BC Hydro
Power smart

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November 14, 2019

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: Project No. 1598990
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (the Application)

BC Hydro writes in compliance with Commission Order No. G-279-19 to provide its responses to Round 4 information requests as follows:

Exhibit B-22	Responses to Commission IRs (Public Version)
Exhibit B-22-1	Responses to Commission IRs (Confidential Version)
Exhibit B-23	Responses to Intervener IRs (Public Version)
Exhibit B-23-1	Responses to Intervener IRs (Confidential Version)

BC Hydro is filing a number of IR responses and/or attachments to responses confidentially with the Commission. In each instance, an explanation for the request for confidential treatment is provided in the public version of the IR response. BC Hydro seeks this confidential treatment pursuant to section 42 of the *Administrative Tribunals Act* and Part 4 of the Commission's Rules of Practice and Procedure.

Overall, BC Hydro received 327 Round 4 information requests. Responses to 260 of those information requests are included in this filing.

Thirty-four information requests are the subject of BC Hydro's letter of November 8, 2019 (the information requests at issue are listed in the attachment to that letter). They are being addressed through the comment process established by Order No. G-279-19.

After accounting for those information requests, only 33 responses are still outstanding. They will be filed by Tuesday, November 19, 2019, in accordance with BCUC Order No. G-279-19. For ease of reference, those outstanding responses are listed below:

BCOAPO 4.177.1	BCSEA 4.87.3	CEABC 4.59.2
CEABC 4.62.2	CEABC 4.63.1	CEABC 4.63.2
CEABC 4.63.3	CEC 4.2.1	CEC 4.2.5
CEC 4.2.6	CEC 4.2.8	CEC 4.2.9
CEC 4.2.10	CEC 4.5.1	CEC 4.5.2
CEC 4.5.3	CEC 4.8.2	CEC 4.15.2
GJOSHE 4.1.4	INCE 4.9.0	INCE 4.18.0
INCE 4.19.0	INCE 4.33.0	INCE 4.37.0
INCE 4.40.0	MOVEUP 4.7.1	ZONE II RPG 4.64.1
ZONE II RPG 4.64.1.1	ZONE II RPG 4.64.1.2	ZONE II RPG 4.64.1.2.1
ZONE II RPG 4.64.1.3	ZONE II RPG 4.66.1.1	ZONE II RPG 4.66.1.1.1

Lastly, to be consistent with the numbering approach used by other interveners in this round of information requests, BC Hydro has re-numbered information requests received from Commercial Energy Consumers (**CEC**) and Edlira Gjoshe (**GJOSHE**) as follows:

Intervener	Original IR Number	Revised IR Number
CEC (Exhibit C9-8)	1.1	9.1
CEC (Exhibit C9-8)	1.2	9.2
CEC (Exhibit C9-8)	1.2.1	9.2.1
CEC (Exhibit C9-8)	2.1	10.1
CEC (Exhibit C9-8)	2.2	10.2
CEC (Exhibit C9-8)	2.3.1	10.2.1
CEC (Exhibit C9-8)	2.3	10.3
CEC (Exhibit C9-8)	3.1	11.1
CEC (Exhibit C9-8)	3.2	11.2
CEC (Exhibit C9-8)	3.2.1	11.2.1
CEC (Exhibit C9-8)	3.3	11.3
CEC (Exhibit C9-8)	3.4	11.4
CEC (Exhibit C9-8)	3.5	11.5
CEC (Exhibit C9-8)	4.1	12.1
CEC (Exhibit C9-8)	4.2	12.2
CEC (Exhibit C9-8)	5.1	13.1
CEC (Exhibit C9-8)	5.1.1	13.1.1
CEC (Exhibit C9-8)	5.2	13.2
CEC (Exhibit C9-8)	5.3	13.3
CEC (Exhibit C9-8)	5.4	13.4

Intervener	Original IR Number	Revised IR Number
CEC (Exhibit C9-8)	5.5	13.5
CEC (Exhibit C9-8)	6.1	14.1
CEC (Exhibit C9-8)	6.2	14.2
CEC (Exhibit C9-8)	6.3	14.3
CEC (Exhibit C9-8)	7.1	15.1
CEC (Exhibit C9-8)	7.2	15.2
CEC (Exhibit C9-8)	7.3	15.3
CEC (Exhibit C9-8)	8.1	16.1
CEC (Exhibit C9-8)	9.1	17.1
CEC (Exhibit C9-8)	10.1	18.1
CEC (Exhibit C9-8)	11.1	19.1
CEC (Exhibit C9-8)	11.2	19.2
CEC (Exhibit C9-8)	12.1	20.1
CEC (Exhibit C9-8)	12.2	20.2
CEC (Exhibit C9-8)	12.3	20.3
CEC (Exhibit C9-8)	13.1	21.1
CEC (Exhibit C9-8)	14.1	22.1
CEC (Exhibit C9-8)	14.2	22.2
CEC (Exhibit C9-8)	14.3	22.3
CEC (Exhibit C9-8)	15.1	23.1
CEC (Exhibit C9-8)	15.2	23.2
CEC (Exhibit C9-8)	15.3	23.3
CEC (Exhibit C9-8)	16.1	24.1
CEC (Exhibit C9-8)	16.2	24.2
CEC (Exhibit C9-8)	17.1	25.1
CEC (Exhibit C9-8)	17.2	25.2
CEC (Exhibit C9-8)	18.1	26.1
CEC (Exhibit C9-8)	19.1	27.1
CEC (Exhibit C9-8)	19.2	27.2
GJOSHE (Exhibit C14-6)	5.1	4.2.1
GJOSHE (Exhibit C14-6)	5.2	4.2.2
GJOSHE (Exhibit C14-6)	5.3	4.2.3
GJOSHE (Exhibit C14-6)	5.4	4.2.4
GJOSHE (Exhibit C14-6)	5.5	4.2.5
GJOSHE (Exhibit C14-6)	5.6	4.2.6
GJOSHE (Exhibit C14-6)	5.7	4.2.7

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

cs/rh

Enclosure

1.0 Water Rentals

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.1.1
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In BCUC IR 3.1.1, the BC Utilities Commission staff created the following table based on information provided in Schedule 4.0 of Appendix A to the Evidentiary Update:

Change in Water Rentals	F2020	F2021
[A] Cost ($ million) (Line 23)	$13.8	$25.9
[B] Volume (GWh) (Line 1)	4,894	477
Average Cost ([A]/[B]	$2.80	$54.30

In its revised response to BCUC IR 3.1.1, BC Hydro states:

The change in the average unit cost of water rentals of $2.80/MWh in fiscal 2020 and $54.30/MWh in fiscal 2021 is not a meaningful comparison because:

- Water rental costs include fixed charges such as plant capacity charges, miscellaneous water license costs and adjustments under the coordination agreements which do not vary with the volumes reported on line 1 of Schedule 4.0; and
- Water rental costs include costs based on generation output of the prior calendar year, which means that there is no direct correlation between the costs as shown on line 23 of Schedule 4.0 and the volumes as shown on line 1 of Schedule 4.0 for the respective years.

BC Hydro has calculated the change in the average unit cost of water rentals between the Evidentiary Update and the Application as $0.6/MWh for fiscal 2020 and $(0.5)/MWh for fiscal 2021, as shown on line 16 of Schedule 4.0 (columns 6 and 9).

This is calculated by subtracting the average cost of water rentals in the Evidentiary Update (line 16 of Schedule 4.0 column 5 for fiscal 2020) from the average cost of water rentals in the Application (line 16 of Schedule 4.0 column 4). The average cost of water rentals is calculated by dividing the water rental costs on line 23 of schedule 4.0 (numerator) by the hydro generation volumes on line 1 of Schedule 4.0 (denominator). However, because the water rental costs on the generation of energy are calculated using prior year calendar generation, the cost variance in the numerator will not correlate to the change in current year's volumes in the denominator. The change in the average unit costs

will vary year over year depending on the hydro generation volumes in those years, even if costs do not vary.

In Appendix A, Schedule 4.0 of the Public Evidentiary Update, BC Hydro provides the following Unit Costs ($/MWh) and Cost of Energy ($ million) for Water Rentals in lines 16 and 23:

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
	Unit Costs ($/MWh)										
16	Water Rentals		7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation		45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments		94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area		258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases		38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales		(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost		33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)
	Cost of Energy ($ million)										
	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)

AMPC seeks to clearly identify government revenue derived from BC Hydro's rates.

4.1.1 Please update Table 4-4 from Chapter 4 of the Application (Exhibit B-1, pdf p. 248) based on any new information provided in the Public Evidentiary Update (Exhibit B-19) or revised responses to the BCUC or interveners (Exhibit B-20). Please fully explain any changes to water rental rates.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 4.1.3.

1.0 Water Rentals

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.1.1
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In BCUC IR 3.1.1, the BC Utilities Commission staff created the following table based on information provided in Schedule 4.0 of Appendix A to the Evidentiary Update:

Change in Water Rentals	F2020	F2021
[A] Cost ($ million) (Line 23)	$13.8	$25.9
[B] Volume (GWh) (Line 1)	4,894	477
Average Cost ([A]/[B]	$2.80	$54.30

In its revised response to BCUC IR 3.1.1, BC Hydro states:

The change in the average unit cost of water rentals of $2.80/MWh in fiscal 2020 and $54.30/MWh in fiscal 2021 is not a meaningful comparison because:

- Water rental costs include fixed charges such as plant capacity charges, miscellaneous water license costs and adjustments under the coordination agreements which do not vary with the volumes reported on line 1 of Schedule 4.0; and

- Water rental costs include costs based on generation output of the prior calendar year, which means that there is no direct correlation between the costs as shown on line 23 of Schedule 4.0 and the volumes as shown on line 1 of Schedule 4.0 for the respective years.

BC Hydro has calculated the change in the average unit cost of water rentals between the Evidentiary Update and the Application as $0.6/MWh for fiscal 2020 and $(0.5)/MWh for fiscal 2021, as shown on line 16 of Schedule 4.0 (columns 6 and 9).

This is calculated by subtracting the average cost of water rentals in the Evidentiary Update (line 16 of Schedule 4.0 column 5 for fiscal 2020) from the average cost of water rentals in the Application (line 16 of Schedule 4.0 column 4). The average cost of water rentals is calculated by dividing the water rental costs on line 23 of schedule 4.0 (numerator) by the hydro generation volumes on line 1 of Schedule 4.0 (denominator). However, because the water rental costs on the generation of energy are calculated using prior year calendar generation, the cost variance in the numerator will not correlate to the change in current year's volumes in the denominator. The change in the average unit costs will vary year over year depending on the hydro generation volumes in those years, even if costs do not vary.

In Appendix A, Schedule 4.0 of the Public Evidentiary Update, BC Hydro provides the following Unit Costs ($/MWh) and Cost of Energy ($ million) for Water Rentals in lines 16 and 23:

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
	Unit Costs ($/MWh)									
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)
	Cost of Energy ($ million)									
	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)

AMPC seeks to clearly identify government revenue derived from BC Hydro's rates.

4.1.2 Please provide a detailed calculation of the Cost of Energy for Water Rentals (Line 23, Schedule 4.0 of Appendix A of Exhibit B-19) for F2019 to F2021 including for each category of water rental rate as shown in Table 4-4 of the Application.

RESPONSE:

Please refer to Attachment 1 to this response for the detailed calculation of water rentals for fiscal 2019 to fiscal 2021. The values at the end of Attachment 1 are consistent with line 23 of Schedule 4.0 of Appendix A.

Calculation of water rental expense for fiscal 2019 to fiscal 2021 by water rental rate

		F2019			F2020			F2021	
		RRA	**Actual**		**Plan**	**Update**		**Plan**	**Update**
	Reference:	1	2	Reference:	4	5	Reference:	7	8
Hydro generation volumes[1]:									
GWh:									
Calendar 2017 generation	A	48,156,718	49,369,498						
Calendar 2018 generation	B	45,840,982	43,041,827		43,937,293	43,041,827			
Calendar 2019 generation	C				43,128,846	39,531,207		43,128,846	39,531,207
Calendar 2020 generation	D							44,858,737	43,421,365
Operating capacity - kW[1]	E	11,543,591	11,592,691		11,592,691	11,596,691		11,592,691	11,596,691
Construction capacity - kW	F	584,000	584,000		584,000	584,000		584,000	584,000
Water rental rates (based on calendar year):		Calendar 2018:	Calendar 2018:						
Output (Tier 1) < 160,000 MWh	G	$ 1.367	$ 1.367						
Output (Tier 2) > 160,000 MWh	H	$ 6.375	$ 6.374						
Operating capacity ($/kW)	I	$ 4.554	$ 4.555						
Construction capacity ($/kW)	J	$ 0.455	$ 0.455						
B.C. CPI (%)		2.0%	2.7%						
		Calendar 2019:	Calendar 2019:		Calendar 2019:	Calendar 2019:			
Output (Tier 1) < 160,000 MWh	K	$ 1.394	$ 1.404		$ 1.404	$ 1.404			
Output (Tier 2) > 160,000 MWh	L	$ 6.503	$ 6.546		$ 6.546	$ 6.546			
Operating capacity ($/kW)	M	$ 4.645	$ 4.678		$ 4.678	$ 4.678			
Construction capacity ($/kW)	N	$ 0.464	$ 0.467		$ 0.467	$ 0.467			
B.C. CPI (%)		2.0%	2.2%		2.3%	2.2%			
					Calendar 2020:	Calendar 2020:		Calendar 2020:	Calendar 2020:
Output (Tier 1) < 160,000 MWh	O				$ 1.436	$ 1.435		$ 1.436	$ 1.435
Output (Tier 2) > 160,000 MWh	P				$ 6.697	$ 6.690		$ 6.697	$ 6.690
Operating capacity ($/kW)	Q				$ 4.786	$ 4.781		$ 4.786	$ 4.781
Construction capacity ($/kW)	R				$ 0.478	$ 0.477		$ 0.478	$ 0.477
B.C. CPI (%)					2.0%	2.1%		2.0%	2.1%
								Calendar 2021:	Calendar 2021:
Output (Tier 1) < 160,000 MWh	S							$ 1.465	$ 1.465
Output (Tier 2) > 160,000 MWh	T							$ 6.831	$ 6.830
Operating capacity ($/kW)	U							$ 4.882	$ 4.881
Construction capacity ($/kW)	V							$ 0.488	$ 0.487
B.C. CPI (%)								2%	2%
Tier 1 energy (MWh)	W	160,000	160,000		160,000	160,000		160,000	160,000
Calculation of water rentals expense:									
$million:									
1) Generation output charges:									
9 months of Calendar year generation									
Output (Tier 1) < 160,000 MWh	W * G * 9 mths	0.2	0.2	W * K * 9 mths	0.2	0.2	W * O * 9 mths	0.2	0.2
Output (Tier 2) > 160,000 MWh	A - W * H * 9 mths	229.5	235.2	B- W * L * 9 mths	214.9	210.5	C- W * P * 9 mths	215.8	197.5
3 months of Calendar year generation									
Output (Tier 1) < 160,000 MWh	W * K * 3 mths	0.1	0.1	W * O * 3 mths	0.1	0.1	W * S * 3 mths	0.1	0.1
Output (Tier 2) > 160,000 MWh	B - W * L * 3 mths	74.3	70.2	C - W * P * 3 mths	71.9	65.8	D - W * T * 3 mths	76.3	73.9
Total water rentals on generation output		**304.0**	**305.6**		**287.1**	**276.6**		**292.4**	**271.6**
2) Operating capacity ($/kW)									
9 months at Calendar year rate	E* I * 9 mths	39.4	39.6	E* M * 9 mths	40.7	40.7	E* Q * 9 mths	41.6	41.6
3 months at Calendar year rate	E * M * 3 mths	13.4	13.6	E * Q * 3 mths	13.9	13.9	E * U * 3 mths	14.1	14.2
		52.8	**53.2**		**54.5**	**54.5**		**55.8**	**55.7**
3) Construction capacity ($/kW)		0.0							
9 months at Calendar year rate	F*J* 9 mths	0.2	0.2	F*N* 9 mths	0.2	0.2	F*R* 9 mths	0.2	0.2
3 months at Calendar year rate	F* N * 3 mths	0.1	0.1	F* R * 3 mths	0.1	0.1	F* V* 3 mths	0.1	0.1
		0.3	**0.3**		**0.3**	**0.3**		**0.3**	**0.3**
4) Other[2] (not calculated in this table)		**(0.7)**	**4.1**		**1.2**	**(2.1)**		**0.6**	**(4.5)**
Total water rentals		**356.4**	**363.1**		**343.1**	**329.3**		**349.1**	**323.2**

[1]Hydro generation volumes and capacity amounts are net of energy and capacity exemptions under the Skagit Treaty and Columbia River Treaty.
[2]Other includes items such as miscellaneous water license costs, water rental fee adjustments related to coordination agreements.

