British Columbia Old Age Pensioners' Organization,
Active Support Against Poverty,
Council of Senior Citizens' Organizations of BC,
Disability Alliance BC,
Tenant Resource and Advisory Centre and
Together Against Poverty Society
("BCOAPO *et al.*")

FINAL SUBMISSION

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY F2017 TO F2019 REVENUE REQUIREMENTS APPLICATION

Project No. 3698869

June 13, 2017

PART ONE: INTRODUCTION

1. Please be advised that we make the following submissions in this British Columbia Hydro and Power Authority ("BC Hydro") Revenue Requirement Application ("RRA") on behalf of our client groups, the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, BC Poverty Reduction Coalition, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Together Against Poverty Society, and the Tenant Resource and Advisory Centre. These groups are known collectively in BC Hydro regulatory processes before the BC Utilities Commission as "BCOAPO *et al.*" Our constituent groups are before this Commission Panel representing the interests of low and fixed income BC Hydro ratepayers.

2. In this BC Hydro RRA, as in many others, BCOAPO *et al.* intervened to explore the financial and service impacts of the approvals BC Hydro seeks in this Application although admittedly, doing so has been and remains a challenge. It was not a challenge because it was difficult for this coalition to access the process or to understand how this Application will affect its interests. BCOAPO is advised and represented before the BCUC by a team of experienced regulatory lawyers working closely with an expert consultant who is well versed not only in BC Hydro's operations, but in the operations of many Canadian electrical utilities. It was a challenge because this RRA is the latest in a string of increasingly complicated and unusual BC Hydro applications over recent years: applications often fettered or halted mid-process by increasingly problematic and unnecessary government interference.

3. It should come as no surprise that BCOAPO, like many others in this process, has struggled with how to effectively represent its interests in this process given the numerous politically-motivated legal constraints under which it, the Utility, and the Commission must now operate. Even the core issue for any Revenue Requirement, "what are the right rates," is effectively off the table because of government imposed rate caps.

4. Adding to the challenge these legal constraints pose is the fact that there are so many issues and decisions that have inserted rate increase pressures into the queue. On some issues, BCOAPO was able to easily determine how to proceed in its intervention because the evidence and legal framework was clear but with others BCOAPO has struggled to navigate the field littered with the messy and expensive aftermath of ill-informed government legislation, policy and actions to find constructive and realistic input on how to shape BC Hydro's operations going forward without compromising the ability of those already experiencing energy poverty to meet what is on BC Hydro's horizon with a modicum of hope.

5. The 2013 10 Year Rates Plan, the long term rates outlook, the current rate caps, and Hydro's DSM plans are the core of BCOAPO's interest in this process although there are a number of other issues that engage their interests as well.

6. Our clients have, despite the many roadblocks discussed above and within this submission, struck a balance and made recommendations to this Commission Panel that it submits are constructive and in the best interests of both the Utility and the public.

PART TWO: LEGAL FRAMEWORK

7. There are a number of regulatory and legal parameters applicable to this Application, set out below, which serve to direct or constrain the Commission's discretion in their determinations.

8. Flowing from the 2013 10 Year Rates Plan, the government issued Direction No. 7 to the Commission by way of Order in Council No. 97, dated March 5, 2014. Direction No. 7 caps the rates during the test period at 4% in fiscal 2017, 3.5% for fiscal 2018 and 3% in fiscal 2019. It also directs that the balance of BC Hydro's forecast revenue requirements in those years be recorded in the Rate Smoothing Regulatory Account. Section 10 of Direction No. 7 sets the deferral account rate rider at 5%.

9. Direction No. 7 further directs the Commission to allow BC Hydro to recover costs incurred to provide reliable electricity service and finance its operations. The costs associated with providing reliable electricity service include the Cost of Energy, operating costs and capital costs. Direction No. 7 also directs that the Commission must allow rates which enable BC Hydro to meet its interest expenses, tax expenses, Net income and return on equity.

10. Section 4 of Direction No. 7 prescribes BC Hydro's deemed equity for rate-making purposes for the test period. For fiscal 2017 it is 11.84%, for fiscal 2018 and 2019 it is the percentage necessary to yield a distributable surplus in the fiscal year equal to the product of (i) the distributable surplus in the immediately preceding fiscal year, and (ii) 100% plus the percentage change in the BC consumer index in the applicable fiscal year.

11. Section 11 of Direction No. 7, establishes specific prohibitions on disallowing costs. Section 11 states:

> 11 When setting rates for the authority under the Act, the commission must not disallow for any reason the recovery in rates of the costs that were incurred by the authority or Powerex Corp. in consequence of decisions of either with respect to
>
> (a) the construction of extensions to the authority's plant or system that come into service before F2017,
> (b) energy supply contracts entered into before F2017,
> (c) the Rock Bay settlement,
> (d) the First Nations settlements,
> (e) the California settlements,

(f) the Burrard costs, and
(g) the costs deferred to the SMI regulatory account.

12. The *Direction to the British Columbia Utilities Commission Respecting Mining Customers* (Order in Council No. 123, dated February 29, 2016) directs the Commission to permit BC Hydro to establish the Mining Customer Payment Plan. Under that Plan, qualifying mining customers can temporarily defer payment of a portion of their electricity bills. Interest is charged on the deferred amounts at rates set in the Direction.

13. The *Direction to the British Columbia Utilities Commission Respecting the Authorities TMP Program* (Order in Council No. 404, dated July 14, 2015) stipulates that the Commission must not disallow the recovery in rates of the costs incurred by BC Hydro, up to $100 million, in carrying out the thermal-mechanical pulping program.

14. Section 7 of the *Clean Energy Act* exempts a number of projects, programs, contracts and expenditures from the requirement to obtain Commission public interest approval. The exemption includes the Standing Offer Program, Mica Units 5 and 6, Revelstoke Unit 6, and the Northwest Transmission Line. The reasonable costs (i.e. amortization or expense) associated with these that affect the test period revenue requirements are recoverable by virtue of section 4(c) of Direction No. 7.

15. Section 8 of the *Clean Energy Act* provides that the Commission must ensure that the rates set enable BC Hydro to collect sufficient revenue in each fiscal year to allow it to recover its costs with respect to (i) the achievement of electricity self-sufficiency, and (ii) the projects, programs, contracts and expenditures referred to in s. 7 of the *Clean Energy Act*.

16. The Minister's March 14, 2016 Mandate Letter, sets out a number of priorities for the test period and directs BC Hydro to undertake the following strategic actions:

    - Continue to implement the 2013 10 Year Rates Plan to keep electricity rates low and predicable by optimizing resources and advancing its Revenue Requirements and Rate Design Applications.

    - Deliver your overall capital plan portfolio on time and on budget to maintain the reliability of the system, support British Columbia's economic growth and meet the needs of customers.

    - Deliver the Site C project on time and on budget and ensure First Nations and local communities have the ability to participate in economic development opportunities arising from the construction of the project.

- Work with Clean Energy BC to identify further opportunities for clean energy producers in British Columbia.

- Improve customer satisfaction by providing timely and responsive service and exploring innovative energy conservation solutions such as load curtailment rates.

- Implement the five-year safety plan to ensure the safety of your workforce and the public.

17. The *Utilities Commission Act* (the Act) sets parameters on the Commission's discretion to make orders regarding a demand-side management expenditure schedule, directs the financial treatment of those expenditures, and sets out factors that must be considered when reviewing a proposed demand-side management expenditure schedule.

18. Subsection 44.2(3) of the Act provides that the Commission must accept a demand-side expenditure schedule if the Commission considers that it would be in the public interest, or reject the schedule if it is determined not to be in the public interest. Alternatively, the Commission may accept or reject a part of the expenditure schedule.

19. Section 44.2(5.1) of the Act requires the Commission to consider a number of factors in determining whether to accept BC Hydro's proposed demand-side measures expenditure schedule. They are:

    - The interests of persons in British Columbia who receive or may receive service from BC Hydro.

    - British Columbia's energy objectives, as set out in section 2 of the *Clean Energy Act*.

    - An applicable Integrated Resource Plan approved under section 4 of the *Clean Energy Act*.

    - The extent to which the demand-side measures are cost effective within the meaning prescribed by the *Demand-Side Measures Regulation*.

20. Pursuant to Direction No. 7, BC Hydro's development, implementation and administration costs for demand-side measures are recorded in the Demand-Side Management Regulatory Account and amortized over 15 years.

21. BCOAPO has, in the crafting of its positions on the various issues addressed in this submission, taken into consideration all of the aforementioned legal constraints.

PART THREE: LOAD AND REVENUE FORECAST

22. The following schedule from the Application sets out the proposed fiscal 2017-2019 revenue requirement by cost element.[1]

Table 1-7 Summary of Fiscal 2017 – Fiscal 2019 Revenue Requirements – Current View

		Schedule Reference	F2016 RRA ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
			1	2	3	4
1	Cost of Energy	3.0 L64	1,514.3	1,723.9	1,838.6	1,951.8
2	Operating Costs	3.0 L65	977.7	976.3	936.4	941.0
3	Taxes	3.0 L66	224.1	223.3	231.8	238.7
4	Amortization	3.0 L67	796.0	863.0	922.2	962.8
5	Finance Charges	3.0 L68	726.6	506.9	523.2	566.6
6	Return on Equity	3.0 L69	651.9	684.7	698.4	712.4
7	Non-Tariff Revenue	3.0 L70	(126.6)	(138.9)	(147.4)	(149.9)
8	Inter-Segment Revenue	3.0 L71	(53.5)	(62.5)	(64.3)	(65.3)
9	Subsidiary Net Income	3.0 L72	(14.7)	(70.8)	(69.3)	(67.3)
10	Other Utilities Revenue	3.0 L73	(16.5)	(12.6)	(12.0)	(12.1)
12	Deferral Rider Revenue	3.0 L75	(223.0)	(223.5)	(231.3)	(241.8)
	Total Revenue Requirements		4,459.7	4,469.9	4,626.1	4,836.8
13	Less Revenue at F2016 Rates		(4,459.7)	(4,298.0)	(4,297.8)	(4,362.5)
14	Revenue Shortfall	1.0 L29	0.0	171.9	328.3	474.3
	Rate Smoothing Account Transfers	2.2 L172	121.2	210.0	285.9	299.4
15	Annualized Rate Increase (%)	1.0 L30	6.00	4.00	3.50	3.00
16	Deferral Account Rate Rider (%)	1.0 L31	5.00	5.00	5.00	5.00
17	Net Bill Increase (%)	1.0 L32	6.00	4.00	3.50	3.00

23. In addition to the legislative context discussed above, there are a number of other considerations relevant to an examination of this RRA.

24. For example, this test period represents the third to fifth years of the 2013 10 Year Rates Plan and rate increases during this period are limited by Direction No. 7 to no more than 4.0%, 3.5% and 3.0% for fiscals 2017, 2018 and 2019 respectively.[2] BC Hydro has forecast that this will result in transfers to the Rate

[1] Exhibit B-1-1, p. 1-38.
[2] Exhibit B-1-1, p. 1-16.

Smoothing Regulatory Account of $210 million in fiscal 2017, $285.9 million fiscal 2018 and $299.4 million in fiscal 2019.[3]

25. It is also worth keeping in mind that, absent the aforementioned rates cap, BC Hydro has estimated their proposed rate increases for fiscal 2017, 2018 and 2019 would have been 8.9%, 5.0% and 3.0% respectively.[4]

26. In regards to the load component of this section, BCOAPO notes that the residential sector represents about 34% of BC Hydro's domestic sales[5] and it is one in which demand growth tends to be steady: it is driven primarily by population growth and general economic trends.[6]

27. A final contextual piece is that the 2013 10 Year Rates Plan anticipates full recovery of any balance in the Rate Smoothing Regulatory Account by the end of fiscal 2024. Therefore, any transfers to the Rate Smoothing Regulatory Account during the period of this Application must be recovered over the later years of the 2013 10 Year Rates Plan.[7] BCOAPO notes that we are already nearing the mid-point of the 10 Year Plan, and the time when ratepayers will be seeing the cost of retiring any amounts owing in the Rate Smoothing Regulatory Account is not that far off. This fast-approaching and daunting inevitability should, in BCOAPO's submission, be front of mind for the Commission in rendering its decision in this process.

28. From the perspective of BCOAPO's constituents, who are among those responsible for paying down by 2024 any balance in the Rate Smoothing Regulatory Account (an account BCOAPO notes is forecast to have a total of $795.3 million added to it during the test period), the Commission must exercise the highest diligence to ensure that the Revenue Requirements approved (as influenced by the load and revenue requirements) have been thoroughly vetted and focused downwards whenever possible, without sacrificing the Utility's safety, customer service and reliability.

29. The following sections address various elements of the revenue requirement requested by BC Hydro, starting with the load forecast underlying a number of elements of the Application.

30. BC Hydro's forecast of domestic sales was initially prepared prior to taking future DSM savings into account. Forecasts were prepared for each of the following sectors: Residential, Light Industrial/Commercial, Large Industrial and Other (including street lights, irrigation and other utilities).[8] Adjustments were then

[3] Exhibit B-1-1, p. 1-44.
[4] Exhibit B-1-1, p. 1-17.
[5] Exhibit B-1-1, p. 3-6.
[6] Exhibit B-1-1, p. 1-8.
[7] Exhibit B-1-1, p. 1-18.
[8] Exhibit B-1-1, p. 3-4.

made consistent with the savings associated with BC Hydro's proposed DSM Expenditures.[9] Adjustments were also made in the preparation of the initial load forecast to account for:

(a) the impact of electric vehicles,

(b) the impact of SMI (on both sales and losses),

(c) the impact of future rate increases, and

(d) overlaps between the codes and standards assumed in the load forecast models and those in BC Hydro's DSM Plan.[10]

31. This load forecast methodology is largely the same as that used in the 2012 Load Forecast, the same forecast underpinning BC Hydro's 2013 Integrated Resource Plan.[11] The key differences are:

(a) a revised approach for new LNG loads that relies on announced industry plans,

(b) a change in the forecast approach of the chemical sector that relies on production information for each large chemical customer, and

(c) the use of internal models to forecast FortisBC's requirements.

