-1-1, p. 7-6, Table 7-2; Exhibit B-9, BCUC IR 124.3.1, 124.5, and 124.11
Fiscal 2024 forecast -10-Year Rate Plan

276.1 For the Other Cash Variance Accounts, Non-Cash Variance Accounts, and the Non-Cash Provisions set out in Table 7-2 in the Application, please provide a table, in a similar format as BCUC IR 124.11 that shows the opening balance, forecast additions, interest and recoveries for F2017 through F2014. Please include an explanation for each of the assumptions considered in determining the forecast additions and recoveries.

276.2 Please expand the table provided in response to BCUC IR 124.3.1 to include a 100 basis point increase and a 200 basis point increase.

276.3 Please include an additions row in the table provided in response to BCUC IR 124.5 to include dollar values.

277.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – DEFERRAL ACCOUNTS
Exhibit B-1-1, p. 7-19; Exhibit B-9, BCUC IR 127.7; Exhibit B-10, BCOAPO IR 39.2
Heritage Payment Obligation (HPO)

277.1 Please cross reference the table provided in response to BCUC IR 127.7 to the corresponding Appendix A, schedule and line item, where the baseline has been expensed.

277.2 Please expand the table provided in response to BCUC IR 127.7 to include F2012 through F2016.

277.3 Please expand the schedule included in the response to BCOAPO IR 39.2 to include the years F2012 through F2015.

277.4 Other than as requested on page 7-19 of the Application, are there any other First Nations related costs where the variance between forecast and actual is not captured in a deferral or regulatory account?

277.4.1 If not, please explain fully why BC Hydro is prepared to take the risks related to negotiation costs and not any of the other costs related to First Nations.

278.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – DEFERRAL ACCOUNTS
Exhibit B-9, BCUC IR 129; BCUC IR 126.1; BCUC IR 130.3; BCUC IR 130.3.1
Non-Heritage Deferral Account (NHDA)

278.1 Please confirm that the preamble, with respect to the load forecast variance, set out in BCUC IR 129 is complete and accurate. If not, please update accordingly.

278.2 As demonstrated in the table below, prior to F2015 there was a corresponding negative COE variance with respect to a positive Domestic Revenue Variance. Please explain the circumstances that led to a positive COE variance in F2015 and F2016 when the Domestic Revenue Variance was also positive.

Non-Heritage Deferral Account Annual Summary			
Year	Cost of Energy	Domestic Revenue Variance (2009)	RRA Adjustments
F2005	154.5		
F2006	44.7		-2.9
F2007	35.5		
F2008	-54.3		-33.7
F2009	-51.5	20.4	43.2
F2010	-22.8	82.5	
F2011	-44.5	42.4	262.9
F2012	-147.0	62.8	65.9
F2013	-166.6	176.1	103.2
F2014	-195.5	137.7	49.8
F2015	50.7	207.3	
F2016	235.4	268.9	
Cummulative Total	-161.4	998.1	488.4

278.3 Please explain each of the RRA Adjustments set out in the table above.

278.4 In response to BCUC IR 130.3.1, BC Hydro explained that a 3 percent variance in the load forecast would result in an approximate $100 million annual addition to the cost of energy variance accounts. Please reconcile this with the response provided in BCUC IR 130.3.

279.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – DEFERRAL ACCOUNTS
Exhibit B-9: BCUC IR 129.3, 129.4; Order G-16-09
Non-Heritage Deferral Account (NHDA)

In response to BCUC IR 129.3 BC Hydro stated that Order G-16-09 approved the deferral treatment of load variances, and the net load variance has since been captured in the cost of energy deferral accounts as the gross cost of energy deferral less the domestic revenue variance as set out in the formula below:

Consequently, the calculation of the Net Cost of Energy Deferral would simplify to:

	Gross Cost of Energy Deferral
–	Domestic Revenue Variance (line 14 above)
=	Net Cost of Energy Deferral

BC Hydro also confirms that the term 'net load variance' and 'variance between the forecast and actual cost of energy arising from differences between forecast and actual domestic customer load' have the same meaning.

In response to BCUC IR 129.4, BC Hydro confirmed that it has been recording the domestic revenue variance in the NHDA since F2009 resulting in a total deferral of $998.1 million and provided the following summary table:

Domestic Revenue Variance F2009 to F2016 $ million			
	Cost of energy due to load	Variance due to revenue	Total Domestic Revenue Variance
F2009	6.5	13.9	20.4
F2010	148.5	(66.0)	82.5
F2011	64.7	(22.2)	42.4
F2012	30.4	32.5	62.8
F2013	82.6	93.4	176.1
F2014	67.9	69.9	137.7
F2015	82.0	125.3	207.3
F2016	59.7	209.0	268.8
	542.3	455.8	998.1

BC Hydro further explained that it does not separately calculate the domestic revenue variance between the cost of energy due to load and the variance due to revenue.

279.1 BC Hydro has been recording the Total Domestic Revenue Variance in the NHDA since 2009, and it appears that there has been no change to the calculation for the COE variance. Please explain how the Domestic Revenue Variance is the same as the net load variance.

279.2 Starting in F2009, it appears that the additions to the NHDA (as set out in the table above) tie directly to Appendix A, schedule 1, line 23, Total Revenue Requirements Variance, which represents the variance between the forecast total revenue requirements and the actual revenue requirement. Please explain fully how the Total Revenue Requirements variance equals the net load variance.

N. CHAPTER 7 – DEFERRAL AND OTHER REGULATORY ACCOUNTS – REGULATORY ACCOUNTS

280.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – REGULATORY ACCOUNTS
Exhibit B-1-1: p. 7-10, Appendix A, schedule 7; Exhibit B-9, BCUC IR 134.3, BCUC IR 134.6
Amortization of Capital Additions regulatory account

280.1 On the basis of the table provided in response to BCUC IR 134.3, please confirm, or explain otherwise, that the average variance added to the Amortization of Capital Additions regulatory account over the five year period between F2012 and F2016 was $2.74 million.

280.1.1 Please explain how this meets BC Hydro's criteria no. 4 ($10 million materiality threshold) as set out on page 7-10 of the Application.

280.2 Please explain why BC Hydro reports Additions and Amortization of certain regulatory accounts, including the Amortization of Capital Additions regulatory account, on a combined basis as a Recovery.

280.3 Appendix A, schedule 7, line 56, shows that all the variances between F2012 and F2016 relating to the Amortization of Capital Additions regulatory account relate to Business Support. Please explain how this supports the explanations provided in response to BCUC IR 134.6.

280.4 The explanations provided in response to BCUC IR 124.6 show that in F2015 and F2016 there was an offsetting variance in amortization expense for Existing Assets related to the same asset that generated the variance related to an Additions. Please confirm, or explain otherwise, that the variance relating to the Existing Asset is not captured in a regulatory account.

280.4.1 Please confirm, or explain otherwise, that the net impact of variance relating to the Existing Asset and the Addition in F2015 is -$1.3 million and in F2016 it is $2.4 million.

280.4.2 In a situation where the variance relates to the same capital asset/project, please explain why the variance related to the Addition is captured in a regulatory account while the variance related to the Existing Asset is not.

280.5 Overall, please explain why variances related to Capital Additions are captured in the regulatory account while variances related to Existing Assets are not. Please provide the supporting wording from the orders or decisions which distinguished the amortization between Additions and Existing Assets and their regulatory treatment.

281.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – REGULATORY ACCOUNTS
Exhibit B-9, BCUC IR 135.3
Finance Charges – IPP capital lease variances

In response to BCUC IR 135.3 BC Hydro stated that in the event that the Commission does not approve the continuation of the Finance Charge regulatory account, any variances between the finance charges related to EPA capital leases would not be eligible for deferral to the NHDA.

281.1 Please confirm, or explain otherwise, that if the Commission approves the continuation of the Finance Charges regulatory account any variance related to EPA Capital Lease would be captured in the Finance Charges regulatory account.

282.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – REGULATORY ACCOUNTS
Exhibit B-9, BCUC IR 138.5, IR 137.4
Asbestos Remediation and Environmental Provisions regulatory account

The response to BCUC IR 138.5 explained that the presentation of Appendix A does not reflect its proposal in regards to the treatment of Polychlorinated Biphenyl (Poly) but the net effect does not change the revenue requirements.

282.1 Which line item on schedule 1 and schedule 5 are the Poly costs set out in schedule 2.2, line 131 expensed in.?

282.1.1 Will BC Hydro make the changes as set out in BCUC IR 138.5 in its compliance filing following the Commission's decision in this proceeding?

282.2 Please confirm, or explain otherwise, that on the basis of the table provided in response to BCUC IR 137.4, the average variance related to Poly costs between F2012 and F2016 is less than $1 million.

282.2.1 Please explain how this meets BC Hydro's criteria no. 4 ($10 million materiality threshold) as set out on page 7-10 of the Application.

283.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – REGULATORY ACCOUNTS
Exhibit B-9, BCUC IR 139.3.1
Future Removal and Site Restoration (FRSR) regulatory account

283.1 Please confirm, or explain otherwise, on the basis of the table provided in response to BCUC IR 139.3.1 that the average variance related to dismantling cost between F2012 and F2016 is approximately $4.5 million.

283.1.1 Please explain how this meets BC Hydro's criteria no. 4 ($10 million materiality threshold) as set out on page 7-10 of the Application.

284.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – REGULATORY ACCOUNTS
Exhibit B-9: BCUC IR 147.1 and 147.2
Arrow Water System and Provision regulatory account

284.1 For regulatory accounts, such as the Arrow Water and the Asbestos Remediation, which have a corresponding provision account, is the expense reported as an operating expense for financial reporting purposes or as amortization when the actual costs are transferred from the provision account to the corresponding regulatory account?

284.2 Please confirm, or explain otherwise, that the response provided in BCUC IR 147.1 relates to Current O&M costs and not Gross O&M Costs on schedule 1, line2.

284.2.1 If yes, please confirm, or explain otherwise, that when actual expenditures are incurred and transferred from the provision account to the divesture account, these expenditures are not included in Gross O&M on schedule 1, line 2.

284.3 Please confirm, or explain otherwise, on the basis of the table provided in response to BCUC IR 147.2, that the average variance between F2012 and F2016 related to the Arrow Water System is approximately $0.2 million and the overall actual expense has not been greater than $0.3 million in the past five years.

284.3.1 If confirmed, please explain how this meets BC Hydro's criteria no. 4 ($10 million materiality threshold) as set out on page 7-10 of the Application.

285.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – REGULATORY ACCOUNTS
Exhibit B-9, BCUC IR 149
Foreign Exchange gains/Losses regularly account

285.1 Please explain why the forecast foreign exchange gains and losses are not included as forecast in calculating the revenue requirements and the regulatory account only is used to record the variance.

286.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – REGULATORY ACCOUNTS
Exhibit B-9 BCUC IR 151.1
Capital Project Investigation Costs

286.1 Please update the table provided in response to BCUC IR 151.1 to include the test period forecast.

287.0 Reference: DEFERRAL AND OTHER REGULATORY ACCOUNTS – REGULATORY ACCOUNTS
Exhibit B-1-1, table 7-2 and Appendix A; Exhibit B-9, BCUC IR 141 and 142; Exhibit B-9-1, BCUC IR 141 and 142
First Nations Costs and First Nations Provision

<u>Negotiating Costs</u>

287.1 Please explain why First Nations negotiating costs require a provision under IFRS as stated in response to BCUC IR 142.2.

287.2 During the test period, please confirm, or explain otherwise, that forecast First Nations Negotiations Costs are included in the Provision regulatory account and then transferred to the First Nations Costs regulatory account as they are forecast to occur.

287.3 In response to BCUC IR 141.1, BC Hydro stated "Negotiation costs for each year of the test period are shown on Appendix A, schedule 5.0, Line 52 and are thus included in the calculation of gross operating costs on Appendix A, Schedule 5.0, Line 65." Please confirm, or explain otherwise, that although these costs are included in schedule 5 they are only included in the calculation of Current O&M and not Gross O&M.