1.0 Water Rentals

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.1.1
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In BCUC IR 3.1.1, the BC Utilities Commission staff created the following table based on information provided in Schedule 4.0 of Appendix A to the Evidentiary Update:

Change in Water Rentals	F2020	F2021
[A] Cost ($ million) (Line 23)	$13.8	$25.9
[B] Volume (GWh) (Line 1)	4,894	477
Average Cost ([A]/[B]	$2.80	$54.30

In its revised response to BCUC IR 3.1.1, BC Hydro states:

The change in the average unit cost of water rentals of $2.80/MWh in fiscal 2020 and $54.30/MWh in fiscal 2021 is not a meaningful comparison because:

- Water rental costs include fixed charges such as plant capacity charges, miscellaneous water license costs and adjustments under the coordination agreements which do not vary with the volumes reported on line 1 of Schedule 4.0; and
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BC Hydro has calculated the change in the average unit cost of water rentals between the Evidentiary Update and the Application as $0.6/MWh for fiscal 2020 and $(0.5)/MWh for fiscal 2021, as shown on line 16 of Schedule 4.0 (columns 6 and 9).

This is calculated by subtracting the average cost of water rentals in the Evidentiary Update (line 16 of Schedule 4.0 column 5 for fiscal 2020) from the average cost of water rentals in the Application (line 16 of Schedule 4.0 column 4). The average cost of water rentals is calculated by dividing the water rental costs on line 23 of schedule 4.0 (numerator) by the hydro generation volumes on line 1 of Schedule 4.0 (denominator). However, because the water rental costs on the generation of energy are calculated using prior year calendar generation, the cost variance in the numerator will not correlate to the change in current year’s volumes in the denominator. The change in the average unit costs

will vary year over year depending on the hydro generation volumes in those years, even if costs do not vary.

In Appendix A, Schedule 4.0 of the Public Evidentiary Update, BC Hydro provides the following Unit Costs ($/MWh) and Cost of Energy ($ million) for Water Rentals in lines 16 and 23:

Cost of Energy
($ million)

Line		Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Unit Costs ($/MWh)										
16	Water Rentals		7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
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21	Surplus Sales		(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost		33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)
	Cost of Energy ($ million)										
	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)

AMPC seeks to clearly identify government revenue derived from BC Hydro's rates.

4.1.3 Please explain any rates and/or fees included in the Cost of Energy for Water Rentals (Line 23, Schedule 4.0 of Appendix A of Exhibit B-19) that differ from the fees shown in Table 4-4 of the Application.

RESPONSE:

The water rental rates included in the Cost of Energy for Water Rentals (line 23, Schedule 4.0 of Appendix A) have been updated for B.C. Consumer Price Index (CPI) assumptions. Water rental rates are calculated as the previous year's rate times the annual percentage change in B.C.'s CPI. The economic assumptions used in the Evidentiary Update were based on the B.C. CPI assumptions from the B.C. Budget (February 2019). The economic assumptions used in the Application were based on the B.C. CPI assumptions from the Treasury Board dated October 5, 2018.

BC Hydro has updated Table 4-4 of the Application to show the updated water rental rates included in the Cost of Energy for Water Rentals in the Evidentiary Update:

Table 4-4 Water Rental Rates

Water Rental: General Power Use	Calendar Year				
	Actual		Forecast		
	2017	2018	2019	2020	2021
Output (Tier 1) ($/MWh) < 160,000 MWh	1.339	1.367	1.404	1.435	1.465
Output (Tier 1) ($/MWh) > 160,000 MWh	6.243	6.374	6.546	6.690	6.830
Output (Tier 3)	6.560	N/A	N/A	N/A	N/A
Operating Capacity ($/kW)	4.461	4.555	4.678	4.781	4.881
Construction Capacity ($/kW)	0.446	0.455	0.467	0.477	0.487
B.C. CPI (%)	2.1	2.7	2.2	2.1	2.0

1.0 Water Rentals

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.1.1
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In BCUC IR 3.1.1, the BC Utilities Commission staff created the following table based on information provided in Schedule 4.0 of Appendix A to the Evidentiary Update:

Change in Water Rentals	F2020	F2021
[A] Cost ($ million) (Line 23)	$13.8	$25.9
[B] Volume (GWh) (Line 1)	4,894	477
Average Cost ([A]/[B]	$2.80	$54.30

In its revised response to BCUC IR 3.1.1, BC Hydro states:

The change in the average unit cost of water rentals of $2.80/MWh in fiscal 2020 and $54.30/MWh in fiscal 2021 is not a meaningful comparison because:

- Water rental costs include fixed charges such as plant capacity charges, miscellaneous water license costs and adjustments under the coordination agreements which do not vary with the volumes reported on line 1 of Schedule 4.0; and
- Water rental costs include costs based on generation output of the prior calendar year, which means that there is no direct correlation between the costs as shown on line 23 of Schedule 4.0 and the volumes as shown on line 1 of Schedule 4.0 for the respective years.

BC Hydro has calculated the change in the average unit cost of water rentals between the Evidentiary Update and the Application as $0.6/MWh for fiscal 2020 and $(0.5)/MWh for fiscal 2021, as shown on line 16 of Schedule 4.0 (columns 6 and 9).

This is calculated by subtracting the average cost of water rentals in the Evidentiary Update (line 16 of Schedule 4.0 column 5 for fiscal 2020) from the average cost of water rentals in the Application (line 16 of Schedule 4.0 column 4). The average cost of water rentals is calculated by dividing the water rental costs on line 23 of schedule 4.0 (numerator) by the hydro generation volumes on line 1 of Schedule 4.0 (denominator). However, because the water rental costs on the generation of energy are calculated using prior year calendar generation, the cost variance in the numerator will not correlate to the change in current year’s volumes in the denominator. The change in the average unit costs

will vary year over year depending on the hydro generation volumes in those years, even if costs do not vary.

In Appendix A, Schedule 4.0 of the Public Evidentiary Update, BC Hydro provides the following Unit Costs ($/MWh) and Cost of Energy ($ million) for Water Rentals in lines 16 and 23:

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
	Unit Costs ($/MWh)										
16	Water Rentals		7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation		45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments		94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area		258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases		38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales		(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost		33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)
	Cost of Energy ($ million)										
	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)

AMPC seeks to clearly identify government revenue derived from BC Hydro's rates.

4.1.4 Is the reduction in Water Rentals Unit Cost (Line 16, Schedule 4.0 of Appendix A of Exhibit B-19) for F2021 connected to the lower supply under Water Rentals (Line 1, Schedule 4.0 of Appendix A for Exhibit B-19) for F2020? Please fully explain your response.

RESPONSE:

Yes, the reduction in the water rentals unit cost for fiscal 2021 is connected to the lower hydro generation for fiscal 2020.

The calculation of water rental costs on line 23 of Schedule 4.0 in Appendix A, which are used in the calculation of the water rental unit cost on line 16 of Schedule 4.0, is described below.

Water rentals are invoiced to BC Hydro on a calendar year basis, and the calculation of the annual water rentals is derived using the prior calendar year's generation multiplied by the current year's water rental rate. The water rental costs shown in the table for a fiscal year include the costs for parts of two calendar years. Using fiscal 2021 as an example, water rentals are calculated as follows:

- **For the period April to December 2020 of fiscal 2021, water rentals are calculated using the prior calendar year generation (2019 calendar year generation) multiplied by the water rental rate times nine months divided by twelve months; plus**
- **For the period January to March 2021, water rentals are calculated using the prior calendar year generation (2020 calendar year generation) multiplied by the water rental rate times three months divided by 12 months.**

From this example, we can conclude that the water rental costs in fiscal 2021 includes part of the lower hydro generation from fiscal 2020 (as shown on line 1 of Schedule 4.0), because fiscal 2020 includes the period April to December 2019, which is the prior calendar year generation referred to in the bullet point above.

The water rental unit costs for fiscal 2021 on line 16 are calculated as the annual water rental costs for fiscal 2021 on line 23 divided by the hydro generation in fiscal 2021 on line 1 of Schedule 4.0. Therefore, despite the fact that the water rental rates only changed in fiscal 2021 by inflation, the unit costs in fiscal 2021 are lower because the fiscal 2021 water rental cost was largely driven by lower hydro generation in fiscal 2020 compared to that in fiscal 2021.

Please also refer to BC Hydro’s response to AMPC IR 4.1.2 which includes a detailed calculation of the water rental expense by fiscal year.

2.0 IPP Generation and Cost of Energy

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.3.3
Exhibit B-6, BC Hydro Response to AMPC IR 1.1.1
Exhibit B-17, BC Hydro Response to AMPC IR 3.3.1
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In its revised response to BCUC IR 3.3.3, BC Hydro provides the following corrected table showing forecast energy volumes from IPP generation:

Resource Type	F2019 Actual (GWh)	F2020 (GWh)	F2021 (GWh)
Non-Storage Hydro	6,122	6,239	6,696
Biomass	2,400	2,773	2,735
Storage Hydro	2,713	1,260	2,636
Wind	1,574	1,626	1,660
Biogas	94	94	98
Gas Fired Thermal	959	1,543	994
Solar	2	2	3
Other	385	411	417
Total	14,248	13,948	15,238

In its response to AMPC IR 1.1.1, BC Hydro states that the October 2018 rupture of the Enbridge T-South pipeline and subsequent gas curtailment “was expected to result in the loss of Island Generation as a capacity and energy resource over the winter. A small reduction in generation from thermal IPPs was also expected during gas curtailments.”

In its response to AMPC IR 3.3.1, BC Hydro states:

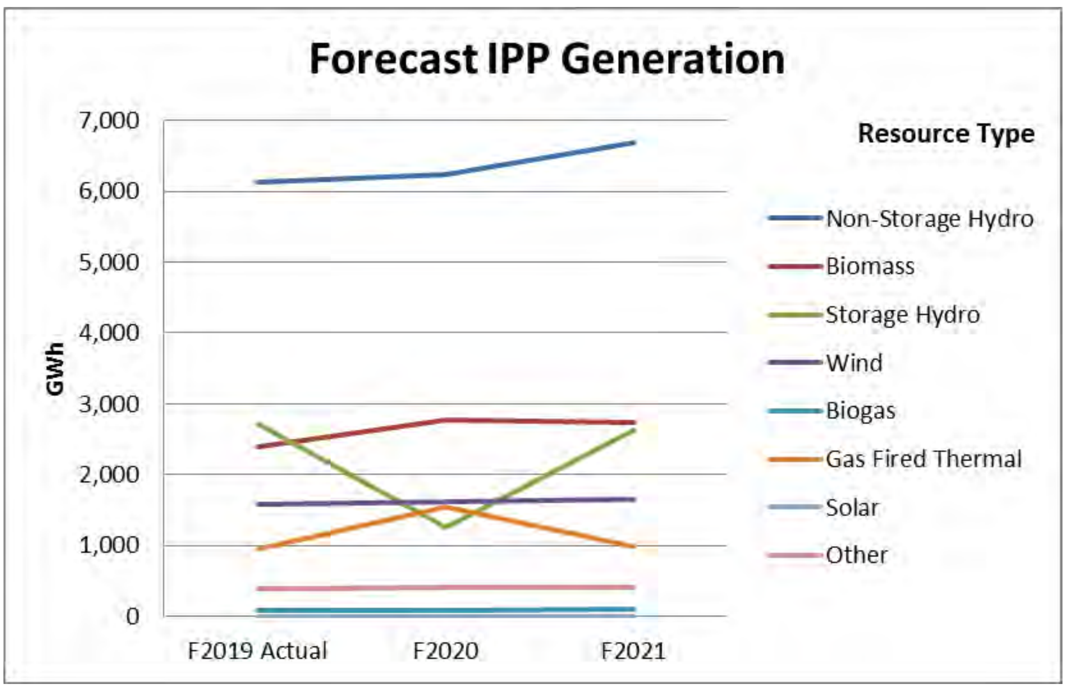
> In fiscal 2019, conditions that increased BC Hydro’s market electricity purchases from Powerex were:
>
> - Dry conditions and lower water inflows that decreased planned hydroelectric generation and purchases from IPPs and Long Term Commitments below forecast;
> - A cold period in February/March that increased BC Hydro customer demand above forecast; and
> - Restricted availability of natural gas due to the Enbridge pipeline rupture.

In Appendix A, Schedule 4.0 of its Public Evidentiary Update, BC Hydro provides a Cost of Energy table (reproduced in part below) that shows the updated unit costs for IPPs and Long-Term Commitments as $87.5/GWh, $92.8/GWh and $92.6/GWh for F2019, F2020, and F2021 and for Market Electricity Purchases as $61.4/GWh, $41.5/GWh and $32.9/GWh for F2019, F2020, and F2021.

Cost of Energy
($ million)

Line		Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
				1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Unit Costs ($/MWh)											
16	Water Rentals			7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation			45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments			94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area			258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases			38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales			(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost			33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

To assist, AMPC has prepared the following chart to graphically depict BC Hydro's forecast IPP generation for F2019, F2020 and F2021, based on BC Hydro's revised response to BCUC IR 3.3.3:



4.2.1 Please explain why the forecast volumes for Gas Fired Thermal generation are significantly higher in F2020 than the F2019 actual and F2021 forecast. In your response, please also explain what inputs were used to generate the forecast volumes and reconcile the F2020 forecast with BC Hydro's earlier statements about restricted gas availability due to the Enbridge pipeline rupture in F2019.

RESPONSE:

This answer also responds to AMPC IR 4.2.3.

The higher fiscal 2020 energy from gas-fired thermal IPPs is primarily related to increased dispatch of Island Generation on Vancouver Island. There are three reasons BC Hydro takes energy from Island Generation:

- **Regular maintenance testing;**
- **System reliability to meet peak loads and transmission requirements; and**
- **System energy needs.**

It was system energy needs that resulted in the forecast of increased generation for fiscal 2020, driven by the low inflow conditions.

Since the forecast increase in Island Generation production was driven by a need for energy to manage a physical supply risk, this generation could not necessarily be replaced by Market Electricity Purchases or generation from BC Hydro's dispatchable resources. Replacing Island Generation volumes by Market Electricity Purchases would result in a higher forecast Cost of Energy if the market price of the equivalent energy were higher than the price of energy from dispatching Island Generation.

The forecast of Island Generation production for system energy requirements is modeled as part of the Energy Studies using forecasts of:

- **Plant availability and heat rate;**
- **Sumas gas price;**
- **Gas transportation and carbon tax prices; and**
- **Value of energy in the system.**

When the forecasted price of energy from dispatching Island Generation is lower than the forecasted value of energy in the system, the model forecasts production from Island Generation.

While the Enbridge pipeline rupture resulted in the loss of Island Generation as a capacity and energy resource over part of the winter, BC Hydro did run Island Generation for most of March in fiscal 2019.

There was, and is forecast to be, sufficient capacity in the T-South pipeline in fiscal 2020 to run Island Generation to support system energy requirements in periods where it is considered economic.

2.0 IPP Generation and Cost of Energy

Reference: **Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.3.3**
Exhibit B-6, BC Hydro Response to AMPC IR 1.1.1
Exhibit B-17, BC Hydro Response to AMPC IR 3.3.1
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In its revised response to BCUC IR 3.3.3, BC Hydro provides the following corrected table showing forecast energy volumes from IPP generation:

Resource Type	F2019 Actual (GWh)	F2020 (GWh)	F2021 (GWh)
Non-Storage Hydro	6,122	6,239	6,696
Biomass	2,400	2,773	2,735
Storage Hydro	2,713	1,260	2,636
Wind	1,574	1,626	1,660
Biogas	94	94	98
Gas Fired Thermal	959	1,543	994
Solar	2	2	3
Other	385	411	417
Total	14,248	13,948	15,238

In its response to AMPC IR 1.1.1, BC Hydro states that the October 2018 rupture of the Enbridge T-South pipeline and subsequent gas curtailment “was expected to result in the loss of Island Generation as a capacity and energy resource over the winter. A small reduction in generation from thermal IPPs was also expected during gas curtailments.”