[9] Exhibit B-1-1, p. 3-4.
[10] Exhibit B-9, BCUC 1.2.1, 1.9.1; Exhibit B-14, BCUC 2.198.1 and 2.201.1; and Exhibit B-10, AMPC 1.3.2 & 1.3.9.
[11] Exhibit B-10, AMPC 1.2.2 and Exhibit B-9, BCUC 1.2.2.

32. The before and after DSM forecasts by sector are set out below:[12]

Table 1

	BEFORE DSM (GWh)	1 F2017 Plan	2 F2018 Plan	3 F2019 Plan
1	Residential	18,654	18,979	19,327
2	Light Industrial and Commercial	19,212	19,360	19,655
3	Large Industrial	13,752	13,936	14,555
4	Total Sales	51,618	52,275	53,537

Table 2

	WITH DSM (GWh)	4 F2017 Plan	5 F2018 Plan	6 F2019 Plan
1	Residential	18,036	18,112	18,250
2	Light Industrial and Commercial	18,832	18,786	18,899
3	Large Industrial	13,380	13,323	13,882
4	Total Sales	50,248	50,219	51,031

Table 3

	Total Difference equal to Demand-Side Management and Var-Voltage Optimzation Saving (GWh)	7=1-4 F2017 Plan	8=2-5 F2018 Plan	9=3-6 F2019 Plan
1	Residential	617	868	1,077
2	Light Industrial and Commercial	380	575	756
3	Large Industrial	372	613	674
4	Total	1,369	2,056	2,507

LNG Loads

33. For purposes of the Application, the forecast for LNG plant load is based on publically available information regarding estimated load and in-service dates provided by the three proponents proposing to electrify their LNG operations.[13] The resulting LNG plant load forecast is fairly small for the test period and it is all associated with the Tilbury LNG facility.[14]

34. During the interrogatory process, BC Hydro indicated that the FortisBC Tilbury LNG plant was not on track to meet it previously projected load requirements for 2017-2019 due to a deferred in-service date.[15] The implications of this are discussed below under “Need for Update”.

35. It also noted that, as part of the Province’s Climate Leadership Plan, the Government and BC Hydro recently announced a new eDrive rate designed to encourage LNG proponents to use electricity for their liquefaction power needs. The three LNG projects included in the load forecast could potentially be

[12] Exhibit B-10, BCOAPO 1.20.1.
[13] Exhibit B-1-1, p. 3-5.
[14] Exhibit B-9, BCUC 1.7.1, 1.7.3 & 1.7.4 and Exhibit B-10, BCOAPO 1.16.1.
[15] Exhibit B-14, BCUC 2.197.3.

candidates for this rate provided they meet the criteria,[16] but whether they do or not does not affect the load forecast for the test period.

36. BCOAPO accepts that BC Hydro's approach to forecasting LNG plant load is reasonable for purposes of this Application. However, it is noted that BC Hydro's May 2016 Load Forecast predicts that over a twenty-year window (fiscal 2017 through fiscal 2036) there will be a 39% growth in demand with LNG before DSM measures and a 29% demand growth with LNG after DSM measures.[17] BCOAPO is of the view that the likelihood of such a robust demand increase is questionable given the exceptional volatility of the LNG industry arising from external factors such as the overall global move towards renewable sources of energy, the development of LNG in other jurisdictions closer to BC's most lucrative LNG markets, and the business development orientation of any particular government at either the provincial or federal level.

Chemical Sector

37. The change in approach to the chemical sector involves relying on production information from a consultant for each large chemical customer rather than regression models linking chemical load to GDP.[18]

38. For purposes of preparing a short-term load forecast for the F2017-F2019 RRA, BCOAPO submits that BC Hydro's approach to the chemical sector appears reasonable.

FortisBC Requirements

39. BC Hydro's forecast for FortisBC is based on the relative cost of electricity purchases from BC Hydro under rate schedule 3808 including forecast real rate increases as compared to electricity market price forecasts.[19] This contrasts with BC Hydro's previous approach which relied on forecasts provided by FortisBC.[20] BC Hydro notes that this change has resulted in an improvement in the accuracy of the forecast.

40. The evidence to date suggests that BC Hydro's revised approach to forecasting FortisBC's requirements is appropriate.

[16] Exhibit B-15, AMPC 2.6.3.
[17] Exhibit B-1-1, p. 3-1.
[18] Exhibit B-9, BCUC 1.2.2.
[19] Exhibit B-10, AMPC 1.3.2.
[20] Exhibit B-9, BCUC 1.201.1.

Residential Forecast

41. For the Residential Class, the load forecast is based on a forecast of use per account (determined with Statistically Adjusted End Use models) multiplied by the forecast number of accounts (based on housing starts projections).[21]

42. The forecast use per account[22] for fiscals 2017-2019 is 10,437 kWh, 10,447 kWh and 10,474 kWh for the three years respectively,[23] figures BCOAPO notes are not out of line with the actual weather normalized results for 2015 and 2016.[24]

43. The forecast number of accounts is based on an economic forecast prepared by Robert Fairholm Economic Consultant in March 2015.[25]

44. This economic forecast was not updated for 2016,[26] and more recent forecasts by CMHC indicate housing starts for the test period will be higher than those forecast by Fairholm:[27]

    (a) the March 2015 Fairholm housing start forecast for 2015 and 2016 is lower than that produced by CMHC in the first quarter of 2015 for the same years,

    (b) the actual housing starts reported by CMHC for 2015 were higher than those forecast by either Fairholm or CMHC,

    (c) CMHC's December 2016 housing start forecast for 2016 is higher than its forecast from the first quarter of 2015, and

    (d) CMHC's December 2016 housing start forecast for 2016-2018 is considerably higher than the March 2015 Fairholm housing start forecast for 2016-2018.

45. A complicating issue is the fact that actual housing starts reported by CMHC do not cover all areas of the province, whereas those reported by Fairholm do.[28]

46. Furthermore, a more recent forecast of housing starts from the BC Ministry of Finance also calls for higher housing starts in the 2017-2019 test period than forecast by Fairholm.[29]

47. Given the variations arising from more recent housing forecasts, it is highly likely that BC Hydro's Residential forecast understates the increasing number of

[21] Exhibit B-1-1, p. 3-6 to 3-7 and Exhibit B-9, BCUC 1.2.1.
[22] Prior to account for the impact of new DSM.
[23] Exhibit B-14, BCUC 2.199.3.
[24] Exhibit B-14, BCUC 2.199.1.
[25] Exhibit B-9, BCUC 1.5.1.
[26] Exhibit B-9, BCUC 1.5.1.
[27] Exhibit B-10, CEC 1,15.5.
[28] Exhibit B-15, BCOAPO 2.131.1.
[29] Exhibit B-9, BCUC 1.5.2.

accounts for fiscals 2017-2019, and, as a result, understates forecast Residential load.

Light Industrial/Commercial Sector Forecast

48. For the Light Industrial/Commercial Sector, the Commercial load forecast is also based on Statistically Adjusted End Use Models. However, in this case the models estimate total sales as opposed to use per account.[30]

49. The main economic drivers for these models are employment, retail sales, Commercial GDP[31] and Provincial GDP. The Fairholm forecast is relied upon for the first three drivers, while the February 2016 Provincial Budget is the source of the forecast for provincial GDP.[32]

50. The Light Industrial portion of the sector's load forecast is developed on an industry segment basis in the case of forestry, oil and gas and coal mines. The forecast for other industrial customers is developed from a regression model that uses the real BC GDP as the driver.[33]

51. More recent forecasts of provincial GDP growth in 2016 and 2017 are higher than those used in the 2016 Load Forecast. As a result, BC Hydro has acknowledged that its forecast for this sector should be higher but does not consider the increase to be material.[34] Having examined the evidentiary record, BCOAPO accepts this proposition.

Large Industrial Forecast

52. BC Hydro's Large Industrial sector currently represents about 27 per cent of BC Hydro's total domestic sales and is comprised of oil and gas, mining and forestry businesses.[35] The Forestry component includes pulp and paper, wood and chemical loads and it represents approximately half of BC Hydro's Large Industrial sales.[36] Sales to mills are dependent on the U.S. housing market, exchange rates and the availability of wood, a precarious business, particularly in light of Trump Administration's April 24, 2017 imposition of import duties ranging from 3% to a punishing 24% on shipments to the US from Canadian forestry companies. Softwood lumber is subject to a 20% import duty now.

[30] Exhibit B-14, BCUC 2.199.3.1 and Exhibit B-15, BCOAPO 2.108.1.
[31] Exhibit B-10, AMPC 1.6.1.
[32] Exhibit B-1-1, p. 3-9.
[33] Exhibit B-1-1, p. 3-8.
[34] Exhibit B-9, BCUC 1.5.2.
[35] Exhibit B-1-1, p. 3-9.
[36] Exhibit B-1-1, p. 3-10 to 3-11.

53. BC Hydro prepares its Large Industrial forecast on an account-by-account basis that includes a risk/probability assessment regarding future expansion or contraction or the likelihood that previous trends will continue.[37]

54. BC Hydro notes that the actual to date 2016 results for the Large Industrial ratepayer group are below forecast.[38] However there have been recent increases in commodity prices in the oil and gas sector, for copper and metallurgical coal and for TMP such that prices are higher than those used in the 2016 Load Forecast.[39] While there is uncertainty about the whether these high prices will continue and their impact on new projects, the expectation is that the current variance from forecast will diminish.

55. In response to a BCOAPO IR, BC Hydro indicated that the forestry sector sales forecast largely consists of two main components: pulp and paper and wood products. For the pulp and paper sector, their consultants produce mill line production forecasts for all sizable mills in B.C.[40] BCOAPO notes that the aforementioned imposition of a 20% tariff on Canadian softwood lumber sales to the United States is expected to have a significant negative impact of British Columbia's mills, which in turn can be expected to exert downward pressure on the mill line forecasts which comprise part of BC Hydro's forecasted forestry sector sales.

56. BCOAPO notes with some surprise that in their May 23, 2017 Final Argument BC Hydro chose not to address this significant development in its section on Forestry Developments (paragraphs 113 to 116).

57. Despite this particular impact, BCOPAO acknowledges that there is considerable uncertainty associated with BC Hydro's Large Industrial load forecast in general, and accepts that this is a sector subject to externally driven fluctuations. As such BCOAPO submits that, despite the Utility's failure to address the softwood lumber issue, the forecast used in the Application is reasonable for the purpose of determining the 2017-2019 revenue requirements and rates.

2016 Forecast Adjustments

58. As noted above, adjustments are made to the sectoral load forecast to account for the impact of:

    (a) DSM,

    (b) SMI (i.e. the conversion of theft to sales),

[37] Exhibit B-1-1, p. 3-9.
[38] Exhibit B-14, BCUC 2.197.3.
[39] Exhibit B-14, BCUC 2.197.3.
[40] Exhibit B-10, BCOAPO 1.19.2.

(c) the codes and standards overlap between DSM savings and the sectoral forecasts,

(d) electric vehicles,

(e) rate impacts, and

(f) VAR and voltage optimization.

59. The DSM adjustment is based on BC Hydro's proposed F2017-F2019 DSM expenditures and associated benefits. BCOAPO addresses BC Hydro's DSM-related proposals in Section 10 of these submissions.

60. BCOAPO has no objection to the other adjustments that BC Hydro has made to its sectoral load forecasts.

Low Carbon Electrification

61. In various IR responses BC Hydro noted that it has not adjusted its 2016 Load Forecast for either the City of Vancouver's Renewable City Strategy or the Province's Climate Leadership Plan.[41] The Utility acknowledges that these initiatives are likely to increase electricity demand but it has not yet quantified these potential effects.

62. In various IR responses, BC Hydro indicated that its "early efforts" regarding low carbon electrification are focusing on upstream gas processing operations.[42] While it is still reportedly assessing opportunities, and BC Hydro has indicated it expects to have programs in place during the test period, it has not concluded any agreements to date. As a result, the actual timing and impacts of any programs remain uncertain.[43]

63. In BCOAPO's view, while it appears that there is some potential for programs associated with low carbon electrification in the short term, there is too little information available currently to be able to reliably quantify the impacts. However, as BC Hydro has indicated, there is substantial potential for increased electricity demand in the longer term.[44]

Need For an Update

64. In this process BC Hydro has acknowledged that there have been some changes in the economic outlook from where things were when they completed the 2016

[41] Exhibit B-10, CEC 1.14.2 and Exhibit B-4, BCUC 2.197.3.
[42] Exhibit B-14, BCUC 2.197.3 and Exhibit B-15, CEA 2.35.1.
[43] Exhibit B-15, BCSEA 2.55.2.1.
[44] Exhibit B-14, BCUC 2.197.3, Attachment 1, Sections 6.1.2, 6.2 and 6.3.