287.3.1 Please confirm, or explain otherwise, that lines 1 to 10 of schedule 5S sum to $1.185 million in F2017 and this represents the Gross O&M as set out on schedule 1, line 2 which is used to calculate the F2017 revenue requirement.

287.3.2 Please confirm, or explain otherwise, that the forecast First Nations Negotiating Costs must be included in lines 1 to 10 of schedule 5S if they are to be included in Gross O&M.

287.3.3 Please identify where on lines 1 through 10 on schedule 5S the First Nations Negotiating Costs are included.

287.4 Please confirm, or explain otherwise, that the variance related to First Nations Negotiating Costs (that has historically been captured in the HDA) is in respect to the amortization variance and not the variance related to the Negotiating Costs themselves.

287.4.1 Please clarify whether BC Hydro is proposing to be at risk for the variance related to the forecast amortization of Negotiating Costs or the variance related to the costs themselves.

287.5 Please confirm, or explain otherwise, that the First Nations Costs regulatory account's actual ending balance captures actual Transfers from Provision and not forecast Transfers from Provision.

287.5.1 If confirmed, why does BC Hydro consider it necessary to have specific Commission approval to record the actual amortization (Recovery) of the regulatory account?

287.6 If the Commission does not approve BC Hydro's request to be at risk for the variance related to First Nations Negotiating Costs, what will the updated HPO be in schedule 4 of Appendix A and Table 7-3 in the Application?

Settlements

287.7 Please confirm, or explain otherwise, that Lump Sum Settlements and Annual Settlement Payment are transferred directly from the First Nations Provision account to the First Nations Costs regulatory account and are recovered though the regulatory account amortization and not through Gross O&M.

287.8 For financial reporting purposes are the First Nations Negotiating Costs and the Settlements Cost included as an operating expense on the income statement or are they always reported as amortization of the regulatory accounts.

287.9 In response to BCUC IR 141.4.1, BC Hydro confirmed that it is seeking approval to recover Lump Sum Settlements with respect to two First Nations that are not provided for in the definition of First Nations Settlements as set out in Direction No. 7. Please identify where in the Application BC Hydro has included this request.

287.9.1 In response to BCUC IR 142.1, BC Hydro provided a breakdown for the First Nations Provision balances set out on line 15 of schedule 2.2 or each of the test year. Please confirm, or explain otherwise, that all the First Nations listed in the confidential response relate to either the two First Nations discuss in the IRs above or are included in the definition of First Nations Settlements in Direction No. 7. (Please specifically address the second to last First Nation identified in the table.)

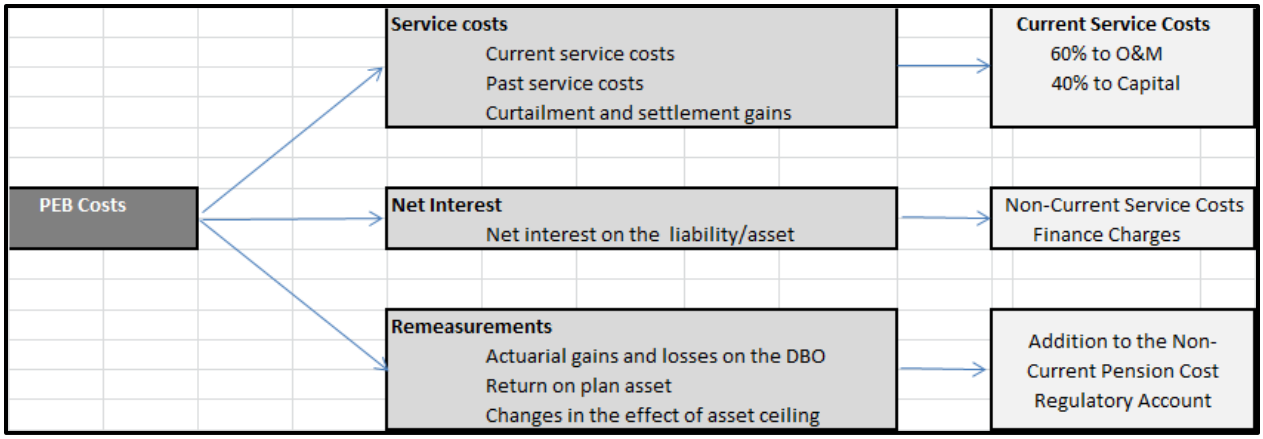
287.9.1.1 If not, please explain.

287.10 On page 7-57 of the Application, BC Hydro states that it is seeking approval, effective F2017, for actual annual settlement payments to be deferred to the First Nations Costs regulatory account each year, and forecast annual settlement payments will be amortized from this account each year. Please explain what the treatment was in F2015 and F2016 and previous years.

O. CHAPTERS 5 & 7–POST EMPLOYMENT BENEFIT COSTS

288.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-1-1-1, p. 7-28
General

288.1 Please confirm or explain otherwise that the following table is accurate.



288.2 Please confirm, or explain otherwise, that currently BC Hydro does not have any Past service costs or Curtailment and settlement costs.

288.3 Please confirm, or explain otherwise, that BC Hydro uses the terms Current Service Costs and Current Pension Costs interchangeably. If not, please provide a definition for each.

288.4 In the future, if BC Hydro does encounter Past service costs or Curtailment and settlement costs will they be considered a Current Pension Cost? If not, please explain.

288.4.1 If yes, is BC Hydro requesting that any future variances related to Past service costs or Curtailment and settlement costs also be captured in the Non-Current Pension Cost regulatory account? If not, please explain how these potential variances would be treated.

288.5 Does the Non-Current Pension Costs regulatory account currently capture variances between all three of the Remeasurement components set out in the table above? If not, please explain how these Other Comprehensive Income (OCI) items are treated for regulatory purposes.

289.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-9, BCUC IR 63 and 140
Data

289.1 Please confirm, or update as necessary, that the table below is accurate. Please fill in the areas shaded in grey.

Post Employment Benefit (PEB) Costs																				
		F2012			F2013			F2014			F2015			F2016			F2017	F2018	F2019
line		Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Forecast	Forecast
Current Service Costs																			
1	Discount rate: Proposed methodology																4.38	4.38	4.38
2	Discount rate: Under ISA 19													4.62	3.51	1.11			
3	Current Service Costs - Registered pension plan	62.5	58.1	4.4	64.8	67.6	-2.8	67.2	78	-10.8	62.5	74.6	-12.1	62.3	94.3	-32	70.7	71.8	73
4	Current Service Costs - PEB Other	12.2	12.1	0.1	12.4	14.2	-1.8	12.6	16.4	-3.8	14	15.2	-1.2	14.2	19.1	-4.9	16.3	16.5	16.7
5	Total (operating and capital)	74.7	70.2	**4.5**	77.2	81.8	**-4.6**	79.8	94.4	**-14.6**	76.5	89.8	**-13.3**	0 76.5	113.4	**-36.9**	87	88.3	89.7
6	60 percent operating costs portion (baseline in test period)			2.7			-2.8			-8.8			-8.0			-22.1	52.2	53.0	53.8
7	Impact due to updated actuarial valuation (operating)																1.8	1.8	1.8
Non-Current Pension Costs																			
8	Discount rate																		
9	Non-Current Pension (Asset Plan Income)	-175.4	-177.2	1.8	-183.3	-179.7	-3.6	-191.7	-125.6	-66.1	-194.8	-149	-45.8	-203.1			-216.1	-225.8	-235.8
10	Non-Current Pension (Liability/Interest Expense)	168	169.6	-1.6	175.1	165.8	9.3	182.5	163.7	18.8	175.2	180.6	-5.4	180			186.7	200.8	207.8
11	Non-Current Other (Liability/Interest Expense)	21.1	21.3	-0.2	21.9	20.6	1.3	23	20.9	2.1	22.5	23.4	-0.9	23.2			22.8	25.2	26.2
12	Total (Baseline in test period)	13.7	13.7	**0**	13.7	6.7	**7.0**	13.8	59	**-45.2**	2.9	55	-52.1	0.1	0	0	-6.6	0.2	-1.8
13	Impact of the updated actuarial valuation																-2.0	-2.0	-2.0
Remeasurements																			
14	Actuarial gains and losses on the DBO																	0	0
15	Return on Plan Asset																	0	0
16	Changes in the effect of asset ceiling																	0	0
17	Total	0	0	0	0	191.7	-191.7	0	-292.4	292.4	0	264.5	-264.5	0	68.5	-68.5	-335.7	0	0

289.2 Please confirm, or explain otherwise, that the F2017 Current Service Costs discount rate of 4.38 is the same rate used to determine the forecast Current Service Costs relating to the Registered Pension Plan and the Other PEB. If not, please include both interest rates in the updated table.

289.3 Please ensure the table is populated for the following items and provide an explanation for any significant variances:

(i) The actual and forecast discount rate for F2012 through F2016 for Current Service Costs;

(ii) The forecast discount rate for F2012 through F2019 and actual discount rate for F2012 through F2016 for Non-Current Pension Costs;

(iii) The F2016 actual Non-Current Pension Costs; and

(iv) The F2012 through F2016 forecast and actual remeasurements and the test period forecast.

290.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-1-1, p. 5-172; Exhibit B-9: BCUC IR 43.3, 63.7, 63.12
Benefits offered

290.1 Please provide a summary of the Registered pension plan offered by BC Hydro and who is entitled to participate in it.

290.2 Please confirm, or explain otherwise, that the following components are the only benefits included in BC Hydro's Other PEB plan: Post-Retirement Medical (MSP), Life Insurance, Extended Health and Extra Extended Health, Dental Benefits and the Supplemental Pension Plan.

290.3 Please expand the table provided in response to BCUC IR 63.7 to include the forecast and actuals Other PEB Current Service Costs for F2012 through F2016 and provide an explanation for any significant variances.

290.4 In detail, please explain what the unfunded Supplemental Pension Plan is and who is eligible to participate in it. Please explain what portion of the contribution to the Plan is made by BC Hydro and what portion is made by the employee.

290.4.1 What percentage of BC Hydro's current employees partakes in the plan?

290.4.2 Please explain why BC Hydro offers the Supplemental Pension Plan.

290.4.3 Please update the table in response to BCUC IR 63.12 to include a row for the number of retirees eligible for the supplemental pension.

290.5 Please explain what the Executive Health Program listed in response to BCUC IR 42.3 is and explain: who is eligible to participate in the program; what percentage of current employees participates in the program; and how many retirees are eligible for the program.

290.5.1 Please explain why BC Hydro offers the Executive Health Program.

290.5.2 Which line item in the table provided in response to BCUC IR 63.7 is the Executive Health Program costs included? Please update the table and break these costs out as a separate line item.

291.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-1-1, p. 5-171; Exhibit B-9, BCUC IR 63.15
Actuarial valuation as at December 31, 2016

291.1 Please file a copy of the actuarial valuation as at December 31, 2016.

291.2 Please file BC Hydro's most recent year-end (12 month period) financial statement pension note.

291.3 Did BC Hydro's third party actuary prepare the Current Service Costs and the Non-Current Pension Costs forecast for F2017, F2018 and F2019? If not, please explain who prepares and reviews the forecast.

291.4 In response to BCUC IR 63.15, BC Hydro provided the dollar impacts to the Current Service Costs and the Non-Current Pension Costs forecast for the test period due to the results of the latest actuarial valuation. If the Commission does not approve BC Hydro's request to defer variances to the Non-Current Pension Costs regulatory account relating to the Current Service costs, does BC Hydro plan to update its forecast for the impacts of the latest actuarial valuation in its compliance filing following the Commission's decision in this proceeding?