In its response to AMPC IR 3.3.1, BC Hydro states:

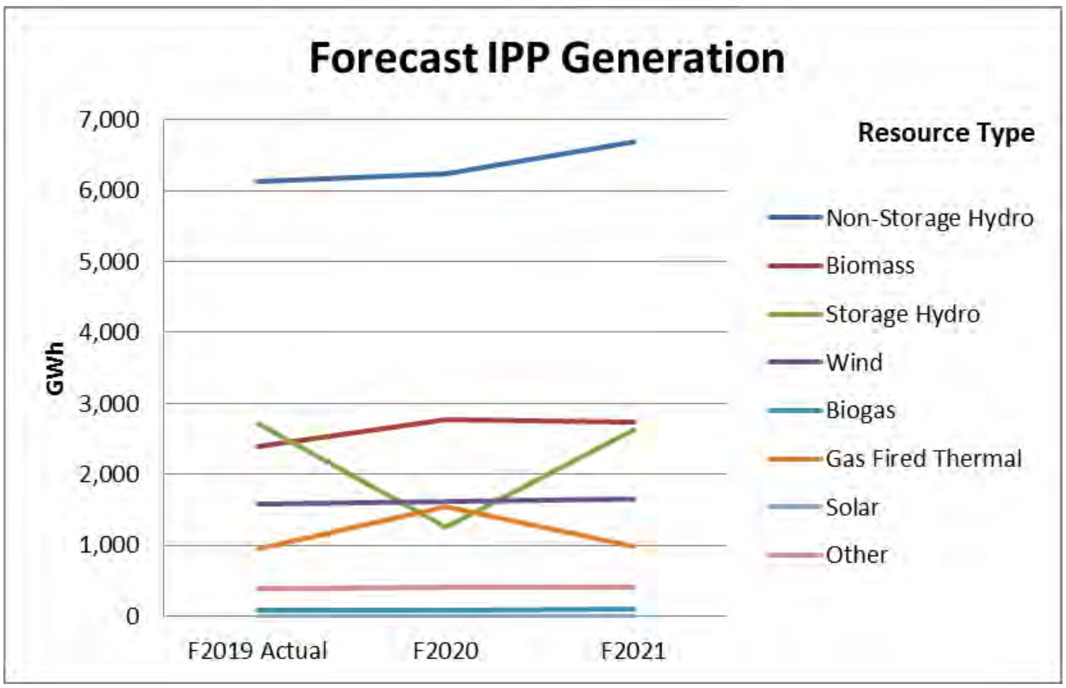
> In fiscal 2019, conditions that increased BC Hydro’s market electricity purchases from Powerex were:
>
> - Dry conditions and lower water inflows that decreased planned hydroelectric generation and purchases from IPPs and Long Term Commitments below forecast;
> - A cold period in February/March that increased BC Hydro customer demand above forecast; and
> - Restricted availability of natural gas due to the Enbridge pipeline rupture.

In Appendix A, Schedule 4.0 of its Public Evidentiary Update, BC Hydro provides a Cost of Energy table (reproduced in part below) that shows the updated unit costs for IPPs and Long-Term Commitments as $87.5/GWh, $92.8/GWh and $92.6/GWh for F2019, F2020, and F2021 and for Market Electricity Purchases as $61.4/GWh, $41.5/GWh and $32.9/GWh for F2019, F2020, and F2021.

Cost of Energy
($ million)

Line		F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Reference Column	1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Unit Costs ($/MWh)									
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

To assist, AMPC has prepared the following chart to graphically depict BC Hydro's forecast IPP generation for F2019, F2020 and F2021, based on BC Hydro's revised response to BCUC IR 3.3.3:



4.2.2 Please explain why the forecast volumes for IPP Storage Hydro generation are significantly lower in F2020 than the F2019 actual and F2021 forecast. In your response, please also reconcile the F2020 forecast with BC Hydro's earlier statements about dry conditions and lower water inflows in F2019.

RESPONSE:

The Rio-Tinto Alcan (RTA) Electricity Purchase Agreement (EPA) was the primary driver that caused the drop in the expected energy delivery in fiscal 2020 for the Storage Hydro category.

Low inflow conditions in the Nechako Basin prompted RTA to curtail deliveries to BC Hydro under its EPA. With the expected return to normal inflows in fiscal 2021, energy deliveries are expected to increase to be similar to previous levels.

Although dry conditions and low water inflows existed in fiscal 2019, these conditions did not impact the RTA EPA until fiscal 2020 in large part due to the storage capability available from RTA's reservoir.

Please note that the BC Hydro response referred to in the preamble is BCUC Confidential IR 3.3.3, not BCUC IR 3.3.3. BC Hydro made that response public in Exhibit B-20.

2.0 IPP Generation and Cost of Energy

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.3.3
Exhibit B-6, BC Hydro Response to AMPC IR 1.1.1
Exhibit B-17, BC Hydro Response to AMPC IR 3.3.1
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In its revised response to BCUC IR 3.3.3, BC Hydro provides the following corrected table showing forecast energy volumes from IPP generation:

Resource Type	F2019 Actual (GWh)	F2020 (GWh)	F2021 (GWh)
Non-Storage Hydro	6,122	6,239	6,696
Biomass	2,400	2,773	2,735
Storage Hydro	2,713	1,260	2,636
Wind	1,574	1,626	1,660
Biogas	94	94	98
Gas Fired Thermal	959	1,543	994
Solar	2	2	3
Other	385	411	417
Total	14,248	13,948	15,238

In its response to AMPC IR 1.1.1, BC Hydro states that the October 2018 rupture of the Enbridge T-South pipeline and subsequent gas curtailment “was expected to result in the loss of Island Generation as a capacity and energy resource over the winter. A small reduction in generation from thermal IPPs was also expected during gas curtailments.”

In its response to AMPC IR 3.3.1, BC Hydro states:

> In fiscal 2019, conditions that increased BC Hydro’s market electricity purchases from Powerex were:
>
> - Dry conditions and lower water inflows that decreased planned hydroelectric generation and purchases from IPPs and Long Term Commitments below forecast;
> - A cold period in February/March that increased BC Hydro customer demand above forecast; and
> - Restricted availability of natural gas due to the Enbridge pipeline rupture.

In Appendix A, Schedule 4.0 of its Public Evidentiary Update, BC Hydro provides a Cost of Energy table (reproduced in part below) that shows the updated unit costs for IPPs and Long-Term Commitments as $87.5/GWh, $92.8/GWh and $92.6/GWh for F2019, F2020, and F2021 and for Market Electricity Purchases as $61.4/GWh, $41.5/GWh and $32.9/GWh for F2019, F2020, and F2021.

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
	Unit Costs ($/MWh)											
16	Water Rentals			7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation			45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments			94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area			258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases			38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
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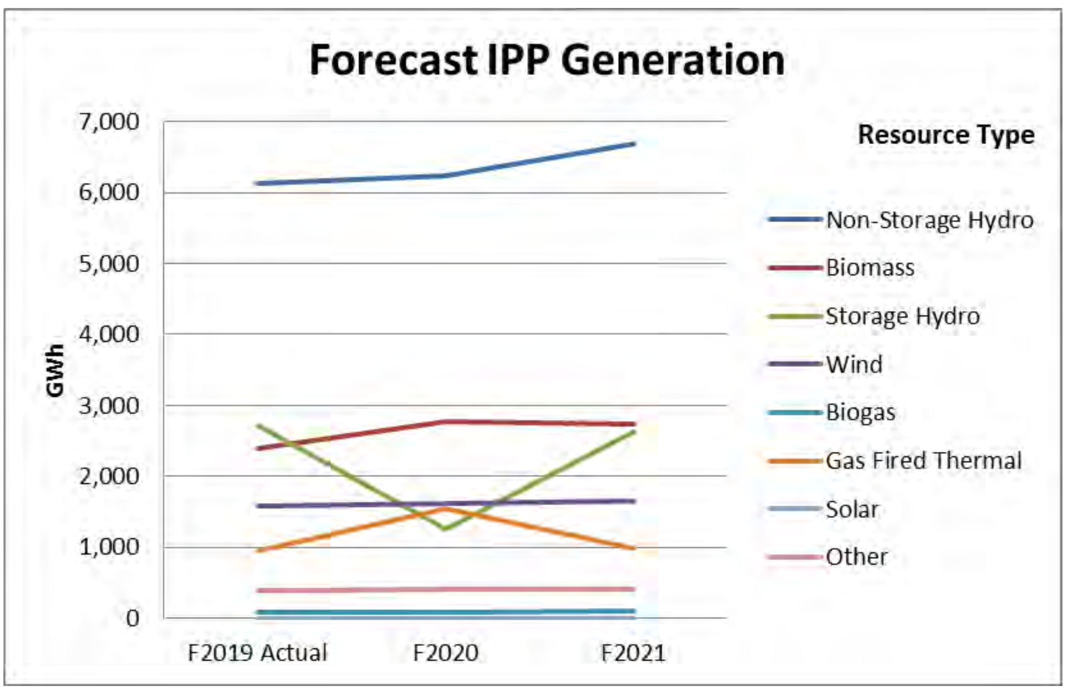
22	Total Weighted Cost			33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

To assist, AMPC has prepared the following chart to graphically depict BC Hydro's forecast IPP generation for F2019, F2020 and F2021, based on BC Hydro's revised response to BCUC IR 3.3.3:



4.2.3 Could the increase in forecast volumes for Gas Fired Thermal generation for F2020 be replaced with Market Electricity Purchases or volumes from other generation sources? Please fully explain your response including any implications for the Cost of Energy.

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 4.2.1, where we explain that part of the increase in forecast volumes for gas-fired thermal generation for fiscal 2020 could potentially be replaced by Market Electricity Purchases, but to the extent that such purchases were priced higher than the cost of equivalent thermal generation, the Cost of Energy would be expected to increase.

2.0 IPP Generation and Cost of Energy

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.3.3
Exhibit B-6, BC Hydro Response to AMPC IR 1.1.1
Exhibit B-17, BC Hydro Response to AMPC IR 3.3.1
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In its revised response to BCUC IR 3.3.3, BC Hydro provides the following corrected table showing forecast energy volumes from IPP generation:

Resource Type	F2019 Actual (GWh)	F2020 (GWh)	F2021 (GWh)
Non-Storage Hydro	6,122	6,239	6,696
Biomass	2,400	2,773	2,735
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Gas Fired Thermal	959	1,543	994
Solar	2	2	3
Other	385	411	417
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In its response to AMPC IR 1.1.1, BC Hydro states that the October 2018 rupture of the Enbridge T-South pipeline and subsequent gas curtailment "was expected to result in the loss of Island Generation as a capacity and energy resource over the winter. A small reduction in generation from thermal IPPs was also expected during gas curtailments."

In its response to AMPC IR 3.3.1, BC Hydro states:

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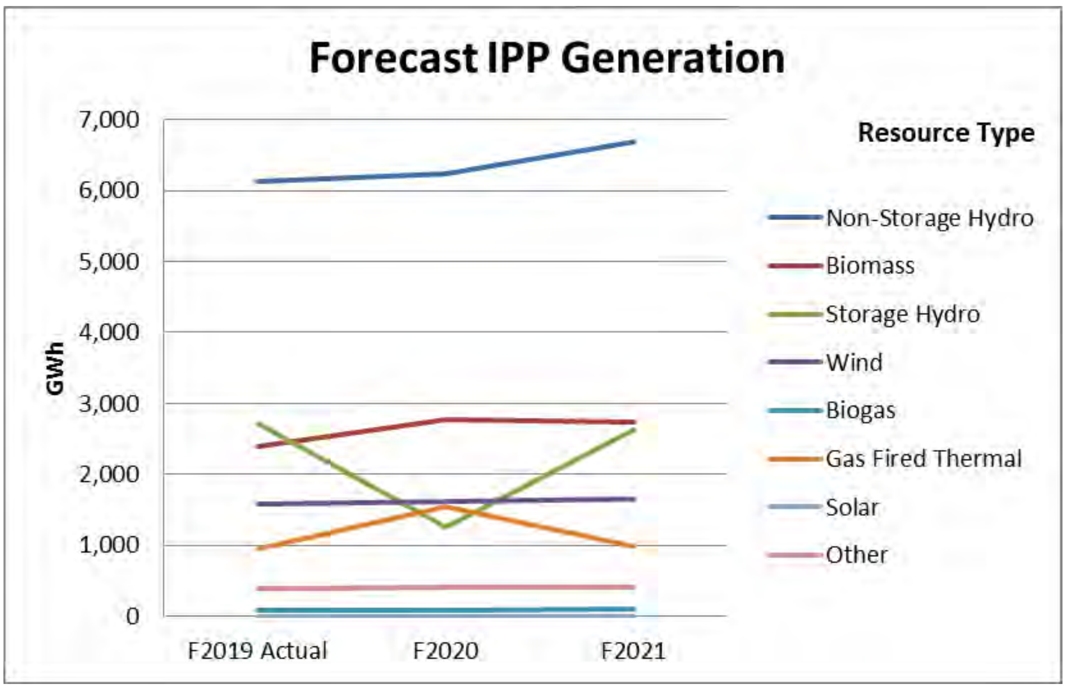
> - Dry conditions and lower water inflows that decreased planned hydroelectric generation and purchases from IPPs and Long Term Commitments below forecast;
> - A cold period in February/March that increased BC Hydro customer demand above forecast; and
> - Restricted availability of natural gas due to the Enbridge pipeline rupture.

In Appendix A, Schedule 4.0 of its Public Evidentiary Update, BC Hydro provides a Cost of Energy table (reproduced in part below) that shows the updated unit costs for IPPs and Long-Term Commitments as $87.5/GWh, $92.8/GWh and $92.6/GWh for F2019, F2020, and F2021 and for Market Electricity Purchases as $61.4/GWh, $41.5/GWh and $32.9/GWh for F2019, F2020, and F2021.

Cost of Energy
($ million)

Line		Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
				1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Unit Costs ($/MWh)											
16	Water Rentals			7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation			45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments			94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area			258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases			38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales			(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost			33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

To assist, AMPC has prepared the following chart to graphically depict BC Hydro's forecast IPP generation for F2019, F2020 and F2021, based on BC Hydro's revised response to BCUC IR 3.3.3:



4.2.4 Please provide the cost impact to revenue requirement in F2020 from the forecast increase in Gas Fired Thermal generation.

RESPONSE:

Forecast costs for gas fired thermal generation IPPs in fiscal 2020 are $19.3 million higher than the fiscal 2019 actual costs, excluding the accounting treatment for one EPA under the IFRS 16 accounting standard for leases. As discussed in BC Hydro's response to AMPC IR 4.2.1, this increase in costs is primarily due to increased dispatch of Island Generation on Vancouver Island.

2.0 IPP Generation and Cost of Energy

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.3.3
Exhibit B-6, BC Hydro Response to AMPC IR 1.1.1
Exhibit B-17, BC Hydro Response to AMPC IR 3.3.1
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In its revised response to BCUC IR 3.3.3, BC Hydro provides the following corrected table showing forecast energy volumes from IPP generation:

Resource Type	F2019 Actual (GWh)	F2020 (GWh)	F2021 (GWh)
Non-Storage Hydro	6,122	6,239	6,696
Biomass	2,400	2,773	2,735
Storage Hydro	2,713	1,260	2,636
Wind	1,574	1,626	1,660
Biogas	94	94	98
Gas Fired Thermal	959	1,543	994
Solar	2	2	3
Other	385	411	417
Total	14,248	13,948	15,238

In its response to AMPC IR 1.1.1, BC Hydro states that the October 2018 rupture of the Enbridge T-South pipeline and subsequent gas curtailment “was expected to result in the loss of Island Generation as a capacity and energy resource over the winter. A small reduction in generation from thermal IPPs was also expected during gas curtailments.”

In its response to AMPC IR 3.3.1, BC Hydro states:

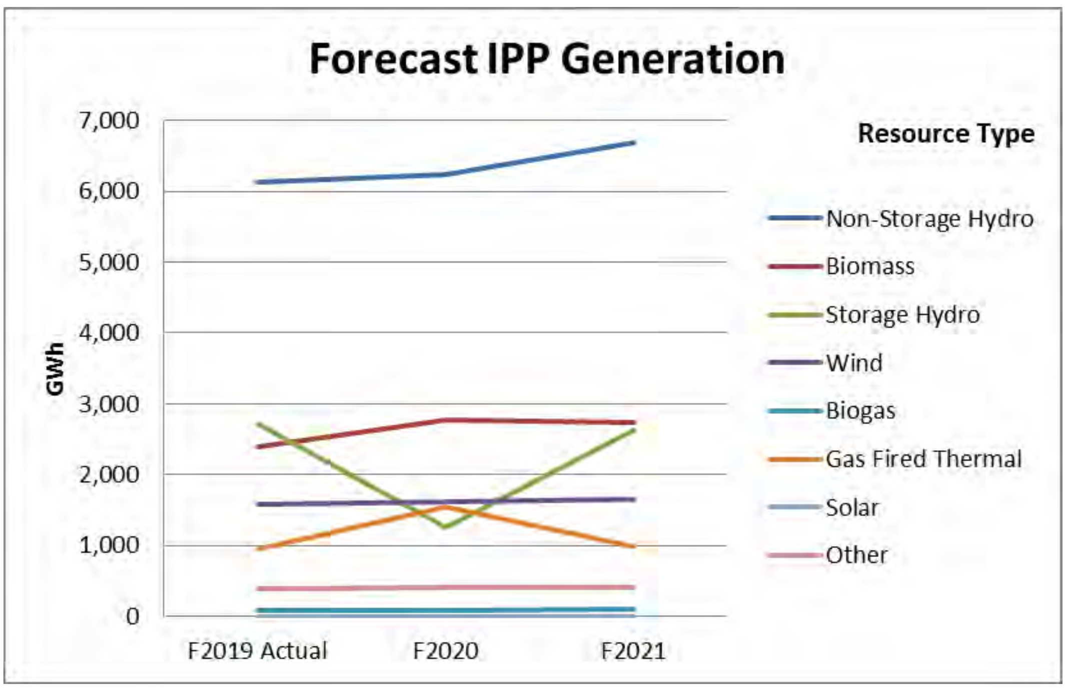
> In fiscal 2019, conditions that increased BC Hydro’s market electricity purchases from Powerex were:
>
> - Dry conditions and lower water inflows that decreased planned hydroelectric generation and purchases from IPPs and Long Term Commitments below forecast;
> - A cold period in February/March that increased BC Hydro customer demand above forecast; and
> - Restricted availability of natural gas due to the Enbridge pipeline rupture.

