4 May 2020

BCPIAC
Public Interest Advocacy Centre

Reply to: Leigha Worth
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Ph: 604-687-3034
Our File: 7500.120

VIA E-FILING

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

Dear Mr. Wruck,

**Re: British Columbia Hydro and Power Authority Application
F2020 to F2021 Revenue Requirements Application ~ Project No. 1598990
BCOAPO Final Argument**

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

Enclosed please find the BCOAPO's Final Argument with respect to the above-noted matter.

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

Sincerely,

BC PUBLIC INTEREST ADVOCACY CENTRE

Original on file signed by:

Leigha Worth
Executive Director | General Counsel

Encl.

BC OLD AGE PENSIONERS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, COUNCIL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, DISABILITY ALLIANCE BC, TENANT RESOURCE AND ADVISORY CENTRE, AND TOGETHER AGAINST POVERTY SOCIETY ("BCOAPO")

British Columbia Hydro and Power Authority Application F2020 to F2021 Revenue Requirements Application ~ Project No. 1598990

BCOAPO Final Argument

May 4, 2020

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Please be advised that we provide the following final argument regarding the above noted application on behalf of our client groups known in this and other regulatory processes as BCOAPO or BCOAPO et al. The constituent groups of BCOAPO et al. represent the interests of residential energy consumers in British Columbia, and more specifically in this process the interests of BC Hydro's residential ratepayers.

INTRODUCTION

On February 25, 2019, BC Hydro filed its Fiscal 2020 to Fiscal 2021 (F2020–F2021) Revenue Requirements Application[1] (the "Application") with the British Columbia Utilities Commission ("BCUC") requesting, among other things:

- Approval of a reduction of the Deferral Account Rate Rider from 5 percent to 0 percent effective April 1, 2019;
- Approval of an increase in rates by 6.85 percent effective April 1, 2019;
- Approval of an increase in rates by 0.72 percent effective April 1, 2020; and
- Approval of the F2020–F2021 Open Access Transmission Tariff rates as set out in Table 9-8 of the Application effective April 1, 2019 and April 1, 2020, respectively[2].

The Application also requested that that the changes be made effective April 1, 2019, on an interim basis, pending the BCUC's final decision regarding the Application[3]. The BCUC subsequently issued Order G-45-19 approving, on an interim basis, the requested rate increase of 6.85 percent, the reduction of the DARR to 0 percent, and the requested OATT rates for F2020, effective April 1, 2019.

On August 22, 2019, BC Hydro filed an evidentiary update to the Application ("Evidentiary Update"), adjusting its rate request effective April 1, 2020 from an increase of 0.72 percent

[1] Exhibit B-1
[2] Reducing the DARR to 0 percent results in a net bill increase of 1.76% effective April 1, 2019 (per Exhibit B-1, page 1-20)
[3] Page 1-30

to a decrease of 0.99 percent. Subsequently, on January 21, 2020, BC Hydro filed a correction to the Evidentiary Update, further adjusting its rate request effective April 1, 2020 from a decrease of 0.99 percent to a decrease of 1.01 percent.

On February 14, 2020, BC Hydro applied for approval of interim and refundable rates reflecting the 1.01 percent decrease effective April 1, 2020 and interim approval of the requested OATT rates for F2021 (F2021 Interim Rates Application). On February 26, 2020, the BCUC issued Order G-32-20 approving, on an interim basis, the requested 1.01% decrease and the requested OATT rates for F2021.

Other approvals sought by BC Hydro as part of the Application[4] include requests related to BC Hydro's regulatory accounts. BC Hydro is seeking approval to:

- Refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the fiscal 2020 to fiscal 2021 test period;
- Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;
- Defer any variances between forecast and actual amounts related to the Biomass Energy Program, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;
- Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period;

[4] Exhibit B-1, page 1-31

- Defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs;

- Remove the reference to the "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS;

- Close the Capital Project Investigation Costs Regulatory Account at the end of fiscal 2021 as its balance will be fully amortized into rates at that time; and

- Close the Rate Smoothing Regulatory Account in fiscal 2020 as this account has a zero balance and BC Hydro is not proposing to smooth rates over the fiscal 2020 to fiscal 2021 test period.

The Application also requests BCUC approval of:

- Depreciation rates for the Burrard synchronous condenser facility, for new Water Rights, Infrastructure Rights and LED Streetlights asset classes and for three new asset classes for agreements recognized as leases under International Financial Reporting Standard 16, Leases.

- A DSM expenditure schedule of $90.8 million in fiscal 2020 and $116.3 million in fiscal 2021[5].

By Orders G-45-19, G-146-19, G-218-19, G-268-19, G-279-19, G-312-19, G-64-20 and a letter issued March 5, 2020, the BCUC Panel established and later amended a Regulatory Timetable for the review of the Application which provided for, among other things, four rounds of interrogatories, an oral hearing and submission of written arguments.

In accordance with the most recent procedural order, we make the following submissions regarding BC Hydro's F2020-F2021 Revenue Requirements Application.

[5] Exhibit B-1, page 1-32

REVENUE REQUIREMENT OVERVIEW

In its evidence, BC Hydro presents its revenue requirement in two formats[6]: the Gross View and the Current View. The Gross View shows the total costs for each component of the revenue requirements before any forecast transfers to regulatory accounts and then shows the regulatory account transfers as a separate total. In other words, the "Gross View" shows the total costs incurred in fiscal 2020 and fiscal 2021. In contrast, the Current View shows the total costs for each component of the revenue requirements after any forecast transfers to regulatory accounts. In other words, the "Current View" shows the actual costs being recovered from customers in rates in fiscal 2020 and fiscal 2021 - a view most residential customers would see as comparable to the difference between their gross and net pay.

BC Hydro's detailed explanations regarding each component of the revenue requirement focuses on the Gross View. The following schedule summarizes the requested revenue requirements for F2020 and F2021 in the Gross View based on the Evidentiary Update (including the January 2020 corrections) as compared to the original Application[7].

[6] Exhibit B-1, page 1-33 – 1-34
[7] Exhibit B-11-2, Appendix A, Schedule 1.0

·nue Requirements Summary llion)										
		F2019			F2020			F2021		
	Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
Cost of Energy	3.0 L1	1,762.9	1,518.7	(244.2)	1,887.0	1,928.9	41.9	1,920.2	1,734.6	(185.6)
Operating Costs	3.0 L13	1,221.0	1,277.0	56.0	1,224.2	1,239.1	14.9	1,229.3	1,217.2	(12.1)
Taxes	3.0 L22	238.7	242.7	4.1	249.8	249.8	0.0	262.2	262.2	0.0
Amortization	3.0 L25	850.9	871.3	20.5	915.7	977.8	62.1	936.5	998.0	61.5
Finance Charges	3.0 L31	773.8	1,192.2	418.4	757.5	874.9	117.4	726.9	743.3	16.4
Return on Equity	3.0 L38	712.0	(428.2)	(1,140.2)	712.0	712.0	0.0	712.0	712.0	0.0
Miscellaneous Revenue	3.0 L42	(140.6)	(224.4)	(83.8)	(240.8)	(240.7)	0.1	(247.2)	(247.0)	0.1
Inter-Segment Revenue	3.0 L51	(65.3)	(62.5)	2.8	(69.0)	(64.9)	4.1	(72.6)	(71.9)	0.7
Deferral Accounts										
Deferral Account Additions	2.1 L24	0.0	586.0	586.0	3.1	3.1	0.0	3.5	3.5	0.0
Interest on Deferral Accounts	2.1 L25	(26.6)	8.2	34.7	8.9	15.4	6.5	3.0	4.0	1.1
Deferral Account Recoveries	2.1 L26	241.8	240.6	(1.3)	(164.5)	(403.9)	(239.4)	(164.5)	(226.9)	(62.3)
Total		215.3	834.7	619.4	(152.5)	(385.4)	(232.9)	(158.1)	(219.4)	(61.3)
Other Regulatory Accounts										
Regulatory Account Additions	2.2 L204	(201.6)	(636.4)	(434.8)	(168.2)	(267.7)	(99.5)	(162.3)	(133.1)	29.1
Interest on Regulatory Accounts	2.2 L205	(33.5)	(35.7)	(2.2)	(33.2)	(33.1)	0.1	(30.5)	(30.0)	0.5
Regulatory Account Recoveries	2.2 L206	(111.6)	956.9	1,068.5	326.7	386.7	60.0	324.7	384.6	59.8
Total		(346.8)	284.8	631.6	125.3	85.9	(39.4)	131.9	221.4	89.4
Subsidiary Net Income										
Powerex Net Income		(115.1)	(435.7)	(320.5)	(120.6)	(120.6)	0.0	(120.6)	(120.6)	0.0
Powertech Net Income		(5.1)	(3.5)	1.6	(3.4)	(3.4)	0.0	(3.7)	(3.7)	0.0
Total		(120.2)	(439.1)	(318.9)	(124.0)	(124.0)	0.0	(124.3)	(124.3)	0.0
Less Other Utilities Revenue	14.0 L18	(12.1)	(29.6)	(17.5)	(28.6)	(28.8)	(0.2)	(28.7)	(28.7)	0.0
Less Liquefied Natural Gas Revenue	14.0 L19	(10.9)	(1.8)	9.1	0.0	(0.6)	(0.6)	0.0	0.0	0.0
Less Deferral Account Rate Rider	14.0 L21	(241.8)	(240.6)	1.2	0.0	0.0	0.0	0.0	0.0	0.0
Total Rate Revenue Requirement		4,836.8	4,795.2	(41.6)	5,256.5	5,223.9	(32.6)	5,288.3	5,197.4	(90.9)
Rate Revenue at Current Rates										
Total Domestic Revenue	14.0 L22	5,101.6	5,067.2	(34.4)	4,948.2	4,918.5	(29.7)	4,942.4	4,942.4	0.1
Less Other Utilities	Line 20	(12.1)	(29.6)	(17.5)	(28.6)	(28.8)	(0.2)	(28.7)	(28.7)	0.0
Less Liquefied Natural Gas Revenue	Line 21	(10.9)	(1.8)	9.1	0.0	(0.6)	(0.6)	0.0	0.0	0.0
Less Deferral Account Rate Rider	Line 22	(241.8)	(240.6)	1.2	0.0	0.0	0.0	0.0	0.0	0.0
Revenue Subject to Rate Increase		4,836.8	4,795.2	(41.6)	4,919.6	4,889.1	(30.5)	4,913.7	4,913.8	0.1
Revenue Shortfall	L23 - L28	0.0	(0.0)	(0.0)	336.9	334.8	(2.1)	374.5	283.6	(90.9)
Rate Increases		3.00%	3.00%	-	6.85%	6.85%	(0.00%)	0.72%	(1.01%)	(1.73%)
Deferral Account Rate Rider		5.00%	5.00%	-	-	-	-	-	-	-
Net Bill Impact		3.00%	3.00%	-	1.76%	1.76%	(0.00%)	0.72%	(1.01%)	(1.73%)

Submissions

Evidentiary Update

The Evidentiary Update filed in August 2019 updated various components of BC Hydro's proposed F2020 and F2021 revenue requirements. However, the update was by no means comprehensive bur rather limited to "targeted adjustments"[8]:

As part of the Evidentiary Update the balances in the regulatory accounts and the proposed recoveries in F2020 and F2021 were revised to reflect F2019 actual financial

[8] Exhibit B-16, BCUC 3.313.2

results[9]. However, in IR's it became clear that these updated actuals were not used to revise the forecast F2020 and F2021 values for Trade Income and Storm Damage Costs, even though the forecast methodology in both cases is based on average historical results[10] - a fact well worth noting.

The load forecast adjustments made were limited to incorporating the actual sales for April and May 2019. BC Hydro states that the results of its more recent load forecast (June 2019) were not available in time for the Update and indicated that in its opinion, the changes were not material[11]. However, knowing as we do that the actuals for May 2019 would not have been available until June 2019 begs the question how BC Hydro could claim that its June 2019 forecast was not available at the time - when does the utility formulate its monthly forecasts that it could not have included the June 2019 forecast in the update? In section "Load Forecast" of our submissions, BCOAPO goes into greater detail regarding the June 2019 Load Forecast, noting the differences between the October 2018 and June 2019 one before putting on the record our view that the June 2019 LF was itself less than comprehensive.

For its capital planning in this Application, BC Hydro uses the peak demand forecast and the capital expenditures forecasts based on the peak demand forecasts prepared in 2016 and 2017[12]. However, there were no adjustments made to BC Hydro's proposed capital expenditures for F2020 and F2021 to reflect more recent peak demand forecasts (including the June 2019 Peak Demand Forecast[13]) despite the obvious linkage between the two values.

BCOAPO submits that, rather than being "targeted", evidentiary updates should be as comprehensive as possible within reason to avoid situations where there is a major disconnect as there is in the current case. To ensure this, BCOAPO asks the BCUC to direct that this be the case in future revenue requirement review proceedings.

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[9] Exhibit B-11, page 2 and Appendix A, Schedules 2.1 & 2.2
[10] Exhibit B-16, BCUC 3.313.2
[11] Exhibit B-11, page 4
[12] Exhibit B-16, AMPC 2.23.3. Note: For Substations and Distribution capital spending allowance was made for the fact actual substation load growth was moderating.
[13] Exhibit B-15, Appendix B

Reported Rate Increases

In BCOAPO's submission, BC Hydro's presentation of the rate increases resulting from its Evidentiary Update is misleading. For purposes of the F2020 and F2021 rate increase calculations (i.e., 6.85% and -1.01% respectively), the total Revenue Requirements have been reduced by $403.9 M and $226.9 M respectively for Deferral Account Recoveries (or in this case Deferral Account refunds to ratepayers). In previous Applications such "recoveries" were accounted for through the Deferral Account Rate Rider and excluded from the base rate increase calculations. Using a similar approach for this Application would produce:

- Total Revenue Requirements for F2020 and F2021 of $5,627.8 M (i.e., $5,223.9 + $403.9) and $5,424.3 M (i.e., $5,197.4 + $226.9) respectively;
- Rate Increases for F2020 and F2021 of 15.1% and -4.1% respectively;
- DARR values for F2020 and F2021 of -7.2% and -4.2% respectively.