Load Forecast. However, it does not consider the changes to be significant enough that they would lead to a material change in the load forecast.[45]

BCOAPO has concerns regarding the timeliness (or, more specifically, the lack thereof) of the Fairholm economic outlook and, in particular, the housing starts and stock forecast, used by BC Hydro in preparing its load forecast.[46] Under other circumstances, BCOAPO's submissions would likely include proposed adjustments to the load forecast. However, the circumstances associated with the 2017-2019 test years are rather unique. First, variations in both revenues and the cost of energy arising from the actual load differing from forecast in the test years will be captured in the Heritage and Non-Heritage Deferral Accounts and either recovered from, or potentially refunded to, ratepayers in subsequent years. Second, given the 10-Year Rate Plan and the rate caps imposed for 2017-2019, it is unlikely that changes in the load forecast would actually change the rate increases for Fiscals 2017-2019. As a result, BCOAPO sees no benefit to advocating for updates or adjustments of the load forecast.

BCOAPO Concerns Regarding BC Hydro's Forecasting Methodology

65. BCOAPO notes that for both its fiscal 2015 and 2016 Domestic Energy Sales Forecast Less Demand-Side Management and its fiscal 2015 and 2016 Domestic Revenues, BC Hydro's predictions were greater than actuals. For Domestic Energy Sales Forecast Less Demand-Side Management fiscal 2015 was predicted (GWh) at 53,130 but the actual was 51,199 and for fiscal 2016 was predicted at 53,759 but the actual was 51,023.[47] For Domestic revenues fiscal 2015 was predicted (in millions) at 4,392.9 but the actual was 4,177.6 and for fiscal 2016 was predicted at 4,699.3 but the actual was 4,418.7.[48]

66. The Application itself acknowledges BC Hydro's history of over forecasting: "The Load Forecast continues to predict long-term load growth across all three customer sectors; however, load is forecast to be lower compared to the 2013 Integrated Resources Plan."[49]

67. This over-forecasting trend goes back eight years. Schedule 14 in Appendix A of the Application shows the historical actual domestic energy sales from fiscal 2007 to 2016, and then compares the historical forecast to actuals from fiscal 2009 to 2016. The actual total domestic energy sales have consistently been below forecast from fiscal 2009 to 2016. The variance is, on average, that domestic sales forecasts exceeded actuals by 3.9% over the last seven years and 3.3% over the last eight years.[50]

[45] Exhibit B-9, BCUC 1.5.2; Exhibit B-14, BCUC 2.197.3.
[46] See discussion above under "Residential Forecast."
[47] Exhibit B-1-1, Table 3-4.
[48] Exhibit B-1-1, Table 3-5
[49] Exhibit B-1-1, p. 3-33
[50] Exhibit B-9, BCUC 1.4.1

68. While in any given year there will a number of variables that may explain that year's variance, BCOAPO notes that this over-forecasting trend is consistent. This suggests that the total domestic energy sales forecasts for fiscal 2017, 2018 and 2019 could, under normal circumstances, each be adjusted downwards by 3% and still fall within an eight year demonstrated allowance for variance.

69. BC Hydro addresses this proposition in its Final Argument, stating, "Some information requests inquired about the impacts of reducing the May 2016 Load Forecast by specific percentages derived from the amount of past variances. BC Hydro submits that such an approach would be arbitrary and unsupported by the evidence."[51]

70. BCOAPO submits that the application of such an approach in future load forecasts would not be arbitrary, particularly because it would be an approach derived from a comparison of BC Hydro's own past forecasts against its past actuals. BCOAPO view such an approach as fully grounded in and supported by the evidence, warranting this Commission's consideration.

PART FOUR: COST OF ENERGY

71. In this Application, BC Hydro has asserted that the principal drivers for increases to the Cost of Energy are higher forecast IPP purchases of $464 million in fiscal 2019 as compared to fiscal 2016, primarily as a result of IPP projects becoming operational over the test period, and higher forecast Non-Heritage Deferral Account recoveries (approximately $96 million) flowing from a higher than forecast balance in that account.[52] The increased forecast for IPP projects is despite targeting the renewal of EPAs which offer the lowest cost, greatest certainty of continued operation and best system support characteristics.[53]

72. The Cost of Energy as set out in Table 1-7 consists of:

    (a) Heritage Energy,

    (b) Non-Heritage Energy, and

    (c) the net impact of HDA and NHDA recoveries.[54]

The forecast amounts for the first two items are set out below:[55]

[51] BC Hydro Final Argument, p. 54
[52] Exhibit B-1-1, p. 1-38 and 39.
[53] Exhibit B-1-1, p. 3-48.
[54] Exhibit B-10, CEA 1.1.1.
[55] Exhibit B-1-1, p. 4-3.

Table 4-1 Cost of Energy Forecast

Cost of Energy	F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Heritage Energy	311.6	388.9	357.6	206.1	279.3	250.2	279.3
Non-Heritage Energy	1,072.9	1,123.6	1,034.1	1,269.5	1,270.0	1,407.6	1,483.6
Total	**1,384.5**	**1,512.5**	**1,391.7**	**1,475.6**	**1,549.3**	**1,657.8**	**1,762.9**

73. The annual changes in the cost of Heritage Energy are primarily due to fluctuations in market electricity purchases and surplus sales which, in turn, are influenced by market prices for electricity, water inflows, initial storage levels and load levels.[56] Another factor affecting the forecast cost of Heritage Energy is the long overdue reduction in water rental fees for fiscal 2018 and 2019.[57]

74. The various cost components for the cost of Heritage Energy are set out below:[58]

5 **Table 4-3 Cost of Heritage Energy**

Cost of Energy	F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Heritage Energy							
Hydroelectric (Water Rentals)	385.1	361.4	384.5	357.7	379.9	350.4	350.1
Market Electricity Purchases	44.7	6.0	56.6	2.8	8.6	30.2	35.9
Market Purchases to Non-Heritage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas for Thermal Generation	26.6	24.0	26.9	20.0	14.9	10.5	10.7
Domestic Transmission	30.5	18.4	25.7	52.6	54.5	57.7	52.0
Columbia River Treaty Related Agreements	(7.8)	13.7	(19.8)	(14.4)	(23.1)	(10.4)	(7.2)
Surplus Sales	(122.6)	(0.2)	(84.2)	(174.1)	(118.1)	(150.4)	(129.2)
Remissions and Other	(44.9)	(34.4)	(32.1)	(38.6)	(37.3)	(37.8)	(33.1)
Total	**311.6**	**388.9**	**357.6**	**206.1**	**279.3**	**250.2**	**279.3**

75. In the case of Non-Heritage Energy, the main cost component is the cost of IPPs and Long Term Commitments as detailed below:[59]

[56] Exhibit B-1-1, p. 4-3 and 12.
[57] Exhibit B-1-1, p. 4-12.
[58] Exhibit B-1-1, p. 4-10.
[59] Exhibit B-1-1, p. 4-17.

1 **Table 4-7 Cost of Non-Heritage Energy**

Cost of Energy	F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Non-Heritage Energy							
Market Purchases from Heritage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric Water Rentals for Waneta	7.7	7.3	7.4	7.6	6.8	6.4	6.3
IPPs and Long-Term Commitments	1,028.6	1,064.0	975.5	1,228.9	1,234.4	1,369.7	1,439.3
Non-Integrated Area	32.9	25.5	34.3	22.6	24.6	27.4	31.1
Gas & Other Transportation	11.8	10.6	12.1	10.5	10.6	10.1	6.1
Net Purchases (Sales) from Powerex	(8.1)	16.2	4.8	(0.1)	(6.5)	(6.0)	0.7
Total	**1,072.9**	**1,123.6**	**1,034.1**	**1,269.5**	**1,270.0**	**1,407.6**	**1,483.6**

76. The increase in the cost of IPPs and Long-term Commitment over the forecast period is primarily the result of currently contracted and new projects reaching commercial operation, partially offset by less than full renewals of expiring Electricity Purchase Agreements.[60] The costs for the various IPPs and Long Term Commitment sources are set out below:[61]

1 **Table 4-10 IPP and Long-Term Purchase Costs**

Call Process	Number of EPAs[1]	F2015 RRA ($ million)	F2015 Actual ($ million)	F2016 RRA ($ million)	F2016 Actual ($ million)	F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Pre-2003 Electricity Purchase Agreements	32	268.2	275.6	273.0	252.4	277.2	281.0	261.6
2003 Green Power Generation Call	6	31.7	37.7	32.0	34.2	33.3	33.7	34.1
2006 Open Call	18	175.6	202.1	177.8	182.8	188.4	190.8	192.7
2008 Bioenergy Call - Phase 1	2	22.1	21.1	22.3	26.3	22.7	23.0	23.3
2008/10 Standing Offer Program	24	18.0	22.0	18.1	24.5	28.9	43.8	52.6
2010 Bioenergy Call - Phase 2	4	12.8	-	16.0	17.6	39.2	99.7	100.9
2010 Clean Power Call	20	158.4	151.2	169.3	171.9	242.0	336.0	358.3
2010 Integrated Power Offer	7	119.6	114.1	128.3	135.2	126.5	131.2	135.1
Negotiated Electricity Purchase Agreements	14	356.1	305.8	294.0	447.5	346.6	357.2	359.9
Expected Standing Offer Program Projects[(2)]	N/A	-	-	-	-	7.8	13.6	29.2
Total Payments to IPPs and Long-Term Commitments	**127**	**1,162.5**	**1,129.6**	**1,130.9**	**1,292.5**	**1,312.5**	**1,509.9**	**1,547.9**
Accounting Adjustments		(133.9)	(65.6)	(155.4)	(63.7)	(78.1)	(140.2)	(108.6)
IPPs and Long-Term Commitments		**1,028.6**	**1,064.0**	**975.5**	**1,228.9**	**1,234.4**	**1,369.7**	**1,439.3**

2 1. As of May 1, 2016 for projects connected to or planned to connect to the integrated grid.
3 2. Includes one co-generation project.

[60] Exhibit B-1-1, p. 4-21 and 22.
[61] Exhibit B-1-1, p. 4-22.

Heritage Energy

77. Water rentals are the most significant component of Heritage Energy costs. They are a function of the level of hydro generation (based on actual generation in the preceding year) and the water rental rates. For the test period, hydro storage levels are above average at the start and decline through the period.[62] Hydro generation correspondingly declines throughout the period.[63] This results in higher water rental fees in 2017, with a subsequent decline in Fiscals 2018 and 2019 as the impact of the annual CPI escalation in fees[64] is offset by the decline in hydro generation and the government's elimination, starting in 2018, of the Tier 3 water rental rate.[65]

78. The other contributing factor to the year over year change in Heritage Energy costs is the net effect of Market Purchases and Surplus Sales. The evidence indicates that there are significant surpluses (close to 5,000 GWh in F2017 and F2018, and 3,500 GWh in F2019) over the test period. [66]

79. Upon initial examination, there would appear to be a disconnect in the test period years between the unit cost of market purchases and the unit price for surplus sale, with the former being materially higher[67] despite the fact that surplus sales are "typically made during higher priced times of the day (i.e. heavy load hours) and higher priced months (i.e. winter months) of the year to maximize the consolidated net revenue".[68] However, BC Hydro's response to BCUC 2.205.1 indicates that this is because there are market purchases during the test period to accommodate system energy shortfalls in the January through April period in some of the hydro production sequences modelled.

80. BCOAPO has no material concerns regarding the forecast cost of Heritage Energy and notes that, via the Heritage Deferral Account, the actual cost of Heritage Energy will be eventually be trued up against the forecast.

Non-Heritage Energy

81. The cost of Non-Heritage Energy is driven primarily by forecasts of IPPs and long term commitments.[69] During the test period, BC Hydro is expecting increased volumes from IPPs as projects with existing purchase agreements come into commercial operation, as well as additional volumes from its current Standing Offer program.[70]

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[62] Exhibit B-1-1, p. 4-9.
[63] Exhibit B-10, BCOAPO 1.26.1.
[64] Exhibit B-1-1, p. 4-11.
[65] Exhibit B-1-1, p. 4-12.
[66] Exhibit B-10, CEC 1.32.3.
[67] Exhibit B-10, BCOAPO 1.26.1.
[68] Exhibit B-15, CEC 2.151.1.
[69] Exhibit B-1-1, p. 4-16.
[70] Exhibit B-9, BCUC 1.17.4.

82. Thankfully, BC Hydro is not expecting to issue any new calls during the test period. However, it does expect to renew some of the existing IPP contracts as they expire, albeit at lower contract prices.[71] The Utility has indicated that in determining whether to renew a particular contract their focus is not on the impacts during the test period but rather, how a renewal will contribute to meeting long-term system needs, for both energy and capacity, over the term of the renewal contract and that this longer term usefulness will be used to determine cost-effectiveness.[72]

83. BCOAPO agrees that, given the long-term nature of such agreements, this is the appropriate, high level, approach to take to renewals, provided the overall impacts can be managed within the 10 Year Rate Plan and BC Hydro pursues the best possible price and contract conditions possible on behalf of its ratepayers.

84. For planning purposes, BC Hydro has assumed that 50% of the energy contribution from expiring biomass EPAs and 75% of the energy contribution from expiring run-of-river hydro projects will be renewed.[73] The renewal assumptions are based on aggregate energy and capacity volumes, as opposed to the number of contracts.[74] This is, in BCOAPO's view, the better basis upon which to make any renewal assumptions.

85. Cost recovery is mandated for these contracts pursuant to section11 of Practice Direction No.7.

86. BC Hydro will file any new or renewed IPP contracts (apart from those exempted by regulation) with the Commission for review under section 71 of the Act.[75] Those reviews are based on a public interest assessment and BCOAPO looks forward to engaging in those reviews as we did for the Akolkolex and Soo River renewals in the fall of 2016.