292.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-9, BCUC IR 63.8; Exhibit B-10, Zone II IR 1.1
Application to Defer Operating Cost Variances between Forecast and Actual F2016 PEB Current Pension Costs Arising from a Change in the Actuarial Discount Rate filed in August 2015, p. 3
Current Service Costs – capital portion

In the BC Hydro Application to Defer Operating Cost Variances between Forecast and Actual F2016 PEB Current Pension Costs Arising from a Change in the Actuarial Discount Rate filed in August 2015 (2015 Pension Application) BC Hydro states on page 3 that "The capital component of Current Pension Costs is allocated to capital projects and therefore is amortized over the life of the related asset, which means that this capital component variance is already being recovered over multiple years…"

292.1 In response to BCUC IR 63.8 BC Hydro stated that 40 percent of current service cost is capitalized and 60 percent is included in operating costs. Please confirm, or explain otherwise, that any variance related to the 40 percent capital portions is already captured through the Amortization of Capital Additions regulatory account. If not, please explain how the variance is being recovered over multiple years.

292.1.1 Please explain how BC Hydro forecasted that 40 percent of Current Pension Costs will be allocated to capital projects in each of the three test periods.

In response to Zone II IR 1.1 BC Hydro provided the breakdown between O&M and Capital as follows:

Statistic Category	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
FTEs - O&M (including overtime)	4,861	4,546	4,552	4,440	4,299	4,027	4,033	4,036
FTEs - Capital (including overtime)	1,527	1,662	1,752	1,872	1,934	2,269	2,311	2,329
FTEs - Total (including overtime)	6,388	6,208	6,303	6,312	6,234	6,296	6,344	6,365
Percentage of Capital FTEs	**24%**	**27%**	**28%**	**30%**	**31%**	**36%**	**36%**	**37%**

292.2 Capital FTE's as a percentage of total FTEs is forecast at 36 percent in both F2016 and F2017 and 27 percent in F2018. Please reconcile these percentages to BC Hydro's position that 40 percent of current service costs are capitalized.

293.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-9: BCUC IR 63 & 140; 2015 Pension Application, p. 5
Current Service Costs – variance

293.1 Please confirm the data in the table below is accurate, or updated as necessary, and fill in the cells highlighted in grey.

Post Employment Benefit (PEB) Current Service Costs Variances

	F2012	F2013	F2014	F2015	F2016
	Variance	Variance	Variance	Variance	Variance
in $ millions					
PART 1					
100% (Operating and Capital)					
Current Service Costs - Registered pension plan	4.4	-2.8	-10.8	-12.1	-32
Current Service Costs - PEB Other	0.1	-1.8	-3.8	-1.2	-4.9
Total Variance	4.5	-4.6	-14.6	-13.3	-36.9
60% Operating					
Current Service Costs - Registered pension plan	2.6	-1.7	-6.5	-7.3	-19.2
5 year average					**-6.4**
Current Service Costs - PEB Other	0.1	-1.1	-2.3	-0.7	-2.9
5 year average					**-1.4**
Registered pension plan and PEB Other	2.7	-2.8	-8.8	-8.0	-22.1
5 year average					**-7.8**
PART 2					
100% (Operating and Capital)					
Variance related to discount rate		-16.5	-31.8	-6.0	-28.7
Variance related to discount rate		11.9	17.2	-7.3	-8.2
Total Variance	4.5	-4.6	-14.6	-13.3	-36.9
60% Operating					
Variance related to discount rate					
Variance related to discount rate					
Total Variance	2.7	-2.8	-8.8	-8.0	0 -22.1
PART 3					
60% Operating					
Current Service Costs - Registered pension plan					
Variance related to the discount rate					
Variance related to rate of inflation					
Variance related to mortality assumptions					
Variance related changes in workforce					
Variance related to the delay in increasing the employee contribution rate	0	0	0		
Variance related to other factors					
Current Service Costs - PEB Other					
Variance related to the discount rate					
Variance related to rate of inflation					
Variance related to mortality assumptions					
Variance related changes in workforce					
Variance related to other factors					
Total Variance	2.7	-2.76	-8.76	-7.98	-22.14

293.2 Please confirm, or explain otherwise, that a variance between the forecast and actual Current Pension Costs can occur year to year based on economic and demographic actuarial assumptions such as the rate or inflation, mortality assumptions and changes in the workforce (Other Assumptions) in addition to the actuarial discount rate.

293.2.1 Please explain why BC Hydro considers each of the Other Assumptions to be outside of BC Hydro's control. Please provide a separate explanation for each assumption.

293.3 Please confirm, or explain otherwise, that the variance due to the delay in increasing the employee contribution rate (as shown in Part 3 of the table above) in F2015 and F2016 is a one-time issue isolated to those years.

293.4 In the 2015 Pension Application, BC Hydro only applied to defer the impact of the actuarial discount rate in F2016, which was less than the full variance. Please explain why BC Hydro requires deferral treatment for the variance related the discount rate as well as the Other Assumptions on a go forward basis.

In the 2015 Pension Application on page 5, BC Hydro states:

> The [$17.2 million] deferral is…an uncontrollable cost and surpasses the $10 million net income threshold described in the Regulatory Account report. Even though this application is not requesting the creation of a new regulatory account, BC Hydro considers the principles it has set out it the Regulatory Account report are applicable in this case where the deferral of a specific amount is being requested through the expansion of an existing regulatory account.

In response to BCUC IR 140.6 BC Hydro stated:

> **Criteria four relates to materiality. There is no clear way to define materiality for this purpose. In section 7.4 of the Application, BC Hydro notes that "…expenditures with a net income impact of greater than $10 million in a fiscal year would be considered material." However, this section relates to the establishment of new regulatory accounts. It also assumed the continuation of existing regulatory accounts – which capture the variances which entail the most risk, and the sum of which is very significant – if this were not the case, the $10 million figure proposed in respect of proposed new regulatory accounts would need to be revisited (and lowered).**

293.5 Please reconcile these two statements.

293.6 Given that the five year average total Current Service Cost variance related to the 60 percent operating portion is $7.8 million, which is below BC Hydro's materiality threshold as set out on page 7-16 of the Application, please explain why BC Hydro considers this to be a material variance requiring deferral treatment.

293.7 Given that the five year average Current Service Cost variance relating to the 60 percent operating portion for Other PEB is $1.4 million, which is below BC Hydro's materiality threshold, please explain why BC Hydro considers the Current Service Cost - Other PEB to be a material variance requiring deferral.

293.7.1 What would the implications be to BC Hydro if the Commission were to approve the deferral of the variance related to the Registered pension plan but not the variance related to Other PEB?

293.7.1.1 What would the impacts be to the revenue requirements in Appendix A, schedule 1, line 22 in each of the test period years?

294.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-1-1, p. 5-171, p. 7-30; Exhibit B-9, BCUC IR 63 and 140; 2015 Pension Application, p. 3; Exhibit B-1-1, p. 7-6, Table 7-2
Current Service Costs – Discount Rate
Change in Proposed Methodology

In the Application on page 7-30 BC Hydro requests to change on an ongoing basis, starting in F2017, the methodology used to forecast Current Service Costs. BC Hydro is proposing to use an average of actual past discount rates used in the calculation of actual current service costs in the preceding five fiscal years for forecasting purposes (Proposed Methodology). The Current Service Costs in previous RRAs was

determined using the current discount rate in effect at the time the forecast was prepared (IAS 19 Methodology).

294.1 Under the Proposed Methodology, will the discount rate used to determine the actual Current Service Costs be different than the actual discount rate used under IAS 19? If yes, please explain fully.

294.2 On page 5-171 of the Application BC Hydro states that it follows IAS 19 except that the return on the plan assets is determined based on the expected long term rate of return rather than the liability discount rate as specified under IAS 19. Please confirm, or explain otherwise, that other than the changes set out in the Proposed Methodology, BC Hydro follow IAS 19. If not, please explain fully.

294.2.1 If there are other differences please reference the order number approving the variance from IAS 19.

294.3 Please provide a comprehensive analysis explaining the pros and cons of applying the Proposed Methodology or maintaining the historic IAS 19 Methodology for both regulatory purposes and financial reporting purposes and explain why the Commission should consider approving this request.

294.3.1 BC Hydro confirmed in BCUC IR 140.11 that the Proposed Methodology will impact regulatory accounting and financial reporting. Please explain in detail each of the changes to financial reporting that will be required if the Proposed Methodology is approved.

294.4 Please populate the table below to show what the Current Service Costs for the Registered pension plan and Other PEB Costs would be in each of the test years without consideration of the Proposed Methodology.

Post Employment Benefit (PEB) Costs under IAS 19 discount Rate

	F2017	F2018	F2019
	Forecast	Forecast	Forecast
Current Service Costs			
Discount rate: Proposed methodology	4.38	4.38	4.38
Current Service Costs - Registered pension plan	70.7	71.8	73
Current Service Costs - PEB Other	16.3	16.5	16.7
Total (operating and capital)	87	88.3	89.7
60 percent operating costs portion	52.2	53.0	53.8
Discount rate: Under ISA 19			
Current Service Costs - Registered pension plan			
Current Service Costs - PEB Other			
Total (operating and capital)			
60 percent operating costs portion	62.3	63.2	64.2

294.5 Please explain in detail the reason for the forecast decrease in the Current Service Costs in the test period under the IAS 19 Methodology as compared to the F2016 actual of $113 million and the increase as compared to the F2012 through F2015 actuals.

294.6 Please explain how the discount rate would be determined under IAS 19 for each of the test period years and explain the reason for any difference between that rate and the 4.38 percent rate proposed.

294.7 In order to determine what the actual variance would have been had BC Hydro used the Proposed Methodology in the years F2012 through F2016, please populate the table below and fill in the grey cells.

Post Employment Benefit (PEB) Costs - Historic variance under Proposed Methodology															
	F2012			F2013			F2014			F2015			F2016		
	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance	Forecast	Actual	Variance
Current Service Costs															
Discount rate: Under ISA 19													4.62	3.51	1.11
Current Service Costs - Registered pension plan	62.5	58.1	4.4	64.8	67.6	-2.8	67.2	78	-10.8	62.5	74.6	-12.1	62.3	94.3	-32
Current Service Costs - PEB Other	12.2	12.1	0.1	12.4	14.2	-1.8	12.6	16.4	-3.8	14	15.2	-1.2	14.2	19.1	-4.9
Total (operating and capital)	74.7	70.2	**4.5**	77.2	81.8	**-4.6**	79.8	94.4	**-14.6**	76.5	89.8	**-13.3** 0	76.5	113.4	**-36.9**
Discount rate under proposed methodology														3.51	
Current Service Costs - Registered pension plan		58.1			67.6			78			74.6			94.3	
Current Service Costs - PEB Other		12.1			14.2			16.4			15.2			19.1	
Total (operating and capital)		70.2			81.8			94.4			89.8			113.4	

294.8 If the historic variances are not significantly smaller under the Proposed Methodology does BC Hydro still consider the five year average to be a better methodology that the IAS 19 Methodology? If yes, please explain.

In the 2015 Pension Application, on page 3, BC Hydro states that "the actuarial discount used to value Current Pension Costs is calculated by BC Hydro's third party actuary and is based on the construction of a hypothetical basket of AA Canadian corporate debt that has the same cash flow as the BC Hydro pension plan in terms of both timing and amount."

294.9 Please confirm, or explain otherwise, that this methodology is in accordance with IAS 19.

294.9.1 Please fully explain why BC Hydro considers the five year average discount rate as set out in the Proposed Methodology to be a better forecast than the discount rate required under IAS 19.

294.10 Please explain why the five year average is considered to be meaningful and why BC Hydro considers a five year average to be a good indication of a future discount rate.

294.10.1 Please explain why BC Hydro considers a five year average to be a better indication than actual future market expectations.

294.10.2 Is BC Hydro aware of any other circumstances where a five year average is used to forecast a future discount rate?

294.11 If the Commission approves BC Hydro's request to capture the variance between forecast and actual Current Service Costs in a regulatory account please explain in detail if there are reasons other than reducing volatility and improving intergenerational equity, as to why the Proposed Methodology is necessary for rate setting purposes.

294.12 Please confirm, or explain otherwise, that any volatility issues can be addressed through an appropriate regulatory account amortization period.