However, the bill impacts for F2020 and F2021 would still be 1.76% and -1.01% respectively, as per the Evidentiary Update.

The key take-away from the preceding analysis is that the year over year cost increases for F2020 vs. F2019 are materially higher than the 6.85% suggested by the presentation used in the Application while the increases for F2021 over F2020 are less.

The following sections address the various elements of the revenue requirements requested, starting with the load forecast underlying the application[14].

LOAD FORECAST

BC Hydro completed the load forecast informing the Application in October of 2018[15]. The methodology used was largely consistent with the one used in the May 2016 Load

[14] Note: The load forecast is used primarily in the determination of the Cost of Energy, DSM Expenditures and Revenues at F2019 Rates
[15] Exhibit B-1, page 3-1

Forecast[16]: the forecast originally used to support the F2017-F2019 RRA. The approach used followed these steps[17]:

- Develop a billed sales forecast before rate or DSM impacts using a combination of forecasting models (residential, commercial, a portion of light industrial sector) and customer-based load forecasts (large industrial and some sub-sectors within the light industrial sectors). This step also included adjustments to model projections, such as including the impacts of emerging new loads (e.g., fuel switching, cannabis, cryptocurrency and electric vehicles);

- Develop a billed sales forecast after rate impacts with the price elasticity assumption of - 0.1 and the forecast of bill impacts;

- Develop a billed sales forecast after load reductions for loss reduction savings and DSM savings; and

- Develop an accrued sales forecast after loss reduction savings and DSM savings for the purpose of forecasting revenues.

However, for the purpose of preparing the October 2018 Load Forecast, a number of changes were made to the approach used in May 2016[18]:

- The approach to forecasting the number of Residential accounts was revised[19];

- The regression models used for the Residential, Commercial/Light Industrial sectors were recalibrated using more recent data[20];

- For the Residential and Commercial sectors customer response to temperature was updated[21];

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[16] Exhibit B-1, pages 3-10, 3-18 and 3-23
[17] Exhibit B-13, AMPC 2.23.1
[18] A more detailed discussion of the changes made is provided in Exhibit B-5, BCUC 1.5.1 and Exhibit B-1, Appendix O, page 19
[19] Exhibit B-1, page 3-15
[20] Exhibit B-1, pages 3-14 and 3-20
[21] Exhibit B-1, pages 3-15 and 3-20

- The electricity price elasticity assumption used for all the main customer sectors was updated from -0.05 to -0.10[22];

- A change was made in how the individual customer probability assessments (for new and operational shut downs) were incorporated into the first three years of the Large Industrial Sector load forecast[23].

As well as recalibrating the Residential and Commercial/Light Industrial models, the October 2018 Load Forecast utilized more recent economic forecasts prepared by the Conference Board of Canada (June 2018) and the BC Ministry of Finance (September 2018)[24]. The Residential and Commercial forecasts also used updated (higher) efficiency projections[25].

As part of the August 2019 Evidentiary Update, BC Hydro updated its load forecast for F2020 to incorporate actual sales for April and May 2019. Otherwise the load forecast was unchanged[26]. The following schedule summarizes the October 2019 Load Forecast used in the initial Application and the revised forecast per the Evidentiary Update[27].

			F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Domestic Energy Sales (GWh)										
1	Residential		18,250	18,000	-250	18,258	18,151	-108	18,330	18,330	0
2	Light Industrial and Commercial		18,899	19,007	108	18,973	18,915	-58	19,030	19,030	0
3	Large Industrial		13,743	13,874	131	14,702	14,592	-110	14,243	14,243	0
4	Irrigation		67	79	12	79	77	-1	79	79	0
5	Street Lighting		239	225	-14	232	230	-2	232	232	0
6	New Westminster & Tongass		491	463	-28	471	467	-3	472	472	0
7	Fortis		527	435	-92	542	545	3	555	555	0
8	Seattle City Light		310	309	-2	310	311	0	310	310	0
9	Liquefied Natural Gas		139	22	-117	0	7	7	0	0	0
10	Total		52,664	52,413	-251	53,567	53,296	-271	53,253	53,253	0

In October 2019 BC Hydro filed its June 2019 Load Forecast, covering fiscal 2020 to fiscal 2039[28]. In the filing, BC Hydro noted[29] that while the June 2019 Load Forecast is on average higher, it is within 0.1 per cent of the October 2018 Load Forecast for the Test

22 Exhibit B-1, page 3-17
23 Exhibit B-1, pages 3-27 – 3-28. See also, Exhibit B-13, BCOAPO 2.96.2
24 Exhibit B-1, pages 3-40 – 3-42 and Exhibit B-6, BCOAPO 1.19.2
25 Exhibit B-13, BCOAPO 2.96.4
26 Exhibit B-11, page 3
27 Exhibit B-11, Appendix A, Schedule 14.0
28 Exhibit B-15
29 Page 10

Period. Accordingly, BC Hydro did not propose any further adjustments to the revenue forecast provided in the Evidentiary Update.

<u>Submissions</u>

Methodology Changes

BCOAPO notes that the methodology changes incorporated by BC Hydro are largely the result of either: i) updating its models/assumptions to incorporate more current data or ii) addressing issues raised by either the BCUC or its own internal audit review of its load forecasting function[30]. In the interest of regulatory efficiency, BCOAPO will forgo addressing all aspects changed, instead opting to note only those aspects of BC Hydro's load forecasting methodology or the resulting forecast for the test period (F2020-F2021) that cause concern.

Application of Elasticity Estimates

In this process, BC Hydro has acknowledged[31] that the rate increases used in calculate the price elasticity impacts are based on the last five years of the 2013 10 Year Rates as opposed to those proposed in the Application. While the impacts are not material in this case (i.e., the proposed load forecasts for F2020 and F2021 are 0.1% and 0.5% respectively lower)[32], the same cannot be said for future revenue requirement applications. BCOAPO submits that the BCUC should direct BC Hydro, to the extent possible[33], to align the rate increase assumptions used for purposes of determining price elasticity impacts on its load forecast with the proposed rate increases.

Economic Forecasts Used

The October 2018 Load Forecast utilized forecasts for BC GDP and BC Commercial GDP prepared earlier the same year[34]. Subsequent forecasts prepared by the BC Ministry of

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[30] Exhibit B-1, pages 3-3 – 3-8 and Appendix O, pages 16-19
[31] Exhibit B-12, BCUC 2.211.2
[32] Exhibit B-12, BCUC 1.211.2
[33] It is recognized that the load forecast is an input to the determination of the test period revenue requirements and resulting proposed rate increases and, as such, total alignment may not be possible.
[34] Exhibit B-6, BCOAPO 1.19,2

Finance projected higher annual increases in BC GDP over the test period years than those provided in 2018 by either the Conference Board or the Ministry of Finance, as can be seen in the following table[35].

GDP Comparison Table – Fiscal 2019 to Fiscal 2022

Calendar Year	June 2018 Conference Board Commercial GDP Growth (%)	June 2018 Conference Board Total B.C. GDP Growth (%)	September 2018 Ministry of Finance Total B.C. GDP Growth (%)	February 2019 Ministry of Finance Total B.C. GDP Growth (%)
2019	2.6	2.2	1.8	2.4
2020	2.6	2.3	2.0	2.3
2021	2.2	1.8	2.0	2.1
2022	2.0	2.1	2.0	2.0

However, the load forecast used in the Evidentiary Update was not revised to reflect these higher BC GDP growth rates. Furthermore, while no updates have been provided for the Conference Board's June 2018 forecast for BC Commercial GDP one would expect, since it is a component of BC's overall GDP, an updated forecast for BC Commercial GDP would also be higher than those used in the 2018 Load Forecast.

The June 2019 Load Forecast filed with the BCUC did use an updated forecast for BC GDP for purposes of the Light Industrial load forecast[36]. However, we note the Commercial portion of the forecast (which is three times larger than the Light Industrial Load[37]) was not updated to reflect more recent forecasts of BC Commercial GDP for the test period[38]. In BCOAPO's view, had the June 2019 Load Forecast also incorporated a revised outlook for BC Commercial GDP, the difference between the October 2018 and the June 2019 Load Forecasts would have been even greater.

EV Forecast

BC Hydro has acknowledged that the October 2018 mid EV energy forecast does not include any incentives or policies during the test period and therefore the inclusion of any

[35] Exhibit B-13, BCOAPO 2.98.2
[36] Exhibit B-15, page 9
[37] Exhibit B-1, Appendix O, page 3
[38] Exhibit B-15, page 6

incentive programs in the model would result in an increase of load relative to the mid forecast[39]. While further analysis is required, BC Hydro has stated it believes, overall, its high EV energy forecast provides a reasonable estimate of the energy impact of the announced revisions to the CEVforBC rebate program. This amounts to an additional 41 GWh in F2020 and 60 GWh in F2021[40].

DSM Persistence

The DSM savings adjustments included in the October 2018 Load Forecast represent the cumulative energy savings (including persistence) from DSM activities starting in fiscal 2019. Persisting savings from DSM activities prior to fiscal 2019 are not included because the actual sales data up to fiscal 2018 (used in the load forecast model calibration) already reflects the impact of historical DSM activities[41].

The problem with this approach is that, as shown in the response to BCOAPO 2.96.5, persistence of saving from DSM activities undertaken prior to F2019 declines after F2019 such that the persisting savings in F2020 and F2021 are less than those in F2018[42]. BC Hydro acknowledges that this decline is not captured in its load forecast, but indicates that it would be difficult to quantify the impact as the DSM measures may continue beyond their assigned persistence period[43]. BCOAPO acknowledges that the loss in persistence may not be as assumed for purposes of DSM program evaluation but BC Hydro's approach effectively assumes no further loss in persisting savings beyond F2018 for DSM activities implemented prior to F2019 and therefore can only overestimate the future impact of these DSM activities. This is, from a ratepayer standpoint, obviously less than optimal. In our submission, future load forecasts should include some allowance for loss in the persistence of savings from historical DSM activities over the forecast period in order to avoid this kind of overestimation of future impacts.

[39] Exhibit B-12, BCUC 2.205.1
[40] Exhibit B-1, Appendix O, page 110
[41] Exhibit B-6, BCOAPO 1.18.4
[42] Exhibit B-13, BCOAPO 2.96.5
[43] Exhibit B-13, BCOAPO 2.97.1

BC Hydro's Overall Load Forecast

The preceding points have identified several aspects of BC Hydro's load forecasting approach resulting in the utility underestimating domestic load/sales in F2020 and F2021. In the normal course of events, BCOAPO's submissions would likely include proposed adjustments to the load forecast to recognize their cumulative effects. However, the COVID-19 Pandemic has had a profound effect not only on the availability of certain consumer goods or the social acceptability of group gatherings – it has had the effect of quieting the world to a far greater degree than seen in either of the author of this argument's lives. Part of that quieting is a decrease in the commercial use of energy – an effect that is, in our opinions, likely be reflected in a decreased volume of BC Hydro's sales in F2020 and F2021. As a result, we are, in these unique circumstances, content to let the load forecast as submitted with the Evidentiary Update, stand as reasonable for the purposes of determining BC Hydro's F2020 and F2021 electricity rates. In coming to this position, we have taken into consideration not only the possible impacts of COVID-19, but the fact that the variances that may occur between the forecast and actual Domestic revenues are eligible for deferral to BC Hydro's regulatory accounts: a fact that lends our clients some small comfort in these uncertain times[44].

BC Hydro's Peak Demand Forecast

On the record, BC Hydro indicated that the 2018 Load Forecast is only for energy and that for capital planning BC hydro uses a peak demand forecast. This evidence was garnered in response to an IR and indicates that in developing the F2020 to F2024 Capital Plan, BC Hydro used the following forecasts:

- The May 2016 System Peak Demand Load Forecast for transmission system projects;
- The 2017 Substation Peak Demand Load Forecast for substation and distribution projects. However, as the actual substation load (MVA) growth was moderating, BC Hydro reduced the overall growth-related substation and

[44] Exhibit B-6, BCOAPO 1.23.1

distribution capital expenditures in the F2020 to F2024 Capital Plan, which formed the basis for the capital expenditures in the test period); and

- The May 2016 (August 2017 Review) System Peak Demand Load Forecast for generation[45].

BC Hydro has indicated[46] that one of the primary drivers for the increase in its revenue requirement between F2019 RRA and F2020 is the forecast capital investments and associated capital additions. This is unsurprising given the fact that BC Hydro has been dealing with the need to maintain, upgrade, and replace an aging suite of assets for quite a number of years now. However predictable this result may be, BC Hydro's residential ratepayers - and indeed any and all of its ratepayers - would be remiss if they failed to seek a direction from this Panel to BC Hydro that the utility make a concerted effort to ensure that, going forward, the peak demand forecast used to develop the capital plan associated with proposed revenue requirements and its inputs are as up to date and as current as its (energy) load forecast.

COST OF ENERGY

BC Hydro's Cost of Energy is broken down into three categories: i) Heritage Energy; ii) Non-Heritage Energy and iii) Market Energy. In the initial Application, the Cost of Energy was forecast to be $1,887.0 M in F2020 and $1,920.2 M in F2021[47] with revisions to those figures in the Evidentiary Update: $1,928.9 M and $1,734.6 M respectively. When examining these global changes by category, the results are set out in the following schedule[48].