87. Overall, while BCOAPO BCOAPO has no material concerns regarding the forecasting of the cost of Non-Heritage Energy, it cannot be said that the actual cost of this energy is of no concern: quite the opposite However, while the focus remains on forecasting, BCOAPO takes some comfort from the fact that the number and final cost of IPP renewals is uncertain, the forecast costs will be trued-up against actual costs via the Non-Heritage Deferral Account.

[71] Exhibit B-1-1, p. 3-43 and 4-22 and Exhibit B-9, BCUC 1.18.1 and 1.82.2.
[72] Exhibit B-9, BCUC 1.15.2.
[73] Exhibit B-1-1, p. 4-22.
[74] Exhibit B-9, BCUC 1.18.1.
[75] Exhibit B-9, BCUC 1.3.1.

PART FIVE: OPERATING COSTS

88. At this point in the 2013 10 Year Rates Plan, BCOAPO et al.'s members are becoming concerned that the Plan's ambitious goals are not achievable within the specified timeframe. However, that healthy scepticism does not mean they do not appreciate or support BC Hydro's ongoing efforts to control its operating costs. It is BCOAPO's view that every step that can be taken without compromising safety, reliability and customer service to free up money to go towards the 2013 10 Year Rate Plan ought to be encouraged and implemented.

89. Given the various cost pressures described in the Application, the Utility's effort to hold its forecast operating cost increases to 1.2 per cent annually over the test period[76] is admirable, although BCOAPO has - without advocating for a reduction in staff, property, or programs - identified specific areas where it submits the Commission can and should reduce the utility's Revenue Requirements for the F2017 to F2019 test period.

Overview of Operating Costs

90. The $976.3 M for F2017 and the comparable values for F2018 and F2019 from Table 1-7 represent the total Operating costs after consideration of Regulatory Account additions and recoveries as well as Provisions for and deferral of Provisions (including Rate Smoothing).

91. Total Operating Costs prior to these considerations are out below[77].

Operating Costs and Provisions - Total Company ($ million)

Line	Reference / Column	F2015 RRA 1	F2015 Actual 2	F2015 Diff 3=2-1	F2016 RRA 4	F2016 Actual 5	F2016 Diff 6=5-4	F2017 Plan 7	F2018 Plan 8	F2019 Plan 9
	Operating Costs by Business Group									
1	Training, Development and Generation	132.9	134.0	1.1	131.3	136.3	5.0	136.4	139.2	146.2
2	Transmission, Distribution and Customer Services	513.4	517.6	4.3	510.9	513.6	2.7	536.0	536.0	537.2
3	Customer Care	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	Capital Infrastructure Project Delivery	48.7	52.7	4.1	48.7	61.0	12.3	56.3	51.8	52.1
5	Operations Support	98.2	93.3	(5.0)	136.0	118.4	(17.6)	148.9	209.1	225.6
6	Severance Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Non-Current PEB - Pension	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Non-Current PEB - Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	F09/F10 RRA Adjustments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	F11 RRA NSA Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	F12-F14 RRA Adjustment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Total Before Regulatory Accounts	793.2	797.6	4.4	826.9	829.3	2.4	877.6	936.1	961.1

92. In this Application, BC Hydro has also introduced what its terms as "Base Operating Costs". This involves removing from the above costs the impacts of: i) IFRS Ineligible Capital Overhead (i.e., overhead costs that were previously capitalized but are now, under IFRS, are charged to operations and whose impact is being phased in), and ii) Operating costs related to Electricity Purchase Agreements accounted for as Capital Leases[78]. These values are summarized

[76] Exhibit B-1-1, p. 5-1.
[77] Exhibit B-1-1, Appendix A, Schedule 5. See also Exhibit B-10, CEA 1.2.1 & 1.2.2.
[78] Exhibit B-1-1, pages 1-23 to 1-24.

below for the three years of this test period and can be compared to the $712.7 M base operating costs from the 2016 RRA[79].

Table 1-2 Net operating Costs during the Test Period

Base Operating Costs (Table 1-1)		**746.5**	**747.2**	**759.0**
Operating Costs Related to Electricity Purchase Agreements Accounted for as Capital Leases (Schedule 5.1 line 15)	A	28.2	63.6	54.3
IFRS Ineligible Capital Overhead	B	102.9	125.3	147.7
Net Operating Costs (Schedule 5.0 line 12)	**C=A+B**	**877.6**	**936.1**	**961.0**

93. The breakdown by Business Unit is shown below[80].

Table 5-11 Operating Costs by Business Group

	($ million)	F2015 RRA	F2015 Actual	F2016 RRA	F2016 Actual	F2017 Plan	F2018 Plan	F2019 Plan
		1	2	3	4	5	6	7
1	Training, Development and Generation	132.9	134.0	131.3	136.3	136.4	139.2	146.2
2	Transmission, Distribution and Customer Services	513.4	517.6	510.9	513.6	536.0	536.0	537.2
3	Capital Infrastructure Project Delivery	48.7	52.7	48.7	61.0	56.3	51.8	52.1
4	Operations Support	98.2	93.3	136.0	118.4	148.9	209.1	225.6
5	Business Group Net Operating Costs	793.2	797.6	826.9	829.3	877.6	936.1	961.1
6	Regulatory Account Recoveries	176.0	175.9	162.9	162.9	203.2	182.6	182.7
7	Total (5.0 L47)	969.1	973.5	989.9	992.2	1,080.8	1,118.8	1,143.7

94. The year over year change in Base Operating costs is summarized below[81].

[79] Exhibit B-1-1, p. 5-19.
[80] Exhibit B-1-1, p. 5-32.
[81] Exhibit B-1-1, pp. 1-23 to 1-25.

Table 1-1 Base Operating Costs during the Test Period

		F2017 Plan ($ million)	F2018 Plan ($ million)	F2019 Plan ($ million)
Base Operating Cost (Table 5-5 Chapter 5)	A	**712.7**	**746.5**	**747.2**
Test Period Savings/Efficiencies	B	**(33.2)**	**(0.3)**	**(0.2)**
Test Period Cost Increases				
Unavoidable Costs		10.1	7.6	9.3
Capital-Driven		19.0	(3.1)	2.6
Initiatives		6.5	(1.5)	
Other Cost Pressures		9.3	(0.6)	0.2
Total Test Period Cost Increases	C	44.9	2.4	12.1
Net Increase/(Decrease) Excluding Smart Metering and Infrastructure - Operationalized Cost Net of Savings	D=B+C	11.7	2.1	11.9
Total Percentage Increase Excluding Smart Metering and Infrastructure - Operationalized Costs Net of Savings (%)	D/A	**1.6**	**0.3**	**1.6**
Smart Metering and Infrastructure	E	22.1	(1.4)	(0.1)
Net Increase/(Decrease) Including Smart Metering and Infrastructure - Operationalized Cost Net of Savings	F=D+E	33.8	0.7	11.8
Base Operating Costs	**G=A+F**	**746.5**	**747.2**	**759.0**
Total Percentage Increase Including Smart Metering and Infrastructure - Operationalized Costs Net of Saving (%)	G/A	**4.7**	**0.1**	**1.6**

BCOAPO Comments and Submissions

Fiscal 2017

95. BCOAPO notes that Actual Base Operating Costs increases for 2015 and 2016 were only those related to increased labour costs (e.g., salaries, wages, and pension) and those amounted to less than 1% per year[82]. However, for F2017, Base Operating Costs are projected to increase by 4.7% over the 2016 RRA level and 4.4% over 2016 actuals[83] despite planned efficiency savings for year of $33.2 M, efficiency savings offset by cost increases in various areas as set out in Table 5-5 of the Application.

96. However, offsetting these $33.2 M in efficiencies are cost increases in various areas as set out in Table 5-5 of the Application.

97. There are four aspects of the projected cost increases BCOAPO has determined are of particular concern: Safety Initiatives, Smart Metering and Infrastructure (Meter Reading Costs), Company-Wide Planned Savings and Efficiency Improvements, and First Nations Negotiations.

<u>Safety Initiatives</u>

98. First, in the Application, $5 M of the increase attributed to the offsetting of these savings is linked to Safety Initiatives. While BCOAPO takes no issue with the increased spending on safety, it does note that in one of its IR responses BC Hydro indicated, "these costs are not new expenditures for BC Hydro as other Business Groups evaluated the value of the investment, agreed that the investment made sense and have reduced their respective group spend in order to fund these safety activities and projects."[84] BC Hydro's response seems to indicate the incremental and sustained safety spends are fully offset by these referenced reductions in other Business Groups. How then is this $5 M incremental and truly an offset to the Utility's efficiency savings?

99. Relying on the information contained in IR 1.61.1, it is BCOAPO's view that, absent a compelling explanation from the Utility, the BCUC should adjust the calculation of BC Hydro's Revenue Requirements to take into account the revenue neutral nature of these cited Safety Initiative costs, thereby reducing BC Hydro's O&M costs in F2017 by $5 M.

<u>Smart Metering and Infrastructure (Meter Reading Costs)</u>

100. Second, roughly one-third of the cost increases ($22 M) are, according to BC Hydro, attributable to sustainment costs related to the Smart Metering and Infrastructure (SMI) program: costs that were previously deferred[85]. Table 5-2 from the Application sets out the incremental cost and savings from the SMI

[82] Exhibit B-9, BCUC 1.38.1 and 1.39.1.
[83] Exhibit B-1-1, p. 5-19 and Exhibit B-9, BCUC 1.38.1.
[84] Exhibit B-9, BCUC 1.61.1.
[85] Exhibit B-1-1, p. 5-24.

program now reflected in the F2017-F2019 RRA. One of the areas of cost savings incorporated in the Application is meter reading costs. For F2017, these have been reduced from $19.7 M to $9 M[86] and in the Application we were told they are expected to decline a further $1.2 M in F2018[87]. However, during the IR process BC Hydro reported that a more comprehensive assessment of the SMI program impacts was completed after the Utility filed its RRA. The figures presented in this IR response indicate that the forecast meter reading costs will be $6.095 M in F2018 and 5.961 M in F2019[88], far lower than the $7.8 presented in the Application.

101. BCOAPO notes that in this IR response there is no indication whether there are or what the savings will be for F2017, but, because that BC Hydro took back the responsibility for manual meter reading in 2016, BCOAPO submits that it is reasonable to assume the meter reading cost will be similar in that year, a full $3 M less than set out in the Application.

102. Given this new information, BCOAPO submits that the Commission should reduce BC Hydro's RRA for F2017 by $3 M, unless the Utility is able to present evidence demonstrating that its meter reading costs in F2017 are somehow forecast to remain at $7.8 M. Should that be the case, BCOAPO would also expect the Utility to explain to the Commission and Intervenors why it failed to realize the meter reading savings in F2017 that it expects to achieve in Fiscals 2018 and 2019.

<u>Company-Wide Cost Savings and Efficiencies</u>

103. Third, as discussed previously, planned savings and efficiency improvements of $33.2 M were incorporated in the 2017 operating cost forecast. In the Application BC Hydro indicated that this consisted of $15 M from the Transmission, Distribution and Customer Service Efficiency Initiative and $4.3 M from ongoing efforts to find company-wide cost savings and efficiencies[89].

104. However, during the IR process BC Hydro reported that the Transmission, Distribution and Customer Service initiative had actually identified savings of $19 M[90], not the forecast $15 M cited in the Application. The difference between those two figures, $4 M, was attributed to the company-wide savings as described on lines 21 to 22 of page 5-20 of the Application[91].

105. Transmission, Distribution, and Customer Service's additional $4 M in savings accounts for virtually all (93%) of what was reported as company-wide savings. Given that this Business Group represents only roughly 60% of BC

[86] Exhibit B-9, BCUC 1.28.1.
[87] Exhibit B-1-1, p. 5-11.
[88] Exhibit B-9, BCUC 1.28.3.
[89] Exhibit B-1-1, p. 5-20.
[90] Exhibit B-10, BCOAPO 1.33.1.
[91] *Ibid.*

Hydro's total operating costs, it would be reasonable to expect that ongoing efforts in the other Business Groups, whose forecast F2017 operating costs exceed $340 M will be able to find more than $0.3 M in cost savings and efficiencies. Even a cost savings from these groups of only 1.0 % would result in additional company-wide cost reductions of over $3 M.

106. BCOAPO cannot fathom why Business Groups representing approximately 40% of BC Hydro's total operating costs fell so far short of the mark, leaving Transmission, Distribution, and Customer Service to carry so much of the load in the identification and implementation of cost reductions. It raises the question whether the Transmission, Distribution and Customer Service Business Group was so inefficient that it could more easily bear such a disproportionate load of the cost cuts or whether other Business Groups somehow failed in their task to find cost savings.

First Nations Negotiations

107. Fourth and finally, for 2017 and after, BC Hydro is proposing that it be at risk for First Nations Negotiation costs[92]. The last RRA's rates were partly based on forecast First Nations Negotiation Costs of $3.5 M for 2015 and $3 M for 2016 but the evidence filed in this process indicates that the actuals were far lower: $1.6 M and $1.5 M[93] respectively.

108. In the Application, BC Hydro has forecast that its First Nations Negotiation costs will amount to $5.6 M for F2017. With respect, in the absence of sufficient evidentiary support for what can only be called a significant increase in the Utility's Negotiation Costs, Intervenors and the Commission must look to F2015 and F2016's actuals as a guideline to determine whether BC Hydro's forecast is reasonable. Because BCOAPO cannot find any support for this increase, it respectfully submits to this Commission Panel that a forecast of no more than $2 M for F2017 is more reasonable and that BC Hydro's Revenue Requirement be reduced accordingly.

Conclusions Regarding F2017 Operating Costs

109. BCOPAO submits that, based on the foregoing, it has demonstrated that, for 2017, BC Hydro's operating costs should be reduced by between $14 and $15 M.