294.13 What would the implications be to BC Hydro if the Commission was to approve the Current Service Costs variance request but not the Proposed Methodology?

As set out in response to BCUC IR 140.12, BC Hydro explained, that if the Commission does not approve the Current Service Costs variance request then BC Hydro would reconsider its request to change the Proposed Methodology as the two are designed to work together.

294.14 Can BC Hydro be more specific? If the Commission does not approve the Current Service Costs variance request is BC Hydro withdrawing its request for the Proposed Methodology.

294.15 If the Commission does not approve the request for the Proposed Methodology will this change BC Hydro's request relating to the Current Service Costs variance? If yes, please explain in detail what those changes would be.

294.16 If the Commission does not approve the request for the Proposed Methodology how will this impact the 2024 forecast with respect to the Non-Current Pension Costs regulatory account on line 15 of Table 7-2 in the Application?

295.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-1-1, Appendix A, Schedule 2.2; Exhibit B-9, BCUC IR 140
Remeasurement & Other Non-Current Pension Cost regulatory account additions

295.1 In response to BC Hydro IR 140.13 BC Hydro confirmed that 100 percent of the forecast $335.7 million additions relating to OCI Deferrals in F2017 relates to the Proposed Methodology change. Please explain in more detail how the $335.7 million was calculated and what specifically it represents. Please identify the other side of the journal entry.

295.2 If the Proposed Methodology is not approved by the Commission but the Current Service Costs variance treatment is approved what will the updated forecast amortization be in schedule 2.2, line 117 in each of the test years? Please ensure that the operating expense and the amortization expense, including the OCI Deferral, are adjusted. For each of the test years please show the detailed calculation and explain each adjustment.

295.2.1 Please provide the same information if the Proposed Methodology is approved but the variance treatment is not.

295.2.2 Please provide the same information if both the Proposed Methodology and the variance treatment is not approved.

295.3 In response to BCUC IR 140.15 BC Hydro stated that the F2017 forecast actuarial gain of $335.7 million will not be used for financial reporting purposes. BC Hydro further explains that financial reporting will be based on the actual gain or loss. Please confirm, or explain otherwise, that the forecast $335.7 million already proposed to be included in the regulatory account will be updated once the actuals are known. If not, please explain.

295.3.1 How are the actuals determined and when would BC Hydro expect to know them?

296.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-1-1: p. 5-15, Appendix A, schedule 2.2; Exhibit B-9, BCUC IR 140
Current Service Costs – Amortization

296.1 In response to BCUC IR 140.8, BC Hydro explains that an amortization period for the variance relating to the Current Service Costs should be amortized over the same time period as the variance related to the Non-Current Pension Costs. Given the characteristic of the Current Service Costs expense are very different than those of the Non-Current portion please explain why it would be appropriate to amortized them over the same time period. Please include a discussion of intergenerational equity in your response.

296.2 Please explain why BC Hydro proposes a different amortization period for the Other Cash Variance Account and the Non-Cash Variance Accounts on page 7-15 of the Application.

296.3 To minimize intergenerational equity please explain why amortizing the Current Service Cost variance in the subsequent test period, similar to the treatment proposed for Other Cash Variance Accounts, would not be more appropriate.

296.3.1 If the reason is because there is potential for the variance to be large and therefore cause volatility please explain why a two or three year amortization period would not be appropriate to smooth out the volatility.

296.3.2 What would the amortization of the Non-Current Pension regulatory account be (schedule 2.2, line 117) in each of the test period be if the F2016 variance of $17.2 million was (i) fully amortized in F2017, and (ii) amortized over F2017, F2018 and F2019.

296.4 If the Commission were to direct a shorter amortization period for the Current Service Costs variance, please explain the pros and cons of establishing a separate Current Service Costs regulatory account.

297.0 Reference: POST EMPLOYMENT BENEFIT COSTS
Exhibit B-1-1: Appendix A, schedule 2.2, and p. 7-31, Table 5-31, Table 7-3, Table 5-38; Exhibit B-9, BCUC IR 140; 2015 Pension Application, BC Hydro Letter dated September 16, 2015, BCUC IR 1.1
Non-Current Pension Expense Regulatory Account

297.1 Please confirm that the Non-Current Pension Costs variance captured in the Non-Current Pension Cost regulatory account represent 100 percent of the variance and has not adjusted for an operating or capital portion.

297.2 Given the updated information provided in response to BCUC IR 60.5, are there any Non-Pension costs included in Chapter 5, Table 5-31? If yes, please quantify and identify the line item.

In response to BCUC IR 1.1 in the 2015 Pension Application BC Hydro stated that "any [Re]measurement changes go the Non-Current Pension Cost regulatory account instead of Other Comprehensive Income."

297.3 Please clarify if this means that the Remeasurements are included in OCI for financial reporting purposes and are then moved to the Non-Current Pensions Cost regulatory account in the following year. If not, please explain.

297.4 Please explain the reason for the addition to the Non-Current Pension regulatory account under OCI Deferrals in F2013 through F2016 as set out in Appendix A, schedule 2.2, line 115.

297.4.1 Please identify which line items in the excel document attached to BCUC IR 140.19 relate to the amortization of these pre F2017 OCI Deferrals.

297.4.2 Please reference the bullet item on page 7-31 of the Application that describes the amortization of pre-F2017 OCI Deferrals.

297.5 Please explain what the F2013 $321.9 million adjustment in schedule 2.2, line 114 relate to.

297.6 Please explain why there are no forecast additions in the test period for Recovery –Finance Charges as set out in schedule 2.2, line 118, when the average balance has been over $50 million in F2014 to F2016. Please explain what Recovery –Finance Charges relates to.

297.7 Schedule 2.2, line 116, shows a forecast addition of $10 million in F2017. In response to BCUC IR 140.17 BC Hydro states the following:

> The $10.1 million addition to the Pension Costs Regulatory Account in fiscal 2017 shown in Appendix A, Schedule 2.2, line 116 represents the operating cost variance between the current service costs forecast in the Application and the expected actual current service costs. The expected actual current service costs are determined at the beginning of the fiscal year based on discount rates as at March 31, 2016 as provided by BC Hydro's actuary.
>
> This unusual situation occurred as a result of the timing of the Application. More specifically, ordinarily in a revenue requirements application, the discount rate at the end of the fiscal year before the test period is not available. In the case of the Application, this became available and hence we were able to include this forecast addition.

297.8 Please provide the portion that is being added to capital.

297.9 BC Hydro used a discount rate of 4.38 percent to prepare the forecast in the test period. What is the discount rate as at March 31, 2016 provided by BC Hydro's actuary?

297.10 Please explain why BC Hydro did not update the forecast in Tables 7-3 and 5-38 to reflect the updated information that was available at the time the Application was prepared.

297.10.1 Please explain why BC Hydro did not update the forecast to calculate the revenue requirements in schedule 1, line 22.

297.11 Does the $10 million forecast addition have any relationship to the Proposed Methodology? If yes, please explain.

297.11.1 What would the addition in F2017 have been had the F2016 Current Service Cost forecast been based on the IAS 19 Methodology discount rate?

297.12 Does BC Hydro now know the actual Current Pension Costs for F2017 (other than any changes due to the workforce)? If yes, please disclose it.

297.13 What is the proposed amortization period for the $10 million addition?

297.13.1 If it is EARSL, please provide the impact to Appendix A, schedule 1, line 22 in F2018 and F2019 if the $10 million was amortized fully in F2018.

297.13.2 What is the impact to Appendix A, schedule 1, line 22 in F2017, F2018 and F2019 if the $10 million was included as an operating expense in F2017 and not as an addition to the Non-Current Pension regulatory account?

P. CHAPTER 8 – OTHER REVENUE REQUIREMENTS ITEMS

298.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-9, BCUC IR 152
Amortization

298.1 Depreciation Study: What are the criteria that would trigger it necessary for BC Hydro to perform a depreciation study? Is one of the criteria the number of years since the last study? If not, please explain.

298.2 Amortization of Existing Assets: Please explain why line 1 of the table provided in response to BCUC IR 152.5.1 for years F2013 and F2014 does not agree to Appendix A, schedule 12, line 8.

298.3 Retired Assets: If an asset, other than real property, is retired earlier than expected and the asset is not fully depreciated, please clarify whether the undepreciated balance is recovered from the ratepayers.

298.4 Dismantling Costs: Please confirm, or explain otherwise, that the response to BCUC IR 152.13.1

is yes and the variance is recorded in the Future Site Restoration regulatory account. If not, please explain.

298.5 Burrard Thermal: Please explain the reason for the depreciation rate changes relating to Burrard Thermal as highlighted in the tables attached as Appendix A to the IRs.

299.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-9, BCUC IR 153.1
Return on Equity

299.1 Please update the table provided in response to BCUC IR 153.1 to include an additional row for a 20 percent Annual Rate of Return on Equity.

300.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-1-1, Appendix A, schedules 1 & 8; Exhibit B-9, BCUC IR 154; Exhibit B-1-1-1, cover letter
Finance charges

300.1 Accretion Costs: In response to BCUC IR 154.1 BC Hydro confirmed that Gross Finance Charges as reported on Appendix A, schedule 1, line 15 includes the accretion costs from lines 7, 8 and 9 of schedule 8. This response supports the model provided in Appendix A. However, in response to BCUC IR 154.2, BC Hydro states that those accretion costs are not included in schedule 1 line 5 but rather are included in line 15. A further explanation is provided in response to BCUC IR 145.2.1; however, because the treatment is not straight forward it remains unclear. Please explain more fully and provide a numerical calculation and references to schedule 2.2 if possible to demonstrate that the accretion costs are not included schedule 1 twice.

300.2 Long-Term Debt Costs: Please expand the table in response to BCUC IR 154.4 to include forecast and actuals for F2012 to F2016 and provide an explanation for any variances.

300.3 WACD: In response to BCUC IR 160.2 BC Hydro stated that a $43 million increase in the revenue requirements would result in a 1 percent increase in the rates (without consideration of the rate cap). Please confirm, or explain otherwise, that a 1 percent increase or decrease in the WACD in 2017 would increase/decrease rates by approximately 4 percent in 2017 and approximately 1 percent in each of the following two years.

300.3.1 Gross Finance Cost: For the test period please provide an updated schedule 8 to reflect the updated forecast interest rates provided in response to BCUC IR 49.1.

300.4 Short term debt rate: What would the Gross Finance Charges be in each of F2017 through F2019 if the short-term debt rate decreased or increased by .5 percent or 1 percent and what would the resulting rate impact be (without consideration of the rate cap).

300.4.1 As set out in Appendix A, schedule 8, line 14, please explain why the actual short term debt has been less than forecast in the years F2012 to F2016 by an average of $36 million. Please pay special attention to the explanation relating to the $78 million variance in 2016.

300.5 Interest Capitalized: Please explain how BC Hydro determined the Interest Capitalized in schedule 8, line 15 in each of the test years. Is the methodology consistent with previous years? If not, please explain.

300.5.1 Is the variance between forecast and actual captured in the Finance Charges regulatory account? If not, please explain.

300.5.2 Please explain why actual capitalized interested was approximately $20 million greater than forecast in each of 2015 and 2016.

300.5.3 Please confirm, or explain otherwise, that without regulatory account protection if the actual capitalized amount is greater than forecast BC Hydro would recover the costs twice – once as part of Gross Finance Charges and again as a capital asset depreciation expense.

Supplemental Appendix I-A shows that the current constructions start dates for Projects A and B is TBD and both projects are capital expenditures and additions in F2017. The cover letter for Exhibit B-1-1-1 explains "These two [projects] address the potential acquisition of land and development of new facilities."

300.5.4 Please calculate the portion of the interest capitalized to Projects A and B and identify the portion related to capital additions and the portion related to capital expenditures.

301.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-9, BCUC IR 155
Taxes

The first table provided in response to BCUC IR 155.3 showed that one of the components of the Grants-in-Lieu of tax is based on 1 percent of revenues.