[45] Exhibit B-13, AMPC 2.23.3
[46] Exhibit B-1, pages 1-38 – 1-40
[47] Exhibit B-1, page 4-19
[48] Exhibit B-11-2, Appendix A, Schedule 4.0

Cost of Energy ($ million)												
				F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Heritage Energy										
28	Total		349.0	177.2	(171.8)	350.9	351.2	0.3	350.8	317.7	(33.1)
	Non-Heritage Energy										
33	Total		1,476.5	1,287.9	(188.6)	1,576.3	1,332.4	(243.9)	1,641.1	1,447.2	(193.9)
	Market Energy										
38	Total		(62.6)	53.5	116.1	(40.2)	245.3	285.5	(71.7)	(30.3)	41.4
39	**Total Gross COE**	L28+L33+L38	1,762.9	1,518.7	(244.2)	1,887.0	1,928.9	41.9	1,920.2	1,734.6	(185.6)

Submissions

Overall System Operation

In the Application[49] and supporting evidence[50] BC Hydro explains that it operates the system to meet domestic load first and then makes decisions to dispatch resources and undertake Electricity Purchases or Surplus Sales to maximize the expected value of its energy supply portfolio within a range of acceptable outcomes. This is accomplished with the aid of a monthly Energy Study which develops an optimal set of reservoir and generation station operations and market transactions given forecast of water inflow, market prices and load[51]. Not surprisingly given the interests our clients have in keeping residential rates low, BCOAPO is of view that maximizing the expected value of BC Hydro's energy supply portfolio is an appropriate objective for system operations and our clients wish to see BC Hydro continue its work in this area as it has proven effective, in our submission, in doing so in the past.

Heritage Energy Costs

Heritage Energy costs consist primarily of Water Rentals which are calculated based on actual hydro-electric generation in the preceding year. The following schedule[52] also demonstrates that year to year variations in water rental costs are also a major source of the year over year changes in Heritage Energy costs.

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[49] Exhibit B-1, page 4-16
[50] For example, Exhibit B-5, BCUC 1.29.2 &1.29.2.1; Exhibit B-6, AMPC 1.15.4 & 1.17.6; Exhibit B-13, BCOAPO 2.108.1; and Exhibit B-16, BCUC 3.309.1
[51] Exhibit B-1, pages 4-13 – 4-14
[52] Exhibit B-11-2, Appendix A, Schedule 4.0

Cost of Energy ($ million)											
			F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line		Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Heritage Energy										
23	Water Rentals		356.4	363.1	6.7	343.1	329.3	(13.8)	349.1	323.2	(25.9)
24	Natural Gas for Thermal Generation		10.7	7.6	(3.1)	8.1	7.5	(0.6)	8.5	8.5	(0.0)
25	Domestic Transmission - Other		22.1	22.3	0.2	22.5	24.5	2.0	22.4	24.4	2.0
26	Non-Treaty Storage and Libby Coordination Agreements		(7.2)	(181.9)	(174.7)	3.3	15.0	11.7	(2.5)	(11.7)	(9.3)
27	Remissions and Other		(33.1)	(33.9)	(0.8)	(26.1)	(25.2)	0.9	(26.8)	(26.7)	0.1
28	Total		349.0	177.2	(171.8)	350.9	351.2	0.3	350.8	317.7	(33.1)

One of the outputs of BC Hydro's monthly Energy Study is valuations of optimal operations with respect to net deposits or withdrawals from storage[53]. This makes a great deal of sense because storage provides the utility with the ability to draw upon additional power when it is needed or otherwise advantageous. In the Application, anticipated lower storage levels at the end of F2019[54] result in an identified need to fill system storage which logically leads to lower levels of hydro generation in the test period[55] (versus those per the 2019 RRA). This difference is clear on the following schedule[56]:

			F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line		Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Sources of Supply (GWh)										
	Heritage Energy										
1	Water Rentals		46,368	42,341	-4,027	44,262	39,368	-4,894	44,999	44,522	-477
2	Natural Gas for Thermal Generation		234	191	-43	192	181	-11	193	195	2
3	Exchange Net		-354	-155	200	-171	-473	-302	-196	-250	-54
4	Total		46,248	42,377	-3,871	44,283	39,075	-5,207	44,996	44,467	-529

The Evidentiary Update a forecast of even lower hydro generation and Water Rental costs due to drier conditions and lower water inflows than anticipated in the original Application[57].

The other major source of variation in Heritage Energy costs is the revenues/costs associated with the Columbia River Treaty. Revenue from the Columbia River Treaty Related Agreements is generated as the storage is released, and correspondingly, costs are incurred to build up the storage. The revenue and costs depend on the market prices at the time of the storage build or storage release[58].

[53] Exhibit B-5, BCUC 1.20.5
[54] Exhibit B-1, page 4-18, Table 4-1
[55] Exhibit B-5, BCUC 1.20.5
[56] Exhibit B-11-2, Appendix A, Schedule 4.0
[57] Exhibit B-11-2, page 8 and Exhibit B-17, BCOAPO 3.163.1
[58] Exhibit B-5, BCUC 1.27.1

Overall, BCOAPO has no issues with BC Hydro's proposed Heritage Energy costs as determined by the May 2019 Energy Study. To the extent that actual conditions (inflows, market prices, etc.) differ from those used in the Energy Study and the resulting operation of BC Hydro's reservoirs and generating facilities varies from forecast, we recognize that any cost differences will be captured in the Heritage Deferral Account and ratepayers will (eventually) be responsible for the actual costs incurred[59].

Non-Heritage Energy Costs

Non-Heritage Energy costs consist primarily of the cost of IPPs and Long Term commitments[60]. Other costs included in this category include the Non-Integrated Area generation costs (i.e., diesel and IPPs), gas and other transportation costs, and water rentals associated with Teck 2/3's lease of Waneta[61]. The following schedule sets out the breakdown of the Non-Heritage Energy costs[62].

Cost of Energy ($ million)											
			F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Non-Heritage Energy										
29	IPPs and Long-Term Commitments		1,439.3	1,247.2	(192.1)	1,538.5	1,294.7	(243.8)	1,601.1	1,410.8	(190.3)
30	Non-Integrated Area		31.1	28.9	(2.2)	31.6	30.5	(1.0)	33.6	30.2	(3.4)
31	Gas & Other Transportation		6.1	9.4	3.3	2.8	3.7	0.9	2.7	2.5	(0.1)
32	Water Rentals (Waneta 2/3)	15.0 L22	0.0	2.4	2.4	3.5	3.5	0.0	3.7	3.7	0.0
33	Total		1,476.5	1,287.9	(188.6)	1,576.3	1,332.4	(243.9)	1,641.1	1,447.2	(193.9)

BC Hydro notes that the forecast increase in the costs of IPPs and Long Term Commitments in the Application (i.e., F2021 Plan vs. F2019 RRA) is primarily related to increased costs associated with existing Electricity Purchase Agreements due to price escalations and increases in output as permitted under the contracts[63]. The lower costs for F2020 and F2021 in the Evidentiary Update are due to: i) the previous mentioned drier conditions and lower water inflows, which decrease hydro generation from IPPs[64]

[59] Exhibit B-1, page 7-15
[60] Exhibit B-6, CEC 1.19.2 describes what is included in Long Term Commitments
[61] These are actually paid by Tech and the offset is included under Miscellaneous Revenues per Exhibit B-1, page 4-6
[62] Exhibit B-11-2, Appendix A, Schedule 4.0
[63] Exhibit B-1, pages 4-32 – 4-33
[64] Exhibit B-17, BCOAPO 3.163.2

and ii) lower forecast deliveries, based on updated historical delivery averages and delayed commercial operation dates[65].

As an aside, albeit an important one, while our clients value energy from clean and environmentally sound sources, far too many of the new sources on the books right now is from grossly overpriced IPP energy that is freshet heavy and therefore even less valuable than that same energy later in the year. Sadly, it also not only puts cost pressures on the energy side, but the capacity-side as well so, while drier conditions in our Hydro-heavy system are something our clients do not embrace, there is a small silver lining.

		F2019			F2020			F2021		
	Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
Sources of Supply (GWh)										
Non-Heritage Energy										
IPPs and Long-Term Commitments		15,199	14,248	-951	15,449	13,949	-1,500	16,040	15,238	-802
Non-Integrated Area		120	103	-17	118	118	0	120	120	1
Total		15,320	14,351	-968	15,566	14,067	-1,500	16,159	15,358	-801

The lower Evidentiary Update costs are also the result of the full implementation of IFRS 16 which shifts costs ($86.4 M and $87.7 M in F2020 and F2021 respectively[66]) from IPPs and Long-Term Commitments (Cost of Energy) to Amortization and Finance Charges[67].

BCOAPO notes that while the lower IPP costs in the Evidentiary Update do provide some relief in terms of the F2020 and F2021 revenue requirements, this relief is to some extent only temporary and IPPs costs will be higher in the future when weather and water flows return to more normal conditions and those facilities whose commercial dates are delayed eventually come into service. As a result, our clients consider it especially important to consider what actions BC Hydro is undertaking to proactively manage its IPP energy costs and whether they are enough.

In terms of new IPP contracts, ratepayers can breathe a sigh of relief because BC Hydro has indicated it does not have any active programs for the procurement of new energy resources from IPPs. To this same end, BC Hydro suspended the SOP while the

[65] Exhibit B-11-2, page 8
[66] Exhibit B-11-2, page 11. See also, Exhibit B-11, Appendix F, page 1
[67] Exhibit B-11-2, page 9

Government's Comprehensive Review was underway and, as part of the same Review, the Government issued a regulation in February 2019 that allowed BC Hydro to indefinitely suspect the SOP[68]. In the Application, BC Hydro has indicated that it will not be executing any other SOP EPAs, with the exception of five First Nations' clean energy projects that are part of Impact Benefit Agreements with BC Hydro and/or are mature projects that have significant First Nations involvement[69]. BCOAPO heartily supports this approach.

In terms of IPP contract renewals, the Application identifies 10 hydro IPPs and 6 biomass IPPs that were included in the F2019 RRA and are subject to renewal prior to the end of the current test period[70]. BCOAPO notes that four of the hydro-related projects renewal applications were approved in 2016 or 2017[71] and notably two more approvals were issued this year with Order G-39-20[72] at prices that were lower than BC Hydro's opportunity cost and the levelized price under the two original EPA's evergreen clauses - facts that did not escape our clients' attention in that BCUC process.

During the proceeding, when discussing those two most recent EPA renewals – Sechelt Creek Hydro, Brown Lake Hydro – BC Hydro indicated that the LRMC values used in those applications were estimated in 2015 and were considered out of date. Instead, we submit that as a conservative interim assumption, market prices would be used to assess EPA renewals until the next IRP is complete. In its Decision G-278-19[73], the BCUC found that "the interim market approach is the more appropriate method to value the EPA renewals" and concluded that, based on this approach, the two proposed EPAs were not "cost effective". However, the BCUC subsequently approved[74] revised versions of the two EPAs with shorter terms based other benefits and considerations. The overall result

[68] Exhibit B-1, page 4-9
[69] Page 4-9
[70] Exhibit B-5, BCUC 1.15.1 and 1.15.1.1. Note: The tables provided identify 8 hydro projects while the footnotes identify an addition two there were omitted. It is noted that the responses did not make reference to the Walden North EPA which was the subject of a 2018 renewal application by BC Hydro. However, BC Hydro has subsequently issued a termination notice to this project as noted in Order G-39-20
[71] Akolkolex, Soo River, Boston Bar, and Doran Taylor
[72] Brown Lake and Sechelt Creek
[73] Page 14
[74] Order G-39-20

is that BC Hydro's recently adopted[75] use of market price as a conservative interim assumption for evaluating cost-effectiveness of EPAs will, at best, apply to four of the 10 hydro projects[76].

Furthermore, BC Hydro has also indicated that the six biomass projects will not be evaluated using the interim approach because they are part of the Biomass Energy Program[77] and the Government intends to provide direction to the BCUC requiring the cost to be recovered from ratepayers[78]. However, while the biomass projects will be renewed at a cost that exceeds market prices[79], they will be renewed at a lower unit cost than currently in place[80].

As a result, it is BCOAPO's view that we cannot expect material cost savings during the test period rooted in the EPA renewals.

Unfortunately, BC Hydro does not have unilateral rights to terminate without cause existing EPAs not yet subject to renewal. Typically, BC Hydro only has a right of termination under an EPA if the counterparty triggers a termination right, such as failing to reach commercial operation by the required date or taking actions that constitute a material default under the specific EPA. That said, BC Hydro has indicated that it continually monitors its portfolio of EPAs to ensure that IPPs are in compliance with the terms of their agreements and considers exercising termination rights when such rights arise[81]. In addition, the Application notes[82] that BC Hydro actively enforces its rights and obligations in EPAs to reduce cost commitments, such as exercising turn down rights when it is cost effective to do so.

In BCOAPO's view, BC Hydro should be active on both these fronts and the BCUC should indicate that, in support of the eventual disposition of Non-Heritage Deferral Account

[75] Exhibit B-5, BCUC 1.15.2.1
[76] Exhibit B-13, BCOAPO 2.104.2.1
[77] Exhibit B-13, BCOAPO 2.104.2.1
[78] Exhibit B-1, page 4-12. OIC #158 issued in April 1, 2019 subsequently set the renewal rate for these projects.
[79] Exhibit B-13, BCOAPO 2.109.1
[80] Exhibit B-13, BCOAPO 2.103.2
[81] Exhibit B-5, BCUC 1.18.1
[82] Page 4-10

balances accrued during the test period, BC Hydro should provide a full accounting of its efforts to proactively manage IPP costs. This accounting should specifically address those circumstances (such as the Walden North EPA[83]) where BC Hydro explicitly choses to refrain from exercising its right to terminate the EPA.