In Appendix A, Schedule 4.0 of its Public Evidentiary Update, BC Hydro provides a Cost of Energy table (reproduced in part below) that shows the updated unit costs for IPPs and Long-Term Commitments as $87.5/GWh, $92.8/GWh and $92.6/GWh for F2019, F2020, and F2021 and for Market Electricity Purchases as $61.4/GWh, $41.5/GWh and $32.9/GWh for F2019, F2020, and F2021.

Cost of Energy
($ million)

Line		Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Unit Costs ($/MWh)										
16	Water Rentals		7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation		45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments		94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area		258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases		38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales		(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost		33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

To assist, AMPC has prepared the following chart to graphically depict BC Hydro's forecast IPP generation for F2019, F2020 and F2021, based on BC Hydro's revised response to BCUC IR 3.3.3:



4.2.5 Please update the table provided in the revised response to BCUC IR 3.3.3 (excerpted above) to include the forecast IPP volumes for F2020 and F2021 from the Application. Please fully explain any variances between the forecast volumes in the BCUC IR 3.3.3 table and the Application.

RESPONSE:

The table below includes energy volumes based on information from the Application as well as the Evidentiary Update. It is an updated table from BC Hydro's response to BCUC Confidential IR 3.3.3, which BC Hydro made publicly available in Exhibit B-20. That table only included information based on the Evidentiary Update.

Resource Type	Application		Evidentiary Update		Variance	
	F2020 (GWh)	F2021 (GWh)	F2020 (GWh)	F2021 (GWh)	F2020 (GWh)	F2021 (GWh)
Non-Storage Hydro	6,794	6,882	6,239	6,696	(555)	(187)
Biomass	2,863	2,910	2,773	2,735	(90)	(176)
Storage Hydro	2,686	3,082	1,260	2,636	(1,426)	(446)
Wind	1,649	1,649	1,626	1,660	(23)	11
Biogas	97	97	94	98	(3)	1
Gas Fired Thermal	897	877	1,543	994	646	117
Solar	3	3	2	3	(1)	(0)
Other	460	539	411	417	(49)	(122)
Total	15,449	16,040	13,948	15,238	(1,500)	(801)

The variances of note, as between the Application and the Evidentiary Update, are generally due to the following reasons for each of the resource type categories:

- **Non-Storage Hydro: For several projects under development, there are expected delays in achieving commercial operation which have a greater impact in fiscal 2020 as compared to fiscal 2021. In addition, as a result of dry conditions there were lower actual deliveries in fiscal 2019 for a number of non-storage hydro projects which resulted in lowering the expected average deliveries for the Test Period. Please also refer to BC Hydro's response to BCOAPO IR 3.163.2;**

- **Biomass: The lower forecast volumes are primarily due to taking into account actual energy deliveries from projects which recently achieved commercial operation, as compared to the forecast deliveries that had originally been provided by the IPPs prior to the projects achieving commercial operation;**

- **Storage Hydro: As discussed in BC Hydro's response to AMPC IR 4.2.2, this variance is primarily driven by the Rio-Tinto Alcan EPA as a result of dry conditions and low water inflows;**

- **Gas Fired Thermal: Due to lower than expected generation, primarily due to dry conditions and low water inflows, Island Generation has been run more than expected; and**

- **Other: As discussed in BC Hydro's response to BCUC Confidential IR 3.3.1, which BC Hydro made publicly available in Exhibit B-20, the "Other" category includes Municipal Solid Waste (MSW) projects, Energy Recovery Generation (ERG) projects and "Expected SOP Projects and other First Nations Commitments". The variance in this category is due to expected delays in achieving commercial operation for certain projects in the "Expected SOP Projects and other First Nations Commitments" category.**

3.0 IPP Accounting Treatment Changes

Reference: Exhibit B-17, BC Hydro Response to AMPC IR 3.9.1
Exhibit B-19, Appendix A, Schedule 4.0 and pp. 14-15

In Exhibit B-19, pp. 14-15, BC Hydro states:

> The implementation of IFRS 16 decreases Cost of Energy while increasing Amortization and Finance Charges. The impact to Amortization is an increase of $58.8 million in fiscal 2020 and $59.9 million in fiscal 2021 … The resulting impact to Finance Charges is an increase of $44.3 million in fiscal 2020 and $43.3 million in fiscal 2021.

In its response to AMPC IR 3.9.3.1, BC Hydro states:

> The changes in amortization of $58.8 million and $59.9 million for fiscal 2020 and fiscal 2021 respectively (as described on lines 10 and 11 of the preamble to question) are for two additional Electricity Purchase Agreements identified as leases as part of BC Hydro's completion of the IFRS 16 impact assessment.

In its response to AMPC IR 3.9.1, BC Hydro shows that implementation of IFRS 16 also increased Cost of Energy by $117.9 million for F2020 and $119.5 million for F2021. BC Hydro also shows the IAS 17 (Previous Standard reversal) impact to Cost of Energy as $132.8 million reduction for F2020 and $134.8 million reduction in F2021. The relevant table is excerpted below:

($ million)	Appendix A Reference	Reference	EPA Impacts	
			F2020	F2021
IAS 17 (Previous Standard reversal)				
Operating expense			(54.5)	(55.1)
Grants and taxes			(2.5)	(2.6)
Depreciation			(22.8)	(22.8)
Finance Charges			(41.7)	(40.8)
Cost of energy			(132.8)	(134.8)
Total			**(254.3)**	**(256.1)**
IFRS 16				
Depreciation	Sch. 4.0, Line 84	A	88.9	90.1
Finance Charges	Sch. 4.0, Line 85	B	48.4	46.1
Cost of energy	Included in Sch. 4.0, Line 29	C	117.9	119.5
Total			**255.2**	**255.6**
Net Change				
Operating expense			(54.5)	(55.1)
Grants and taxes			(2.5)	(2.6)
Depreciation			66.1	67.3
Finance Charges			6.7	5.3
Cost of energy			(14.9)	(15.4)
Impact before amortization of regulatory transfer to NHDA at adoption		D	**1.0**	**(0.5)**
Amortization of amount deferred to NHDA (adoption impact deferred)			41.5	23.3
Impact on Revenue Requirement		E	**42.5**	**22.8**

4.3.1 Please fully explain how BC Hydro has adjusted the Cost of Energy due to the implementation of IFRS 16. In your response, please include how the increased Amortization expense and Finance Charges in F2020 and F2021 have affected the Cost of Energy.

RESPONSE:

The total impact on the revenue requirement of the implementation of IFRS 16, as shown at the bottom of the schedule in the preamble to the question, is $42.5 million and $22.8 million for fiscal 2020 and fiscal 2021 respectively.

The question requests the impact on Cost of Energy only. The net impact to Cost of Energy is a decrease of $14.9 million and $15.4 million for fiscal 2020 and fiscal 2021 respectively. This is shown in the table in the preamble to the question on the "Cost of Energy" line under the "Net Change" heading. This net impact is broken down in the table below.

($ million)	F2020	F2021
Reversal of costs under IAS 17 from table in preamble	(132.8)	(134.8)
EPAs that are no longer leases under IFRS 16	117.9	119.5
Net decrease in Cost of Energy	(14.9)	(15.4)

The first row in the table above represents a reduction to Cost of Energy for three Electricity Purchase Agreements (EPAs) that are now considered leases under IFRS 16. The second row in the table represents an increase to Cost of Energy for three different EPAs that were previously considered finance leases under IAS 17 but are no longer considered leases under IFRS 16.

The amortization expense and finance charges attributable to EPA leases under IFRS 16 in fiscal 2020 and fiscal 2021 are not included in Cost of Energy.

The net increase in depreciation expense is $66.1 million and $67.3 million in fiscal 2020 and fiscal 2021 respectively as shown in the "Depreciation" line under the "Net Change" heading in the table to the preamble to the question. This impact is included in Depreciation and Amortization expenses in the revenue requirement.

The net increase in finance charges is $6.7 million and $5.3 million in fiscal 2020 and fiscal 2021 respectively as shown in the "Finance Charges" line under the "Net Change" heading in the table to the preamble to the question. This impact is included in Finance Charges in the revenue requirement.

4.0 Market Electricity Purchases

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.6.1, Attachment 1, p. 6 of 8
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In its response to BCUC IR 3.6.1, BC Hydro states (emphasis added):

> In the Evidentiary Update, the Surplus Sales consisted of only a small volume of forced exports made during the freshet (May 2019), when market prices were low. No other Surplus Sales were forecast to occur in fiscal 2020 in the Evidentiary Update <u>due to continued dry conditions and low water inflows resulting in decreased hydro generation</u>.

Line 8 in Schedule 4.0 of Appendix A in the Public Evidentiary Update (reproduced in part below) shows that Market Electricity Purchases increased from 1,504 GWh to 5,104 GWh for F2020 and from 648 GWh to 1,326 GWh for F2021 when compared to the original Application.

Cost of Energy
($ million)

Line		Column / Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
			1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Market Energy										
8	Market Electricity Purchases		934	2,035	1,101	1,504	5,104	3,600	648	1,326	678
9	Surplus Sales		(4,517)	(2,230)	2,287	(2,409)	(84)	2,325	(3,087)	(2,065)	1,022
10	Net Purchases (Sales) from Powerex		105	647	542	177	468	290	90	(279)	(369)
11	Total		(3,478)	452	3,930	(727)	5,488	6,215	(2,349)	(1,018)	1,331
	Unit Costs ($/MWh)										
16	Water Rentals		7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation		45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments		94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area		258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases		38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales		(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost		33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On p. 6 of 8 of Attachment 1 of BC Hydro's response to AMPC IR 3.3.1, BC Hydro describes its future outlook on reservoir inflows as follows:

> Evidence suggests a modest increase in annual inflows over time, but the trends are too small to be considered statistically significant. However, there is evidence that suggests the seasonality of reservoir inflows has changed. Fall and winter average inflows have increased in almost all regions, and there is some evidence of a modest decline in late summer flows in basins that are primarily filled with glacial ice or seasonal snowpack melt.

4.4.1 Please update Table 4-1 from Chapter 4 of the Application (Exhibit B-1) for annual system storage. Why are the factors leading to decreased hydroelectric generation forecast in F2020 not anticipated to apply in F2021?

RESPONSE:

An updated version of Table 4-1 from Chapter 4 of the Application is shown below, based on information from the June 2019 Energy Study:

GWh	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Actual	F2020 Plan	F2021 Plan
End of Period System Storage	11,918	13,208	10,746	9,736	10,576	7,690	8,253	10,216

The hydroelectric generation forecast for fiscal 2020 was largely driven by observed dry conditions and lower water inflows, part of which was due to below-average snowpack. Snowpack levels, which are expected to contribute to inflows in fiscal 2021 were not yet known, and BC Hydro has no evidence to suggest that dry conditions and lower inflows are likely to continue into fiscal 2021.

4.0 Market Electricity Purchases

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.6.1, Attachment 1, p. 6 of 8
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In its response to BCUC IR 3.6.1, BC Hydro states (emphasis added):

> In the Evidentiary Update, the Surplus Sales consisted of only a small volume of forced exports made during the freshet (May 2019), when market prices were low. No other Surplus Sales were forecast to occur in fiscal 2020 in the Evidentiary Update <u>due to continued dry conditions and low water inflows resulting in decreased hydro generation</u>.

Line 8 in Schedule 4.0 of Appendix A in the Public Evidentiary Update (reproduced in part below) shows that Market Electricity Purchases increased from 1,504 GWh to 5,104 GWh for F2020 and from 648 GWh to 1,326 GWh for F2021 when compared to the original Application.

Cost of Energy
($ million)

Line		Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Column		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7
	Market Energy										
8	Market Electricity Purchases		934	2,035	1,101	1,504	5,104	3,600	648	1,326	678
9	Surplus Sales		(4,517)	(2,230)	2,287	(2,409)	(84)	2,325	(3,087)	(2,065)	1,022
10	Net Purchases (Sales) from Powerex		105	647	542	177	468	290	90	(279)	(369)
11	Total		(3,478)	452	3,930	(727)	5,488	6,215	(2,349)	(1,018)	1,331
	Unit Costs ($/MWh)										
16	Water Rentals		7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation		45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments		94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
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On p. 6 of 8 of Attachment 1 of BC Hydro's response to AMPC IR 3.3.1, BC Hydro describes its future outlook on reservoir inflows as follows:

> Evidence suggests a modest increase in annual inflows over time, but the trends are too small to be considered statistically significant. However, there is evidence that suggests the seasonality of reservoir inflows has changed. Fall and winter average inflows have increased in almost all regions, and there is some evidence of a modest decline in late summer flows in basins that are primarily filled with glacial ice or seasonal snowpack melt.

4.4.2 Based on system storage levels and water inflows at present, are BC Hydro's F2020 forecast decreases in the Public Evidentiary

Update still up to date? If not, please fully explain your response including any potential implications on revenue requirement.

RESPONSE:

The Cost of Energy forecast in the Evidentiary Update is based on a June 2019 Energy Study. The Energy Study is updated each month for current conditions and the most recent forecasts of inflows and market conditions, which are constantly evolving. The Evidentiary Update provides a snapshot at one point in time, and any Cost of Energy variances from the Evidentiary Update will be captured in the Cost of Energy variance accounts so that, over time, customers only pay the actual costs.

4.0 Market Electricity Purchases

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.6.1, Attachment 1, p. 6 of 8
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In its response to BCUC IR 3.6.1, BC Hydro states (emphasis added):

> In the Evidentiary Update, the Surplus Sales consisted of only a small volume of forced exports made during the freshet (May 2019), when market prices were low. No other Surplus Sales were forecast to occur in fiscal 2020 in the Evidentiary Update <u>due to continued dry conditions and low water inflows resulting in decreased hydro generation</u>.

Line 8 in Schedule 4.0 of Appendix A in the Public Evidentiary Update (reproduced in part below) shows that Market Electricity Purchases increased from 1,504 GWh to 5,104 GWh for F2020 and from 648 GWh to 1,326 GWh for F2021 when compared to the original Application.

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
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On p. 6 of 8 of Attachment 1 of BC Hydro's response to AMPC IR 3.3.1, BC Hydro describes its future outlook on reservoir inflows as follows:

> Evidence suggests a modest increase in annual inflows over time, but the trends are too small to be considered statistically significant. However, there is evidence that suggests the seasonality of reservoir inflows has changed. Fall and winter average inflows have increased in almost all regions, and there is some evidence of a modest decline in late summer flows in basins that are primarily filled with glacial ice or seasonal snowpack melt.

4.4.3 In the table reproduced above, BC Hydro forecasts Market Electricity Purchases to increase in F2020 and F2021 and Unit Costs for Market Electricity Purchases to increase in F2020 and

F2021. Please explain BC Hydro's approach to forecasting market electricity prices and the causes of increases to market electricity unit prices (Line 20, Schedule 4.0 of Appendix A of Exhibit B-19).

RESPONSE:

BC Hydro's approach to forecasting market electricity prices is described on page 4-15 of the Application, "At the beginning of each Energy Study, Powerex provides BC Hydro with forward market price curves for electricity at Mid-C and gas prices at Sumas. The Energy Study uses these forward curves as a starting point and then adds variability to these prices to capture an expected range of price uncertainty."

The causes for increases in Market Electricity Purchases unit prices are discussed in BC Hydro's response to BCUC IR 3.307.2.