301.1 Please expand the table to show forecast and actuals for F2012 to F2016.

301.2 Are the revenues used in the calculation based on the revenue reported in the financial statements (adjusted for the calendar-year basis)? If not, please explain.

301.3 For the past five years please provide a table showing the revenues approved as part of the revenue requirements and the revenues reported on the financial statements. Please provide an explanation for any variances.

301.4 The second table provided in response to BCUC IR 155.3 shows the details of one of the components of the Grants-in-Lieu. Please explain why the 2018 Domestic Revenues are forecast to be significantly higher on a percentage basis than 2017. Please explain how this forecast is consistent with the percentage increase in revenues shown in Appendix A, schedule 1.

301.4.1 Please explain why the Domestic Revenues forecast increase is not consistent with the percentage rate increase.

302.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-9, BCUC IR 156
Non-tariff revenues

302.1 Contributions in Aid of Construction (CICA): In response to BCUC IR 156.2 BC Hydro summarized the Amortization for CIAC as $50.6 million, $54.7 million and $57.1 million in F2017, F2018 and F2019 respectively. Please reconcile this to Appendix A, schedule 11, line 55 + 58.

302.2 Secondary Revenues: Please explain what Secondary Revenues are as set out in Appendix A, schedule 15, line 8 and 13 and confirm, or explain otherwise, that there is no deferral account to capture the variance between forecast and actual.

302.2.1 Please explain how BC Hydro derived the test years' forecasts for Secondary Revenue and provide any relevant support for the calculation.

302.2.2 As set out in the table provided in response to BCUC IR 156.2, please explain why, over the past five years, actual Secondary Revenues are consistently greater than forecast. Please also explain why BC Hydro considers the forecast for the test period to be more accurate than in the past.

302.3 Other: Over the past five years, on average the actual Other balance in Appendix A, schedule 15, line 4 has been $3.9 million. Please explain what this balance relates to and explain why the forecast in each year of the test period has dropped to approximately $1.7 million.

303.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-9, BCUC IR 157
Inter-segment revenues

In response to BCUC IR 157.2 BC Hydro provided the following table:

$ million	F2012 RRA	F2012 Actual	F2013 RRA	F2013 Actual	F2014 RRA	F2014 Actual	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 RRA	F2018 RRA	F2019 RRA
Powerex - Corporate Allocation	(2.7)	(2.7)	(2.8)	(2.8)	(2.6)	(2.6)	(3.0)	(3.0)	(3.0)	(3.0)	(2.8)	(2.8)	(2.9)
Mark to Market Losses (Gains)	-	12.9	-	(3.9)	-	15.2	-	(4.8)	-	(0.5)	-	-	-
Other	0.7	-	0.7	-	0.7	-	-	-	-	-	-	-	-
Powerex PTP Charges	(25.5)	(27.5)	(26.2)	(21.3)	(27.0)	(23.8)	(23.4)	(30.4)	(29.2)	(6.1)	(11.8)	(10.1)	(16.6)
BC Hydro PTP Charges	(11.1)	(12.8)	(11.1)	(35.1)	(11.1)	(15.9)	(26.2)	(12.4)	(21.3)	(46.1)	(47.8)	(51.4)	(45.9)
Total Current Inter-Segment Revenues (Schedule 3.0, line 51)	(38.6)	(30.1)	(39.5)	(63.1)	(40.0)	(27.1)	(52.6)	(50.6)	(53.5)	(55.7)	(62.5)	(64.3)	(65.3)

303.1 Are the variances between the forecast ($0) and actual Mark to Market Losses (Gains) recorded in a deferral account? If yes, which one?

In response to BCUC IR 157.3 BC Hydro explained that the Powerex Corporate Allocation is based on the F2009–F2010 decision which directed the amount to be $4.3 million per year based on a two year average. BC Hydro also explains that the actuals are always based on the forecast which is calculated on the basis of the five year average.

303.2 Please explain when and why BC Hydro changed to a five year average.

303.3 Please explain why the F2017 allocation dropped to $2.8 million which does not appear to be either the two year or the five year average.

303.4 If the allocation was to increase would it be reasonable to conclude that the forecast Powerex net income on schedule 1, line 17, would decrease by an equal amount?

304.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-1-1, p. 8-12, Table 8-11
Subsidiary net income

304.1 Does the variance between forecast and actual Powertech net income go into the TIDA or any other deferral account?

305.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-10, CEC IR 1.4
Schedule 1

305.1 In response to CEC IR 1.4, BC Hydro explained that the transfers to the Rate Smoothing regulatory account are shown in Appendix A, schedule 1 as a negative recovery for presentation purposes. Please explain why BC Hydro chose not to show the additions as a regulatory account addition. Please explain why showing the additions as a negative recovery is a preferable presentation.

306.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-1-1, Appendix A: schedule 5S, line 9, schedule 5, lines 79-84
Provisions

306.1 In response to BC Hydro IR 159.2 BC Hydro explained that the majority of the Provisions, lines 79-87 related to Capital Asset Gains/Losses. Please expand the table provided in response to BCUC IR 159.2 to include forecast and actuals for F2012 through F2016.

306.2 Please explain why all the forecast are capital losses with no forecast capital gains.

306.3 Please provide the methodology that BC Hydro uses to estimate what the gains and losses on capital assets will be in the test period. Historically, how accurate has BC Hydro been able to forecast future gains and losses on capital assets?

307.0 Reference: OTHER REVENUE REQUIREMENTS ITEMS
Exhibit B-9, BCUC IR 144.1 and 152
Provisions

FRSR

307.1 Please confirm, or explain otherwise, that the average Future Removal and Site Restoration (FRSR) cost in the five years between F2012 and F2016 was $23.1 million.

307.2 It appears that on average over the past five years BC Hydro has over forecast costs related to FRSR by approximately $4.5 million. Please explain why BC Hydro is confident that its forecast for the test period will be more accurate than it has in the past.

307.3 Please explain the reason for the approximately 30 percent forecast increase to FRSR costs in F2017 as set out in Table 7-3 and Appendix A, schedule 5.

307.4 Please explain why the FRSR costs are forecast to increase by 15 percent in F2018 and then drop by 15 percent in F2019 as set out in Table 7-3 and Appendix A, schedule 5.

Real Property Sales

307.5 Appendix A, schedule 5.0, line 101 shows Gross Provisions of $66 million in F2017. In accordance with schedule 5S, line 9, the $66 million is included in Gross O&M costs on schedule 1, line 2 in calculating the revenue requirements. Please confirm, or explain otherwise that the Net Gains on Property shown in line B of the table included in response to BCUC IR 144.1 are a credit in calculating Gross O&M on schedule 1, line 2.

307.5.1 If yes, please explain why it is necessary to include line C, from the table included in response to BCUC IR 144.1, to the Real Property Sales regulatory account as an addition.

Q. CHAPTER 9– TRANSMISSION REVENUE REQUIREMENTS

308.0 Reference: TRANSMISSION REVENUE REQUIREMENTS
Exhibit B-9, BCUC IR 165.3, BCUC IR 166.1
OATT

The following table was provided in response to BCUC IR 166.1:

	Reference	Fiscal 2017 Plan
Non-Tariff Revenue ($ million)	Schedule 15.0, line 6. Included in Schedule 1, line 7.	14.1
Powerex Point-To-Point Charges ($ million)	Schedule 3.4, line 21. Included in Schedule 1, line 8.	11.8
BC Hydro Point-To-Point Charges ($ million)	Schedule 3.4, line 22. Included in Schedule 1, line 8.	47.8
Total		73.8

308.1 For each of the three line items please confirm, or explain otherwise, that the variance between the forecast and the actual charges are deferred to the NHDA. If not, please break out the balance representing the baseline for deferral and provide the same information for F2018 and F2019.

In response to BCUC IR 1.165.3, BC Hydro confirmed that the variance between the forecast and actual Powerex and BC Hydro Skagit Valley Treaty PTP charges are deferred to the NHDA. BC Hydro also stated that some of the PTP charges relate to surplus sales.

308.2 Please confirm, or explain otherwise, that the variance between the forecast and actual surplus sales PTP charges are deferred to the NHDA.

309.0 Reference: TRANSMISSION REVENUE REQUIREMENTS
Exhibit B-9, BCUC IR 157.8
Inter-Segment Revenues – OATT

In response to BCUC IR 157.8 BC Hydro stated that the OATT rate increase is forecast to be 9.3 percent in F2017, negative 1.1 percent in F2018 and 2.6 percent in 2019.

309.1 Please explain the main drives for the 9.3 percent OATT rate increase in F2017 as compared to F2018 and F2019.

R. CHAPTER 10 – DEMAND SIDE MANAGEMENT EXPENDITURES

310.0 Reference: DEMAND SIDE MANAGEMENT (DSM) EXPENDITURES
Exhibit B-9, BCUC IR 170.2; Exhibit B-1-2, pp. 1, 2
$36 per MWh screening filter

BC Hydro stated in BCUC IR 170.2 that the $36/MWh screening filter is the average electricity market sell price at the BC Border from F2017 to F2033 based on BC Hydro's current long-term electricity market price forecast. BC Hydro describes its avoided cost assumptions in Appendix X to the Application.

310.1 Please provide analysis and assumptions to support the $36/MWh screening filter estimate. For example, generator type assumed, gas price forecast, exchange rate forecast, wheeling/losses adjustment, etc.

310.2 Please calculate BC Hydro's levelized reference price, using the market price for F2016 to F2021, $87/MWh (F2016) for F2022 to F2033 and $102/MWh (F2016) for F2034 onwards.

310.2.1 Please explain why BC Hydro used the $36/MWh market price as the screening filter, rather than the levelized reference price calculated above.

311.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 171.3, 168.3, 169.3, 169.5
Consistency with the 2013 Integrated Resource Plan (IRP) – rationale for change

BC Hydro stated in BCUC IR 171.3: "The reduction in the demand-side management portfolio was influenced by the Utility Cost test at market price and rate impact considerations."

BC Hydro stated in BCUC IR 169.3: "… in the Application, programs are forecast to have a net levelized Utility Cost of $22/MWh. This value compares favourably to BC Hydro's long-run marginal cost of $100/MWh or the B.C. border sell price forecast of $36/MWh, which indicates that they will reduce BC Hydro's overall revenue requirements. BC Hydro does not consider that the emphasis has changed regarding affordable rates rather than affordable bills in this Application compared to the 2013 IRP."

BC Hydro stated in BCUC IR 169.5: "We estimate that the 2013 IRP [DSM] Plan Alternative would result in an incremental annual rate increase of approximately 0.5 per cent relative to the proposed [DSM] Plan over the fiscal 2020 to fiscal 2024 period, all else equal. We estimate that about 50 per cent of the rate increase would be due to an increase in [DSM] savings (i.e., decrease in load with a corresponding increase in export or decrease in other supply-side resources) while the remaining 50 per cent would be as result of an increase in [DSM] expenditures."

311.1 Please explain whether rate impact considerations result in preference (all else equal) for:

- DSM programs that do not reduce revenue (e.g. capacity focused DSM) over DSM programs that do reduce revenue (e.g. residential DSM programs); and
- DSM programs targeted at customers with lower c/kWh lost revenue (e.g., industrial customers) over those targeted at customers with higher c/kWh lost revenue (e.g. residential customers).

311.2 Given the DSM portfolio levelized utility cost of $22/MWh, please explain (i) why BC Hydro submits that the emphasis on affordable rates rather than affordable bills has not changed in this Application compared to the 2013 IRP, and (ii) what weight BC Hydro placed on the program rate impact measure (RIM) result when determining which DSM programs to reduce/eliminate.

311.3 In a format consistent with the first table provided in response to BCUC IR 168.3 (excluding codes and standards, rate structures and supporting initiatives), please provide in one table the following F2017 to F2019 data:

- DSM planned spend (total $ and as a percentage of the 2013 IRP planned class spend)
- DSM energy savings (total GWh and as a percentage of the 2013 IRP planned class energy savings)
- Class total resource cost (TRC), utility cost (in $/MWh), RIM result

Please include totals/portfolio averages where appropriate.