Fiscals 2018 and 2019

110. In the Application, base operating costs are projected to increase by 0.1% in F2018 and 1.6% in F2019.[94] Unfortunately, the four problematic areas BCOAPO identified for 2017 remain active concerns in its evaluation of BC

[92] Exhibit B-1-1, p. 7-19.
[93] Appendix A, Schedule 5.0; Exhibit B-10, BCOAPO 1.39.1; and Exhibit B-9, BCUC 1.129.6 & 1.141.1.
[94] Exhibit B-1-1, Table 5-5

Hydro's Revenue Requirements for F2018 and F2019 for much the same reasons.

Safety Initiatives

111. In this submission, BCOAPO has already identified its concern and discussed the reasons for its opposition to BC Hydro's treatment of the $5 M increased cost for Safety Initiatives in F2017 as incremental. It notes that this same cost continues to be treated as incremental in the two remaining fiscal years in this Revenue Requirement. As a result, it should come as no surprise that this coalition of low income ratepayer groups is asking the BCUC to reduce BC Hydro's O&M costs in each of those two fiscal years by the corresponding amount: $5 M.

Smart Metering and Infrastructure (Meter Reading Costs)

112. As noted above, in the Application meter reading costs were projected to decrease to $7.8 M in F2018 and F2019. However, given that the more recent estimate of meter reading cost for these years is roughly $6 M[95], BCOAPO submits that operating costs can be reduced by approximately $2 M in each of these two fiscal years without any impact to BC Hydro's meter reading service.

Company-Wide Cost Savings and Efficiencies

113. While the cost reductions through savings and efficiencies are forecast be substantial in 2017, the further savings expected to be achieved in 2018 and 2019 are very minor ($0.3 M and $0.2 M respectively)[96]. BC Hydro's explanation is that:

> *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 commence in November 2016. Planning for fiscal 2019 will commence in November 2017[97].*

114. It is BCOAPO's view that, for purpose of the F2017-F2019 RRA, some recognition should be given to the additional savings that will arise in Fiscals 2018 and 2019 from BC Hydro's continuation of its Work Smart initiative, particularly when BC Hydro is planning on further enhancing it.[98] The response to BCUC 2.213.4 indicates that if 10 Work Smart initiatives were undertaken each year then the savings would increase by approximately $1 M per year. BC Hydro notes that not all of this would be operating cost savings but at the same time,

[95] Exhibit B-9, BCUC 1.28.3
[96] Exhibit B-1-1, Table 5-5.
[97] Exhibit B-9, BCUC 1.32.4.
[98] Exhibit B-9, BCUC 1.32.4.

operating costs in F2018 and F2019 will also be reduced by any additional corporate-wide savings identified for F2017.

First Nations Negotiations

115. For F2018 and F2019 BC Hydro has included First Nations negotiation cost of $3.7 M and $2.8 M respectively. Again, based on historic spending levels and the lack of evidence to justify these increased asks, BCOAPO sees no reason why the forecast for these costs should exceed $2 M in each year and asks the Commission to reduce BC Hydro's Revenue Requirement by the corresponding amounts.

Conclusions Regarding F2018 and F2019 Operating Costs

116. Based on these observations, BCOAPO submits that the operating cost for F2018 and F2019 should be reduced by at least $9 M and $8 M respectively.

PART 6: CAPITAL EXPENDITURES AND ADDITIONS

Overview of Capital Expenditures and Additions

117. Capital expenditures and the resulting capital additions drive changes in a number of the revenue requirement elements including depreciation, interest and return on equity (for 2017[99]).

118. The capital expenditure forecast for the test years (F2017-F2019) is part of a 10 Year Capital Forecast that is updated annually[100]. Key considerations in developing the 10 Year Capital Forecast are that the ten year capital forecast for F2015-F2024 should not exceed that included in the 10 Year Rates Plan and spending after F2024 should be reasonably consistent with capital expenditures in F2024 [101]:

119. Actual and planned capital expenditures are summarized in the following table[102]:

[99] Exhibit B-1-1, p. 8-6.
[100] Exhibit B-1-1, p. 6-11 and Appendix G, p. 1.
[101] Exhibit B-1-1, p. 6-11 and Appendix G, p. 1.
[102] Exhibit B-1-1, p. 6-6.

Table 6-3 BC Hydro Actual and Planned Growth and Sustaining Capital Expenditures Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Generation							
Growth (Schedule 13, Line 4)	116.1	108.0	71.2	61.2	20.0	2.4	0.7
Growth - Site C Clean Energy (Schedule 13, Line 15)	-	25.2	-	489.4	742.5	716.5	829.2
Sustaining (Schedule 13, Line 5)	516.5	418.2	535.7	436.8	530.0	534.0	424.3
Transmission & Distribution							
Growth	972.2	1,029.0	679.8	607.4	641.8	455.4	402.2
Sustaining	357.6	332.4	421.4	427.5	440.5	486.4	561.6
Business Support							
Technology (Schedule 13, Line 19)	164.1	115.2	109.3	122.3	83.9	93.4	78.8
Properties (Schedule 13, Line 22)	96.3	83.9	85.1	78.8	95.7	75.0	88.3
Fleet / Other (Schedule 13, Line 25)	29.7	47.9	36.6	72.5	49.7	48.6	39.6
Total	2,252.5	2,159.8	1,939.2	2,296.0	2,604.0	2,411.8	2,424.6
Less: Contribution in Aid	(85.1)	(333.9)	(124.1)	(135.5)	(86.4)	(100.2)	(106.4)
TOTAL	2,167.4	1,825.9	1,815.1	2,160.5	2,517.6	2,311.6	2,318.2

120. The resulting capital additions for the same period are[103]:

Table 6-4 BC Hydro Actual and Planned Growth and Sustaining Capital Additions Fiscal 2015 to Fiscal 2019

($ millions)	F2015		F2016		F2017	F2018	F2019
	RRA	Actual	RRA	Actual	Plan	Plan	Plan
Generation							
Growth	298.4	293.4	298.7	245.4	26.6	0.9	0.2
Sustaining	314.8	189.7	305.6	289.0	486.4	386.2	1,332.0
Transmission & Distribution							
Growth	1,313.3	1,137.9	1,627.0	1,486.8	581.9	472.8	442.8
Sustaining	330.0	340.5	400.3	431.5	437.4	374.6	429.0
Business Support							
Technology (Schedule 13, Line 45)	113.7	82.3	103.0	145.2	81.6	91.1	112.6
Properties (Schedule 13, Line 53)	113.4	83.6	92.4	160.9	68.3	118.1	25.5
Fleet / Other (Schedule 13, Line 56)	28.0	26.5	35.2	23.7	55.3	46.1	45.7
Total	2,511.6	2,153.8	2,862.2	2,782.6	1,737.6	1,489.9	2,387.8
Less: Contribution in Aid	(162.7)	(333.2)	(129.3)	(110.9)	(89.8)	(88.0)	(84.4)
TOTAL	2,348.9	1,820.6	2,732.9	2,671.7	1,647.8	1,401.9	2,303.4

[103] Exhibit B-1-1, p. 6-7.

BCOAPO Comments and Submissions

121. As a unit, BC Hydro uses a corporate investment risk framework which is then applied by its various business units to identify, assess and rank risk and value-driven capital projects in a consistent way[104]. This framework allows business units to prioritize capital projects to determine which should proceed over the short term and which can be delayed or moved to later periods. BCOAPO supports the use of this approach for capital planning as it allows for a consistent and risk-sensitive assessment of the diverse range of projects BC Hydro could potentially undertake.

122. It is noted that the current 10 Year Capital Forecast[105]:

- Is less than the capital expenditures in the 10 Year Rates Plan for the period (F2015-F2024) – excluding Site C.

- Is less than the previous year's (i.e., 2015) 10 Year Forecast for the period F2016-F2025.

123. For the test period, both capital spending and capital additions are less than previously planned in all areas of activity except Site C[106].

124. In response to information requests[107], BC Hydro provided the prioritization score for all uncommitted and discretionary (i.e. not mandatory) projects over $5 M that it is proposing to undertake as well as the scores for those projects it has delayed or cancelled[108]. BC Hydro has also explained provided its rationale for delaying some projects with higher risk scores than those it plans on pursuing.[109]

125. After reviewing the evidence generated on this subject matter, BCOAPO has no issues with BC Hydro's proposed capital expenditures or in-service additions for the test period.

126. Because the Growth portion of Generation includes Site C, counsel wishes to clarify that BCOAPO's position on this issue in this RRA cannot under any circumstances be said to be an endorsement of BC Hydro's Site C project. Because that project was exempted from review before this Utilities Commission by section 7(1)(d) of the *Clean Energy Act*, counsel for BCOAPO has not sought nor received instructions from the coalition's various member organizations regarding their support or opposition to Site C. The coalition's position is merely to indicate that in the absence of an opportunity to examine Site C on its merits,

[104] Exhibit B-1-1, p. 6-12; Appendix G, p. 4; and Exhibit B-9, BCUC 1.64.1.
[105] Exhibit B-1-1, Appendix G, p. 2.
[106] Exhibit B-1-1, Table 6-5.
[107] Exhibit B-10, BCOAPO 1.36.1.
[108] Exhibit B-10, BCOAPO 1.36.2 and Exhibit B-14, BCUC 2.149.8.
[109] Exhibit B-9, BCUC 1.73.9 and Exhibit B-15, BCOAPO 2.77.1.

and given the evidence BC Hydro has presented regarding its process and results, it has no objection to the capital proposals found in this Application.

PART SEVEN: DEFERRAL ACCOUNTS

127. As of the start of the 2017 rate year, BC Hydro has twenty eight regulatory accounts,[110] twenty-five of which have balances for disposition.[111] In its Application, BC Hydro seeks approval of the following, the specifics of which are summarized in Table 7-9[112]:

- Amortization periods for fund/recovery of the balances in those accounts that currently do not have an approved recovery mechanism.
- The continuation of certain regulatory accounts.
- The closure of certain accounts.
- Changes to the names and scope of some of the accounts.
- The application of interest to certain accounts.

128. While BC Hydro is requesting approval to change the scope of some of its regulatory accounts, it is not requesting any new accounts.

BCOAPO's General Concerns Regarding Deferral Accounts

129. Before commenting on specific aspects of BC Hydro's requests concerning its Deferral Accounts, BCOAPO offers broader contextual comments for the Commission's consideration. Although BC Hydro notes that regulatory accounts are common in the utility industry,[113] our client organizations are concerned about the air of complacency that has developed regarding the use of BC Hydro's deferral accounts in particular, and the apparent perception that the 10 Year Rates Plan stretches far enough into the future that we can take comfort in BC Hydro's assertion that the deferral accounts will be brought down to 3.6 billion[114] – which, in itself is a massive figure – and the Rate Smoothing Account cleared to zero by F2024. The target rate increases for the last 5 year of the 10 Year Rate Plan (F2020-F2024) are 2.6% per annum,[115] which are expected to fully recover the balances in the Rate Smoothing Regulatory Account by the end of F2024[116].

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[110] Table 7-2 in the Application (Exhibit B-1-1, p. 7-6) lists 29 accounts; however, according to BCUC 1.125.2, the "Home Options Purchase Plan" Regulatory Account is now closed.
[111] Exhibit B-1-1, p. 7-6.
[112] Exhibit B-1-1, p. 7-51 to 7-60, Table 7-9.
[113] Exhibit B-1-1, p. 7-3.
[114] Exhibit B-1-1, p. 7-5.
[115] Exhibit B-10, AMPC 1.1.3.
[116] Exhibit B-1-1, p. 1-18.

130. In reality, 2024 is not that far away. BCOAPO's constituents live on very low and fixed incomes, with no financial cushion to pay for massive increases in electricity rates. BC Hydro's deferral accounts are not an abstract accounting concept, but a debt that ratepayers will eventually have to pay – and a significant one at that. BC Hydro's deferral accounts had a shocking combined net balance of $5.9 billion at the beginning of fiscal 2017.[117] While government-directed rate caps have kept bills lower than they otherwise would have been in the short term, the increasingly aggressive use of deferral accounts shows that rate caps have been an artificial and short-sighted political solution.

131. Based on the revenue requirements approved by the Commission for F2015 and F2016, BC Hydro estimates that if the rate caps had not been in effect, the rate increases required for fiscal 2015 and fiscal 2016 would have been approximately 13.3 per cent and 4.6 per cent, respectively.[118]

132. Given these figures, BCOAPO's economically vulnerable constituents are understandably fearful of rate increases in the long term – specifically, what will happen after 2024 at the conclusion of the 10 Year Rates Plan when the piper must be paid.

133. BCOAPO submits that the Commission must be particularly vigilant in ensuring that BC Hydro is engaging in all activities that will allow it to reach its target of bringing deferral accounts down as planned by the end of the 10 Year Rates Plan while balancing this goal with concerns regarding rate shock as this is entirely in the public interest.

134. With those looming concerns in mind, BCOPAO provides the comments below on BC Hydro's specific proposals regarding its Deferral Accounts.

Requested Amortization Periods

135. In the Application BC Hydro has outlined five situations in which it is appropriate to use regulatory accounts[119]:

(a) To defer to a future period differences between forecast and actual costs or revenues;

(b) To better match costs with benefits for customers;

(c) To establish a non-cash provision regulatory account, in order to create a regulatory asset to match an accounting liability that is required under the accounting standards, prior to the actual expenditure of funds;

[117] Exhibit B-1-1, p. 7-5.
[118] Exhibit B-10, BCOAPO 1.8.1.
[119] Exhibit B-1-1, p. 7-9.