Market Energy

Market Energy is electricity purchased from or sold to Powerex and consists of: i) market purchases of electricity from Powerex by BC Hydro to meet domestic load requirements (referred to as Market Electricity Purchases), ii) sales of electricity to Powerex when BC Hydro has generation in excess of its domestic load requirements (referred to as Surplus Sales) and iii) trade purchases/sales where Powerex purchases or sells electricity from/to BC Hydro for purposes of trade-related activities (referred to as Net Purchases (Sales) from Powerex[84]. The forecast for each of these components is set out in the following schedule[85]. The Domestic Transmission costs included in the schedule represent the transmission costs within BC related to Surplus Sales.

Cost of Energy ($ million)			F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Sources of Supply (GWh)										
	Market Energy										
34	Market Electricity Purchases		35.9	125.0	89.1	40.0	211.6	171.5	18.2	43.7	25.4
35	Surplus Sales		(129.2)	(115.0)	14.2	(97.1)	(0.4)	96.7	(111.4)	(97.0)	14.4
36	Net Purchases (Sales) from Powerex		**0.7**	**25.0**	24.3	**(0.5)**	**33.1**	33.6	**0.5**	**6.1**	5.6
37	Domestic Transmission - Export		**29.9**	**18.5**	(11.4)	**17.4**	**1.1**	(16.3)	**21.0**	**17.0**	(4.0)
38	Total		(62.6)	53.5	116.1	(40.2)	245.3	285.5	(71.7)	(30.3)	41.4

Surplus Sales in F2020 and F2021 are forecast to be lower than those in the F2019 RRA and the Market Purchases higher due to the previously referenced filling of system storage during the test period and higher domestic sales[86]. The even higher Market Purchases and lower Surplus Sales in the Evidentiary Update are the result of the continuing dry conditions from fiscal 2019 through to fiscal 2020, with low reservoir levels recorded at the end of fiscal 2019 and a reduction in the water supply forecast for fiscal 2020[87]. Indeed, the F2020 forecast Surplus Sales in the Evidentiary Update consists of

83 Exhibit B-16, BCUC 3.315.2
84 Exhibit B-1, pages 4-6 – 4-7
85 Exhibit B-11-2, Appendix A. Schedule 4.0
86 Exhibit B-1, page 4-37
87 Exhibit B-19, Appendix C, page 1

only a small volume of forced exports to be made during the freshet[88]. Surplus Sales increase in F2021 (over F2020) as less hydro inflow is diverted to increasing storage levels[89].

BCOAPO notes that the F2020 and F2021 forecasts for Market Electricity Purchases are driven by its Energy Study and the same considerations with respect to the optimal operation of BC Hydro reservoirs.

Overall, BCOAPO has no issues with BC Hydro's proposed Market Energy Costs as determined by the May 2019 Energy Study. Again, to the extent that actual conditions (inflows, market prices, etc.) differ from those used in the Energy Study and the resulting decision regarding surplus sales and market electricity purchases vary from forecast any cost/revenue differences will be captured in BC Hydro's Deferral Accounts and ratepayers will (eventually) be responsible for the actual costs incurred.

OPERATING COSTS

For purposes of discussing the Operating Cost component of the Revenue Requirement BC Hydro does not focus on the Gross Operating Costs as set out above but rather on what it defines as Base Operating Costs and Net Operating Costs. The following table sets out the differences between the three[90] and additional details regarding the F2020 and F2021 differences were provided in the response to BCOAPO 1.27.1[91].

($ million)			F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
124	**Base Operating Costs**	Line 9	769.5	757.2	(12.2)	777.9	793.8	15.9	787.8	803.9	16.1
125	Base Operating Costs Adjustments	Line 14	202.0	209.8	7.8	181.1	181.1	0.0	203.6	203.6	0.0
126	**Net Operating Costs**	Line 15	**971.5**	**967.1**	**(4.4)**	**959.0**	**974.9**	**15.9**	**991.4**	**1,007.5**	**16.1**
127	Provisions & Other	Line 77	65.7	95.9	30.2	116.2	116.2	0.0	95.1	95.1	0.0
128	Operating Costs - Deferral Account Additions and Regulatory Account Additions	L52 + L63	197.9	198.0	0.1	157.1	157.1	0.0	150.9	123.7	(27.2)
129	Provisions & Other - Deferral Account Additions and Regulatory Account Additions	L102 + L109	(14.0)	16.0	30.0	(8.1)	(9.1)	(1.0)	(8.1)	(9.1)	(1.0)
130	**Gross Operating Costs and Provisions & Other**	Line 123	**1,221.0**	**1,277.0**	**56.0**	**1,224.2**	**1,239.1**	**14.9**	**1,229.3**	**1,217.2**	**(12.1)**

88 Exhibit B-20, BCUC 3.6.1
89 Exhibit B-1, Table 4-1 and Exhibit B-23, AMPC 4.4.1. In both the initial Application and the Evidentiary Update system storage increases in F2020 are greater than those in F2021.
90 Exhibit B-11-2, Appendix A, Schedule 5.0
91 Exhibit B-6

The difference between Gross and Net Operating costs is that the former includes costs incurred in the current period but recovered in rates in future years (i.e., regulatory account additions)[92]. The difference between Base and Net Operating costs is set out in the following table[93].

Operating Costs and Provisions - Total Company ($ million)											
			F2019			F2020			F2021		
		Reference	RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff
Line	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
9	**Base Operating Costs**		769.5	757.2	(12.2)	777.9	793.8	15.9	787.8	803.9	16.1
10	IFRS Ineligible Capitalized Costs		147.7	147.7	0.0	170.1	170.1	0.0	192.5	192.5	0.0
11	Independent Power Producer Capital Leases		54.3	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Waneta 2/3		0.0	3.7	3.7	5.7	5.7	0.0	5.9	5.9	0.0
13	Customer Crisis Fund		0.0	4.1	4.1	5.3	5.3	0.0	5.3	5.3	0.0
14	**Total Base Operating Costs Adjustment**		202.0	209.8	7.8	181.1	181.1	0.0	203.6	203.6	0.0
15	**Net Operating Costs**	L9+L14	971.5	967.1	(4.4)	959.0	974.9	15.9	991.4	1,007.5	16.1

The changes in Base Operating costs as between the original Application and the Evidentiary Update are due to a decrease in the discount rate used to value BC Hydro's pension liability which results in a higher present value of BC Hydro's pension liability. This increased BC Hydro's current service pension costs by $15.9 million in fiscal 2020 and $16.1 million in fiscal 2021[94].

<u>Submissions</u>

Calculation of Base Operating Cost Increases

In the Application BC Hydro touts the fact that Base Operating Costs are increasing (F2019 to F2021) at below the forecast rate of inflation by partially offsetting non-controllable cost increases with reductions in controllable costs[95]. However, the reported increases (1.1% in F2020 and 1.3% in F2021) are based on the forecast F2019 Base Operating Costs at the time of the Application of $769 M[96]. In contrast actual F2019 Base Operating Costs were $757.2 M[97]. Indeed, combining this value with the forecast Base

[92] Exhibit B-1, page 5-20
[93] Exhibit B-11-2, Appendix A, Schedule 5.0
[94] Exhibit B-11-2, page 12
[95] Exhibit B-1, pages 1-48 and 5-1
[96] This is equivalent to the F2019 RRA Base Operating Costs.
[97] Exhibit B-11-2, Appendix A, Schedule 5.0

Operating Costs in the Evidentiary Update produces increases in Base Operating Costs of 4.8% for F2020 and 1.3% for F2021[98], negating BC Hydro's claim.

The 4.8% increase in F2020 is partially due to the increase in F2020 Base Operating Costs in the Evidentiary Update arising from the higher F2020 current service pension costs. However, it is also rooted in the lower actual F2019 Base Operating costs as compared to the F2019 forecast in the original Application. BCOAPO notes that even after excluding the updated current service pension costs the F2020 increase more than doubles from the reported 1.1% to 2.7%[99].

A comparison of the F2019 forecast versus actual Base Operating Costs indicates that the difference is primarily due to the costs included in Other (i.e., the Office of General Counsel and the Office of the President and Chief Operating Officer[100]) as indicated in the following schedule[101].

Operating Costs and Provisions - Total Company							
($ million)							
				F2019		**F2019**	Diffrence
				Actual		**Forecast**	
Line			**Column**	2		8	
		Operating Costs by Business Group					
1			Integrated Planning	285.9		279.3	6.6
2			Capital Infrastructure Project Delivery	85.9		82.9	3.0
3			Operations	215.6		214.5	1.1
4			Safety	53.6		54.8	(1.2)
5			Finance, Technology, Supply Chain	261.2		258.5	2.7
6			People, Customer, Corporate Affairs	105.5		112.9	(7.4)
7			Other	(250.5)		(233.4)	(17.1)
8			F17-F19 RRA Compliance Filing Adjustment	0.0		0.0	0.0
9			**Base Operating Costs**	757.2		769.5	(12.3)

A closer examination shows that the majority of the $17.1 M difference is due to a difference in the Corporate Costs component which in the F2019 forecast included $15 M in unallocated funds.[102] It is only by including these unallocated (unspent) funds in the

98 F2020: $793.8/757.2=1.0483 and F2021: $803.9/$793.8=1.0127
99 $777.9/$757.2=1.0273
100 Exhibit B-1, page 5G-1
101 Extracted from Appendix A, Schedule 5.0 in Exhibit B-1 and Exhibit B-11-2
102 Exhibit B-1, page 5G-12

F2019 costs that BC Hydro's calculation of the increase in Base Operating costs for F2020 falls below the rate of inflation.

BCOAPO submits that, when actual costs for the base year (i.e., the last year of the prior RRA's test period) are known then it is the actual cost and not forecast/budgeted costs that form the appropriate "starting point" from which to calculate and characterize the cost increases during any RRA's test period. To allow otherwise encourages inflating actual costs to camouflage unfavourable actual cost increases.

Increases in FTEs versus Operating Costs

BC Hydro's total FTEs increased from 6,365 in the F2019 RRA forecast to the 7,477 in the F2020 Plan. This increase in FTEs is primarily attributable to the impacts of the Work Force Optimization Program and the Accenture Repatriation[103] in conjunction with increases staffing needs for Site C[104]. Similarly, the Work Force Optimization Program and the staffing needs for Site C are the major factors contributing to the increase in FTEs between: i) the F2019 RRA versus F2019 Forecast levels and ii) the F2019 Forecast in the Application versus the F2020 Plan[105]. For F2021 the total FTE forecast is just slightly less than the F2020 Plan levels[106].

However, while both the Work Force Optimization Program and the Accenture Repatriation have increased BC Hydro's FTE levels, each has resulted in a decrease in Base Operating Costs. In the case of the Work Force Optimization Program, BC Hydro estimates that F2020 costs have been reduced by $18.5 M[107] while the Accenture Repatriation is estimated to have decreased costs (based on the F2019 RRA) by $8.2 M[108]. From a ratepayer standpoint, that is a strong case for maintaining the Utility's services in-house going forward.

[103] Accenture Repatriation was not included in the F2019 RRA forecast.
[104] Exhibit B-1, page 5-43
[105] Exhibit B-5, BCUC 1.35.2 and Exhibit B-6, CEC1.27.1
[106] Exhibit B-1, page 5-43
[107] Exhibit B-1, page 5-29
[108] Exhibit B-1, page 5-41

Overall, excluding the Workforce Optimization Program, Accenture Repatriation, Site C and SMI, BC Hydro's FTEs would be lower in fiscal 2020 and fiscal 2021 than they were in fiscal 2016[109].

As a result, BCOAPO does not consider BC Hydro's forecast increases in FTEs as being an issue in the current proceeding.

Pension Costs

The Evidentiary Update's $15.9 M and $16.1 M increases in Operating Costs are a direct result of a decrease in the discount rate used to value BC Hydro's pension liability from 3.83 % as of September 30, 2018 to 3.33 % as of April 1, 2019. This discount rate is determined by BC Hydro's external actuary and is based on 'AA' Canadian Corporate bonds[110]. In the F2017-F2019 RRA BC Hydro noted that over the period from fiscal 2011 to fiscal 2016 the annual discount rate has ranged from a high of 6.12 % to a low of 3.51 %, giving rise to large variations between actual and planned results. To minimize the volatility of the discount rate used for revenue requirements applications, BC Hydro had proposed as part of its F2017-F2019 RRA that, starting in fiscal 2017 and on an ongoing basis, an average of actual discount rates from the preceding five fiscal years be used in the calculation of actual current service costs for the purposes of revenue requirement applications[111]. However, the BCUC rejected BC Hydro's proposal[112].

In BCOAPO's view the 3.33% discount rate used in the Evidentiary Update further demonstrates the year to year volatility of the discount rate calculation used in BC Hydro's pension liability calculations. As a result, BCOAPO submits that the BCUC should, as part of its deliberation for the current proceeding, revisit BC Hydro's previous proposal to use a five-year historical average, considering this revenue requirement as additional context to inform its deliberations.

[109] Exhibit B-6, BCOAPO 1.33.3
[110] Exhibit B-11-2, page 12
[111] Order G-47-18, Decision, page 67
[112] Order G-47-18, Decision, page 71

Storm Restoration Costs

At the time of Evidentiary Update, the actual Storm Restoration costs were available and were used to update both the balance in the Storm Restoration Costs Regulatory Account and the amortization of the account for F2020 and F2021[113]. However, the F2019 actual values were not used to update the 5-year historical average used to forecast Storm Restoration Costs for F2020 and F2021.

BCOAPO acknowledges that using the historical period for F2015-F2019 would increase the Storm Restoration Costs from $17.8 M[114] to $22.0 M[115]. However, as the F2019 actual results were readily available at the time of the Evidentiary Update BCOAPO submits that they should have been used in the Update and that the BCUC should direct they be used for purposes of establishing the Storm Restoration Costs for F2020 and F2021.