311.3.1 In a separate table, for the same DSM categories please provide the following F2017–F2019 data: Incentives as a % of class DSM spend; DSM spend as a percentage of class revenues.

312.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-10, BCSEA IR 2.1 Attachment 1, p. 5; BCSEA IR 27.2
Reduce spending strategy

BC Hydro states in response to BCSEA IR 27.2 that "We are not suggesting that comparing the Utility Cost to the market price is a new cost-effectiveness test for demand-side management. Rather, it was a filter used internally to help prioritize reduced spending."

On page 5 of 11 of BCSEA IR 2.1 Attachment 1, BC Hydro lists in Table 1 the programs eliminated and the Customer/Industry Impact of eliminating the listed programs.

312.1 Please elaborate on BC Hydro's internal reduced spending strategy, including its considering of the utility cost test (UCT) compared to the market price, RIM, any other indicators, and their respective ranking.

312.2 Please explain how comparing the utility cost to the market price rather than the long run marginal cost (LRMC) would impact the ranking of a program measure's cost effectiveness performance relative to other programs in the portfolio.

312.3 Please explain whether BC Hydro has done any consultation in analyzing the customer/industry impact from eliminating the numbers listed in Table 1 of BCSEA 2.1 Attachment 1

313.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 175.1, 169.2; Exhibit B-10, BCSEA IR 7.1
Consistency with the 2013 IRP – longer term effect of funding reduction

BC Hydro provides in BCUC IR 175.1 an estimate of the long-term net benefits from F2017–F2019 DSM programs: $1,141 million (TRC), $1,477 million (utility cost test (UCT) – LRMC)) and $286 million (UCT – market price).

BC Hydro defines a missed opportunity as a time-limited opportunity to cost-effectively improve energy efficiency that is lost for a period of time if not acted upon when available. BC Hydro estimated that, compared to the 2013 IRP, the proposed DSM plan results in 10 to 30 GWh per year of missed opportunities (BCSEA IR 7.1).

BC Hydro's F2017–F2019 DSM planning framework no longer includes 'market transformation' (as stated in BCUC IR 169.2).

313.1 Does BC Hydro consider that, based on the response provided to BCUC IR 175.1, the proposed F2017–F2019 DSM program portfolio results in a (i) $1,141 million net benefit to BC, (ii) a $1,477 million net benefit to BC Hydro ratepayers (assuming the energy saved by DSM is valued at BC Hydro's long run marginal cost), and (iii) a $286 million net benefit to BC Hydro ratepayers (assuming the energy saved from DSM is surplus to requirements and so is resold on the BC border)? Please explain.

313.1.1 Please estimate the additional net benefit in the three categories above if BC Hydro's F2017–F2019 DSM funding level was not reduced from 2013 IRP level.

313.1.2 Please estimate the potential dollar cost to (i) BC and (ii) BC Hydro ratepayers from the 10 to 30 GWh/year of missed opportunity estimated by BC Hydro in BCSEA IR 7.1.

313.2 Please explain why BCH's DSM planning framework no longer includes market transformation.; how this has affected the proposed F2017-F2019 DSM portfolio; and whether this could be a barrier to facilitate the introduction of new codes and standards.

314.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-10, BCSEA IR 43.2; Exhibit B-9, BCUC IR 175.4, 175.4.2, 175.5
Effectiveness review - general

BC Hydro states in BCSEA IR 43.2 that the updated Conservation Potential Review (CPR) will inform the 2018 IRP. BC Hydro provides a comparison of its DSM portfolio results to the Lawrence Berkeley 2014 report in BCUC IR 175.4 and 175.4.2.

BC Hydro shows in BCUC IR 175.5 that F2018 incentives increase to 82 percent of total DSM portfolio costs.

314.1 Please describe the flexibility BC Hydro has to (i) shift funding between program areas, (ii) shift funding between years and (iii) start new DSM programs within the F2017–F2019 period without Commission approval.

314.2 Please estimate the period of time that will elapse between the completion of the updated CPR and BC Hydro's update of its DSM programs to reflect the new CPR results. If the update will occur prior to F2019, please explain when and describe the process BC Hydro plans to follow to obtain acceptance of any new DSM programs. If the update will occur after F2019, please explain why and whether this delay could reduce the potential effectiveness of BC Hydro's DSM programs.

314.3 Please explain why forecast incentives increase to 82 percent of total DSM costs in F2018.

314.4 Please update the response to BCUC IR 175.4.2 by excluding the costs and energy savings of BC Hydro rates and codes & standards programs from the BC Hydro portfolio total, and estimate BC Hydro's gross savings where the Lawrence Berkeley 2014 figures reflect gross savings.

314.5 Where the Lawrence Berkeley 2014 figures in BCUC IR 175.4 reflect gross energy savings, please update BC Hydro's response to this IR to provide BC Hydro's gross energy savings.

315.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 172.1, 175.2.2, 178.1.1; FortisBC Energy Inc. (FEI) 2014–2018 Performance Based Ratemaking (PBR) Decision, Order G-138-14, p. 269
Effectiveness review – specific programs

In BCUC IR 172.1 BC Hydro showed the F2013–F2016 gross levelized utility cost of its load displacement program as $30/MWh. BC Hydro stated in BCUC 175.2.2 that the Energy Conservation Assistance Program (ECAP) does not pass the mTRC.

BC Hydro stated in BCUC IR 178.1.1: "An analysis of recent data … indicates that customers have started to respond to the RIB rate by taking longer lasting measures related to home improvements."

In the FEI 2014–2018 PBR Decision (page 269) the Commission stated: "FEU also request $2.4 million in funding for new low-income programs: low income space and water heating top-up and a non-profit custom program. The top-up programs are based on the commercial programs, and provide an incentive that is about 30% higher than the regular program where buildings have a significant proportion of low-income residents."

315.1 Please explain why the ECAP program does not pass the mTRC, even though incentives are not included as a cost in the mTRC calculation. Specifically, does this indicate that this program does not provide a net benefit to BC or is not focused on energy savings?

315.1.1 Has BC Hydro considered low-income DSM programs that provide top-up DSM incentives to existing DSM programs where the energy consumers (home-owners or renters) are low-income? Please explain.

315.2 Please describe BC Hydro's industrial load displacement program and explain why BC Hydro is discontinuing this program. Please include a description of other (non-DSM) options available to BC Hydro industrial self-generators to sell generation fed into BC Hydro's grid.

315.3 Please explain how BC Hydro can ensure that energy savings assumed to relate to rate design changes are not being double counted as savings related to BC Hydro DSM programs.

316.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 176.1
Balance review

In BCUC IR 176.1, BC Hydro showed that F2017–F2019 annual DSM expenditure as a percentage of class revenues are: residential 1%; light industrial and commercial: 3%; and large industrial: 5%.

316.1 Please provide a table comparing the percentage allocation of F2017–F2019 DSM costs between customer class for revenue recovery purposes, with the percentage of F2017–F2019 DSM funding proposed to be spent on each customer class. Please also include in the table average TRC and UCT results for DSM programs for each customer class.

316.1.1 Does BC Hydro consider that there is a reasonable balance of DSM spending between customer classes? Please explain.

317.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-10, CEC IR 111.1; Exhibit B-9, BCUC IR 182.1, 170.4, 181.1.1
Capacity focused DSM: need

BC Hydro provides the following table for capacity-focused DSM in CEC IR 111.1:

	F2014 Actual ($ million)	F2015 Actual ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)	F2014-F2019 Total ($ million)
Capacity Focused Demand-Side Management	0.0	4.7	8.6	10.0	14.2	14.4	52.0

In BCUC IR 182.1 BC Hydro estimated the long run marginal cost of meeting the annual forecast capacity gap as $6 million (F2023) and $16 million (F2024), with a net present value of $13 million over the next ten years. BC Hydro also provides the following annual breakdown for the next 20 years in the same IR:

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026
Cost (Million $ Nominal)	0	0	0	0	0	0	6	16	0	0

	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Cost (Million $ Nominal)	0	0	19	51	29	62	99	135	154	203

BC Hydro stated that the capacity value based on the market value of surplus capacity is $37/kW-year (BCUC IR 170.4). BC Hydro stated in BCUC 181.1.1 that it did not consider alternative approaches would provide enough information on their own to understand if capacity-focused DSM can be relied upon.

317.1 Please explain whether the expected need for capacity resources has increased or decreased compared to the capacity need assumed in the 2013 IRP.

317.2 Please update the response to BCUC IR 182.1 to show the net present value of meeting the capacity gap over the next (i) 10 years and (ii) 15 years using, using as the generation capacity value the generation capacity estimates in Appendix X of the Application (F2016–F2019: $37/kW-year, F2020-F2028: $58/kW-year etc.).

317.2.1 Please perform the same analysis above using the cost estimate (i) the cost of BC clean generation capacity, and (ii) from Appendix X to the Application, the generation capacity cost plus BC Hydro's avoidable network costs.

317.3 Please explain why BC Hydro proposes to spend a total of $52 million for the information gathering/testing stage of the capacity conservation initiative, when BC Hydro estimates the long-run marginal cost of meeting the capacity gap over the next 10 years is $13 million.

318.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 183.1, 183.3; Exhibit B-10, CEC IR 102.2; Exhibit B-1-1, IRP, p. 3-32
Capacity focused DSM – F2014–F2016 spend

BC Hydro stated in BCUC IR 183.1 that the IRP F2014-2016 budget for industrial load curtailment was $0.75 million, however BC Hydro spent $11.7 million (an overspend of $11mIn the breakdown of the spend in BCUC IR 183.3, it appears that $11.4 million was paid out in incentives in F2014–F2016.

BC Hydro stated in CEC IR 102.2 that bids for the load curtailment project totaled 126 MW from four participants. This compares to a forecast capacity gap of 96 MW in F2022 and 236 MW in F2024, with no further forecast capacity gaps until F2029 (Application, p. 3-32).

318.1 Please estimate the cost to BC Hydro (in $/kW-year) of the capacity obtained from industrial customers in year one of the pilot (based on the cost of the incentive only).

318.1.1 Please explain BC Hydro's analysis and internal review/approval process in determining that $11.7 million should be spent on this program (as opposed to the $0.75 million planned in the 2013 IRP). Please also provide the business case for this program and identify where the funds were transferred from.

318.2 Please describe BC Hydro's process in determining which customers would be eligible to participate in the industrial load curtailment program and provide a breakdown of the incentive to show the amount paid to each customer.

318.3 Please update Table 1 to 4 of BC Hydro's response to BCUC IR 183.3 to show F2014-F2016 results and include a (i) $ total column and (ii) % column (e.g., incentives as a % of the total). Please also include a summary table.

319.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-10, BCSEA IR 2.1, Attachment 1, p. 9; FEI 2014-2018 PBR Decision, G-138-14, p. 278
Capacity focused DSM - F2017-F2018 proposed spend

In response to BCSEA IR 2.1, BC Hydro stated in its briefing to the Board on meeting the 10 year rates plan (November 16, 2015): "A budget of $10 million per year has been allocated from F2017 to F2019 … Annual budget includes $7.5 million for Industrial Load Curtailment and $2.5 million to support other initiatives such as demand response."

In the FEI 2014–2018 PBR Decision (page 278) the Commission stated: "The Panel requires that when FEU [Fortis Energy Utilities] identifies and develops a new program it wants to implement, FEU must demonstrate through a written request to the Commission that the new program results in a net long-term improvement in portfolio effectiveness and/or is required to ensure appropriate balance in terms of different customers' ability to access [DSM] programs. The filing should include a business plan for the new program, and should identify where the funds will be transferred from."

319.1 Please provide, in table form, BC Hydro's F2017–F2019 request for capacity focused DSM funding, split between Industrial Load Curtailment and other demand response initiatives. Please compare the request to the proposed spending in BC Hydro's November 16, 2015 briefing to the Board (total of $10 million/year budgeted) and explain any difference.