(d) To smooth out the rate impact of a large non-recurring cost or to smooth out rate increases; or

(e) To defer the impact of a required change in the accounting treatment of costs to ensure proper recovery of those costs in rates.

136. BCOAPO accepts that BC Hydro's proposals regarding the amortization periods for various regulatory accounts are generally linked to the purpose that initially gave rise to the accounts.[120]

137. In general, BCOAPO is not opposed to BC Hydro's rationale for setting recovery periods and the resulting proposals for the various regulatory accounts.

138. BC Hydro seeks approval of the recovery mechanisms and periods on an ongoing basis. During the balance of the 10 Year Rate Plan period, the impact of any resulting recoveries on year-to-year rate changes will be tempered by the rate caps established through government Direction[121], established targets for future rate increases, and the Rate Smoothing Regulatory Account. However, as noted above, once the 10 Year Rate Plan period ends those mechanisms will not apply. BC Hydro noted in its Application the need to balance the objectives underlying its proposed recovery periods "with the objective of keeping rates low, which may give rise to rate mitigation or smoothing mechanisms."[122]

139. BCOAPO partially agrees with that statement but believes the objective should be expanded to "keeping rates low and any necessary rate increases stable." To this end, BCOAPO submits that BC Hydro's recovery period proposals cannot be accepted and applied blindly on an ongoing basis (particularly after the conclusion of the 10 Year Rate Plan), as they may need to be adjusted in order to smooth future year over year rate adjustments. This need should be explicitly recognized by the Commission rather than approving the proposed recovery mechanisms on an ongoing basis.

Continuation of Certain Accounts

140. BC Hydro is requesting approval for the continuation of the following regulatory accounts:

- Capital Additions Regulatory Account[123]; and
- Total Finance Charges Regulatory Account.[124]

[120] Exhibit B-1-1, p. 7-15, Table 7-4.
[121] *Direction No. 7 to the British Columbia Utilities Commission*, BC Reg. 28/2014, s. 9: http://www.bclaws.ca/civix/document/id/lc/statreg/28_2014#section9
[122] Exhibit B-1-1, p. 7-15.
[123] Exhibit B-1-1, p. 7-21.
[124] Exhibit B-1-1, p. 7-22.

141. In general, BCOAPO is not opposed to the continuation of these accounts. However, we emphasize that its acceptance of any regulatory account is contingent upon Commission oversight of such accounts, including determining the appropriateness of the refund/recovery of any balances before they are incorporated into rates. In BCOAPO's view, such oversight may be particularly important for the Capital Additions Regulatory Account if actual additions were to exceed the forecast. In such a case, variance explanations such as those provided in BCUC 1.134.6 would become more relevant and require careful consideration. Such oversight could also be important in considering future balances in the proposed (re-named) Dismantling Cost Regulatory Account.

Closure of Certain Accounts

142. BC Hydro is requesting that the Minimum Reconnection Charges Deferral Account be closed upon recovery of the balance in the account in F2017 rates.[125] Once the current balance is recovered, BCOAPO agrees the account should be closed as it will have served its purpose.

Name and Scope Changes

143. BC Hydro is requesting approval for changes in scope of the following regulatory accounts:

(a) *Heritage Deferral Account* – Requested change to exclude annual negotiation costs (including litigation costs[126]) related to First Nations.[127]

(b) *Rock Bay Remediation Regulatory Account* - Effective starting in fiscal 2017, and on an ongoing basis, actual Rock Bay remediation costs will be deferred to this account each year, which is consistent with Direction 7 to the Commission,[128] and forecast Rock Bay remediation costs will be amortized from the account in each year.[129]

(c) *Asbestos Remediation Regulatory Account* – BC Hydro is proposing to change the name of this account to the "Remediation Regulatory Account."[130] Effective starting in fiscal 2017, and on an ongoing basis, actual asbestos remediation costs at BC Hydro facilities will be deferred to this account each year, and forecast asbestos remediation costs will be amortized from this account each year. Also, effective starting in fiscal 2017, and on an ongoing basis, actual expenditures related to compliance with polychlorinated biphenyl regulations will be deferred to this account each year, and forecast

[125] Exhibit B-1-1, p. 7-27.
[126] Exhibit B-15, BCOAPO 2.89.1.
[127] Exhibit B-1-1, p. 7-19.
[128] *Supra* note 17, s. 7(e).
[129] Exhibit B-1-1, p. 7-23 & Exhibit B-9, BCUC 1.136.1.
[130] Exhibit B-1-1, p. 7-25.

expenditures related to compliance with polychlorinated biphenyl regulations will be amortized from this account each year.[131]

(d) *Non-Current Pension Costs Regulatory Account* - BC Hydro is proposing to change the name of this account to the "Pension Costs Regulatory Account, effective fiscal 2017, and on an ongoing basis.[132] In addition to the current definition of variances that may be charged to the account, BC Hydro is proposing that the annual variance between the forecast costs and actual costs related to the operating cost portion of the post-employment benefits current pension costs also be deferred to the Pension Costs Regulatory Account, on an ongoing basis. These variances arise primarily due to changes between the planned and actual actuarial assumptions. Finally, The methodology used to forecast current service costs on BC Hydro's post-retirement benefit plans is to be changed, effective fiscal 2017 and on an ongoing basis. The forecast current service costs in previous revenue requirements applications were determined using the current discount rate in effect at the time the forecast was prepared. To minimize the volatility of the discount rate used for revenue requirements applications, starting in fiscal 2017 and on an ongoing basis, 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.[133]

(e) *First Nations Costs Regulatory Account* - Effective starting in fiscal 2017, and on an ongoing basis, actual lump sum settlement payments will be deferred to this account each year, and the forecast lump sum settlement payments are to be amortized over ten years, starting in the year of payment. Any difference between amortization of forecast lump sum settlement payments and the calculation of amortization based on actual settlement payments will give rise to a variance. Similarly, effective starting in fiscal 2017, and on an ongoing basis, actual annual settlement payments will be deferred to this account each year, and forecast annual settlement payments will be amortized from this account each year. In contrast, effective starting in fiscal 2017, and on an ongoing basis, actual negotiations costs will be deferred to this account each year, and actual negotiations costs will be recovered from this account each year. As a result, variances between forecast and actual negotiations costs will not be deferred to the First Nations Costs Regulatory Account, as BC Hydro believes it should bear the risks associated with the variances between forecast and actual annual negotiations costs.[134]

[131] Exhibit B-1-1, p. 7-26 & Exhibit B-9, BCUC 1.137.1 & 1.137.3.
[132] Exhibit B-1-1, p. 7-29.
[133] Exhibit B-1-1, pp. 7-29 to 7-30; Exhibit B-10, BCOAPO 1.43.1.
[134] Exhibit B-1-1, pp. 7-34 to 7-35.

(f) *Site C Regulatory Account* - BC Hydro requests the ability to defer to the account any costs related to the Site C Clean Energy Project that are not able to be capitalized under the Prescribed Standards.[135]

(g) *Future Removal and Site Restoration Regulatory Account* - The Future Removal and Site Restoration Regulatory Account is to be renamed the Dismantling Cost Regulatory Account. The terms of the account are to be changed so that the account defers, on an annual basis, any variances between planned and actual dismantling costs, to be effective starting in fiscal 2017. Actual dismantling costs are subject to a number of non-controllable events such as project schedule changes and cost variances, and therefore could differ materially from plan in a given year.[136]

(h) *Environmental Provisions Regulatory Account* - Starting in fiscal 2017 and on an ongoing basis, BC Hydro is proposing that, as the actual costs associated with compliance with polychlorinated biphenyl regulations are deferred to the Asbestos Remediation Regulatory Account (renamed the Remediation Regulatory Account), the Environmental Provisions Regulatory Account be reduced by an equal amount.[137]

(i) *Rate Smoothing Regulatory Account* – BC Hydro is requesting approval of the additions to the account for fiscal 2017 to fiscal 2019.[138]

144. BCOAPO is generally not opposed to BC Hydro's proposed name and scope changes for its regulatory accounts, with one exception. In response to an information request, BC Hydro indicated that it did not request a directive to defer cost variances related to Electricity Purchase Agreements classified as finance leases in the Application, as BC Hydro was not anticipating any variances related to accounting classification or commercial operation date timing.[139] However, BC Hydro is now aware that the commercial operation dates for the two new Fiscal 2017 Electricity Purchase Agreement finance leases have been delayed and will cause variances in Fiscal 2017. BC Hydro has indicated that, for the test period, it would not be opposed to a directive requiring the deferral to the Non-Heritage Deferral Account of all variances attributable to Electricity Purchase Agreements classified as finance leases that would not be transferred to existing regulatory accounts pursuant to existing orders.

145. BCOAPO submits that the Commission, as part of its Decision, should issue such a directive.

[135] Exhibit B-1-1, p. 7-36; Exhibit B-9, BCUC 1.150.2.
[136] Exhibit B-1-1, pp. 7-37 to 7-38.
[137] Exhibit B-1-1, p. 7-43.
[138] Exhibit B-1-1, p. 7-44.
[139] Exhibit B-9, BCUC 1.131.3,

Application of Interest

146. For certain accounts, BC Hydro is seeking to address the refund/recovery of interest applied to the accounts; namely that the forecast interest on the account be refunded/recovered in that year.[140] BC Hydro is also proposing the interest be applied to the balance in the (renamed) Dismantling Cost Regulatory Account, now that forecast dismantling costs will be included in rates.[141]

147. BCOPAO is not opposed to BC Hydro's proposals in this regard.

Principles for Establishing Regulatory Accounts

148. In Section 7.3 of the Application, BC Hydro sets out the five situations that it had noted in its F2005-F2006 Revenue Requirements Application where it considers it appropriate to use regulatory accounts, and notes that in some cases regulatory accounts are used to transfer risks and benefits that are non-controllable to its customers.[142] In the same section, BC Hydro describes its criteria for assessing whether a risk is controllable or non-controllable, and notes that these criteria were generally accepted by the Commission in 2004 – although the Commission also concluded that risk/reward considerations were a valid consideration.[143]

149. In Section 7.4, BC Hydro discussed what it considers to be an appropriate materiality threshold for creating a new regulatory account – namely un-forecast and non-controllable expenditures with a net income impact of greater than $10 M in a fiscal year.[144]

150. However, in response to information requests, BC Hydro indicated that it is <u>not</u> requesting approval of the positions put forward in sections 7.3 and 7.4 of the Application[145]; rather, it states that "proposals regarding specific regulatory accounts should be evaluated by the British Columbia Utilities Commission individually on their merits, recognizing that exceptions to principles can sometimes be warranted."[146]

151. BCOAPO agrees that that proposals regarding specific regulatory account should be evaluated individually on their merits. As a result, BCOAPO takes no position on the generic use of the principles and materiality threshold put forward by BC Hydro in sections 7.3 and 7.4 of the Application. BCOAPO also submits that the Commission should not make a determination on either the principles or the materiality threshold set out in these sections.

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[140] Exhibit B-1-1, pp. 7-23, 7-26 & 7-35.
[141] Exhibit B-1-1, pp. 7-37 to 7-38.
[142] Exhibit B-1-1, p. 7-9.
[143] Exhibit B-1-1, p. 7-10.
[144] Exhibit B-1-1, p. 7-16.
[145] Exhibit B-9, BCUC 1.125.1.
[146] *Ibid.*

PART EIGHT: OTHER REVENUE REQUIREMENTS ITEMS

152. Other revenue requirement items include amortization expense, return on equity, finance charges, taxes, non-tariff and inter-segment revenues, the allocation of BC Hydro's support costs and provisions, and other.

Depreciation and Amortization

153. In the Application BC Hydro is seeking approval for depreciation rates for certain property, plant and equipment at the Burrard Synchronous Condense Facility. Apart from this request the depreciation rates used by BC Hydro are based on its last depreciation study which was performed in 2006.[147]

154. During the 2012-2014 Revenue Requirements Application proceeding, BC Hydro indicated that it expected to undertake a depreciation study prior to its next revenue requirements application. However, BC Hydro subsequently determined that there was no expectation that asset lives had changed in a material way such that the benefits of a study would outweigh the costs.[148] In this Application BC Hydro has again indicated that it has no plans to carry out a depreciation study prior to its next rates application.[149]

155. In BCOAPO's view, considerable time (more than 10 years) has elapsed since the last depreciation study. While this does not necessarily mean that a new study should be done, it does suggest that the need for such a study should be carefully considered. In this regard, BCOAPO would support the Commission requiring BC Hydro to conduct a new depreciation study prior to their next revenue requirements application.

156. Apart from this submission regarding the next RRA cycle, BCOAPO has no concerns regarding BC Hydro's proposed depreciation and amortization charges for the F2017 to F2019 test years.

Finance Charges

157. The finance charges proposed in the Application are based on a Treasury Board forecast prepared in January 2016.[150] Since then, the Treasury Board has issued a more recent forecast (September 2016) wherein the interest rates for 2017-2019 are generally lower and the US/CAD exchange rate outlook has improved.[151]

158. In response to BCUC 2.300.3.1, BC Hydro provided an estimate of the impact of the updated forecast on the test period's finance charges and the

[147] Exhibit B-9, BCUC 1.151.1
[148] Exhibit B-14, BCUC 2.298.1
[149] Exhibit B-9, BCUC 1.151.2
[150] Exhibit B-1-1, p. 8-9
[151] Exhibit B-10, BCOAPO 1.49.1

results are material (more than $15 million in 2018 and 2019). However, BC Hydro noted that these changes would also impact other aspects of the revenue requirement and it would take considerable further work to fully revise the Application.