CAPITAL EXPENDITURES

Capital Expenditures and the related capital additions underpin a number of revenue requirement items including depreciation and finance expense.

The capital expenditures in the F2020 and F2021 test years are derived from the F2020 to F2024 Capital Plan that BC Hydro completed in October 2018[116].

Past actual and planned expenditures are set out in the following table[117].

[113] Exhibit B-11, page 12
[114] Exhibit B-1, page 7-35
[115] Exhibit B-17, CEC 3.96.1
[116] Exhibit B-1, page 6-1
[117] Exhibit B-1, page 6-7

Table 6-1 BC Hydro Actual and Planned Growth and Sustaining Capital Expenditures Fiscal 2017 to Fiscal 2021[289]

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Generation								
Growth (Schedule 13, Line 1)	20.0	21.2	2.4	10.2	0.7	4.0	3.2	-
Sustaining (Schedule 13, Line 3)	530.0	563.6	534.1	533.9	424.3	365.9	341.8	435.5
Total Generation	550.0	584.8	536.5	544.1	425.0	369.9	345.1	435.5
Site C Project (Schedule 13, Line 8)	742.5	662.7	716.5	704.8	829.2	1,186.8	1,530.0	1,535.5
Generation - Waneta 2/3 (Schedule 13, Line 2)						1,219.5		
Transmission								
Growth (Schedule 13, Line 4)	262.0	247.3	222.0	280.5	192.7	223.7	185.0	198.9
Sustaining (Schedule 13, Line 5)	255.5	268.1	326.3	218.3	373.9	209.1	222.6	286.5
Total Transmission	517.5	515.4	548.3	498.8	566.6	432.8	407.6	485.4
Distribution								
Growth (Schedule 13, Line 6)	224.7	226.0	233.4	287.6	209.5	305.7	300.0	284.6
Sustaining (Schedule 13, Line 7)	185.0	224.5	160.1	235.2	187.6	190.9	187.5	176.8
Total Distribution	409.8	450.5	393.4	522.8	397.0	496.6	487.5	461.4
Business Support								
Technology (Schedule 13, Line 9)	83.9	76.5	93.4	71.2	78.8	95.6	95.6	56.0
Properties (Schedule 13, Line 10)	95.7	86.6	75.0	63.5	88.3	43.5	58.9	55.3
Fleet / Other (Schedule 13, Line 11)	204.7	58.9	48.6	59.6	39.6	67.4	63.6	75.1
Total	2,604.0	2,435.4	2,411.9	2,464.8	2,424.6	3,912.2	2,988.3	3,104.1
Less: Contribution in Aid	(86.4)	(138.4)	(100.2)	(156.3)	(106.4)	(146.9)	(157.8)	(148.4)
TOTAL	2,517.6	2,297.0	2,311.7	2,308.5	2,318.2	3,765.3	2,830.5	2,955.7

There were no changes to the forecast capital spending for the test period as a result of the Evidentiary Update. Subsequent to the Application, the actual spending for F2019 has become available and it totaled $3,816.7 M (before Contributions in Aid)[118].

If one excludes the spending on Waneta 2/3 and Site C, the planned spending for each of the two test years is less than the annual spending in F2017-F2019.

The following table summarizes the past and planned capital additions per the Application[119].

[118] Exhibit B-11, Appendix A, Schedule 13.0
[119] Exhibit B-1, page 6-7

Table 6-2 BC Hydro Actual and Planned Growth and Sustaining Capital Additions Fiscal 2017 to Fiscal 2021[290, 291]

($ millions)	F2017		F2018		F2019	F2019	F2020	F2021
	RRA	Actual	RRA	Actual	RRA	Forecast	Plan	Plan
Generation								
Growth	26.6	24.2	0.9	9.6	0.2	(1.3)	2.7	-
Sustaining	486.4	318.5	386.2	397.6	1,332.1	1,304.7	312.0	297.0
Total Generation (Schedule 13, Line 13)	513.0	342.7	387.1	407.2	1,332.3	1,303.3	314.7	297.0
Site C Project (Schedule 13, Line 17)						-	27.9	189.4
Generation - Waneta 2/3 (Schedule 13, Line 14)						1,219.5	-	-
Transmission								
Growth	237.1	255.8	222.8	176.9	213.8	309.9	97.9	83.3
Sustaining	255.2	227.1	216.9	230.8	245.0	223.5	195.9	146.3
Total Transmission (Schedule 13, Line 15)	492.3	482.9	439.7	407.7	458.8	533.4	293.8	229.6
Distribution								
Growth	189.8	232.7	241.6	232.2	229.0	305.2	306.9	344.2
Sustaining	182.3	188.3	157.7	213.3	184.0	222.3	195.3	196.5
Total Distribution (Schedule 13, Line 16)	372.1	421.0	399.3	445.5	413.0	527.5	502.2	540.7
Business Support								
Technology (Schedule 13, Line 18)	81.6	81.6	91.1	97.2	112.6	67.1	147.6	75.5
Properties (Schedule 13, Line 19)	68.3	54.8	118.2	126.9	25.5	28.7	39.9	55.6
Fleet / Other (Schedule 13, Line 20)	210.3	85.6	54.5	59.4	45.7	69.8	64.9	71.3
Total	1,737.6	1,468.5	1,489.8	1,543.8	2,387.8	3,749.4	1,391.0	1,459.1
Less: Contribution in Aid	(90.1)	(103.6)	(88.0)	(129.5)	(84.6)	(148.5)	(146.1)	(165.8)
TOTAL	1,647.5	1,364.9	1,401.8	1,414.3	2,303.2	3,600.8	1,244.9	1,293.2

Again, there were no changes as a result of the Evidentiary Update and actual capital additions for F2019 totaled $3,553.1 M (prior to Contribution in Aid)[120].

As was the case with capital expenditures, annual capital additions during the test period are less than during the F2017-F2019 period.

<u>Submissions</u>

Capital Planning

BC Hydro has established an Enterprise Planning Work Group whose purpose is to apply a common approach to planning, prioritizing and governing investments across the company[121].

Capital planning is accomplished through a top-down/bottom-up approach. This involves the Executive Team first providing "top-down" direction on long-term investment levels

[120] Exhibit B-11, Appendix A, Schedule 13.0
[121] Exhibit B-1, page 6-17

based on balancing affordability, system performance and safety[122]. This is followed by a bottom-up process for each asset category to identify specific capital investments for the planning period[123].

The results of the two approaches are reconciled by classifying proposed investments as: i) Mandatory, ii) Committed or iii) To Be Prioritized. The investments in the third category are then assessed using a common framework where[124]:

- Investments that primarily mitigate risk are scored for prioritization using a methodology that is aligned with the BC Hydro Corporate Risk Matrix[125]; and
- Investments that primarily create value are scored for prioritization using a net value per dollar invested metric. (Note: The value prioritization is mainly used for some capital expenditures in the Technology Portfolio).

However, an investment's risk or value score is only one of the criteria BC Hydro considers when making prioritization decisions. Other criteria include resource and outage constraints (when considering the portfolio of investments)[126].

One issue with BC Hydro's current prioritization process is that while BC Hydro's Corporate Risk Matrix considers a number of "risks" (e.g., financial, reliability, safety, environmental and reputational), the risk "score" for purposes of prioritization is based on "the highest risk that the project is exposing the organization to"[127]. To further improve its investment planning process, BC Hydro has initiated the Asset Investment Planning Tool project[128] which will develop and implement an enterprise value framework that will

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[122] Exhibit B-1, page 6-19
[123] Exhibit B-1, page 6-28
[124] Exhibit B-1, page 6-29
[125] This approach is used to assess most (97%) of the discretionary investments per Transcript Volume 13, page 2379
[126] Exhibit B-6, CEC 1.43.4; Exhibit B-13, BCOAPO 2.134.1; Transcript Vol. 12, page 2304 and Transcript Vol. 13, page 2383
[127] Transcript Vol. 11, pages 1848-1849
[128] Exhibit B-1, Appendix I, page 9 and Exhibit B-6, CEC 1.43.4

enable a more consistent and objective approach to compare the risks, costs and benefits of different investments[129].

During the oral proceeding BC Hydro indicated that the project is currently on hold and that one of the reasons was that the projected cost ($5.8 M) has changed and the Company felt it "prudent to pause and make sure that we can demonstrate benefits to the ratepayer of continuing to invest in this type of project"[130].

BCOAPO acknowledges that BC Hydro has a fairly robust capital planning process. However, it also supports BC Hydro's efforts to improve its capital planning process where cost effective to do so and looks forward to the reviewing its conclusions regarding the Asset Investment Planning Tool at the time of its next RRA.

Property Purchases

The property purchases for the Downtown Vancouver West End Substation project and the East Vancouver Substation project were both completed as separate "projects"[131] with costs of $80.7 M (forecast)[132] and $46.6 M (actual)[133] respectively. However, in both cases, the Substation projects will be subject of a future CPCN which will encompass the choice of site and the property purchases[134].

Of concern to BCOAPO is the fact that the costs of these two properties are included in rate base for the test period[135] even though the substations that are to be built on them will not be completed and in-service until after the F2020-F2021 test period[136]. From the responses provided it appears that the carrying costs for these properties are expensed rather than being capitalized during the test period because the related substation development projects have not commenced[137]. However, once under construction, the

[129] Exhibit B-6, CEC 1.4.2
[130] Transcript Vol. 11, page 1845
[131] Exhibit B-5, BCUC 1.117.1 and 1.118.1
[132] Exhibit B-1, Appendix I, page 4.
[133] Exhibit B-5, BCUC 1.118.1.1
[134] Exhibit B-5, BCUC 1.117.1.1 and 1.118.2.1
[135] Exhibit B-57, Undertaking 42 and Exhibit B-12, BCUC 2.249.3
[136] Transcript Vol. 12, pages 2293-2204 and 2296
[137] Exhibit B-12, BCUC 2.249.2

carrying costs will be charged to the substation project (i.e., capitalized) until it is placed in-service[138].

While this treatment may conform with IRFS accounting requirements[139], from a regulatory perspective it makes no sense that ratepayers are responsible for the carrying costs of land related to construction projects that have not yet commenced while the carrying costs will be capitalized once project construction has commenced – when in both cases the land/property is not being used to provide service to ratepayers.

In Section 7 of the Application[140] BC Hydro set out the different types and purposes of regulatory accounts. In BCOAPO's submission, the circumstances associated with both of these properties clearly meet the "benefit matching" criterion[141] which is meant to "reflect timing differences between when a utility spends money to provide a service or acquire an asset and when that expenditure provides benefits to ratepayers". The BCUC should direct BC Hydro to establish a regulatory account to defer such costs until such time as they are eligible for capitalization and then either record them as part of the cost of the relevant project or amortize them over the life of the project.

Peace Region Electric Supply Project

In a March 26, 2020 Letter[142] the BCUC requested that, in their final arguments parties include their positions and rationale as to whether the Peace Region Electric Supply (PRES) project meets the requirements to be considered a prescribed undertaking under section 18 of the *Clean Energy Act*, pursuant to section 4(2) of the *Greenhouse Gas Reduction (Clean Energy) Regulation* (*GGRR*).

138 Exhibit B-12, BCUC 2.249.2.3 and BCUC 2.249.3
139 Exhibit B-12, BCUC 2.249.3
140 Exhibit B-1, pages 7-14 to 7-20
141 Exhibit B-1, page 7-16
142 Exhibit A-31

BCOAPO agrees with BC Hydro's statement that "the PRES project is a prescribed undertaking under section 18 of the *Clean Energy Act* and section 4(2) of the *GGRR*"[143] which states:

> (2) A public utility's undertaking that is in a class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:
>
> > (a) for the purpose of reducing greenhouse gas emissions in British Columbia, the public utility constructs or operates an electricity transmission or distribution facility, or provides for temporary generation until the completion of the construction of the facility, in northeast British Columbia primarily to provide electricity from the authority to (i) a producer, as defined in section 1 (1) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation, B.C. Reg. 495/92,513 or (ii) an owner or operator of a natural gas processing plant;
> >
> > (b) the public utility reasonably expects, on the date the public utility decides to carry out the undertaking, that the facility will have an in-service date no later than December 31, 2022.

The PRES project is a transmission project in northeast British Columbia which is designed to meet incremental load[144] driven primarily by natural gas production[145]. In the absence of the PRES project fossil fuels would need to be used to supply electricity and compression. As a result, the project serves to reduce greenhouse gas emissions[146] and meets the requirements set out in part (a) of section 4(2) of the *GGRR*.

The PRES project is expected to be in-service by October 2021[147] and therefore, meets the requirements set out in part (b) of the *GGRR*.

143 BC Hydro Final Argument, page 140
144 Exhibit B-5, BCUC 1.119.1
145 Exhibit B-5, BCUC 1.119.3
146 Exhibit B-5, BCUC 1.119.2 and Exhibit B-12, BCUC 2.250.5
147 Exhibit 13, BCOAPO 2.138.1

However, BCOAPO notes that since PRES project is not expected to be in-service during the F2020-F2021 test period it does not affect the revenue requirement for the test period. While section 18(2) of the CEA requires that "the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking", BCOAPO expects these "costs" will be the subject to consideration in BC Hydro's next RRA.

Minette Station to LNG Canada Interconnection Project

The same Letter[148] from the BCUC also requested that, in their final arguments parties include their positions and rationale as to "whether the Minette Station to LNG Canada Interconnection project meets the requirements of the Transmission Upgrade Exemption Regulation, as amended by B.C. Reg. 160/2018, to exempt the project from Part 3 of the *Utilities Commission Act*."