319.1.1 Please compare the F2017–F2019 funding request to the 2013 IRP. If the funding request is in excess of the 2013 IRP levels, please identify where the funds were transferred from and how the funding transfer results in a net improvement of the DSM portfolio.

319.2 Please update Tables 1 to 4 of BCUC IR 183.3 to show, in addition to the years shown, BC Hydro's best estimate of the budget for F2018 and F2019 for each existing program. Please explain any significant changes in annual funding requests from F2014–F2016 to F2017–F2019. Please include totals for each table, and a summary table.

319.2.1 For the F2017–F2019 capacity focused DSM expenditures that represent new DSM initiatives, please provide the annual budget, business case and describe the internal review process BC Hydro undertook to review the budgeted amount.

319.3 Regarding the $38.6 million F2017–F2019 request for capacity focused DSM, please describe the implication of (i) Commission rejection of this funding request and (ii) Commission rejection of 50 percent of the funding request.

319.3.1 If the $38.6 million request for capacity focused DSM was denied, please estimate the maximum amount of additional dollars that could be reallocated to BC Hydro DSM programs (in proportion to existing funding levels) in order to keep the overall rate impact from DSM unchanged.

320.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC 175.3
Portfolio approach

BC Hydro states in response to BCUC IR 175.3 that it "… makes its decisions on demand-side management cost-effectiveness at the program and portfolio level, including as described in the Demand-Side Measures Regulation."

320.1 Please confirm, or explain otherwise, that cost effectiveness of the capacity DSM program can be determined based on (i) the TRC result, and (ii) the UCT result according to section 4(1.8) of the DSM Regulation.[1]

320.2 Please explain whether the capacity DSM program would be considered cost effective under the (i) portfolio approach and (ii) program approach.

320.2.1 Please explain whether BC Hydro is proposing the Commission to use the portfolio or program approach when evaluating the cost effectiveness of its proposed DSM programs as presented in the Application.

321.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-10, BCSEA IR 39.2, 3.6.2, 1.2.1, Attachment 1, p. 5; Exhibit B-1-1, Appendix V, pp. 22–23
Residential new home program – general

The BC Climate Leadership Action Plan includes as an action item "encouraging development of net zero building" (BCSEA IR 39.2). BC Hydro has eliminated the residential new home program (BCSEA IR 1.2.1). BC Hydro stated: "BC Hydro did hear from some of the [electricity conservation and efficiency committee] members that they were concerned with the change in strategy for new construction …" (BCSEA IR 3.6.2).

321.1 In a format similar to the description of the commercial new construction program (Application, Appendix V, pp. 22–23), please describe the residential new home program offered by BC Hydro at the time of the 2013 IRP. For financial information, please use data from the most recent period the program was available.

[1] Accessed at http://www.bclaws.ca/Recon/document/ID/freeside/10_326_2008#section4 in December 2016.

321.1.1 Please explain why BC Hydro no longer plans to offer the residential new home program, and how elimination of this program aligns with the BC Climate Leadership Action Plan item of "encouraging development of net zero building."

322.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 169.2.1; Exhibit B-10, BCSEA IR 41.3
Residential new home – linkage to codes and standards

BC Hydro stated in BCUC 169.2.1 that it "no longer offer direct incentives to builders and shift the focus to Codes and Standards initiatives."

In response to BCSEA IR 41.3, BC Hydro stated that "The Codes and Standards Initiative in the Demand-Side Management Plan does not employ utility financial incentives to influence market actors," and that codes and standards activities include workshops with the building industry, showcase building projects, and training initiatives. BC Hydro also states in the same IR: "BC Hydro also works with local governments to support the development of financial and other incentives to encourage the adoption of advanced, energy efficient buildings."

322.1 Please compare the initiatives under BC Hydro's canceled residential New Home program and its Codes and Standards program, and discuss the potential reduction in energy savings and lost opportunities from initiatives that are dropped off as a result of the shift in effort from the New Home program to the Codes and Standards program.

323.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-10, BCSEA IR 35.1, 38.2; Exhibit B-9, BCUC IR 177.1, 177.2; FEI 2014-2018 PBR Decision, Order G-138-14, p. 267
Electrification

BC Hydro stated in BCSEA IR 35.1 that it is exploring potential low-carbon electrification initiatives in response to the Province's Climate Leadership Plan released in August 2016. BC Hydro stated in BCSEA IR 38.2 that the proposed DSM plan does not include any low-carbon electrification programs, and in BCUC IR 177.1 that low-carbon electrification could potentially reduce rates.

BC Hydro stated in BCUC IR 177.2 that customers seeking to switch from natural gas to electricity are excluded from DSM incentive eligibility. The FEI 2014–2018 PBR Decision stated on page 267: "FEU … permit switching from another fuel source to natural gas for the ENERGY STAR® Water Heater Program and the EnerChoice Fireplace Program."

323.1 Please explain why BC Hydro excludes customers switching from natural gas to electricity from DSM incentive eligibility in light of the FEI program eligibility described above.

323.2 Please explain how BC Hydro plans to explore potential low-carbon electrification initiatives given the lack of a DSM budget requested for these activities. Specifically, does BC Hydro plan to fund these activities out of non-DSM dollars, from a reallocation of funding from other DSM programs (and if so, which programs), or by making supplemental DSM expenditure schedule filings?

324.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 184.3; Long- Run Savings and Cost-Effectiveness of Home Energy Report Programs (winter 2014/2015)[2]
Behaviour program input assumptions

BC Hydro states in response to BCUC IR 184.3 Attachment 1, tab "Behaviour" that "Full savings for a given participant are counted for 1 year, then 85% of the original savings are counted for the next 5 years, and finally 66% of the original savings are counted for the next 18 years (i.e. to make 24 years total)."

Long- Run Savings and Cost-Effectiveness of Home Energy Report Programs published by Cadmus (Winter 2014/2015) states on page 7:

> we suggest that planners apply a 20% annual savings decay rate to all Opower-type HER programs, without regard to treatment duration or frequency, or to the amount time since last treatment. We base this recommendation on the need for a simple yet valid approach for determining post-treatment savings. However, when resources allow, we strongly recommend that evaluators conduct a post-treatment persistence study to true up the savings decay rate.

324.1 Please explain what is the savings decay rate assumed by BC Hydro in its savings persistence estimate for the Behaviour program. If it is different than 20 percent, please explain.

324.1.1 Please provide the TRC, UCT and RIM of the Behaviour program if a 20 percent savings decay rate is used.

324.2 Please explain whether BC Hydro conducts post-treatment persistence study for any of its programs.

324.3 Please explain and provide references for whether a savings life of 24 years is appropriate for the Behaviour program.

325.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 187.2
Industrial incentive

In response to BCUC IR 187.2 BC Hydro quoted its response to an information request provided on March 6, 2012 regarding the Power Smart Partner – Transmission (PSP-T) program incentive costs. BC Hydro stated in the 2012 IR response that "Feedback from the Joint Industry Electricity Steering Committee (JIESC, now AMPC) and customers was that the 2 cent per kWh incentive was insufficient to generate interest in energy efficiency projects."

325.1 Please explain whether a similar consultation process was conducted to determine that an incentive of less than 75 percent of cost of the energy efficiency upgrade projects is insufficient under the Leaders in Energy Management programs for transmission and distribution.

[2] Accessed at http://www.cadmusgroup.com/wp-content/uploads/2014/11/Cadmus_Home_Energy_Reports_Winter2014.pdf in December 2016.

326.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 187.4
Leaders in Energy Management – Distribution

In response to BCUC IR 187.4, BC Hydro stated that 2 percent of the total qualifying customers participated in the Leaders in Energy Management – Distribution program.

326.1 Please discuss whether BC Hydro is looking at ways to increase the participation rate of the Leaders in Energy Management – Distribution program. If yes, please elaborate. If not, why not?

327.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 191.3, 192.5
EM&V independence

In response to BCUC IR 191.3 BC Hydro stated that "[t]he draft report is reviewed by two external evaluation advisors… Appropriate changes are made in response to comments."

In response to BCUC IR 192.5 BC Hydro stated that "[v]erification occurs after the fact, and can include engineering review, invoice reconciliation, site inspection, measurement and verification and/or evaluation."

327.1 Please provide the affiliation of the external evaluation advisors, and explain how BC Hydro ensures that the external advisors are free from conflict of interest with BC Hydro.

327.2 Out of the different types of verification listed in the preamble, please explain how often each type of verification methods are used, and how often are external evaluation advisors involved in each type of verification conducted.

328.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 192.2
EM&V deliverables

In response to BCUC IR 192.2, BC Hydro presents the Timing of Primary EM&V Deliverables and the associated planned expenditure for each program.

328.1 Please explain why BC Hydro has allocated evaluation budgets for the Behaviour program but does not have any evaluations planned.

328.2 For each program that does not have planned EM&V deliverable during the F2017–F2019 period, please explain why that is appropriate.

329.0 Reference: DEMAND SIDE MANAGEMENT EXPENDITURES
Exhibit B-9, BCUC IR 191.1 Attachment 1, p. 6 of 15, BCUC IR 192.5; *Energy Savings Lifetimes and Persistence: Practices, Issues and Data (May 2015) by* Lawrence Berkeley National Laboratory[3], p. 17
Savings persistence

BC Hydro states in response to BCUC IR 192.5 "Impact evaluations estimate electricity savings from a program or initiative…"

BC Hydro states in response to BCUC IR 191.1 Attachment 1, on page 6 of 11 that "savings effective

[3] Accessed at https://eaei.lbl.gov/sites/all/files/lbnl-179191.pdf in December 2016.

measure life and persistence is not commonly included in the scope of impact evaluation. It is typically assigned in accordance with the Conservation and Energy Management Standard on Effective Measure Life and Persistence."

Energy Savings Lifetimes and Persistence: Practices, Issues and Data published by the Lawrence Berkeley National Laboratory states on page 17 that "Persistence may turn out to be a significant issue for a subset of measures that play, or are expected to play, a more prominent role in efficiency portfolios in the future (e.g., behavioral programs, retro-commissioning, new technologies). More up-to-date research is warranted for at least these measure types."

329.1 Please reconcile and explain whether BC Hydro estimates electricity savings of its programs or initiatives in its impact evaluations.

329.2 Please explain the benefit and cost associated with measuring savings persistence as part of BC Hydro's impact evaluations rather than assigned in accordance with the Conservation and Energy Management Standard on Effective Measure Life and Persistence.