4.0 Market Electricity Purchases

Reference: Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.6.1, Attachment 1, p. 6 of 8
Exhibit B-19, Public Evidentiary Update, Appendix A, Schedule 4.0

In its response to BCUC IR 3.6.1, BC Hydro states (emphasis added):

> In the Evidentiary Update, the Surplus Sales consisted of only a small volume of forced exports made during the freshet (May 2019), when market prices were low. No other Surplus Sales were forecast to occur in fiscal 2020 in the Evidentiary Update <u>due to continued dry conditions and low water inflows resulting in decreased hydro generation</u>.

Line 8 in Schedule 4.0 of Appendix A in the Public Evidentiary Update (reproduced in part below) shows that Market Electricity Purchases increased from 1,504 GWh to 5,104 GWh for F2020 and from 648 GWh to 1,326 GWh for F2021 when compared to the original Application.

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
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	Unit Costs ($/MWh)										
16	Water Rentals		7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation		45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments		94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area		258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases		38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales		(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost		33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On p. 6 of 8 of Attachment 1 of BC Hydro's response to AMPC IR 3.3.1, BC Hydro describes its future outlook on reservoir inflows as follows:

> Evidence suggests a modest increase in annual inflows over time, but the trends are too small to be considered statistically significant. However, there is evidence that suggests the seasonality of reservoir inflows has changed. Fall and winter average inflows have increased in almost all regions, and there is some evidence of a modest decline in late summer flows in basins that are primarily filled with glacial ice or seasonal snowpack melt.

4.4.4 Please explain how BC Hydro's 2018 Powerex Letter Agreement, which is in place for F2019 and allows forward electricity purchases, has impacted Market Electricity Purchases (Line 8, Schedule 4.0 of Appendix A of Exhibit B-19).

RESPONSE:

Volumes and costs for contract deliveries under the 2018 Letter Agreement are included in Schedule 4.0 of Appendix A, in lines 8 and 34 respectively. Market Electricity Purchases (line 8) for fiscal 2019 includes the 1,348 GWh delivered under the 2018 Letter Agreement, and the 1,080 GWh delivered in April 2019 under the 2018 Letter Agreement are included in the total for fiscal 2020.

5.0 20 Year Load Forecast

Reference: Exhibit B-15, Appendix B, p. 4

On p. 4, BC Hydro describes its methodology for forecasting the distribution peak:

> The distribution peak process starts with the historical substation data collection and analysis. Temperature adjusted peak demands are estimated for each substation.
>
> In addition, a mid forecast of peak demand from Electric Vehicles (EVs) is developed using the number of EVs, consistent with the mid energy forecast.
>
> A mid guideline forecast is developed using deterministic and econometric methods with various inputs, including:
>
> - Historical temperature normalized substation peak demands;
> - Rate impacts;
> - Residential account forecasts; and
> - Distribution energy forecasts from BC Hydro's end use model projections.

Other adjustments are made using peak load projections for emerging sectors, including EVs, cannabis and cryptocurrency.

4.5.1 Please explain what "rate impacts" inputs BC Hydro uses to develop its mid guideline forecast and how they are incorporated.

RESPONSE:

In developing the mid guideline forecast, BC Hydro uses the same methodology for rate impacts as described on page 3-14 of Chapter 3 of the Application. The rate impacts were calculated using a projection of real dollar bill increases, an assumed price elasticity of demand of -0.1, and the load forecast before rate impacts.

For further discussion on the rate impact adjustment in the June 2019 Load Forecast, please refer to section 3.5 of Exhibit B-15.

6.0 20 Year Load Forecast

Reference: Exhibit B-15, BC Hydro's 20-Year Load Forecast, Figure 2, p. 6
Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.3.3

In Figure 2, BC Hydro provides charts depicting forecast adjustments from the October 2018 load forecasts to the June 2019 load forecast for F2020 and F2021.

4.6.1 Figure 2 shows a reduction to load forecast of 459 GWh for F2020 and an increase of 399 GWh for F2021. Please explain the impact of the lower load forecast for F2020 and higher load forecast for F2021 to (i) Cost of Energy; (ii) overall revenue requirement; and (iii) rates.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 4.321.1.

6.0 20 Year Load Forecast

Reference: Exhibit B-15, BC Hydro's 20-Year Load Forecast, Figure 2, p. 6
Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.3.3

In Figure 2, BC Hydro provides charts depicting forecast adjustments from the October 2018 load forecasts to the June 2019 load forecast for F2020 and F2021.

4.6.2 Please explain any corresponding changes to generation sources by GWh. For example, would reduced load requirements for F2020 likely result in decreases to Gas Fired Thermal IPP purchases, Market Energy Purchases or in increases to Surplus Sales?

RESPONSE:

BC Hydro's 20-Year Load Forecast was not yet available to be used in the June Energy Study that informed the Evidentiary Update.

In general, when the load is reduced and all other inputs are unchanged, the optimization process in the Energy Studies would, when the system is in an annual deficit situation as in fiscal 2020, likely result in decreases in gas-fired thermal IPP generation and market energy purchases.

6.0 20 Year Load Forecast

Reference: Exhibit B-15, BC Hydro's 20-Year Load Forecast, Figure 2, p. 6
Exhibit B-20, BC Hydro Revised Response to BCUC IR 3.3.3

In Figure 2, BC Hydro provides charts depicting forecast adjustments from the October 2018 load forecasts to the June 2019 load forecast for F2020 and F2021.

4.6.3 Please update the table provided in response to BCUC IR 3.3.3 based on the June 2019 load forecast for F2020 and F2021.

RESPONSE:

The data in the table is not impacted by the June 2019 Load Forecast, other than changes which may impact the extent to which the Island Generation facility is dispatched.

Moreover, the data in the table is based on the Energy Study carried out prior to the completion of the June 2019 Load Forecast, and the Energy Study has not been updated to reflect the June 2019 Load Forecast for the purposes of the Application. Therefore, there are no changes to the table provided in response to BCUC Confidential IR 3.3.3, made public in Exhibit B-20, based on the June 2019 Load Forecast for fiscal 2020 and fiscal 2021.

7.0 20 Year Load Forecast

Reference: Exhibit B-15, Appendix D

On page 1 of Appendix D, BC Hydro states:

> In response to a commitment made in BC Hydro's response to BCUC IR 1.15.3, this appendix provides an updated planning Load Resource Balance (LRB) based on the June 2019 Load Forecast.
>
> The following updates have been included:
>
> - The load forecast has been updated from the adjusted May 2016 Load Forecast to the June 2019 Load Forecast;
> - The IPP forecast has been updated from November 2018 to June 2019, and is consistent with the IPP forecast vintage used in the Evidentiary Update; and
> - The assumption for the in-service date of Revelstoke Unit 6 (which is included as a planned resource) has changed from fiscal 2030 to fiscal 2036.
>
> In Tables D-1 through D-4 in Appendix D, BC Hydro provides the Planning View of the Energy Load Resource Balance and Peak Capacity Load Resource Balance before and after planned resources.

4.7.2 Please confirm that the impacts from DSM measures are incremental DSM energy and peak reductions for the new programs BC Hydro is planning to implement. If not confirmed, please fully explain your response.

RESPONSE:

Confirmed. The DSM savings are based on new activities from fiscal 2019 onwards. The DSM savings shown do not include the persistence of savings from activities prior to fiscal 2019. The savings shown include system losses.

BC Hydro notes that there is a labeling error in the referenced Tables D-3 and D-4 of Appendix D of Appendix B-15. In Table D-3, Row 11 should be "F20+ Programs (F20-F21 RRA)" and Row 12 should be "F20+ Rates (F20-F21 RRA)". In Table D-4, Row 12 should be "F20+ Programs (F20-F21 RRA)" and Row 13 should be "F20+ Rates (F20-F21 RRA)".

7.0 20 Year Load Forecast

Reference: Exhibit B-15, Appendix D

On page 1 of Appendix D, BC Hydro states:

> In response to a commitment made in BC Hydro's response to BCUC IR 1.15.3, this appendix provides an updated planning Load Resource Balance (LRB) based on the June 2019 Load Forecast.
>
> The following updates have been included:
>
> - The load forecast has been updated from the adjusted May 2016 Load Forecast to the June 2019 Load Forecast;
> - The IPP forecast has been updated from November 2018 to June 2019, and is consistent with the IPP forecast vintage used in the Evidentiary Update; and
> - The assumption for the in-service date of Revelstoke Unit 6 (which is included as a planned resource) has changed from fiscal 2030 to fiscal 2036.
>
> In Tables D-1 through D-4 in Appendix D, BC Hydro provides the Planning View of the Energy Load Resource Balance and Peak Capacity Load Resource Balance before and after planned resources.

4.7.3 Please provide DSM energy and peak reductions shown in Tables D-3 and D-4 by customer class.

RESPONSE:

Attachment 1 to this response shows the DSM energy and peak reductions by customer class at the customer meter, along with VVO savings and system losses. The energy and peak totals reconcile to Rows 9 to 12 of Table D-3 and Rows 10 to 13 of Tables D-4, respectively.

F19 DSM Portfolio Cumulative Energy Savings (GWh)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Residential	270	270	270	270	268	267	267	266	265	264	264	264	264	264	264	264	261	260	256
Commercial	163	163	163	162	154	149	149	148	146	143	138	136	131	127	116	106	100	96	96
Industrial	198	190	183	181	180	180	177	175	167	156	153	136	123	65	13	10	10	10	10
Losses	63	63	63	63	62	62	61	61	60	59	58	56	55	48	42	41	40	39	39
Total																			
Row 9 of Table D-3	**695**	**686**	**679**	**676**	**665**	**657**	**654**	**650**	**638**	**622**	**613**	**593**	**572**	**505**	**434**	**420**	**411**	**406**	**401**

F19 DSM Portfolio Cumulative Peak Savings (MW)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Residential	69	68	67	67	66	65	64	64	63	62	61	61	60	60	60	60	59	59	57
Commercial	24	24	23	23	22	21	20	20	20	19	18	18	17	16	15	13	13	12	12
Industrial	24	22	21	21	21	20	20	19	18	17	16	14	13	7	1	1	1	1	1
Losses	12	12	12	12	12	11	11	11	11	10	10	10	10	9	8	8	8	8	8
Total																			
Row 10 of Table D-4	**128**	**126**	**124**	**123**	**120**	**117**	**116**	**114**	**111**	**108**	**106**	**103**	**99**	**92**	**84**	**82**	**80**	**80**	**78**

F20+ Codes and Standards and VVO Energy Savings (GWh)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Residential	350	527	656	774	886	989	1,083	1,166	1,241	1,310	1,376	1,441	1,503	1,564	1,627	1,689	1,751	1,813	1,876
Commercial	174	300	407	502	590	665	725	781	838	902	957	1,001	1,045	1,090	1,135	1,180	1,225	1,270	1,315
Industrial	17	25	31	37	42	48	53	58	62	66	69	72	76	79	82	85	88	91	94
Losses and VVO	75	112	142	169	195	219	247	267	286	305	324	342	359	377	396	413	431	448	466
Total																			
Row 10 of Table D-3	**615**	**964**	**1,235**	**1,482**	**1,713**	**1,920**	**2,108**	**2,271**	**2,427**	**2,584**	**2,726**	**2,856**	**2,982**	**3,110**	**3,239**	**3,367**	**3,494**	**3,622**	**3,750**

F20+ Codes and Standards and VVO Peak Savings (MW)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Residential	90	135	165	191	216	238	258	276	292	306	319	332	344	359	374	390	405	420	435
Commercial	25	41	54	66	76	84	89	95	100	107	112	116	120	125	131	136	141	146	152
Industrial	2	3	4	4	5	5	6	6	7	7	7	7	8	8	8	9	9	9	10
Losses and VVO	12	19	24	28	31	35	38	40	43	45	47	49	51	53	56	58	60	63	65
Total																			
Row 11 of Table D-4	**129**	**198**	**246**	**289**	**327**	**361**	**391**	**417**	**441**	**465**	**486**	**505**	**523**	**546**	**569**	**592**	**615**	**638**	**662**

F20+ Programs Cumulative Energy Savings (GWh)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Residential	52	82	112	140	167	191	212	231	249	264	275	286	296	304	314	323	332	338	343
Commercial	81	124	160	192	217	239	264	289	312	333	352	368	383	397	404	401	392	380	368
Industrial	214	310	361	422	481	539	600	656	705	755	741	719	734	739	745	750	750	749	747
Losses	35	52	64	77	89	100	111	122	132	141	143	144	149	153	156	157	157	157	156
Total																			
Row 11 of Table D-3	**381**	**569**	**698**	**832**	**954**	**1,070**	**1,188**	**1,298**	**1,398**	**1,493**	**1,512**	**1,517**	**1,562**	**1,592**	**1,619**	**1,631**	**1,630**	**1,624**	**1,615**

F20+ Programs Cumulative Peak Savings (MW)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Residential	14	22	30	38	45	52	57	62	67	71	75	78	80	84	87	90	93	96	98
Commercial	13	19	25	29	33	36	39	43	46	48	51	53	54	56	57	57	55	54	53
Industrial	26	37	43	50	56	63	69	75	80	85	83	80	81	81	82	83	83	82	82
Losses	5	8	10	12	14	16	18	19	21	22	22	23	23	24	25	25	25	25	25
Total																			
Row 12 of Table D-4	**57**	**87**	**108**	**129**	**148**	**166**	**183**	**199**	**213**	**226**	**230**	**232**	**238**	**244**	**250**	**254**	**256**	**257**	**257**

F20+ Rate Structure Cumulative Energy Savings (GWh)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Industrial	117	131	135	131	129	127	126	125	124	124	124	124	123	123	123	123	122	122	122
Losses	12	13	14	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Total Row 12 of Table D-3	**128**	**144**	**149**	**145**	**142**	**140**	**139**	**138**	**137**	**137**	**137**	**137**	**136**	**136**	**136**	**136**	**135**	**135**	**135**

F20+ Rate Structure Cumulative Peak Savings (MW)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Industrial	14	15	16	15	15	14	14	14	13	13	13	13	13	13	13	13	13	13	13
Losses	1	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1
Total Row 13 of Table D-4	**15**	**17**	**17**	**17**	**16**	**16**	**15**	**15**	**15**	**15**	**15**	**14**	**14**	**14**	**14**	**14**	**14**	**14**	**14**

8.0 20 Year Load Forecast

**Reference: Exhibit B-15, BC Hydro's 20-Year Load Forecast, Table 1, p. 4
Exhibit B-6, BC Hydro Responses to INCE IR 1.8.16 and 1.8.36 and CEABC IR 1.10.5**

Table 1 shows the changes in methodology and input assumptions between the October 2018 load forecast and the June 2019 load forecast.

In Attachment 1 of BC Hydro's response to INCE IR 1.8.16, BC Hydro provided a list of major capital projects included in the 2018 BC Regional Economic Forecast.

In its response to INCE IR 1.8.36, BC Hydro states that "BC Hydro considered the Trans Mountain Expansion project when developing the Load Forecast."

In its response to CEABC IR 1.10.5, BC Hydro states that "in the absence of a specific customer request, BC Hydro does not have sufficient information about the Coastal Gaslink Pipeline project to quantify the annual electrical energy consumption needed to throughput 4.4 bcf per day."

4.8.1 Please explain if BC Hydro used updated information on the major capital projects listed in Attachment 1 to INCE IR 1.8.16 for its 2020-2039 load forecast. If not, please explain why not.

RESPONSE:

The June 2019 Load Forecast did not directly include updated capital project information listed in Attachment 1 to BC Hydro's response to INCE IR 1.8.16. The list was used as an input by the Conference Board of Canada in the development of its June 2018 Economic Forecast. The economic forecast was used in the development of the October 2018 Load Forecast.

As noted in Exhibit B-15, the June 2019 Load Forecast updated and extended the October 2018 Load Forecast. In doing so, BC Hydro did not ask the Conference Board of Canada to produce another economic forecast with updated capital project information.

An updated economic forecast is being developed for BC Hydro's next load forecast, which will be completed in early 2020. That load forecast will be the basis for BC Hydro's upcoming Integrated Resource Plan.

8.0 20 Year Load Forecast

Reference: Exhibit B-15, BC Hydro's 20-Year Load Forecast, Table 1, p. 4
Exhibit B-6, BC Hydro Responses to INCE IR 1.8.16 and 1.8.36 and CEABC IR 1.10.5

Table 1 shows the changes in methodology and input assumptions between the October 2018 load forecast and the June 2019 load forecast.

In Attachment 1 of BC Hydro's response to INCE IR 1.8.16, BC Hydro provided a list of major capital projects included in the 2018 BC Regional Economic Forecast.

In its response to INCE IR 1.8.36, BC Hydro states that "BC Hydro considered the Trans Mountain Expansion project when developing the Load Forecast."