B.C. Reg 160/2018 amended the *Transmission Upgrade Exemption Regulation* by adding the following subsections:

> (2) Subject to subsection (3), the authority is exempt from Part 3 of the Act in respect of the construction or operation of a plant or system, or an upgrade or extension of either, to provide service for the following:
>
> > (a) an LNG facility in the vicinity of the District of Kitimat;
> >
> > (b) a facility necessary for the construction of an LNG facility in the vicinity of the District of Kitimat.
>
> (3) The exemptions under subsection (2) do not apply in respect of a plant, system, upgrade or extension that, on the date the authority decides to construct the plant,

[148] Exhibit A-31

system, upgrade or extension, cannot reasonably be expected to come into service before October 1, 2025.

(4) Subsection (3) does not limit any of the exemptions under subsection (1).

The MIN to LNG Interconnection is in the District of Kitimat and is expected to come into service prior to October 1, 2025[149]. As a result, BCOPAO agrees with BC Hydro that "the MIN to LNG Canada Interconnection project is exempt pursuant to the Transmission Upgrade Exemption Regulation"[150].

However, BCOAPO notes that since the project is not expected to be in-service during the F2020-F2021 test period it does not affect the revenue requirement for the test period. Again, BCOAPO expects the cost of the project will be the subject to consideration in BC Hydro's next RRA.

EV Charging Infrastructure

Finally, the same Letter[151] from the BCUC requested that, in their final arguments parties include their positions and rationale as to "whether British Columbia Hydro and Power Authority's investments in electric vehicle charging infrastructure should be included in rate base during the current test period and recovered from ratepayers or be separately tracked and excluded from rate base until the British Columbia Utilities Commission directs otherwise, given the developing landscape of the electric vehicle charging stations market in BC."

In its Final Argument[152] BC Hydro expresses the view that "BC Hydro's capital additions related electric vehicle charging stations, net of any contribution from Government or third parties, are included in rate base pursuant to section 1 of Direction No. 8". BC Hydro then goes on to say:

[149] Exhibit B-1, Appendix I, page 4, line 20
[150] BC Hydro Final Argument, page 139
[151] Exhibit A-31
[152] Page 145

> "However, amounts included or excluded from rate base have no practical effect during the Test Period because BC Hydro's net income is not dependent on a specific rate base amount. Rather, BC Hydro's net income is currently prescribed by section 3 of Direction No. 8 to be a specific dollar amount of $712 million per fiscal year in each of fiscal 2020 and fiscal 2021".

BCOAPO disagrees with BC Hydro's assertion that the inclusion/exclusion of electrical vehicle charging infrastructure in/from rate base has no practical effect during the test period. Inclusion of EV charging infrastructure costs in rate base leads to the inclusion of any associated depreciation and financing (interest) costs in the revenue requirement. Furthermore, there will also be O&M costs associated with these investments that will be included in the revenue requirement for the test period.

BCOAPO also questions BC Hydro claim that section 1 of Direction No. 8 requires the inclusion of EV charging infrastructure costs in rate base. BCOAPO notes that section 1 of Direction No. 8 specifically states "In determining rate base for a fiscal year, the amounts A, B and F must have subtracted from them any amount included in them that is an expenditure incurred by the authority, on or after April 1, 2011, that the commission determines under the Act must not be recovered by the authority in rates", where A represents the "amount listed as property, plant and equipment in service, less accumulated amortization". From BCOAPO's perspective this means that for EV charging infrastructure costs incurred on or after April 1, 2011 the BCUC can determine whether or not they are to be included in rate base.

Returning to the question posed by the BCUC, it is BCOAPO's view that the costs should be excluded from rate base and, as a consequence, any associated costs should be excluded from the revenue requirements for the test period. These costs are not required to support the provision of electric service to BC Hydro's customers and BC Hydro's role in promoting EV charging (at a cost to all ratepayers) is still to be determined. BCOAPO finds the inclusion of cost for EV charging infrastructure owned by BC Hydro to be particularly problematic in those circumstances where the facilities are not leased to/operated by 3rd parties but rather owned/operated by BC Hydro and BC Hydro has yet to establish rates for the use of the facilities[153]. BCOAPO submits that the BCUC should direct that the costs and revenues (e.g., lease payments and any future rate revenues) associated with EV charging infrastructure be separately tracked and excluded from the revenue requirement during the test period.

REGULATORY ACCOUNTS

BC Hydro currently has 29 Regulatory Accounts with a total net balance of $5.5 B as of F2019 year end[154]. In the current Application BC Hydro is seeking approval[155] for:

- Two changes related to the refund/recovery of the Account balances,
- Five changes related to the scope of the Accounts, and
- Closure of four of the Accounts.

BC Hydro is not proposing any new regulatory accounts.

Submissions

Regulatory Account Refund/Recovery

Since fiscal 2015 BC Hydro has recovered the balances in the Cost of Energy Variance Accounts using the Deferral Account Rate Rider ("DARR") in accordance with Direction No. 7. However, Direction No. 7 has been repealed[156] and BC Hydro is seeking approval to[157]:

- Reduce the DARR from 5% to 0% effective April 1, 2019 and

[153] Exhibit B-5, BCUC 1.122.2.1; BCUC 1.122.2.1.1; BCUC 1.122.5
[154] Exhibit B-1, page 7-10 and Appendix A, Schedules 2.1 & 2.2
[155] Exhibit B-1, pages7-5 to 7-7 and Exhibit B-4, BCUC 1.40.3.1
[156] Exhibit B-1, page 2-9
[157] Exhibit B-1, page 7-26

- Amortize into rates, over the fiscal 2020 to fiscal 2021 test period, the fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts.

Under BC Hydro's proposal ratepayers will realize the benefit of the net credit balance more immediately than if the credit were to be refunded through the DARR[158]. In support of its approach BC Hydro notes[159] that a significant portion of the net credit balance relates to a one-time accounting adjustment of $319 million related to the recognition of revenues under the Skagit River Agreement, which resulted in a retroactive decrease in unearned revenues and a corresponding adjustment to the Heritage Deferral Account to the benefit of ratepayers. As the retroactive adjustment relates to ratepayers from prior periods, BC Hydro's request allows ratepayers to realize the benefit of this net credit balance more immediately than if the credit were to be refunded to ratepayers through the previous DARR table mechanism[160]. BC Hydro also notes that its proposal is "administratively simple and transparent, and contributes to what BC Hydro considers to be relative rate stability in the test period".

In the initial Application, BC Hydro had proposed to refund the forecast fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the fiscal 2020 to fiscal 2021 test period with equal amounts being amortized in fiscal 2020 and fiscal 2021. However, in the Evidentiary Update, BC Hydro has proposed to amortize a higher amount of the credit balance in the Cost of Energy Variance accounts in fiscal 2020 and a lower amount in fiscal 2021. The result is that BC Hydro's requested rate increase for fiscal 2020 remains unchanged, avoiding the need for a retrospective adjustment to fiscal 2020 interim rates and customer bills[161].

BCOAPO supports BC Hydro's proposal to refund the current net balance in the Cost of Energy Variance Accounts to ratepayers over the two year test period covered by the

[158] Exhibit B-1, page 7-26; Exhibit B-5 and BCUC 1.145.2
[159] Exhibit B-5, BCUC 1.148.5
[160] Exhibit B-13, BCOAPO 2.143.1
[161] Exhibit B-11-2, page 10

current Application. However, as noted above under the heading Revenue Requirement Overview (under Reported Rate Increases), BCOAPO does not consider the approach used to be particularly transparent. BCOAPO submits that, if approved as proposed, any communications to ratepayers regarding the rate increases will need to clearly communicate that while the DARR is zero the costs that would have been refunded to ratepayers through the DARR are now included a cost reductions in the determination of the general rate increase/decrease.

Scope Changes

BC Hydro is proposing to change the scope (i.e., the types of costs that can be deferred or the period for which the account will apply) of five of its Regulatory Accounts[162]:

- Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account;

- Defer any variances between forecast and actual amounts related to the Biomass Energy Program which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account. This will ensure that BC Hydro recovers its costs with respect to the Biomass Energy Program;

- Continue to defer, on an annual and ongoing basis, any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account, continue to apply interest to the balance of the account and recover the forecast interest charged to the account each year, and continue to recover the forecast account balance at the end of a test period over the next test period;

- Defer low-carbon electrification expenditures to the DSM Regulatory Account, consistent with the Direction to the BCUC Respecting Undertaking Costs; and

[162] Exhibit B-1, page 7-6

- Remove the reference to the "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Account, as BC Hydro has fully adopted IFRS.

Effective April 1, 2019 BC Hydro will adopt a new IFRS 16 Leases standard. At the time of the Application, BC Hydro's preliminary assessment of its Electricity Purchase Agreements was that the impacts of IFRS 16 would be a net credit adjustment at transition of $18 M to the Non-Heritage Deferral Account in fiscal 2020 and had included this in the Application[163]. However, in the Evidentiary Update BC Hydro noted that it had completed this assessment and has now included a one-time debit adjustment of $64.8 M[164].

BCOAPO supports BC Hydro's proposal to include the transition adjustment in the opening F2020 balance for the Non-Heritage Deferral Account, particularly now that the assessment of the transition impact has been completed.

BCOAPO notes that the costs of EPAs are, in reality, a cost of energy regardless of how they are classified for accounting and reporting purposes. As a result, BCOAPO also supports BC Hydro's proposal to defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account (i.e. costs classified as depreciation/amortization or taxes for accounting purposes – as variances in costs classified as cost of energy and financing charge are already subject to deferral).

For similar reasons, BCOAPO also supports BC Hydro's proposal[165] to defer any variances related to the Biomass Energy Program which are not eligible for deferral treatment under existing orders, to the Non-Heritage Deferral Account.

BC Hydro plans for dismantling costs in its revenue requirements applications and these planned amounts are recovered from ratepayers. However, actual dismantling costs can vary significantly from planned amounts[166]. By Order No. G-47-18 the BCUC approved

[163] Exhibit B-1, page 7-27 and 8-29
[164] Exhibit B-11, Appendix F, page 1 and Exhibit B-16, BCOC 3.302.2
[165] Exhibit B-1, page 7-28
[166] Exhibit B-6, CEC 1.71.1 and Exhibit B-1, page 7-29

the deferral of variances between forecast and actual dismantling costs over the F2017-F2019 period. In the current Application, BC Hydro seeks to continue to defer, on an ongoing basis, the variances between forecast and actual dismantling costs. To the extent that actual dismantling costs vary from the forecast dismantling costs included in BC Hydro's revenue requirements applications, BC Hydro is seeking approval to continue to defer any variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account for recovery from ratepayers. In support of its proposal BC Hydro notes that dismantling cost variances can be positive or negative and continue to be significant in recent years[167].

BCOAPO supports BC Hydro's proposal to continue the over the Dismantling Cost Regulatory Account. Continued use of the account recognizes the uncertainty associated with the forecast values and means that ratepayers pay the actual costs of dismantling.

Order in Council No. 100 requires the BCUC to allow BC Hydro to defer the costs incurred for prescribed undertakings to the DSM Regulatory Account. As a result, BC Hydro is formally requesting that the BCUC approve the deferral of low-carbon electrification expenditures to the DSM Regulatory Account consistent with the Direction to the BCUC[168]. This approval is required as BC Hydro does not consider the low-carbon electrification projects it has undertaken and the BC Hydro LCE Program to be a "demand side measure" as defined under section 1 of the *Clean Energy Act*[169]. BCOAPO has no issues with BC Hydro's request as it serves to clarify and formalize the direction the BCUC has received from the Provincial Government.

BCOAPO supports BC Hydro's request to remove the reference to "Prescribed Standards" from the scope of what may be deferred to the Site C Regulatory Accounts as it will allow BC Hydro to continue to defer to the Site C Regulatory Account any costs related to the Site C Project that are not able to be capitalized[170].

[167] Exhibit B-1, page 7-29
[168] Exhibit B-1, pages 7-31 – 7-32
[169] Exhibit B-5, BCUC 1.150.4 and Exhibit B-13, BCOAPO 2.144.1
[170] Exhibit B-1, pages 7-31 – 7-32

Regulatory Account Closures

In the initial Application BC Hydro sought approval to close two Regulatory Accounts[171]:

- The Rate Smoothing Regulatory Account (in F2020) as this account has a zero balance and BC Hydro is not proposing to "smooth" rates over the F2020 to F2021 period; and

- The Capital Project Investigation Costs Regulatory Account (at the end of F2021) as the balance will be fully amortized into rates at that time.

In its responses to the information requests BC Hydro noted that, subsequent to the filing of the Application, it had written off the balance in the Arrow Water Systems Provision Regulatory Account. As result, BC Hydro has amended its request in the Application to also seek approval to close the Arrow Water Systems Provision Regulatory Account as well as the related Arrow Water Systems Regulatory Account[172].

BCOAPO has no issues with BC Hydro's request to close these Accounts.

Other Issues

The 2013 10 Year Rates Plan included a target of $50 million of net gains from real property sales for the fiscal 2015 to fiscal 2019 period. Consistent with this target, BC Hydro included $10 million in forecast net gains from real property sales in each fiscal year in both the F2015 to F2016 Revenue Requirements Rate Application and the F2017-F2019 Revenue Requirements Application. By Order No. G-48-14, the Real Property Sales Regulatory Account was established to defer the variances between BC Hydro's actual and forecast real property gain/loss from real estate sales[173].

In the current Application, BC Hydro has increased the gains target from $50 million to $100 million and extended the timeframe to achieve this target to the end of fiscal 2024. Consistent with this revised target, BC Hydro has included $10 million in forecast net

[171] Exhibit B-1, pages 7-33 – 7-34
[172] Exhibit B-5, BCUC 1.40.3.1
[173] Exhibit B-1, page 7-41

gains from real property sales in both fiscal 2020 and fiscal 2021, in the Application. The revised target of $100 million in net gains from real property sales is expected to clear the balance in this regulatory account by the end of fiscal 2024[174].