159. Under other circumstances, BCOAPO's submissions would likely have called for such an update as part of the Compliance filing or, at a minimum, a bottom-line adjustment to the proposed finance charges. However, as discussed above, the circumstances associated with the F2017 to F2019 test years are rather unique.

160. BCOAPO's decision not to ask for such an update is based on two factors. First, variations between forecast and actual finance charges will be captured in the Total Finance Charges Regulatory Account, and recovered from or refunded to ratepayers in subsequent years. Second, , given the 10 Year Rate Plan and the rate caps imposed for F2017 to F2019 it is unlikely that any changes in this Revenue Requirement resulting from updating the interest rate forecasts would actually change the rate increases for Fiscals 2017-2019.

161. Given the combined impact of these two facts, BCOAPO sees no benefit to requesting an update or adjustment to the Revenue Requirement Application to capture this new information.

162. BCOAPO has no further issues with the other revenue requirements as set out in the Application.

PART NINE: TRANSMISSION REVENUE REQUIREMENTS

163. BC Hydro is seeking final approval for its Open Access Transmission Tariff (OATT) Rates effective April 1 2017, April 1, 2018 and April 1, 2019.[152] The OATT rates are designed to collect BC Hydro's Transmission Revenue Requirement, which is based on BC Hydro's net transmission function costs.[153] The OATT Rates are not subject to the general rate increases or the associated rate caps.[154]

164. OATT rates are charged for Network Integration Transmission Service, Point-To-Point Transmission Service and Ancillary Services. BC Hydro and Powerex account for approximately 98.5% of the revenue collected through these rates, while external customers account for the remaining 1.5%.[155]

[152] Exhibit B-1-1, Appendix B
[153] Exhibit B-1-1, p. 9-1
[154] Exhibit B-9, BCUC 1.1.2
[155] Exhibit B-9, BCUC 1.165.2

165. Total revenue requirement offsets from external customers and inter-segment revenues due to transmission charges are in the order of $75 million per year over the test period.[156]

166. The methodology used to calculate the Transmission Revenue Requirement is consistent with that used in the fiscal 2012 –2014 Transmission Revenue Requirement as approved pursuant to Order No. G-77-12A, and the fiscal 2015 –2016 Transmission Revenue Requirement as approved pursuant to Order No. G-48-14.[157]

167. In its IR responses, BC Hydro acknowledged that the methodology was not updated to reflect the Commission's decision in BC Hydro's recent RDA proceeding. However, it has indicated it will do so as part of its Compliance Filing following the decision in this proceeding.[158]

168. BCOAPO agrees that the difference between the proposed fiscal 2017 and 2018 OATT rates and the interim fiscal 2017 and 2018 OATT rates approved by the Commission in Order No. G-40-16 and Order G-46-17, respectively, are appropriately recovered through a one-time charge to Transmission Customers.[159]

169. BCOAPO has no issues with the derivation of the OATT Rates proposed for Fiscals 2017, 2018 and 2019.

PART TEN: DEMAND-SIDE MANAGEMENT EXPENDITURES

170. Pursuant to section 44.2(5.1), in determining whether to accept the DSM expenditure schedule filed by BC Hydro, the Commission must consider:

- the interests of persons in British Columbia who receive or may receive service from BC Hydro;
- British Columbia's energy objectives;
- an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,
- the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

[156] Exhibit B-9, BCUC 1.166.1 and Exhibit B-1-1, Appendix A, Schedules 3.4 and 15
[157] Exhibit B-9, BCUC 1.161.1
[158] Exhibit B-9, BCUC 1.161.2 and 1.162.1
[159] BC Hydro Final Argument, p. 178

- the extent to which the DSM are cost-effective within the meaning prescribed by the *DSM Regulation*.

171. BC Hydro is seeking acceptance of the DSM Expenditure Schedule set out in Table 10-1 in the Application. Further details regarding this Schedule were provided in Table 10-7,[160] and it was amended in response to BCUC IR 2.314.3.

172. According to section 44.2(3), the Commission must accept the DSM schedule if the Commission considers that making the expenditures would be in the public interest or it may reject the schedule. Alternatively, the Commission may accept or reject a part of the schedule.

Background

173. BC Hydro's most recent Integrated Resource Plan was submitted to government and approved in November 2013 (the "2013 IRP"),[161] based on the load forecast and the load resource balances generated at that time. The 2013 IRP recommended "moderating" (i.e. reducing) DSM expenditures for F2014-F2016, and ramping expenditures back up in subsequent years to achieve 7,800 gigawatt-hours per year in energy savings, and 1,400 MW in capacity savings by F2021.[162]

174. Section 10.2 of the Application discusses the results of BC Hydro's F2014-F2016 DSM initiatives as compared to those approved in Order G-48-14 as part of the approval of BC Hydro's F2015-F2015 RRA.[163] The following tables show that both incremental electricity savings and DSM expenditures were less than planned[164]:

[160] Exhibit B-10, BCSEA 1.1.1.
[161] https://www.bchydro.com/energy-in-bc/planning-for-our-future/irp/current-plan/document-centre/reports/november-2013-irp.html
[162] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0009-nov-2013-irp-chap-9.pdf
[163] Added to this was the $19.6 M subsequently approved for the TMP program, per Exhibit B-1-1, page 10-5.
[164] Exhibit B-1-1, p. 10-5.

Table 10-3 Demand-Side Management Incremental Electricity Savings (GWh/year)

	Plan Values	Actual
F2014	737	686
F2015	578	444
F2016	927	872

Table 10-4 Demand-Side Management Expenditures ($ million)[66]

	Plan Values	Actual
F2014	236.3 (Note 1)	120.3
F2015	150.5	124.8
F2016	150.6[67]	145.2

175. The Application states that the major variance in F2014 was due to the fact that the F2014 plan value in the F2015-F2016 RRA did not reflect the transition to the moderation strategy as recommended in the 2013 IRP.[165] As a result of this strategy the F2014 DSM expenditures were reduced to $151.3 M and planned savings set at 778 GWh for the year.[166]

176. BC Hydro states that the remaining variances were largely due to project delays by customers, adjustments made to the offer to manage participation and incentive levels in the Commercial Power Smart Partner program, and the evaluation results for Residential, Commercial and Industrial Distribution rate structures where customer response to rates was lower than anticipated.[167]

177. Despite this, BCOAPO notes that planned and actual DSM expenditures evince a consistent trend of BC Hydro underspending its approved DSM budget for each of the years F2012-F2016.[168]

Proposed F2017-2019 DSM Expenditure Schedule

178. BC Hydro states that given the reduction in the rate of growth of demand for electricity in the short term, it has extended its “moderation strategy” (as applied in F2014-F2016) for three more years.[169]

179. BC Hydro states that the moderation strategy is appropriate, “in light of the reduced rate of growth of demand for electricity in the short-term, additional

[165] Exhibit B-10, BCOAPO 1.54.1.
[166] Exhibit B-1-1, p. 10-6.
[167] Exhibit B-1-1, p. 10-6.
[168] Exhibit B-10, BCOAPO 1.53.1; BCUC 1.174.1.
[169] Exhibit B-1-1, p. 10-2; BCH Final Argument, para. 404.

demand-side management resources are not required in the short-term to meet system needs or the 66 per cent BC Energy Objective in Fiscal 2021."[170]

180. The proposed demand-side management expenditure schedule includes a total of $361.1 million in spending over the test period, including funding for codes and standards, rate structures, programs, capacity-focused pilots, and supporting initiatives. [171] This represents an average of $125 million in expenditures during each year of the test period.[172] BC Hydro has stated that its DSM programs are designed to complement rates structures and are critical in setting the stage for changes to codes and standards.[173]

181. In its Final Submission, BC Hydro stated that:

> The broad accessibility of BC Hydro's demand-side management activities is reflected in the substantial forecast bill savings for customers. Customers are forecast to save $203.9 million in cumulative bill savings by participating in programs over the test period and to save over $950 million over the fiscal 2017 to fiscal 2024 period. With the inclusion of savings from Rate Structures and Codes and Standards, customers are forecast to save $568.7 million on their electricity bills over the test period, and over $2.8 billion from fiscal 2017 to fiscal 2024.[174]

182. BC Hydro further stated that those savings are attributable to all customer classes.[175]

183. Overall, the DSM schedule represents a significant reduction in planned expenditures in comparison to F2014-F2016, and an average annual amount below actual expenditures in F2016.[176]

184. BC Hydro states that there is a limited increase in "lost" or "missed" opportunities.[177] 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."[178]

185. BC Hydro has indicated that the considerations it took into account in developing the proposed DSM Plan were:

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[170] BCH Final Argument, para. 437.
[171] BC Hydro Final Argument, para. 403.
[172] BCH Final Argument, para. 406.
[173] Exhibit B-10, BCOAPO 1.44.1.
[174] BCH Final Argument, para. 413.
[175] BCH Final Argument, para. 414.
[176] Exhibit B-1-1, p. 10-5, Table 10-4.
[177] Exhibit B-10, BCSEA 1.7.1.
[178] BCH Final Argument, para. 450; Exhibit B-10, BCSEA 1.7.1.

(a) The 2013 IRP,[179] along with the reduced demand for electricity and postponed need date for new resources in the updated load/resource balance.[180]

(b) Cost-effectiveness tests,[181] including both the Total Resource Cost (TRC) Test and the Utility cost test, where the latter used both long-run marginal costs and the forecast BC-border sell price as avoided costs.

(c) Other Attributes which included[182]:

- Meeting the BC Energy Objective of BC Hydro reducing its expected increase in demand for electricity by the year 2020 by at least 66 per cent;
- Maintaining flexibility (to ramp up) through sustaining energy conservation presence and relationships with customers and suppliers (e.g., the BC Hydro Alliance of Energy Professionals);
- Supporting priority BC Hydro and government initiatives and strategic objectives (e.g., explore the full potential of energy conservation, and customer strategy);
- Meeting the targets of the 2013 10 Year Rates Plan;
- Providing broad access and coverage to conservation programs and information across each customer sector;
- Limiting missed opportunities for demand-side management customer projects; and
- Addressing energy and capacity load resource balance system needs (e.g., capacity initiatives).

186. In particular, BC Hydro considered an alternative DSM plan which was based on the 2013 IRP outlook, updated to reflect new developments such as lower planned savings from conservation rates and new energy savings from codes and standards. [183] BC Hydro cited a need to balance the various considerations outlined to justify its proposed Plan. Its evaluation of alternatives

[179] Exhibit B-1-1, p. 10-17.
[180] Exhibit B-1-1, pp. 3-28 and 3-33.
[181] Exhibit B-1-1, p. 10-18 to 10-19.
[182] Exhibit B-1-1, p. 10-20.
[183] Exhibit B-1-1, p. 10-21.

also included also a "No Programs" alternative (i.e., winding down programs but continuing with codes & standards and rate structures).[184]

187. In an IR response, BC Hydro stated that[185]:

(a) The selected DSM Plan has the benefits of mitigating rate increases while maintaining broad customer access to conservation programs and the ability to ramp up conservation program activity in the future, if required.

(b) The Plan provides an expanded energy management scope and reflects changing customer needs and meets the 66 per cent B.C. Energy Objective in F2021.

(c) As a result of the changes to the Plan, DSM program cost-effectiveness has improved.

BCOAPO Comments

188. BCOAPO is generally supportive of DSM and efforts to conserve energy – both in terms of environmental benefits potential for bill reductions for customers, particularly those living on lower and fixed incomes.

189. On the one hand, BCOAPO submits that the Commission should consider whether the proposed decrease in DSM spending is a response to what is a largely political problem of over-planning (including but not limited to government-directed calls for power, and actions undertaken to comply with the now-defunct government direction to purchase enough electricity from IPPs to achieve self-sufficiency in low water years) – and whether it is actually in the public interest to scale back DSM in a context where conservation culture should be encouraged. Although BC Hydro states that its DSM Plan retains the ability to ramp up expenditures in the future if resources are required,[186] BCOAPO submits there is significant value in maintaining a conservation culture in terms of customer outreach awareness, and take-up for programs.

190. On the other hand, BCOAPO recognizes that BC Hydro is, in fact, in an energy surplus, at least in the short term.

191. BCOAPO would not be supportive of No Programs alternative, as it was evaluated.[187] BCOAPO agrees with BC Hydro that such an alternative "would be contrary to the public interest, particularly given its negative impact on

[184] Exhibit B-1-1, p. 10-21, Table 10-5.
[185] Exhibit B-10, BCSEA 1.2.1.
[186] BCH Final Argument, para. 452.
[187] Exhibit B-1-1, p. 10-21, Table 10-5.

customers."[188] In any event, as BC Hydro notes, there is no indication that any other party is supportive of that alternative.[189]

192. BCOAPO notes that there have been some significant changes since the 2013 IRP, including the following:

(a) The change in BC Hydro's Load Resource Balances, which shows that new energy and capacity resources are needed in F2022 and F2020, respectively – later dates than envisioned in the 2013 IRP; and

(b) The adoption of the 10 Year Rate Plan and the associated objective of clearing the Rate Smoothing Account by 2024.

193. The changes in the present DSM plan for the Residential sector (from the F2014-F2016 Plan) involve[190]:

(a) Cancelling the Refrigerator Buy-Back program due to diminished savings;

(b) Removal of some Retail offers as they are not cost-effective at current market price;

(c) Shifting the New Home focus to codes and standards as opposed to incentives;

(d) Increased support for in-home display devices;

(e) Greater focus on leveraging data to provide customers with insights on their electricity consumption; and

(f) No change/reduction in Low Income Programs.