In its response to CEABC IR 1.10.5, BC Hydro states that "in the absence of a specific customer request, BC Hydro does not have sufficient information about the Coastal Gaslink Pipeline project to quantify the annual electrical energy consumption needed to throughput 4.4 bcf per day."

4.8.2 Please provide an updated list of major capital projects originally provided in Attachment 1 to INCE IR 1.8.16.

RESPONSE:

As explained in BC Hydro's response to AMPC IR 4.8.1, BC Hydro does not have an updated economic forecast from the Conference Board of Canada and therefore there is no update to the major capital project list. BC Hydro will be able to provide the major capital project list used in the next economic forecast when our next load forecast is finalized.

8.0 20 Year Load Forecast

Reference: Exhibit B-15, BC Hydro's 20-Year Load Forecast, Table 1, p. 4
Exhibit B-6, BC Hydro Responses to INCE IR 1.8.16 and 1.8.36 and CEABC IR 1.10.5

Table 1 shows the changes in methodology and input assumptions between the October 2018 load forecast and the June 2019 load forecast.

In Attachment 1 of BC Hydro's response to INCE IR 1.8.16, BC Hydro provided a list of major capital projects included in the 2018 BC Regional Economic Forecast.

In its response to INCE IR 1.8.36, BC Hydro states that "BC Hydro considered the Trans Mountain Expansion project when developing the Load Forecast."

In its response to CEABC IR 1.10.5, BC Hydro states that "in the absence of a specific customer request, BC Hydro does not have sufficient information about the Coastal Gaslink Pipeline project to quantify the annual electrical energy consumption needed to throughput 4.4 bcf per day."

4.8.3 Please explain whether BC Hydro updated its 20 year Load Forecast to include the Trans Mountain Expansion project and Coastal Gaslink Pipeline project impacts. If not, please explain why not.

RESPONSE:

As stated in BC Hydro's responses to AMPC IRs 4.8.1 and 4.8.2, the same economic forecast, including the underlying major capital projects inputs, underpins both the June 2019 Load Forecast and the October 2018 Load Forecast. Both the Trans Mountain Expansion and Coastal GasLink projects are included in the major project list that informed that economic forecast.

The June 2019 Load Forecast considers both projects. For general information on BC Hydro's large industrial forecast methodology, please refer to section 3.2.8.1 of Chapter 3 and section 7 of Appendix O of the Application.

Appendix A to Exhibit B-15 identifies the customer-specific changes made to the June 2019 Load Forecast relative to the October 2018 Load Forecast for the fiscal 2020 through fiscal 2024 period.

9.0 Deferral Account Recoveries

Reference: Exhibit B-19, Public Evidentiary Update, p. 10

On p. 10, BC Hydro states (emphasis added):

> In the Application, BC Hydro 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 1 fiscal 2020 to fiscal 2021 test period with equal amounts being amortized in fiscal 2020 and fiscal 2021. In the Evidentiary Update, BC Hydro is proposing 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.
>
> As a result of this proposal and the difference between forecast and actual fiscal 2019 closing account balances, net recoveries from the Heritage Deferral Account and Non-Heritage Deferral Account are higher than planned in fiscal 2020 and lower than planned in fiscal 2021.

4.9.1 Please provide a table that shows what the rate changes would be for F2020 and F2021 if the equal amounts being amortized in F2020 and F2021 were maintained in the Public Evidentiary Update.

RESPONSE:

Please refer to Scenario C on page 11 of BC Hydro's response to BCUC IR 3.296.3 for the information requested.

176.0 20-YEAR LOAD FORECAST

Reference: Exhibit B-15, page 1
Exhibit B-19, page 3 and Appendix A, Schedule 4

The referenced page from Exhibit B-15 states:

> "BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (Application) provided an October 2018 Load Forecast, covering fiscal 2019 to fiscal 2024. The calculation of the Test Period revenue requirements, as updated by the Evidentiary Update, uses actual financial results for April 2019 and May 2019 and the October 2018 Load Forecast for the remainder of fiscal 2020 and all of fiscal 2021".

The referenced page from Exhibit B-19 states:

> "The Evidentiary Update replaces BC Hydro's forecasts in the Application for April and May 2019 with the actual financial results for those months. This includes an update to domestic sales revenue. Domestic sales revenue for the remainder of fiscal 2020 and all of fiscal 2021 remains based on the October 2018 Load Forecast".

4.176.1 For each of the following please clarify for which months in the period fiscal 2019 to fiscal 2021 the forecast for load and/or revenue was based on actuals:

- October 2018 Load Forecast and the Initial Application (Exhibit B-1-2)
- The Evidentiary Update (Exhibit B-11)
- The June 2019 Load Forecast (Exhibit B-15)

RESPONSE:

The table below summarizes where actuals were used.

	Fiscal 2019	Fiscal 2020	Fiscal 2021
October 2018 Load Forecast of Billed Sales on page 3 of Appendix O (Exhibit B-1)	**Six months of actuals (April to September 2018)**	**No actuals**	**No actuals**
Revenue Calculations in the Application (Exhibit B-1)	**Six months of actuals (April to September 2018)**	**No actuals**	**No actuals**

	Fiscal 2019	**Fiscal 2020**	**Fiscal 2021**
Revenue Calculations in the Evidentiary Update (Exhibit B-11)	**Twelve months of actuals**	**Two months of actuals (April and May 2019)**	**No actuals**
June 2019 Load Forecast of Billed Sales (Exhibit B-15)	**Not included in this filing**	**No actuals included. Information from current year was used to inform updates.**	**No actuals**

The June 2019 Load Forecast was not used in the calculation of the revenue forecast in the Evidentiary Update.

176.0 20-YEAR LOAD FORECAST

Reference: Exhibit B-15, page 1
Exhibit B-19, page 3 and Appendix A, Schedule 4

The referenced page from Exhibit B-15 states:

> "BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (Application) provided an October 2018 Load Forecast, covering fiscal 2019 to fiscal 2024. The calculation of the Test Period revenue requirements, as updated by the Evidentiary Update, uses actual financial results for April 2019 and May 2019 and the October 2018 Load Forecast for the remainder of fiscal 2020 and all of fiscal 2021".

The referenced page from Exhibit B-19 states:

> "The Evidentiary Update replaces BC Hydro's forecasts in the Application for April and May 2019 with the actual financial results for those months. This includes an update to domestic sales revenue. Domestic sales revenue for the remainder of fiscal 2020 and all of fiscal 2021 remains based on the October 2018 Load Forecast".

4.176.2 With respect to Exhibit B 19, Appendix A, Schedule 4, is the reduction in Total Domestic Sales in F2020 from 53,567 GWh to 53,296 GWh entirely due to the Update including actual values for April and May 2019? If not, please explain what else is contributing to the change.

RESPONSE:

Confirmed. The reduction in fiscal 2020 Total Domestic Sales is entirely due to including actual values for April and May 2019.

178.0 20-YEAR LOAD FORECAST

Reference: Exhibit B-15, page 4, Table 1

4.178.1 Please provide the GDP forecast for F2018 through F2023 per:

- The BC Ministry of Finance September 2018 Q1 Report for fiscal 2019 to fiscal 2023, and
- The BC Ministry of Finance February 2019 Budget for fiscal 2019 to fiscal 2023.

RESPONSE:

The table below provides the requested GDP forecasts, which are publicly available from the following links:

- **B.C. Ministry of Finance September 2018 Q1 report, page 44: https://www2.gov.bc.ca/assets/gov/british-columbians-our-governments/government-finances/quarterly-reports/2018-19-q1-report.pdf; and**
- **B.C. Ministry of Finance February 2019 Budget , page 84: https://www.bcbudget.gov.bc.ca/2019/default.htm.**

Calendar Year (Ministry of Finance)	Fiscal Year Equivalent (BC Hydro)	September 2018 Ministry of Finance Q1 2018 Total B.C. GDP Growth (%)	February 2019 Ministry of Finance 2019 Budget Total B.C. GDP Growth (%)
2017	F2018	3.6*	3.8*
2018	F2019	2.2	2.2
2019	F2020	1.8	2.4
2020	F2021	2.0	2.3
2021	F2022	2.0	2.1
2022	F2023	2.0	2.0

***estimated actual as per Ministry of Finance reports.**

In responding to this question, BC Hydro identified an error in the table provided in BC Hydro’s response to BCOAPO IR 1.19.2. The B.C. Ministry of Finance September 2018 Q1 GDP growth rates were incorrectly reported in fiscal years instead of calendar years.

To clarify, BC Hydro has inserted two columns in the above table: Calendar Year, as per the original Ministry of Finance reporting and BC Hydro's Fiscal Year Equivalent.

BC Hydro's fiscal year extends from April 1 to March 31 of the following year. As an example, in the table above, Calendar Year 2018 becomes Fiscal Year Equivalent 2019 for BC Hydro, since nine months of the calendar 2018 are included in fiscal 2019.

179.0 20-YEAR LOAD FORECAST

Reference: Exhibit B-15, page 4 and page 10

4.179.1 Please provide a schedule that compares the net bill increases for the years F2020 through F2021 as used in: i) the initial Application; ii) June 2019 Load Forecast and iii) the Evidentiary Update. Please also explain the source(s) for each.

RESPONSE:

The table below shows the real dollar bill increases used in the Application, the Evidentiary Update and the June 2019 Load Forecast.

Real Dollar Bill Increases	Source	Fiscal 2020 (%)	Fiscal 2021 (%)
Application and Evidentiary Update	**Last five years of the 2013 10 Year Rates Plan**	**0.4**	**0.6**
June 2019 Load Forecast	**Five-year bill impact forecast provided in the Government of B.C.'s Phase 1 Report on the Comprehensive Review (Appendix C of the Application)**	**-0.5**	**-1.3**

180.0 20-YEAR LOAD FORECAST

Reference: Exhibit B-15, Appendix B, pages 4-6

4.180.1 What percentage of the Total Integrated (mid) June 2019 System Peak Forecast after Demand-Side Management (DSM) savings is attributable to the EV Peak for each year F2020 through F2024?

RESPONSE:

The table below provides the EV Peak Demand as a percentage of the Total Integrated Peak Demand after DSM savings for fiscal 2020 to fiscal 2024.

Fiscal Year	EV Peak Demand as a percentage of Total System Peak after DSM Savings (%)
Fiscal 2020	0.2
Fiscal 2021	0.3
Fiscal 2022	0.4
Fiscal 2023	0.7
Fiscal 2024	1.0

181.0 EVIDENTIARY UPDATE – COST OF ENERGY

Reference: Exhibit B-19, Appendix C, page 2 and Appendix A, Schedule 4
Exhibit B-17, BCOAPO 3.163.1

4.181.1 The Update forecasts a reduction in hydraulic generation for F2021 relative to the initial Application. Is this at all due to the lower hydro generation now forecast for F2020 (relative to the initial Application)?

RESPONSE:

No. In general, when there is a reduction in inflows in the current year, the optimization models forecast the amount that should be withdrawn from storage and generated in the current year to compensate for the reduced inflows, and the amount that should be met by a decrease in hydro generation and a corresponding increase in net Market Electricity Purchases and thermal generation in the current year, with a commensurate reduction in hydro generation in future year(s). Other factors such as changes in load, IPP deliveries, and market prices can also be drivers.

BC Hydro’s capability to use system storage to manage inflow variability depends on the starting level of storage (for example, lower initial storage means less ability to manage low inflows and greater ability to manage high inflows). Typical year-over-year drafts or fills are about 1500 GWh.

181.0 EVIDENTIARY UPDATE – COST OF ENERGY

Reference: Exhibit B-19, Appendix C, page 2 and Appendix A, Schedule 4
Exhibit B-17, BCOAPO 3.163.1

4.181.2 If yes, please discuss BC Hydro's year over year storage capability and the extent to which the dry conditions in F2019 and F2020 impact F2020 year-end storage and, therefore, impact the level of hydro generation in F2021.

RESPONSE:

Please refer to BC Hydro's response to BCOAPO IR 4.181.1.

182.0 EVIDENTIARY UPDATE – COST OF ENERGY

Reference: Exhibit B-19, Appendix C, page 3 and Appendix A, Schedule 4
Exhibit B-17, BCOAPO 3.165.1 and BCOAPO 3.166.1

The response to BCOAPO 3.166.1 notes that:

> "The Evidentiary Update uses forward market prices as of June 2019, while the Application used forward market prices as of October 2018. The June 2019 forward market prices have increased by 23 per cent for fiscal 2020 and 26 per cent for fiscal 2021 relative to the October 2018 forward market prices".

4.182.1 The Updated forecast includes a 56% increase in the unit cost of market purchases for F2020 and a 17% increase in F2021. Please explain why the F2020 increase in unit costs is materially higher than the increase in forward market prices for F2020 while the increase in unit cost for F2021 is materially less than the increase in forward market prices for the same period.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.307.2 for a discussion of how the forecasted volumes of Market Electricity Purchases impact the forecast unit costs.

182.0 EVIDENTIARY UPDATE – COST OF ENERGY

Reference: Exhibit B-19, Appendix C, page 3 and Appendix A, Schedule 4
Exhibit B-17, BCOAPO 3.165.1 and BCOAPO 3.166.1

The response to BCOAPO 3.166.1 notes that:

> "The Evidentiary Update uses forward market prices as of June 2019, while the Application used forward market prices as of October 2018. The June 2019 forward market prices have increased by 23 per cent for fiscal 2020 and 26 per cent for fiscal 2021 relative to the October 2018 forward market prices".

4.182.2 Please explain the decrease in the "unit cost" for Surplus Sales (i.e., from $40.3/MWh per the Plan to $5.0/MWh per the Update) in F2020.

RESPONSE:

Please refer to BC Hydro's response to BCUC Confidential IR 3.6.1 (Exhibit B-20), which has been publicly filed with redactions, for an explanation for the decrease in the unit cost of Surplus Sales.

86.0 Topic: Load Forecast

Reference: Exhibit B-15, June 2019 Load Forecast F2020-F2039

BC Hydro refers to its June 2019 Load Forecast for F2020-F2039 and also refers to a comprehensive load forecast, for example that was completed for the 2013 IRP, and that will be completed in early 2020 for the 2021 IRP.

4.86.1 What distinguishes a "comprehensive" 20-year load forecast from the June 2019 F2020-F2039 Load Forecast?

RESPONSE:

As discussed in BC Hydro's response to BCUC IR 2.209.1, a comprehensive load forecast encompasses updates to key inputs and model calibration periods.

The June 2019 Load Forecast:

- **Is primarily an extension of the October 2018 Load Forecast because, with the exception of Electric Vehicles, the methodology is the same and only selected inputs were changed (for further information on which inputs were changed, please refer to section 2 of Exhibit B-15).**
- **Is a comprehensive update relative to the May 2016 Load Forecast.**

87.0 Topic: Load Forecast

Reference: Exhibit B-15, June 2019 Load Forecast F2020-F2039, "4. June 2019 Load Forecast Expects Annual Load Growth of Approximately 1 per cent Over Next 20 Years"

"As shown in Table 2 below, on a billed sales basis, the June 2019 Load Forecast expects load growth of approximately one per cent per year from fiscal 2020 to fiscal 2039."

"As shown in Figure 1 above, BC Hydro's load forecast includes projections for the mid, high and low forecast."

4.87.1 Please confirm, or otherwise explain, that the figure provided is a compound annual growth rate.

RESPONSE:

Confirmed. The 1 per cent per year growth rate is a compound annual growth rate.

87.0 Topic: Load Forecast

Reference: Exhibit B-15, June 2019 Load Forecast F2020-F2039, "4. June 2019 Load Forecast Expects Annual Load Growth of Approximately 1 per cent Over Next 20 Years"

"As shown in Table 2 below, on a billed sales basis, the June 2019 Load Forecast expects load growth of approximately one per cent per year from fiscal 2020 to fiscal 2039."

"As shown in Figure 1 above, BC Hydro's load forecast includes projections for the mid, high and low forecast."

4.87.2 Please provide the high and low load forecast in terms of an approximate compound annual growth rate from F2020 to F2039.

RESPONSE:

The approximate compound annual growth rates for the June 2019 energy forecast from fiscal 2020 to fiscal 2039 are:

- **Low forecast: 0.6 per cent;**
- **Mid forecast: 1.0 per cent; and**
- **High forecast: 1.4 per cent.**

88.0 Topic: Load Forecast

Reference: Exhibit B-15, June 2019 Load Forecast F2020-F2039

“The Total Integrated (mid) June 2019 System Peak Forecast after Demand-Side Management (DSM) savings expects growth in peak demand of approximately 1.0 per cent per year over the next 20 years.” [pdf p.27]

Figure B-3, Total Integrated System Peak Forecast June 2019 Forecast, shows the forecast uncertainty range.