BCOAPO supports BC Hydro's proposals with the respect to the Real Property Sales Regulatory Account. Maintaining the Real Property Sales Regulatory Account and continuing to include the forecast net gains from property sales in the revenue requirements means that the existing account balance will not be borne by ratepayers and the ratepayers will benefit from the anticipated future sales of surplus properties.

OTHER REVENUE REQUIREMENT ITEMS

Other Revenue Requirement Items include amortization expense, return on equity, capital structure, finance charges, taxes, miscellaneous and inter-segment revenues, subsidiary net income, the allocation of BC Hydro's business support costs, and provisions and other.

Submissions

Amortization Expense – New Asset Classes

BC Hydro is seeking approval for new asset classes and associated depreciation rates related to: i) Water Rights (Finite), ii) Infrastructure Rights and iii) LED Street Lights[175]. BC Hydro is also seeking approval for three new asset classes related to IFRS 16 Leases and to amortize the assets in each class over the lease term[176]. BCOAPO has no issues with BC Hydro's proposals.

Burrard Synchronous Condense Facility Depreciation Rates

BC Hydro is seeking approval for the depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for F2020 and F2021. The methodology used to determine the depreciation rates is consistent with the methodology

[174] Exhibit B-1, page 7-42
[175] Exhibit B-1, pages 8-6 to 8-7
[176] Exhibit B-1, page 8-8

underlying the depreciation rates approved by the BCUC in its Decision on the F2017-F2019 RRA[177]. BCOAPO has no issues with BC Hydro's proposal.

Depreciation Study

BC Hydro's most recent depreciation study was completed by Gannett Fleming and filed as part of the F2007-F2008 Revenue Requirements Application[178]. In response to information requests filed in this proceeding BC Hydro stated that it is not planning to perform or file an updated depreciation study with the BCUC[179]. Subsequently, in correspondence[180] to the BCUC following the oral proceeding, BC Hydro stated:

> "BC Hydro has reflected on the feedback received during the Oral Hearing and understands that performing a depreciation study may be necessary for parties to have confidence in BC Hydro's depreciation rates going forward. Accordingly, BC Hydro will perform a depreciation study."

However, in the same correspondence BC Hydro noted that it was likely not possible to complete a depreciation study in time to inform the next Revenue Requirements Application. This timing was confirmed in BC Hydro's Final Argument[181].

BCOAPO notes that during the 2012-2014 Revenue Requirements Application proceeding BC Hydro had indicated that it expected to undertake a depreciation study prior to its next revenue requirements application. However, the Company subsequently changed its plans[182].

BCOAPO submits that, given BC Hydro's acknowledgement as to the need for a new depreciation study, the BCUC should direct BC Hydro to complete such a study for filing during the next RRA[183] and, if not practical, no later than the following RRA.

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[177] Exhibit B-1, page 8-3
[178] Exhibit B-1, page 7-49
[179] Exhibit B-6, AMPC 1.23.7
[180] Exhibit B-43
[181] Page 204
[182] F2017-F2019 RRA, Exhibit B-9, BCUC 1.152.1
[183] While BC Hydro anticipates filing its next RRA in February 2021, it may be possible to incorporate the results of a depreciation study into a subsequent evidentiary update.

Subsidiary Net Income

Subsidiary Net Income consists primarily of Powerex's Net Income (also referred to as Trade Income). The forecast value for Trade Income is based on a five year historical average consistent with the approach used in past revenue requirement applications. In initial Application the average for the most recent five years of actual results (F2014-F2018) was $120.6 M and this was the Trade Income values used for F2020 and F2021[184].

In the Evidentiary Update BC Hydro continued to use the F2014-F2018 average even though the actual results or F2019 were available (and used elsewhere in the Update)[185]. BC Hydro rationale for not updating the Trade Income forecast for F2020 and F2021 was that it considered the scope of the Evidentiary Update to be limited to targeted adjustments, primarily related to fiscal 2019 actuals and the new Cost of Energy forecast.

It is BCOAPO's submission that given the actual F2019 Trade Income results were available at the time of the Evidentiary Update, they represent more recent information that should have been used to update the five-year historical average for Trade Income used in the Application. In BCOAPO's view limiting the Evidentiary Update to "targeted adjustments" results in a "partial update" based on parameters of BC Hydro's choosing. In BCOAPO's view a more robust Update is one that updates all values were possible and practical to reflect more recent information. BCOAPO notes that its submissions in this regard are consist with those made previously with respect to Storm Restoration Costs. The updated value for Trade Income for F2020 and F2021 would be $176.3 M[186].

Provisions and Other

The cost of project write-offs was not included as a revenue requirement item in previous revenue requirement applications[187]. However, the current Application includes, in

[184] Exhibit B-1, page 8-17
[185] Transcript Vol. 7, page 906
[186] Exhibit B-17, BCOAPO 3.168.3
[187] Exhibit B-6, BCUC 1.161.1 and Exhibit B-13, BCOAPO 2.147.1

Provisions and Other, forecast costs for project write-offs of $9.9.M in F2020 and $9.7 M in F2021[188].

Including a forecast of project write-off costs in the revenue requirement represents a change in the costs that are to be to the account of ratepayers versus shareholders. Direction No. 8 (B.C. Reg. 24/2019) provided a number of directives to the BCUC in regard to the determination of the revenue requirement and subsequent rates for F2020 and F2021, including setting BC Hydro's net income (i.e., the planned shareholder return) at $712 M for each of the two years. It is BCOAPO's view that if the Government had intended there to be further changes from past practice as to the cost that are to be to the account of the shareholder versus the ratepayer they too would have been referenced in Direction No. 8. As a result, it is BCOAPO's view that the $712 M annual return to shareholders is based on the current practices/paradigm with respect to shareholder risk and the BCUC should deny BC Hydro's proposal to include project write-off costs in the revenue requirement for purposes of setting rates for F2020 and F2021.

TRANSMISSION REVENUE REQUIREMENT ("TRR")

BC Hydro is seeking approval of its proposed OATT rates for F2020 and F2021[189]. The rates charged under the OATT are designed to collect the TRR, which is the sum of BC Hydro's net transmission function costs, as calculated using a cost of service methodology[190].

The rates charged under the OATT are for Network Integration Transmission Service (NITS), Point-To-Point (PTP) Transmission Service and Ancillary Services. BC Hydro and Powerex account for approximately 98.5 per cent of the revenue collected through the OATT[191], while external transmission customers account for approximately 1.5 per cent of the revenue. Total external revenues from the OATT are forecast to be $15.9 M in each of F2020 and F2021[192].

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188 Exhibit B-1, page 8-22
189 Exhibit B-11-2, Appendix E, page 4
190 Exhibit b-1, page 9-1
191 Exhibit B-1, page 9-1
192 Exhibit B-13, BCOAPO 2.149.1

Submissions

BC Hydro's proposed Open Access Transmission Tariff (OATT) rates are determined to recover BC Hydro's Transmission Revenue Requirement (TRR), consistent with past Orders of the BCUC[193].

BCOAPO has no issues with the derivation of BC Hydro's proposed OATT rates.

DEMAND SIDE MANAGEMENT

As part of its Application, BC Hydro requested BCUC approval of a DSM expenditure schedule of $90.8 M in F2020 and $116.3 M in F2021. This request was made pursuant to section 44.2 of the UCA[194]. In the Evidentiary Update BC Hydro reduced the DSM expenditure request in F2021 by $27.2 M to $89.1 M, saying that two projects it originally expected to proceed within the test period under the Thermo-Mechanical Pulp (TMP) Program did not submit applications by the required deadline[195].

BC Hydro's Application also set out its planned Low Carbon Electrification Expenditures for F2020-F2021 totaling $15.66 M[196]. However, BC Hydro is not seeking acceptance of these expenditures under section 44.2 of the *Clean Energy Act*[197].

Submissions

Section 44.2 Requirements

Section 44.2 (5.1) states:

> "In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider

[193] Exhibit B-5, BCUC 1.162.1
[194] Exhibit B-1, pp. 1-32 and 10-1
[195] Exhibit B-11, p. 4
[196] Exhibit B-1, Appendix Y, p. 13, Table 4-1
[197] Exhibit B-12, BCUC 2.227.1

(a) British Columbia's energy objectives,

(b) the most recent of the following documents:

(i) an integrated resource plan approved under section 4 of the Clean Energy Act before the repeal of that section;

(ii) a long-term resource plan filed by the authority under section 44.1 of this Act,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the Clean Energy Act, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any."

BC Hydro's Application sets out how its proposed DSM activities and related expenditures support each of these factors. More specifically, with respect to cost-effectiveness, BC Hydro's Application demonstrated that its proposed DSM activities for F2020-F2021 are cost-effective using the TRC test and BC Hydro's long-run marginal cost (LRMC) of acquiring electricity from clean or renewable energy resources in British Columbia: $105/MWh, the value used in BC Hydro's last Application[198]. In addition, in response to information requests, BC Hydro also demonstrated that its proposed DSM expenditures would still be considered cost-effective using more recent, and lower, LRMC of acquiring electricity from clean or renewable resources in British Columbia costs[199].

Furthermore, BC Hydro's Application has demonstrated that its proposed DSM expenditures satisfy the Utility Cost Test using export market prices to value electricity savings[200].

Residential Expenditures

In its Decision regarding BC Hydro's F2017-F2019 RRA[201], the BCUC noted the relatively low level of DSM spending for residential customers (including low-income customers)

[198] Exhibit B-1, page 10-30
[199] Exhibit B-5, BCUC 1.175.2 and 175.3
[200] Exhibit B-1, pp 10-28 – 10-29 and Exhibit B-5, BCUC 1.175.1
[201] Order G-47-18, Decision, page 81

and recommended BC Hydro consider more targeted DSM programs directed at residential customers in the next DSM application. In the same Decision the BCUC found the overall size of the funding envelope in BC Hydro's proposed DSM expenditure schedule provides a balanced response to a reduction in the load forecast and the need to meet certain targets under the 2013 10 Year Rates Plan[202].

BC Hydro claims that it "has increased expenditures for the residential sector and non-integrated areas in the DSM Plan for fiscal 2020 and fiscal 2021, while staying within the overall portfolio spending envelope"[203]. However, BC Hydro annual proposed spending for F2020 and F2021 ($90.9 M and $89.1 M respectively, excluding TMP[204]) is lower than that set out in previous plan, which ranged from $100.7 M to $113.7 M[205].

BC Hydro also claims that expenditures targeted at the Residential sector have increased by 50%[206]. If one compares the average annual planned spending for F2017-F2019 in the previous Application ($13.07 M)[207] with the average annual planned spending for F2020-F2021 in the current Application ($19.05)[208] – the increase is only 46%. Furthermore, the increase in spending for between the F2019 Plan and the F2020 Plan is only 29%[209].

Overall, BC Hydro's proposed F2020-F2021 planned DSM expenditures are not as aggressive, either in total or specifically with respect to the Residential sector as the Application would suggest.

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202 *Ibid,* page 78.
203 Exhibit B-1, page 10-8
204 Exhibit B-1, page 10-26
205 Order G-47-18, Decision, page 72 – excluding TMP related expenditures
206 Exhibit B-1, page 10-8
207 Exhibit B-6, CEC 1.80.2 (for RRA F2017 & F2018) and GJOSHE 1.14.2 (for RRA F2019)
208 Exhibit B-1, page 10-26
209 $14.3 M in F2019 Plan versus $18.4 M in F2020 Plan

Low Income Expenditures

1. <u>Low-Income DSM program is not an alternative to low-income rates</u>

BCOAPO submits that BC Hydro has failed to comply with the BC Government's 2018 Mandate Letter requiring BC Hydro to make substantive progress toward implementing low income rates.

On April 18, 2018, the BC Minister of Energy, Mines and Petroleum in a Mandate Letter to BC Hydro set out several priorities for BC Hydro in which BC Hydro is expected to make substantive progress during the 2018/2019 fiscal year, including the priority to "implement affordability measures, such as low income rates and expanded demand-side management programs targeted to low income ratepayers"[210]. However, during the hearing, BC Hydro confirmed that it is not doing any work on a lifeline rate today because the legislative framework has not changed[211], and it is not planning to advance a lifeline rate because the government policy "has said no to lifeline rates"[212].

Further, BC Hydro elaborated that because the government "did not want BC Hydro to go forward with lifeline rates", the government in Phase One of the Comprehensive Review requested that BC Hydro shift more expenditures from its DSM plan into funding more residential low-income programs.[213] In other words, it appears that BC Hydro considers proposed extra expenditures for the Low Income DSM program as an alternative to lifeline rates.

At the same time, neither Phase One of the Comprehensive Review of BC Hydro[214] nor the BC Hydro's January 2019 Mandate Letter from the Minister of Energy, Mines and Petroleum[215] suggests that increasing DSM expenditures for the low-income ratepayers should be offered instead of lifeline rates. Although expanding DSM programs targeted to

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[210] Exhibit B-1, Appendix E, page 2
[211] Transcript, Volume 5, page 471, lines 23 – 24; page 472 line 25 - page 473 line 1
[212] Transcript, Volume 7, page 986, lines 15-22
[213] Transcript, Volume 7, page 986, lines 25-26 & page 987, lines 1-4
[214] Exhibit B-1, Appendix C, page 40
[215] Exhibit B-13, BCOAPO 2.90.1

low income ratepayers is an important affordability measure, it cannot be considered as a comparable alternative to lifeline rates.

2. <u>The proposed Low-Income DSM program does not support the BC Government's priority of making life more affordable</u>

BCOAPO submits that BC Hydro has failed to adequately address a key priority of "making life more affordable" listed in the BC Government's April 2018 Mandate Letter[216].