194. . BCOAPO submits that while it may not be an appropriate time to ramp up DSM expenditures, the expenditures should not be further reduced – it is important and in the public interest that customers continue to have reasonable access to DSM. Inevitably some of the positive effects achieved so far with DSM will be lost or eroded by further scaling back spending. BCOAPO submits that it is also in the public interest to consider the long term – although BC Hydro has stated that its DSM expenditures can be ramped up in the future if resources are required, this not occur with the flick of a switch; it takes time and extra effort to ramp back up such a complex strategy and associated programs, time ratepayers may not have in the face of rising energy costs, particularly with the

[188] BCH Final Argument, para. 440.
[189] BCH Final Argument, para. 441.
[190] Exhibit B-9, BCUC 1.169.2.1.

crest of the very large wave of increases now being artificially held at bay by politically-motivated rate caps. BC Hydro itself has acknowledged that ramp up its programs would take 3-5 years.[191]

195. At the same time, BCOAPO agrees with BC Hydro that it is in the public interest for the utility to prioritize certain DSM expenditures, and to reduce, discontinue, or amend DSM programs that are no longer cost effective, that have served their purpose, or are not responsive to customer needs.[192]

196. BCOAPO submits that BC Hydro should maintain its current spending envelope, and work together with ratepayers and stakeholders to mitigate potential rate impacts, and to determine which programs need to be eliminated, modified, or expanded. BCOAPO would be willing to participate in such a process through its representatives at BCPIAC.

197. Finally, BCOAPO disagrees with BC Hydro's assertion[193] that the Commission should give the letter from the Minister of Energy and Mines expressing government support for the DSM Plan[194] significant weight in determining whether to accept the proposed DSM Expenditure Schedule. The letter does not assist in answering the relevant question – that is, whether acceptance of the proposed DSM Expenditure Schedule is in the public interest.

Low Income DSM

198. BCOAPO is pleased to see that there will be no reduction in Low Income Program spending; however, we are of the view that these programs should be expanded and improved, with more focus on outreach and installations for the Energy Conservation Assistance Program than the far less impactful Energy Savings Kits.

199. In its Final Argument, BC Hydro stated that the Low Income Program "assists residents of low-income households, low-income housing providers, and First Nations communities in reducing energy consumption."[195] It also asserted that the Low Income Program "is designed to overcome market barriers to adoption of more energy efficient products, particularly affordability."[196]

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[191] BCH Final Argument, para. 455.
[192] BCH Final Argument, paras. 457-458. BCOAPO notes that BC Hydro uses the term "served their purpose" to indicate that the demand-side management initiative has been successful at achieving its objectives or that a new opportunity or change in the market place has signaled the need for a new or adjusted strategy (Exhibit B-10, BCSEA 1.5.1).
[193] BCH Final Argument, para. 444.
[194] Exhibit B-1-1, Appendix BB.
[195] BCH Final Argument, para. 419.
[196] *Ibid.*

200. In the 2015 BC Hydro Rate Design Application proceeding (the "2015 RDA"), BCOAPO requested the Commission Panel recommend that BC Hydro expand installs of its low income ECAP to serve a significantly higher percentage of the low income households than it was then serving.[197] In its decision, the Panel denied BCOAPO's request regarding the expansion of ECAP, stating that DSM strategy and individual program justifications, including the ECAP program, should instead be reviewed in the BC Hydro F2017 to F2019 RRA proceeding.[198] As such, we bring forward the same argument here.

201. BC Hydro offers two DSM programs to its low income customers (defined as LICO plus 30% in the *Demand-Side Measures Regulation*): Energy Saving Kits (ESK) and the Energy Conservation Assistance Program (ECAP).

202. ESKs provide "a package of basic, low-cost energy savings measured believed to be easily installed by any homeowner or tenant."[199] The ESKs have generated annual savings per customer of between 241 kWh and 329 kWh per year for participants.[200] These savings, however, include the ESKs that were "professionally installed"; the savings from ESKs that were self-installed reached only 203 kWh per year.[201]

203. ECAP offers two approaches: "basic" ECAP and "advanced" ECAP. Basic ECAP provides the same low-cost measures as the ESK plus "additional energy saving products such as energy-efficient refrigerators."[202] Advanced ECAP provides the basic ECAP services as well as comprehensive home insulation.[203] A program evaluation ECAP for F2010 and F2011 showed that ECAP resulted in an average annual energy savings of 874 kWh.[204]

204. In reality, BC Hydro is systematically reducing its commitment to low income DSM. Although BC Hydro indicates that it expects annual participation in its low income programs to be approximately 10,000,[205] this number combines both ESKs and ECAP (both basic and advanced).[206] As demonstrated in the paragraphs above, there is a major difference between these programs. While ECAP can provide substantial bill savings, those resulting from ESKs are negligible – and even lower when participants are left to their own devices to try

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[197] See BC Hydro Rate Design Application proceeding, BCOAPO September 26th Final Argument, p. 95: http://www.bcuc.com/Documents/Arguments/2016/DOC_47664_09-26-2016-BCOAPO-Final-Arguments.pdf.
[198] Decision, BC Hydro Rate Design Application proceeding, p. 107 http://www.bcuc.com/Documents/Proceedings/2017/DOC_48618_01-20-2017_G-5-17_BCH-2015-RDA-Decision-WEB.pdf.
[199] Exhibit B-5, BCOAPO 1.105.1 REVISED ATT 1, p. 6 of 27.
[200] Exhibit B-5, BCOAPO 1.105.1 REVISED ATT 1, p. 7 of 27, Footnote 2.
[201] Exhibit B-5, BCOAPO 1.105.1 REVISED ATT 1, p. 13 of 27.
[202] Exhibit B-5, BCOAPO 1.105.1 REVISED ATT 2, p. 8 of 31.
[203] *Ibid.*
[204] Exhibit B-5, BCOAPO 1.105.1 REVISED ATT 2, p. 20 of 31
[205] BCH Final Argument, para. 424.
[206] Exhibit B-10, BCSEA 1.20.2.

to install the products. BC Hydro now seeks to serve only 1,500 homes per year through basic ECAP, and a paltry 15 per year through advanced ECAP.[207]

205. BC Hydro has no mechanism in place to ensure that its annual low income targets are met, and, in fact, it has not spent to its budget for its low income DSM programs in past years. In F2014, BC Hydro budgeted $2.652 million for its low-income programs; in that fiscal year it spent only $2.185 million (spending only 82% of its budget).[208] In F2015, BC Hydro underspent even more, spending only $1.925 million while having budgeted $2.478 million.[209] BCOAPO understands that unspent funds budgeted for low income DSM are not rolled over into future years.

206. BCOAPO notes that during the time period when BC Hydro was underspending its Low Income DSM funds, there was no corresponding drop in eligible participants. During this time, Hydro rates have risen, even at the artificially low rates set by government caps, and housing costs have risen catastrophically, so more, not less British Columbians are experiencing energy poverty and could benefit from ESK and especially ECAP.

207. While BC Hydro has stated that its DSM Plan provides a reasonable opportunity for all customers to participate in one or more demand-side management programs,[210] BCOAPO submits that for low income customers there is a significant gap in the accuracy of that assertion, the gap between theory and practice.

208. There is, in our submission, room for the expansion of BC Hydro's low income ECAP, particularly given that low income customer awareness of this program is quite limited. Poverty rates are also especially acute for certain demographic groups that may face additional barriers to accessing programs, such as seniors, people with disabilities and recent immigrants and refugees.

209. BC Hydro details some efforts it makes to reach low income customers such as promotion through the Ministry of Social Development and Social Innovation, events at local foodbanks and other community organizations, and program promotion at Service BC locations,[211] its failure to meet its targets makes it clear that these outreach efforts could be improved. When asked, BC Hydro conceded that it "has not tried to create a list of organizations with the capability of delivering low-income DSM."[212]

210. Further, BC Hydro has not undertaken the steps that its own DSM evaluators have recommended in response to BC Hydro's failure to reach low

[207] Exhibit B-10, BCSEA 1.20.2.
[208] Exhibit B-5, BCOAPO 2.333.1.
[209] *Ibid.*
[210] Exhibit B-9, BCUC 1.176.5.
[211] Exhibit B-9, BCUC 1.176.5.1.
[212] Exhibit B-5, BCOAPO 2.329.1

income customers. In a February 2012 evaluation of ECAP, the third-party evaluator recommended that "BC Hydro should develop a better understanding of the characteristics of the residential customers that are not participating in DSM initiatives due to limited financial means to qualify and support an appropriately sized factor."[213] Moreover, BC Hydro's own evaluator concluded that "one barrier to higher market penetration in British Columbia may be the apparent difficulty in identifying those low income customers in electrically heated homes who require the more significant insulation upgrades. *As this is most likely the result of insufficient outreach methods, a rigorous process review might identify important areas for improvement*" (emphasis added).[214] The evaluator concluded that "[b]etter penetration and understanding of the target market would result in a higher participation rate and savings value."[215]

211. BC Hydro estimates that of its 1.6 million residential accounts (representing households), 11 percent fall into the low income category as defined by Statistics Canada Low Income Cut-off (LICO),[216] and about 21 percent of its residential customers have incomes at or below LICO plus 30%.[217] Clearly there is no shortage of eligible program participants – it is a matter of reaching those customers and incenting the Utility to do so.

212. To that end, BCOAPO submits that BC Hydro should actively seek community partnerships to deliver low income DSM more effectively, and should utilize the recently formed Low Income Advisory Council to determine how outreach can be improved.

213. BCOAPO hopes to see the number of program participants and the per-household savings both increase for low income customers in subsequent years.

PART ELEVEN: CONCLUSION

214. These submissions are made on behalf of the coalition of community groups collectively known in this proceeding as BCOAPO *et al*. These groups reflect lower and fixed income ratepayers who will be directly affected by the decisions made in this proceeding.

215. In this Application, BC Hydro has requested final approval by the Commission of rates for the three-year test period of fiscal 2017, 2018 and 2019. Previously, on March 22, 2016, the Commission approved an interim increase of 4.0% effective April 1, 2016. BC Hydro now requests permanent rate increases

[213] Exhibit B-5, BCOAPO IR 1.106.1 ATT 2, p. 34 of 40.
[214] Exhibit B-5, BCOAPO 1.105.1 (revised), ATT 2, at p. 27 of 31.
[215] Exhibit B-5, BCOAPO 1.105.1 (revised), ATT 2, at p. 10 of 31.
[216] Exhibit B-5, BCOAPO 1.106.1 REVISED ATT 1
[217] BC Hydro 2015 RDA, Exhibit B-1, Appendix C-3B, p. 216 of 609 (p. 2011 of PDF): http://www.bcuc.com/Documents/Proceedings/2015/DOC_44664_B-1-BCH-2015-Rate-Design-Appl.pdf. Figure based on BC Hydro's 2012 Residential End Use Survey.

of 4.0% effective April 1, 2016, 3.5% effective April 1, 2017 and 3.0% effective April 1, 2018.

216. These rate increases reflect the cap on rates directed by section 9 of Direction No. 7 to the Commission. Direction No. 7 also directs that the balance of BC Hydro's forecast revenue requirements in fiscal 2017, 2018 and 2019 be recorded in the Rate Smoothing Regulatory Account. The forecasted transfer to the Rate Smoothing Regulatory Account during the test period is $210 million in fiscal 2017, $286 million in fiscal 2018 and $299 million in fiscal 2019.

217. BC Hydro has estimated that but for the rates cap established by Direction No. 7 their proposed rate increases for the three-year test period would have been 8.9%, 5.0% and 3.0%, respectively.

218. An overarching consideration is that under the 2013 10 Year Rates Plan, any transfers to the Rate Smoothing Regulatory Account over the test period will have to be fully recovered by 2024. In other words, any revenue requirements the Commission approves over the rates cap will not be paid by ratepayers in the test period, but will be paid by ratepayers in the not too distant future.

219. Throughout these submissions, BCOAPO has crafted its positions taking into consideration the regulatory and legal parameters applicable to this Application, as detailed in Part 2 of these submissions, Legal Framework.

220. BCOAPO's main concerns are:

(a) We are already nearing the mid-point of the 2013 10 Year Rates Plan, and the time when ratepayers will be seeing the cost of retiring any amounts owing in the Rate Smoothing Regulatory Account is not that far off. This fast-approaching and daunting inevitability should, in BCOAPO's submission, be front of mind for the Commission in rendering its decision in this process.

(b) BC Hydro's history of over-forecasting its revenue requirements.

(c) BCOAPO has identified specific areas where it submits the Commission can and should reduce the utility's Revenue Requirements for the F2017 to F2019 test period. Specifically, BCOPAO submits that it has demonstrated that for F2017, BC Hydro's operating costs should be reduced by between $14 and $15 M, and F2018 and F2019 should be reduced by at least $9 M and $8 M respectively.

(d) Our client organizations are concerned about the air of complacency that has developed regarding the use of BC Hydro's deferral accounts in particular, and the apparent perception that the 10 Year Rates Plan stretches far enough into the future that we can take comfort in BC

Hydro's assertion that the deferral accounts will be brought down to 3.6 billion and the Rate Smoothing Account cleared to zero by F2024.

(e) BCOAPO submits that while it may not be an appropriate time to ramp up DSM expenditures, the expenditures should not be further reduced – it is important and in the public interest that customers continue to have reasonable access to DSM.

(f) BCOAPO notes that while BC Hydro has been underspending its Low Income DSM funds, there has been no corresponding drop in eligible participants. During this time, Hydro rates have risen, even at the artificially low rates set by government caps, and housing costs have risen catastrophically, so more, not less British Columbians are experiencing energy poverty and could benefit from ESK and especially ECAP.

All of which is respectfully submitted this 13th day of June, 2017.

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