Burrard Synchronous Condense Facility
Depreciation Rates

Class of Property, Plant and Equipment		F2012 Depreciation Rate (%/year)	F2013 Depreciation Rate (%/year)	F2014 Depreciation Rate (%/year)	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)	F2017 Depreciation Rate (%/year)	F2018 Depreciation Rate (%/year)	F2019 Depreciation Rate (%/year)
C11501	Land Fee Simple	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C12002	Road, Paved / Gravel	11.1%	12.5%	14.3%	16.7%	20.0%	25.0%	33.3%	50.0%
C12005	Roads Trails, Comp	50.0%	100.0%	-	-	-	-	-	-
C12101	Tracks, Railway	25.0%	33.3%	50.0%	100.0%	-	-	-	-
C12203	Bridge, Concrete	-	-	-	16.7%	20.0%	25.0%	33.3%	50.0%
C12401	Drainage System Yard	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C21901	Roofs	11.1%	12.8%	14.5%	9.1%	16.6%	11.1%	12.5%	14.3%
C22001	Plant Concrete Steel	11.1%	12.5%	15.1%	30.8%	43.3%	11.1%	12.5%	14.3%
C22002	Comm Concrete Steel	11.1%	12.4%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C22005	Building, Comp Pool	10.0%	12.5%	14.3%	9.4%	10.5%	11.1%	12.5%	14.3%
C22006	Equipment Shelter	12.1%	13.8%	16.0%	19.0%	23.5%	30.8%	44.4%	80.0%
C22009	Building-HVAC Sys&Cp	-	-	18.6%	11.0%	13.4%	11.9%	12.6%	14.3%
C22101	Off Trailer/Mob Home	11.4%	12.8%	14.7%	9.3%	10.2%	11.1%	12.5%	14.3%
C23801	Cranes	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C24402	Ramp, Boat/Barge	24.0%	31.6%	46.2%	85.7%	100.0%	-	-	-
C25101	Structure Supp Steel	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C25201	Pole Struct < 60Kv	11.1%	100.0%	-	-	-	-	-	-
C25301	Foundations	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C25401	Ducts & Trenches	13.4%	12.1%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C25601	Barriers & Enclos	12.5%	14.3%	16.7%	20.0%	25.0%	33.3%	50.0%	100.0%
C30101	Casing, Boiler	-	-	14.3%	50.0%	100.0%	-	-	-
C30102	Insulation, Boiler	11.1%	12.5%	14.3%	14.3%	23.4%	11.1%	12.5%	14.3%
C30103	Roof, Boiler	11.1%	12.5%	14.3%	50.0%	100.0%	-	-	-
C30203	Superheater HighTemp	11.1%	12.5%	14.3%	50.0%	100.0%	-	-	-
C30204	Superheater Low Temp	-	-	-	50.0%	100.0%	-	-	-
C30205	Reheater, Boiler	11.1%	12.5%	14.3%	50.0%	100.0%	-	-	-
C30206	Desuperheater/Attemp	71.6%	100.0%	-	-	-	-	-	-
C30301	Header / Drum	11.1%	12.5%	14.9%	50.0%	100.0%	-	-	-
C30401	Valves, Safety	7.0%	13.5%	14.8%	50.0%	100.0%	-	-	-
C30501	Piping, High Press	16.8%	19.8%	28.9%	41.7%	84.0%	15.6%	18.5%	22.6%
C30601	Fan, Forced Draft	11.1%	12.5%	14.3%	50.0%	100.0%	-	-	-
C30602	Breaching / Flue Sys	15.9%	19.0%	23.4%	54.5%	100.0%	-	-	-
C30603	Stack, Flue Gases	11.1%	12.5%	14.3%	50.0%	100.0%	-	-	-
C30605	Burner, Fuel	13.5%	15.5%	18.4%	50.0%	100.0%	-	-	-
C30606	Instrument, Boiler	15.0%	17.6%	21.4%	52.0%	100.0%	33.3%	50.0%	100.0%
C30607	DNU - Asbe Abatement	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C30611	Desuperheater System	32.4%	13.1%	15.5%	50.0%	100.0%	-	-	-
C30612	Refractory, Boiler	-	-	-	50.0%	100.0%	-	-	-
C30613	Boiler, Package	-	-	-	50.0%	100.0%	-	-	-
C30701	Equip, Water Treat	11.1%	12.5%	14.3%	50.0%	100.0%	-	-	-
C30801	Transfer Sys Ammonia	24.5%	32.4%	48.0%	92.3%	100.0%	-	-	-
C30802	Water Sys Ammonia	24.5%	32.4%	48.0%	92.3%	51.0%	11.1%	12.5%	14.3%
C30803	Vapouriser, Ammonia	24.5%	32.4%	48.0%	92.3%	100.0%	-	-	-
C30804	Comp Vapour, Ammonia	24.5%	32.4%	48.0%	92.3%	100.0%	-	-	-
C30805	Piping Sys, Ammonia	11.1%	12.5%	14.4%	50.0%	100.0%	-	-	-
C30901	Monitor Equip, Cem	-	-	-	50.0%	100.0%	-	-	-
C30903	Deliver Sys,Ammonia	17.3%	20.9%	26.5%	57.5%	100.0%	-	-	-

Burrard Synchronous Condense Facility
Depreciation Rates

Class of Property, Plant and Equipment		F2012 Depreciation Rate (%/year)	F2013 Depreciation Rate (%/year)	F2014 Depreciation Rate (%/year)	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)	F2017 Depreciation Rate (%/year)	F2018 Depreciation Rate (%/year)	F2019 Depreciation Rate (%/year)
C30904	Catalyst, Scr	63.9%	100.0%	-	-	-	-	-	-
C31001	Water Intk/DisStruct	21.8%	28.0%	39.1%	9.1%	10.2%	11.1%	12.5%	14.3%
C31002	Protection, Cathodic	14.1%	16.4%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C31003	Gates, Inlet/Outlet	11.1%	12.5%	100.0%	10.1%	11.4%	11.1%	12.5%	14.3%
C31004	Screens, Intake	33.3%	50.0%	100.0%	-	-	-	-	-
C31005	Conduit, Intake/Disc	11.1%	12.5%	14.3%	50.0%	100.0%	-	-	-
C31006	Valves	100.0%	-	-	-	-	-	-	-
C33001	Heat Exch,Shell Tube	11.1%	12.5%	14.3%	50.0%	100.0%	-	-	-
C33002	Pump And Motor	14.3%	16.7%	21.4%	50.0%	100.0%	-	-	-
C33004	Condenser, Boiler	-	-	14.3%	50.0%	100.0%	-	-	-
C34004	Turbine, Comp Pool	12.6%	14.4%	16.8%	49.3%	100.0%	11.1%	12.5%	14.3%
C34005	Coils, Stator	11.1%	12.5%	14.3%	9.3%	10.3%	11.4%	12.9%	14.8%
C34006	Rotor, Generator	14.1%	13.7%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C34007	Generator, Comp Pool	12.0%	13.0%	15.8%	31.8%	46.7%	17.4%	18.5%	21.9%
C34008	Supervisory Sys Turb	22.7%	29.3%	41.5%	73.4%	70.6%	40.4%	67.8%	100.0%
C34009	Cooling Sys Hydrogen	11.1%	12.5%	14.3%	21.9%	22.5%	16.5%	19.7%	24.4%
C34015	Turbine Blades Sets	14.9%	17.5%	21.3%	50.0%	100.0%	-	-	-
C42004	Major Maint.-Rewedge	-	-	15.5%	26.4%	100.0%	11.2%	12.6%	14.4%
C42102	Exciter, Static	11.8%	13.4%	15.6%	42.7%	74.6%	11.1%	12.5%	14.3%
C46701	Heat Exchanger	11.1%	12.5%	14.3%	50.0%	100.0%	-	-	-
C47201	Turbine, Gas	11.1%	8.7%	14.3%	50.0%	100.0%	-	-	-
C47202	Major Maint.-Gas Tur	-	-	44.4%	80.0%	100.0%	-	-	-
C48001	Coils, Stator	3.2%	13.0%	13.8%	17.4%	19.3%	-	-	-
C48003	Generator, Composite	11.1%	11.9%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C48004	Generator, Diesel	13.1%	15.0%	17.7%	20.5%	26.5%	35.0%	53.9%	61.8%
C49001	Pump	12.6%	14.2%	16.5%	49.2%	100.0%	19.2%	23.7%	31.1%
C49002	Motor	11.1%	12.5%	14.4%	12.3%	14.1%	11.1%	12.5%	14.3%
C51001	Condensor,SyncRotary	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C52104	Transformer, <100Mva	12.6%	14.5%	16.9%	50.0%	100.0%	-	-	-
C52105	Transformer, Stn Ser	11.9%	13.3%	15.3%	10.5%	10.0%	11.1%	12.5%	14.3%
C52302	Reactor, Dry Type	25.0%	33.3%	50.0%	100.0%	-	-	-	-
C52405	Transformer,Curr,Com	17.1%	20.7%	26.1%	35.3%	54.6%	-	-	-
C52504	Trans,Volt,Encaps.	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C54101	Breaker,Air/Magnetic	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C54201	Use Ind Disconnect	20.8%	9.5%	16.7%	20.0%	25.0%	33.3%	50.0%	100.0%
C55401	Buswork & StnConduct	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C55501	Grounding Systems	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C56001	Insulators	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C59001	Power Supp Uninterr	13.1%	15.1%	17.8%	39.4%	65.1%	34.3%	52.2%	74.3%
C59101	Regulator FeederCirc	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C59201	Charger System, Batt	12.3%	14.0%	16.3%	13.3%	15.3%	18.1%	13.0%	14.3%
C61001	Fencing	15.5%	18.3%	20.1%	9.1%	10.0%	11.1%	12.5%	14.3%
C61101	Alarm/Security Sys	11.8%	13.0%	13.1%	-	-	-	-	-
C62001	Fire Protection Sys	11.1%	12.5%	14.3%	12.0%	13.1%	25.1%	33.5%	50.4%
C62501	Firefighting Equip	16.7%	20.0%	25.0%	33.3%	50.0%	100.0%	-	-
C65001	Panels/Cubicles, P&C	12.4%	14.1%	16.4%	12.7%	11.3%	11.2%	12.6%	14.4%
C67003	Contain Fac, Concret	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%

Burrard Synchronous Condense Facility
Depreciation Rates

Class of Property, Plant and Equipment		F2012 Depreciation Rate (%/year)	F2013 Depreciation Rate (%/year)	F2014 Depreciation Rate (%/year)	F2015 Depreciation Rate (%/year)	F2016 Depreciation Rate (%/year)	F2017 Depreciation Rate (%/year)	F2018 Depreciation Rate (%/year)	F2019 Depreciation Rate (%/year)
C67005	Oil Spill Containmen	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C68202	Term Unit,Rem(Slave)	14.1%	13.2%	18.7%	21.8%	25.0%	33.4%	50.0%	100.0%
C68204	Distributed Ctrl Sys	21.8%	27.8%	31.9%	30.8%	43.7%	12.0%	13.6%	14.6%
C68301	Radio,MW,Analog	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C68901	Tele Equip, Pbx/Pax	-	-	-	100.0%	-	-	-	-
C68904	Telephone Sys Cell	-	-	-	-	-	20.7%	26.1%	35.3%
C70104	Instrumentation-Digi	-	-	14.3%	9.1%	54.1%	11.1%	12.5%	14.3%
C74001	Motor-Generator Sets	24.5%	32.4%	48.0%	92.3%	100.0%	-	-	-
C75104	Compressor, Air	14.0%	16.3%	19.5%	18.3%	21.3%	11.1%	12.5%	14.3%
C75201	Tanks,Steel,Air/Fuel	11.1%	12.5%	14.3%	9.1%	10.0%	11.1%	12.5%	14.3%
C75202	Tank,Fibrglas,DblB	0.0%	12.6%	14.3%	50.0%	100.0%	-	-	-
C75301	Water Supply System	11.1%	12.5%	17.7%	15.3%	15.1%	16.7%	20.1%	25.1%
C80101	Computer,HW,Micro	-	-	-	-	31.6%	46.2%	85.7%	100.0%
C82501	Forklift / Pallet Ja	0.0%	0.0%	100.0%	-	-	-	-	-
C82504	Loader / Backhoe	-	-	7.8%	9.1%	10.0%	11.1%	12.5%	14.3%
C82505	Trailer, Reel/Pole	0.0%	0.0%	100.0%	-	-	-	-	-
C82513	Manlift	24.7%	30.0%	40.0%	66.7%	100.0%	-	-	-
C82550	Tools/Work EquipMisc	10.9%	18.1%	15.6%	11.8%	15.5%	13.9%	16.2%	18.1%
C82551	DNU - Tools/Work Equ	14.1%	16.4%	19.6%	21.7%	27.1%	37.1%	59.0%	26.0%
C82601	Test/Calibration	18.5%	22.7%	29.4%	43.9%	73.2%	94.2%	100.0%	-
C82603	Manufacturing/Test	15.9%	18.9%	23.4%	24.4%	12.5%	11.1%	12.5%	14.3%
C85001	Office Furniture	16.3%	18.2%	23.0%	29.9%	40.7%	62.8%	63.2%	100.0%
C85002	DNU - Office Equipme	12.5%	14.3%	16.7%	20.0%	25.0%	33.3%	50.0%	100.0%
C88002	Lab Equipment, Misc	16.0%	19.1%	23.6%	30.8%	27.3%	37.5%	60.0%	100.0%
H00004	HFS-Land	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%