4.88.1 Please confirm, or otherwise explain, that the figure provided is a compound annual growth rate.

RESPONSE:

Confirmed. The 1.0 per cent per year growth is a compound annual growth rate.

88.0 Topic: Load Forecast

Reference: Exhibit B-15, June 2019 Load Forecast F2020-F2039

"The Total Integrated (mid) June 2019 System Peak Forecast after Demand-Side Management (DSM) savings expects growth in peak demand of approximately 1.0 per cent per year over the next 20 years." [pdf p.27]

Figure B-3, Total Integrated System Peak Forecast June 2019 Forecast, shows the forecast uncertainty range.

4.88.2 Please provide the high and low peak forecast in terms of an approximate compound annual growth rate from F2020 to F2039.

RESPONSE:

The approximate compound annual growth rates for the June 2019 peak forecast from fiscal 2020 to fiscal 2039 are:

- **Low forecast: 0.3 per cent;**
- **Mid forecast: 1.0 per cent; and**
- **High forecast: 1.7 per cent.**

90.0 Topic: Cost of Energy, Biomass Energy Program and Retired Railway Ties

Reference: Exhibit B-17, BC Hydro Response to BCSEA 3.82.1; Exhibit B-13, BC Hydro Response to BCSEA 2.59.1; Exhibit B-7, BC Hydro Response to BCSEA 1.13; Exhibit B-1, s.4.3.2, pdf p.237

In BCSEA IR 1.13, BCSEA asked about the current status of renegotiation of long-term EPAs with certain biomass generation facilities, and in particular whether a long-term EPA with Atlantic Power's Williams Lake facility did or would require power to be exclusively from clean or renewable resources (i.e., precluding the use of retired rail ties as fuel).

BC Hydro's response to BCSEA IR 3.82.1 states in part that "As of September 30, 2019, BC Hydro has executed new long-term Electricity Purchase Agreements with Atlantic Power for its NW Energy facility as well as with Tolko Armstrong." However, the response is silent regarding whether the long-term EPA with Atlantic Power requires power exclusively from clean or renewable resources.

4.90.1 Does BC Hydro's new long-term EPA with Atlantic Power for power from the Williams Lake biomass generation facility require delivery of power exclusively from clean or renewable resources? For greater certainty, does the new long-term EPA with Atlantic Power preclude delivery of power from retired railway ties?

RESPONSE:

As noted in the preamble to the question, as of September 30, 2019, BC Hydro has executed a new long-term Electricity Purchase Agreement (EPA) with Atlantic Power for its NW Energy facility.

This EPA is a "biomass contract" within the meaning of the Direction to the BCUC respecting the Biomass Energy Program dated April 1, 2019 (Order in Council No. 158, BC Reg. 71/2019). BC Hydro expects to file the NW Energy EPA with the BCUC on a confidential basis by the end of November 2019.

The NW Energy EPA does not preclude delivery of power from retired railway ties.

90.0 Topic: Cost of Energy, Biomass Energy Program and Retired Railway Ties

Reference: Exhibit B-17, BC Hydro Response to BCSEA 3.82.1; Exhibit B-13, BC Hydro Response to BCSEA 2.59.1; Exhibit B-7, BC Hydro Response to BCSEA 1.13; Exhibit B-1, s.4.3.2, pdf p.237

In BCSEA IR 1.13, BCSEA asked about the current status of renegotiation of long-term EPAs with certain biomass generation facilities, and in particular whether a long-term EPA with Atlantic Power's Williams Lake facility did or would require power to be exclusively from clean or renewable resources (i.e., precluding the use of retired rail ties as fuel).

BC Hydro's response to BCSEA IR 3.82.1 states in part that "As of September 30, 2019, BC Hydro has executed new long-term Electricity Purchase Agreements with Atlantic Power for its NW Energy facility as well as with Tolko Armstrong." However, the response is silent regarding whether the long-term EPA with Atlantic Power requires power exclusively from clean or renewable resources.

4.90.2 If the new long-term EPA with Atlantic Power would allow delivery of power from retired railway ties, please provide the details of the current status of BC Hydro's provision of the EPA to the Commission for acceptance under UCA section 71.

RESPONSE:

Please refer to BC Hydro's response to BCSEA IR 4.90.1.

54.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Figures 2 and 3, and Appendix A, Schedule 4.0.

In Figure 2, BC Hydro describes the changes in Volumes of Supply as between the volumes in the original Application (Exhibit B-1) and those in the Evidentiary Update for F2020 and F2021.

4.54.1 Please confirm that +3,600 for Market Electricity Purchases in F2020 indicates an increase in purchases, but the +2,325 captioned “Less Surplus Sales” means there will be a reduction in surplus sales. I.e. that positive numbers have the effect of increasing electricity supply and negative numbers reduce the total supply.

RESPONSE:

Confirmed.

54.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Figures 2 and 3, and Appendix A, Schedule 4.0.

In Figure 2, BC Hydro describes the changes in Volumes of Supply as between the volumes in the original Application (Exhibit B-1) and those in the Evidentiary Update for F2020 and F2021.

4.54.2 Since these numbers represent the changes relative to the original forecast in the Application, please confirm that the final forecast numbers (as shown on lines 8 and 9 of Appendix A, Schedule 4.0) will now be:
Surplus Sales F2020 = 84 GWh and F2021 = 2,065 GWh
Market Purchases F2020 = 5,104 GWh and F2021 = 1,326 GWh

RESPONSE:

Confirmed.

55.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix A, Schedule 4.0.

Line 1 of Schedule 4.0 forecasts the GWh of BC Hydro generation subject to provincial water rental rates. It shows that the original forecast for F2019 was for generation of 46,368 GWh, but the actual generation was substantially less, at only 42,341 GWh, and the current forecast for F2021 is for an even lower generation of only 39,368 GWh. However, the generation for F2021 is expected to rebound to 44,522 GWh.

4.55.1 When was the original forecast for F2019 done, that indicated 46,368 GWh? Was this based on a year of average water flows? If not, what assumption was made about the percentage of average water flows in the two major river systems?

RESPONSE:

The forecast for fiscal 2019 was part of BC Hydro’s Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, and was based on the May 2016 Energy Study. In that Study, average inflows were assumed for fiscal 2019. Please refer to BC Hydro’s response to BCUC IR 1.31.1 for an explanation of how inflows are used in the Energy Study.

55.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix A, Schedule 4.0.

Line 1 of Schedule 4.0 forecasts the GWh of BC Hydro generation subject to provincial water rental rates. It shows that the original forecast for F2019 was for generation of 46,368 GWh, but the actual generation was substantially less, at only 42,341 GWh, and the current forecast for F2021 is for an even lower generation of only 39,368 GWh. However, the generation for F2021 is expected to rebound to 44,522 GWh.

4.55.2 The original F2019 forecast in the Application showed 42,340 GWh and this was almost exactly in agreement with the Actual shown in the Evidentiary Update (42,341). Please confirm that the Application forecast was based on the October 2018 Energy Study, and that this proved to be very accurate in predicting the generation up until March 31, 2019. What assumption was made about F2019 water flows for the October 2018 Energy Study?

RESPONSE:

Confirmed that the original Fiscal 2020 to Fiscal 2021 Revenue Requirements Application forecast was based on the October 2018 Energy Study, and that the October 2018 forecast of the fiscal 2019 heritage energy was very close to actuals (1 GWh).

At the time of the October 2018 Energy Study the short-term inflow forecast for fiscal 2019 was based on the Ensemble Streamflow Prediction methodology used by BC Hydro's hydrology department. Also, since the October 2018 study occurred in the middle of fiscal 2019, after the freshet, most of the inflows for fiscal 2019 were already known.

Please also refer to BC Hydro's response to BCUC IR 1.31.1 for an explanation of how inflows are used in the Energy Study.

55.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix A, Schedule 4.0.

Line 1 of Schedule 4.0 forecasts the GWh of BC Hydro generation subject to provincial water rental rates. It shows that the original forecast for F2019 was for generation of 46,368 GWh, but the actual generation was substantially less, at only 42,341 GWh, and the current forecast for F2021 is for an even lower generation of only 39,368 GWh. However, the generation for F2021 is expected to rebound to 44,522 GWh.

4.55.3 The October 2018 Energy Study was forecasting an improvement in hydro generation for F2020 and F2021 (to 44,262 and 44,999 GWh, respectively). What was the assumption being made at that time about the expected percentage of average water flows in F2020 and F2021?

RESPONSE:

The October 2018 Energy Study assumed 100 per cent of average inflows for both fiscal 2020 and fiscal 2021.

55.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix A, Schedule 4.0.

Line 1 of Schedule 4.0 forecasts the GWh of BC Hydro generation subject to provincial water rental rates. It shows that the original forecast for F2019 was for generation of 46,368 GWh, but the actual generation was substantially less, at only 42,341 GWh, and the current forecast for F2021 is for an even lower generation of only 39,368 GWh. However, the generation for F2021 is expected to rebound to 44,522 GWh.

4.55.4 In June 2019, however, the new Energy Study greatly reduced the expected generation for F2020 (to 39,368 GWh), but only slightly reduced it for F2021 (to 44,522 GWh). What happened to water flows between April 1, 2019 and June, 2019 that caused BC Hydro to so drastically reduce the forecast generation for the entire F2020 year (a reduction of almost 4,900 GWh when compared to the forecast done as recently as October 2018, and of 7,000 GWh when compared to the original F2019 forecast)?

RESPONSE:

As noted in BC Hydro's response to CEABC IR 4.55.5, inflows for fiscal 2020 are forecast to be well below average in both of our large basins (Peace and Columbia), and on a system wide basis are forecast to be 87 per cent of average.

The decrease was the result of a combination of substantially below average snowpack across the province as of April 1, 2019, followed by near normal precipitation in April, and then below average rainfall in May and early June across all our basins except the Bridge River system.

55.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix A, Schedule 4.0.

Line 1 of Schedule 4.0 forecasts the GWh of BC Hydro generation subject to provincial water rental rates. It shows that the original forecast for F2019 was for generation of 46,368 GWh, but the actual generation was substantially less, at only 42,341 GWh, and the current forecast for F2021 is for an even lower generation of only 39,368 GWh. However, the generation for F2021 is expected to rebound to 44,522 GWh.

4.55.5 What assumption is now being made about the percentage of average water flows, in the two major river systems, that is expected for the full F2020 year?

RESPONSE:

The following table provides the percentage of average water inflows for the Peace and Columbia basins assumed for fiscal 2020.

Basin	Inflow Percentage of Average as Energy Equivalent – Fiscal 2020 (%)
Peace	**81**
Columbia	**91**

55.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix A, Schedule 4.0.

Line 1 of Schedule 4.0 forecasts the GWh of BC Hydro generation subject to provincial water rental rates. It shows that the original forecast for F2019 was for generation of 46,368 GWh, but the actual generation was substantially less, at only 42,341 GWh, and the current forecast for F2021 is for an even lower generation of only 39,368 GWh. However, the generation for F2021 is expected to rebound to 44,522 GWh.

4.55.6 What assumption is now being made about the percentage of average water flows, in the two major river systems, that is expected for the full F2021 year?

RESPONSE:

As shown in the table below, both the Peace and Columbia basins are assumed to be at 100 per cent of average water inflows for fiscal 2021.

Basin	Inflow Percentage of Average as Energy Equivalent – Fiscal 2021 (%)
Peace	**100**
Columbia	**100**

55.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix A, Schedule 4.0.

Line 1 of Schedule 4.0 forecasts the GWh of BC Hydro generation subject to provincial water rental rates. It shows that the original forecast for F2019 was for generation of 46,368 GWh, but the actual generation was substantially less, at only 42,341 GWh, and the current forecast for F2021 is for an even lower generation of only 39,368 GWh. However, the generation for F2021 is expected to rebound to 44,522 GWh.

4.55.7 To what extent, if any, has the level in Williston reservoir been drawn down, or will it be drawn down to facilitate the construction of the Site C project?

RESPONSE:

Please refer to BC Hydro's response to AMPC IR 4.4.1 for the forecast of the end of period system storage. The hydroelectric generation forecast for fiscal 2020 was driven by observed dry conditions and lower water inflows, and not by the construction of Site C. Operation of Williston Reservoir in the spring and summer of fiscal 2021 will be adjusted as needed for the construction of Site C.

56.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix C, Cost of Heritage Energy, and Appendix A, Schedule 4.0.

In Section 1.1, BC Hydro states that the “Total costs for Non-Treaty Storage and Libby Coordination Agreements are forecast to $11.7 million higher in fiscal 2020 and $9.3 million lower in fiscal 2021…”

And line 26 of Schedule 4.0 shows that the total amounts are now forecast to be $15.0 million for F2020 and ($11.7) million for F2021. The Actual amount for F2019 is shown as ($181.9) million.

4.56.1 Is line 26 used to show either a cost (as for the positive value in F2020) or a benefit (as indicated by the negative amounts in F2021 and F2019)? Or is the benefit shown somewhere else? If so, where else?

RESPONSE:

Yes, line 26 of Schedule 4.0 is the net cost of the Non-Treaty Storage and Libby Coordination Agreements. When the value is positive it is a net cost, and when it is negative it is a net benefit for the fiscal year.

56.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix C, Cost of Heritage Energy, and Appendix A, Schedule 4.0.

In Section 1.1, BC Hydro states that the "Total costs for Non-Treaty Storage and Libby Coordination Agreements are forecast to $11.7 million higher in fiscal 2020 and $9.3 million lower in fiscal 2021…"

And line 26 of Schedule 4.0 shows that the total amounts are now forecast to be $15.0 million for F2020 and ($11.7) million for F2021. The Actual amount for F2019 is shown as ($181.9) million.

4.56.2 Please explain how costs or benefits arise from these agreements. In particular, how did the exceptionally large revenue arise in F2019? And why is F2020 expected to show a net cost?

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.45.4 where we explain how costs or benefits arise from Non-Treaty account activities.

Please refer to BC Hydro's response to AMPC IR 3.4.1 for an explanation on the larger than expected revenues for fiscal 2019 from these agreements. Higher than planned water releases occurred during the winter of fiscal 2019 due to high market prices that were not forecast in advance.

Fiscal 2020 is expected to show a net cost due to anticipated storage activity under the agreements.

57.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix C, Cost of Non-Heritage Energy, and Appendix A, Schedule 4.0.

In Section 1.2, BC Hydro states that the forecast total costs for IPPs and Long-Term Commitments have been reduced from the original Application amounts by $243.8 million in F2020 and by $190.3 million F2021. Schedule 4.0 shows that the Actual cost in F2019 was lower than forecast by $192.1 million. BC Hydro states that these reductions are *"due to a number of factors…"* and enumerates four different factors.

4.57.1 What are the "Long-Term Commitments" that are included in this category, and how much of the total costs do they account for in each year?

RESPONSE:

As provided in BC Hydro's response to CEC IR 1.19.2,"Long Term Commitments" refers to the following three categories of energy supply contracts, which are not considered to be EPAs with IPPs:

1. **Miscellaneous power purchases, such as ad hoc purchases, border accommodations or other similar arrangements where a particular area is not connected to the BC Hydro integrated system;**
2. **Surplus Power Rights Agreement between Teck and BC Hydro; and**
3. **Residual Capacity Agreement between FortisBC Electric and BC Hydro.**

Please refer to BC Hydro's response to CEABC IR 1.20.1 for further information on the Surplus Power Rights Agreement and the Residual Capacity Agreement.

The Cost of Energy purchases for Long Term Commitments is expected to be about 1 per cent of total Cost of Energy, in each year, for IPPs and Long Term Commitments.

57.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix C, Cost of Non-Heritage Energy, and Appendix A, Schedule 4.0.

In Section 1.2, BC Hydro states that the forecast total costs for IPPs and Long-Term Commitments have been reduced from the original Application amounts by $243.8 million in F2020 and by $190.3 million F2021. Schedule 4.0 shows that the Actual cost in F2019 was lower than forecast by $192.1 million. BC Hydro states that these reductions are *"due to a number of factors…"* and enumerates four different factors.

4.57.2 Please provide a breakdown of the amounts of the cost reductions that are due to each of the four listed factors in each of the years F2019, F2020, and F2021.

RESPONSE:

The table below updates the table included in BC Hydro's response to BCUC Confidential IR 3.4.1, which was made public in Exhibit B-20, such that it includes fiscal 2019, as well as fiscal 2020 and fiscal 2021.