BC Hydro states that each of key government priorities listed in the Mandate Letter is reflected in BC Hydro's DSM initiatives[217]. With respect to the priority "Making life more affordable" BC Hydro writes that "This has been accomplished by expanding the Low Income and Home Renovation Rebate program, and launching the Non-Integrated Areas program"[218]:

Government Priorities	Demand-Side Management Aligns with These Priorities by:
Making life more affordable	This has been accomplished by expanding the Low Income and Home Renovation Rebate programs, and launching the Non-Integrated Areas program. In addition, EE activities generally help to reduce bills for participating customers.

However, the alleged expanding of the Low Income program involves only increased expenditures and participation for existing programs without proposing new DSM measures targeted to low income ratepayers.

BCOAPO acknowledges that the planned F2020 and F2021 expenditures on Low Income programs ($5.8 M and $6.9 M respectively[219]) are materially higher than the actual values for F2019 ($3.6 M[220]) – 61% and 92% respectively. However, BCOAPO takes issue with the fact that BC Hydro has not proposed any new programs or measures for its F2020-

[216] Exhibit B-1, Appendix E, page 1
[217] Exhibit B-1, Appendix X, page 11
[218] *Ibid*
[219] Exhibit B-1, Appendix X, Table A-1
[220] Exhibit B-58, UT #62 (a)

F2021 Low Income Program[221]. The proposed Program consists of the same two components which include Energy Savings Kits (ESK) and the Energy Conservation Assistance Program (ECAP), which have not been modified since 2019[222].

2.1 The overall level of participation in the ECAP program when compared to the total number of BC Hydro's eligible low income customers is not adequate to characterize this program as a meaningful affordability measure

According to the Application, the forecast of residential customers for F2020 will be a total of 1,861,572[223]. BC Hydro estimates that 21% of residential customers are eligible for the Low Income Program based on the LICO + 30% income ceiling[224]. This suggests there are roughly 391,000 low income residential customers potentially eligible for a free ESK and ECAP. We will use this number of eligible low income customers as a basis for our analysis below, although we acknowledge that the actual numbers for 2017 – 2019, and 2021 – 2022 may vary slightly if numbers of total residential customers and/or eligible low income customers are different in those years.

Based on the data above, between F2017 and F2019 only 41,377, or 10.6% of eligible low income customers participated in the ESK program[225]:

Year	Number of ESK Participants	Percentage of Eligible Participants
F2017	10,611	2.7%
F2018	13,489	3.5%

[221] Transcript, Volume 14, page 2729, lines 4-17 & page 2745, lines 5-16.
[222] Exhibit B-1, Appendix X, page 30; Exhibit B-13, Zone II Ratepayers Group 2.43.1
[223] Exhibit B-1, Appendix O, page 26
[224] Exhibit B-1, Appendix AA, Attachment 2, page 21
[225] Exhibit B-6, BCSEA IR 1.44.1 and Exhibit B-58, UT #62 (m)

F2019	17,277	4.4%
Total for F2017-F2019	41,377	10.6%

The participation numbers for the ECAP program are significantly lower: between F2017 and F2019 in this program participated only 10,278, or 2.6% of eligible low income customers[226].

Year	Number of ECAP Participants	Percentage of Eligible Participants
F2017	2,836	0.7%
F2018	3,600	0.9%
F2019	3,842	1%
Total for F2017-F2019	10,278	2.6%

In response to BCUC direction, to support Government priorities related to residential affordability, BC Hydro is taking steps to increase participation for the Low-Income program[227]. However, the increase in the planned number of participants in the ESK and ECAP programs is materially low. In the case of ESK participants, the planned numbers for F2020 is 22,250, and for F2022 and F2021, 22,800 in each year[228], as compared to 17,277 actual F2019 participants[229] for an increase of 28% and 32% respectively. Based

[226] *Ibid*
[227] Exhibit B-1, page 10-24
[228] Exhibit B-6, BCSEA 1.44.1
[229] Exhibit B-58, UT #62 (m)

on BC Hydro forecast, the total participation in the ESK program in F2020-F2022 would be 67,850, which represents only 17.3% of eligible low income customers:

Year	Number of ESK Participants	Percentage of Eligible Participants
F2020	22,250	5.7%
F2021	22,800	5.8%
F2022	22,800	5.8%
Total for F2020-F2022	67,850	17.3%

In the case of ECAP participants, the planned levels for F2020 - F2022 are 3,905, 4,360 and 4,495[230] respectively as compared to 3,842 actual participants in F2019[231], for increases of 1.6%, 13.5% and 17% respectively. The total participation in the ECAP program in F2020-F2022 would be 12,760, or 3.3% of eligible low income customers:

Year	Number of ESK Participants	Percentage of Eligible Participants
F2020	3,905	1%
F2021	4,360	1.1%
F2022	4,495	1.1%

[230] Exhibit B-6, BCSEA 1.44.1
[231] Exhibit B-58, UT #62 (m)

Total for F2020-2022	12,760	3.2%

In BCOAPO's submission, the proposed increases in planned participation do not adequately respond to the BCUC recommendation from the last RRA.

Additionally, considering the consistently small percentage of eligible low income customers participating in the ECAP program (around 1% in each fiscal year), it is reasonable to conclude that the only DSM program that is really accessible to low income customers is the ESK, which targets to cover 17.3% of eligible low income customers in F2020-F2022.

2.2 <u>The average bill savings achieved from the installation of ESKs are not adequate to consider the ESK program a meaningful affordability measure.</u>

According to BC Hydro estimates, a fully installed ESK in an electrically space heated and electric hot water heated single family home could save up to $131 per year[232]. Average bill savings for installing an ESK are, according to BC Hydro's own estimates, only $37.12 to $44.78 per year[233].

BCOAPO submits that facilitating an average savings of $3.00 to $3.60 per month is far from the adequate response needed in order to make an appreciable difference in the lives of people living in poverty.

3. <u>The ESK program does not provide adequate energy savings to its participants</u>

BC Hydro indicates that the average savings per participant from ESKs in 2011 - 2016 are between 262 and 316 kWh per year[234]. The average annual consumption of the low income customers after they have participated in the ESK program in 2011 - 2016 is

[232] Exhibit B-58, UT #62 (n)
[233] Exhibit B-58, UT #62 (o). This is an average estimate across all household types, and includes both electrically heated, and non-electrically heated homes.
[234] Exhibit B-1, Appendix AA, Attachment 2, page 25

between 8,616 and 9,381[235]. Accordingly, the average annual savings from ESK would represent 3% to 3.3 % over the average annual consumption.

Additionally, BCOAPO takes issue with BC Hydro's limited activities for verification of energy savings related to Energy Savings Kits. After ESKs are mailed to the home, BC Hydro does not conduct post-audits on customers who have received them[236]. Instead, BC Hydro conducts billing analysis of random participant groups, and non-mandatory participation surveys[237]. Considering that the significant amount of the historic and planned savings for Low Income DSM has been allocated to savings from the ESKs[238], it would be practical to develop a mechanism to track installation of the ESK measures in order to calculate actual energy savings.

Overall, in BCOAPO's submission, the proposed Low Income DSM program does not adequately respond to the BCUC recommendation from the last RRA that BC Hydro should consider more targeted DSM programs directed at low income customers in the next DSM application. The ECAP program which is accessed by about 1% of total eligible BC Hydro's low income customers in each year since 2017, and the ESK program that on average saves its participants around $3.00 per month cannot be considered a meaningful affordability measures directed by the Government Mandate Letters to BC Hydro.

It is BCOAPO's position that the BCUC should direct BC Hydro to modernize its DSM program for low-income customers by incorporating new successful measures from other jurisdictions, such as California multifamily whole-building program[239], in order to achieve deeper retrofits and deeper savings for significant number of eligible low income customers.

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[235] Exhibit B-58-2, Supplemental Response to UT #62 (p).
[236] Exhibit B-6, Zone II Ratepayers Group 1.25.5
[237] Transcript, Volume 14, page 2715, lines 9-11, page 2716, lines 4-8; page 2717, lines 16-19, page 2725, line 13 - page 2726, line 21
[238] Exhibit B-6, BCSEA 1.44.1
[239] Transcript, Volume 14, page 2751, lines 5 – page 2755, line 2

PAST BCUC DIRECTIVES – REQUEST TO RECONSIDER AND RESCIND

The Application requests that the BCUC reconsider and rescind the following directives[240]:

- Directive 61 of the BCUC's Decision on BC Hydro's Fiscal 2005 to Fiscal 2006 Revenue Requirements Application which directs that a prorated amount of costs from portfolio-level initiatives be added to the cost of each DSM program to assess cost effectiveness.

- Directive 57 of the BCUC's Decision on BC Hydro's Fiscal 2009 to Fiscal 2010 Revenue Requirements Application which directs that BC Hydro revenue requirement applications filed after January 1, 2011 contain financial information that follows the Uniform System of Accounts.

Submissions

Directive #61

BC Hydro's rationale for requesting the BCUC to reconsider and rescind this Directive is based on the fact that, since Directive 61 was issued, the cost effectiveness testing of DSM expenditures has become subject to the DSM Regulation and is inconsistent with the requirements of the Regulation[241].

BCOAPO supports BC Hydro's request regarding Directive 61.

Directive #57

BC Hydro requests that the BCUC reconsider and rescind Directive 57 of the BCUC's Decision on BC Hydro's F2009 - F2010 Revenue Requirements Application which directs

[240] Exhibit B-1, page 1-33
[241] Exhibit B-1, pages 10-33 – 10-35 and Exhibit B-5, BCUC 1.172.1 & 1.172.2

that BC Hydro revenue requirements applications filed after January 1, 2011, contain financial information that follows the BCUC the Uniform System of Accounts (USoA).[242]

Since F2017 BC Hydro ceased following the USoA framework, following a discussion with BCUC staff on May 2, 2017.[243] During the discussion with BCUC staff, "BC Hydro indicated that using the USoA framework was costly and of limited use and value".[244]

The reason for implementing the USoA was outlined in BC Hydro's F2009 - F2010 Revenue Requirements Application Decision as follows:

> The Commission Panel believes that a consistent and standard reporting methodology that does not change from year to year is highly desirable for all stakeholders. The ability to have reported information in a particular year that is comparable without modification to any other year assists in establishing a historical financial record that is transparent, comparable, and consistent.[245]

Having transparent, comparable, and consistent information continues to be beneficial and desirable for all stakeholders.

Additionally, the Brattle Group Benchmarking Study on BC Hydro's operating costs demonstrated the importance of the USoA framework for effective cost benchmarking against U.S. investor owned electric utilities that follow the Federal Energy Regulatory Commission's (FERC's) USoA.

BCOAPO points out that BC Hydro retained the Brattle Group in response to the BCUC's comments in its Decision on BC Hydro's Previous Application regarding the absence of evidence that BC Hydro uses benchmarking[246].

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242 Exhibit B-1, page 1-33
243 Exhibit B-5, BCUC IR 1.54.3
244 Exhibit B-5, BCUC IR 1.54.3
245 The BCUC's Decision dated March 13, 2009 on BC Hydro's F2009 - F2010 Revenue Requirements Application, page 216
246 Exhibit B-1, page 5-49

Mr. Zarakas, who prepared the Study, made the following comments regarding the need for the information reported on a comparable and consistent basis:

- "[e]ffective cost benchmarking requires that both elements—accounting standardization and the comparability of peers—are adhered to as closely as possible";[247]

- "conducting a cost benchmarking study requires consistency of cost data";[248] and

- the fact that Canadian electric utilities do not consistently employ USoA reporting, can make comparisons of costs—NFOM or otherwise— challenging.[249]

BC Hydro confirmed that using the BCUC USoA allows for more robust benchmarking[250], and that the BCUC USoA is easier to compare to the FERC USoA than BC Hydro's non-USoA accounts[251].

Although BC Hydro indicated that using the USoA framework was costly[252], when asked to quantify a specific dollar amount of the additional cost associated with using the USoA framework, BC Hydro noted "in terms of staff effort … it would be a fraction of one FTE"[253] and that "it would be a portion, probable less than half of an FTE".[254]

Accordingly, BCOAPO submits that BC Hydro should resume USoA reporting. BCOAPO further submits that Directive 57 of the BCUC's Decision on BC Hydro's F2009 - F2010 Revenue Requirements Application should remain in force. In the alternative, we ask the Commission to require BC Hydro to adopt FERC USoA, in accordance with section 49(a) of the *Utilities Commission Act*.

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[247] Exhibit B-1, Appendix T, page 8, para 15
[248] Exhibit B-1, Appendix T, page 16, para 29
[249] Exhibit B-1, Appendix T, page 16, para 30
[250] Transcript, Volume 5, page 485, lines 14 - 16
[251] Transcript, Volume 7, page 1014, lines 7 - 15
[252] Exhibit B-5, BCUC IR 1.54.3*;* and BC Hydro Final Argument, para 240
[253] Transcript, Volume 7, page 1014, lines 20 - 22
[254] Transcript, Volume 7, pages 1014 line 26 - page 1015, line 1

Finally, BCOAPO takes issue with BC Hydro stopping using the USoA framework prior to the BCUC's decision on this matter. During the Oral Hearing BC Hydro indicated that it is not its regular practice to cease following a BC Utilities Commission directive without formal approval from B.C. Utility Commission,[255] and acknowledged that it is incumbent upon it to come to the Commission to seek the formal approval. BCOAPO takes no small amount of comfort from that assurance.

CONCLUSION

Throughout these submissions, BCOAPO has crafted its positions, and set out its concerns and recommendations, taking into consideration the regulatory and legal parameters applicable to this Application.

ALL OF WHICH IS RESPECTFULLY SUBMITTED:

Original on file signed by:

Leigha Worth, Executive Director	**Irina Mis**, Staff Lawyer
BC Public Interest Advocacy Centre	BC Public Interest Advocacy Centre

[255] Transcript, Volume 7, page 1016, line 19 - page 1017, line 4