$Million	F2019	F2020	F2021
Change in accounting treatment under IFRS 16 (capital leases)	**0.8**	**(87.3)**	**(89.0)**
Lower forecast inflows & history update for hydro IPPs	**(38.1)**	**(92.9)**	**(69.5)**
History update for Non-hydro IPPs	**(83.3)**	**(24.7)**	**(24.3)**
Delays in projects reaching commercial operation	**(30.1)**	**(19.8)**	**(10.1)**

As noted in BC Hydro's response to BCUC Confidential IR 3.4.1, "there are also factors, other than those listed above, that impact the difference between the Evidentiary Update and the Application. These other factors may result in increases or decreases in the difference between the two cost estimates. Also, it is difficult to quantify the impact of one factor in isolation of other factors. Accordingly, the total estimated impact associated with the four factors listed above will not exactly match the cost differences identified in the preamble."

57.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix C, Cost of Non-Heritage Energy, and Appendix A, Schedule 4.0.

In Section 1.2, BC Hydro states that the forecast total costs for IPPs and Long-Term Commitments have been reduced from the original Application amounts by $243.8 million in F2020 and by $190.3 million F2021. Schedule 4.0 shows that the Actual cost in F2019 was lower than forecast by $192.1 million. BC Hydro states that these reductions are *"due to a number of factors…"* and enumerates four different factors.

4.57.3 In the case of the adjustment for IFRS 16, is it only the costs that are removed from line 29 of Schedule 4.0, while the GWh volumes are still included in line 5 under "IPPs and Long-Term Commitments"?

RESPONSE:

Yes, in the case of the IFRS 16 adjustment, only the costs are allocated to other line items in Appendix A; no adjustments are made to the GWh volumes which are included in line 5 of Schedule 4.0 in Appendix A. Total payments made to IPPs, excluding accounting adjustments, are included on line 89 of Schedule 4.0 in Appendix A.

Please refer also to BC Hydro's response to AMPC IR 1.14.1 which provides a reference to where else the costs are included in the revenue requirements.

57.0 Reference: Exhibit B-19, Evidentiary Update (un-redacted), Appendix C, Cost of Non-Heritage Energy, and Appendix A, Schedule 4.0.

In Section 1.2, BC Hydro states that the forecast total costs for IPPs and Long-Term Commitments have been reduced from the original Application amounts by $243.8 million in F2020 and by $190.3 million F2021. Schedule 4.0 shows that the Actual cost in F2019 was lower than forecast by $192.1 million. BC Hydro states that these reductions are *"due to a number of factors…"* and enumerates four different factors.

4.57.4 Line 5 of Schedule 4.0 shows a shortfall in GWh from IPPs for each of the 3 years F2019 to F2021 (shortfalls of 951, 1500, and 802 GWh for the three years, respectively. How much of the shortfall of IPP energy in each year was due to "Lower forecast inflows for hydro IPPs due to dry weather conditions"?

RESPONSE:

BC Hydro cannot with a reasonable degree of certainty isolate how much of the IPP energy shortfall in deliveries is attributable to dry weather conditions as opposed to other factors (e.g., energy shortfall deliveries could be due to plant shut downs, other operational issues). However, to be responsive, the table below shows the reduction in forecast energy deliveries for fiscal 2019, fiscal 2020, and fiscal 2021 for both storage and non-storage hydro IPPs and provides an indication of how much of the reduction in forecast energy deliveries from IPP are related to hydro facilities.

	Variance		
	F2019 (GWh)	**F2020 (GWh)**	**F2021 (GWh)**
Total IPP Volumes (Sourced from Question)	**951**	**1,500**	**802**
Non-Storage Hydro IPPs	**381**	**410**	**86**
Storage Hydro IPPs	**(307)**	**1,423**	**446**
Total Hydro IPPs	**74**	**1,833**	**532**

As discussed in BC Hydro's response to AMPC IR 4.2.2, the Rio-Tinto Alcan EPA was the primary driver that caused the drop in the expected energy delivery in fiscal 2020 for the Storage Hydro category.

58.0 Reference: Exhibit B-15, 20-Year Load Forecast, and Exhibit B-13, BC Hydro's response to CEABC IR 2.41.

In its response to CEABC IR 2.41.1, BC Hydro stated:

> The information provided below also responds to the entire CEABC IR 2.41 series.
>
> This IR series asks BC Hydro to explain the lower service percentage forecast of shale gas production and processing in each of the five Montney shale basin areas served by BC Hydro in the October 2018 Load Forecast compared to the December 2012 Load Forecast.
>
> BC Hydro notes that the December 2012 Load Forecast was produced six years ago and is therefore out-dated. Consequently any direct comparison between this forecast and the October 2018 Load Forecast beyond fiscal 2024 is not meaningful. <u>BC Hydro will be filing an updated 20-year load forecast as part of this proceeding on October 3, 2019</u>. [underlining added]

In its response, BC Hydro provided Tables 1 and 2, and an excellent summary of the industry activities in the 5 regions of the Montney basin, and of BC Hydro's expected service percentages. However, the analysis was based on the previous load forecast (October, 2018), which did not go beyond F2024.

In its response, BC Hydro cited *"the main reason"* for its declining service percentage was the decline in natural gas prices, from $4.15/MMBtu in 2012 to $1.50/MMBtu in 2018, stating that: *"This decline impacts the relative competitiveness of electricity versus natural gas to provide work energy requirements."*

4.58.2 For the Dawson Creek and Groundbirch areas, that contain the new PRES transmission line, how much of the change in service percentages (between the October 2018 and June 2019 Load Forecasts) result from the construction of the PRES transmission line?

RESPONSE:

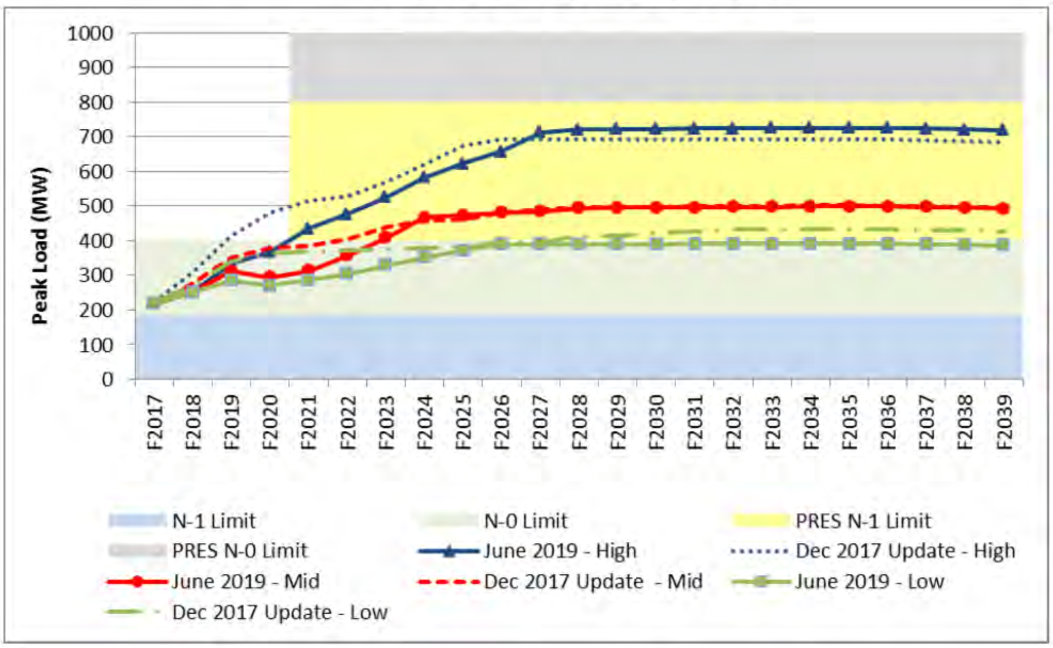
Both the October 2018 and June 2019 Load Forecasts assume the PRES transmission line is constructed. Any changes in service percentages between the two forecasts would be due to customer-specific updates for the period fiscal 2020 to fiscal 2024. These updates are provided in Appendix A of Exhibit B-15.

Clean Energy Association of B.C. Information Request No. **4.59.1** Dated: **October 30, 2019** British Columbia Hydro & Power Authority Response issued **November 14, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-23**

59.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix C, June 2019 update to South Peace River forecast.

In Appendix C, BC Hydro provides the following chart to illustrate the differences between the previous (May 2016) and the latest (June 2019) Load Forecast for the area to be serviced by the PRES project:

Figure C-1 South Peace Region Load Forecasts June 2019 and December 2017 Update



The chart appears to show the Mid Forecast of Peak Loads reaching around 500 MW by F2024, and the High Forecast of Peak Loads reaching around 700 MW by F2027. These are approximately the same levels as were forecast in May 2016, except that the newer High Forecast reaches a level about 20 MW higher, which BC Hydro describes as *"due to increased electrification assumptions in the Groundbirch area as a result of LNG development."*

4.59.1 When will the PRES project be completed and in service?

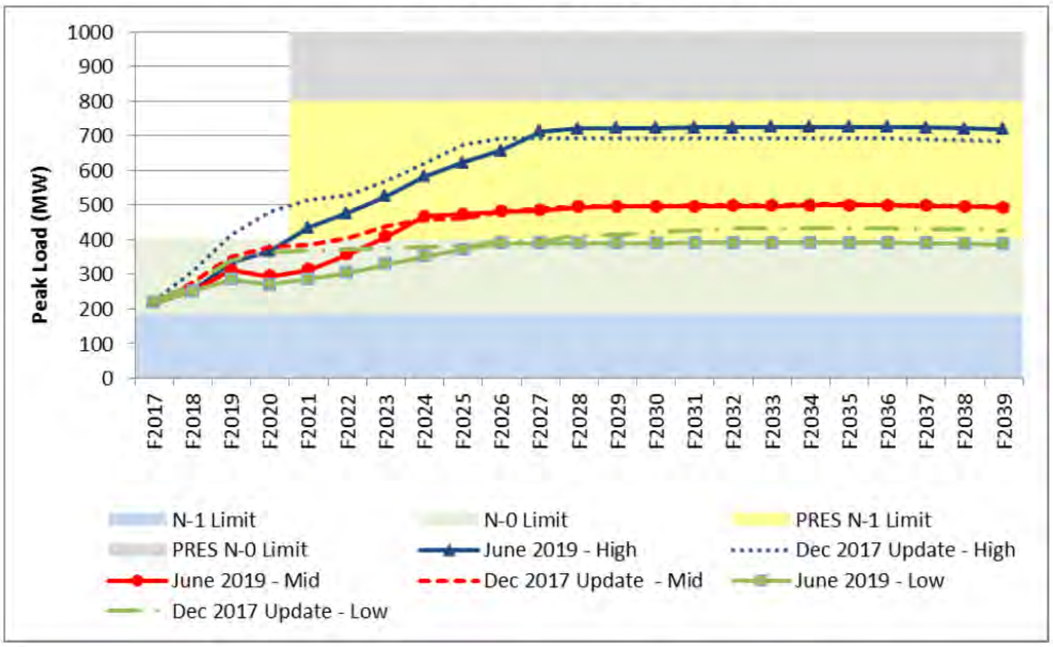
RESPONSE:

The planned in-service date for the PRES project is October 2021.

59.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix C, June 2019 update to South Peace River forecast.

In Appendix C, BC Hydro provides the following chart to illustrate the differences between the previous (May 2016) and the latest (June 2019) Load Forecast for the area to be serviced by the PRES project:

Figure C-1 South Peace Region Load Forecasts June 2019 and December 2017 Update



The chart appears to show the Mid Forecast of Peak Loads reaching around 500 MW by F2024, and the High Forecast of Peak Loads reaching around 700 MW by F2027. These are approximately the same levels as were forecast in May 2016, except that the newer High Forecast reaches a level about 20 MW higher, which BC Hydro describes as *"due to increased electrification assumptions in the Groundbirch area as a result of LNG development."*

4.59.3 Please provide a table listing all of the customer facilities in the area, that could be serviced by the PRES project (whether or not they have requested service to date), including both existing and planned facilities (indicate a projected in-service date, if planned). Indicate the type of each facility (e.g. gas processing, shallow cut, etc.); the operating capacity and average production rate from each facility; the total work energy that will be consumed by each facility operating at its average production rate; how much BC Hydro service each facility has requested to date, and how much service is assumed in the Mid and High June 2019 Forecasts.

RESPONSE:

The information requested in the question is commercially sensitive because BC Hydro's assessment of customer loads and timing is based on confidential commercial information provided by customers.

In response to the question, BC Hydro is able to provide the following publicly available information:

- **The BC Oil & Gas Commission maintains an inventory of existing and planned facilities in British Columbia. This information is available at https://www.bcogc.ca/online-services. For reference, a list of oil and gas facilities currently operating is included as Attachment 1 to this response;**
- **BC Hydro's response to CEABC IR 1.12.2 provides a list of the electrified oil and gas facilities in British Columbia; and**
- **BC Hydro's response to CEABC IR 1.9.3 provides the average work energy assumption used to develop the load forecast.**

Gas Processing Plants in British Columbia

Plant	Location	Facility ID	Operator	Plant Process	Jurisdiction	Raw Gas (e3m3/d)	Sales Gas (e3m3/d)	C3 (m3/d)	C4 (m3/d)	C5 (m3/d)	Sulphur (tonnes/d)	Sulphur Emmission (tonnes/d)	Sulphur Recovery (%)
AITKEN GAS AITKENCREEK D-044-L/094-A-13 002	D-044-L/094-A-13	160	Aitken Creek Gas Storage ULC	Fractionation; Refrigeration	Provincial								
ALTAGAS BLAIR D-058-F/094-B-16 003	D-058-F/094-B-16	7442	AltaGas Ltd.		Provincial	3398	3194	41	57	138			
ALTAGAS HOLDINGS TOWNSEND A-033-J/094-B-09 002	A-033-J/094-B-09	18246	Altagas Holdings Inc.		Provincial	11218	9998.68	1787		1210.53		0	
ARCRES ATTACHIE 05-20-084-24 002	05-20-084-24	26937	ARC Resources Ltd.			5600	4817	378911	155825	66141	1.9	1.89	
ARCRES DAWSON CREEK 13-07-080-14 002	13-07-080-14	18270	ARC Resources Ltd.		Provincial	5947	5220	278133.145	124562.697	101242.74		0	
ARCRES DOE 05-35-079-14 001	05-35-079-14	24114	ARC Resources Ltd.			4085	4021	121312	64537	34311	55	0	
ARCRES PARKLAND 03-09-081-16 002	03-09-081-16	7743	ARC Resources Ltd.		Provincial	5238.6	4813.9	352401.7	40913.6	129917.7		0	
ARCRES SUNRISE 13-36-078-18 001	13-36-078-18	7858	ARC Resources Ltd.		Provincial	6938	6796	73363	26017	8256		0	
BLACK SWAN AITKENCREEKNORTH C-038-C/094-H-04 001	C-038-C/094-H-04	18237	Black Swan Energy Ltd.		Provincial	2835	2077	0	0	276.6	1	0	0
BLACK SWAN NIG CREEK C-046-C/094-H-04 001		26623	Black Swan Energy Ltd.			5622	4800	425	425	866			
CANLIN BOUNDARYLAKE 11-24-084-15 001	11-24-084-15	465	Canlin Energy Corporation	Absorption; Stabilization	Provincial	563	557	53					
CANLIN BOUNDARYLAKE 13-10-085-14 001	13-10-085-14	440	Canlin Energy Corporation	Adsorption; Monoethanolamine	Provincial								
CANLIN BOUNDARYLAKE 14-24-084-15 003	14-24-084-15	730	Canlin Energy Corporation	Absorption; Methyldiethanolamine; Modified Claus; Stabilization	Provincial	1296	1268			91.3	3.7	1.1	70
CANLIN PARKLAND 06-29-081-15 004	06-29-081-15	317	Canlin Energy Corporation		Provincial	400	0			79.5			
CE PORTAGE C-004-A/094-B-01 001	C-004-A/094-B-01	7702	Canada Energy Partners Inc.		Provincial	56.6							
CHINOOK MARTIN B-002-E/094-H-06 003	B-002-E/094-H-06	1647	Chinook Energy (2010) Inc.		Provincial	1000							
CNRL ALCES 08-34-083-15 001	08-34-083-15	298	Canadian Natural Resources Limited	Absorption; Stabilization	Provincial								
CNRL BOUNDARYLAKE 01-14-085-13 002	01-14-085-13	2084	Canadian Natural Resources Limited		Alberta	250							
CNRL CLEARHILLS 16-11-088-13 001	16-11-088-13	2110	Canadian Natural Resources Limited		Alberta								
CNRL CYPRESS B-099-C/094-B-16 002	B-099-C/094-B-16	464	Canadian Natural Resources Limited	Absorption; Monoethanolamine; Modified Claus	Provincial	1275					14.1	0.742	95
CNRL KAHNTAHRIVER C-053-D/094-I-02 003	C-053-D/094-I-02	1692	Canadian Natural Resources Limited		Provincial	1141	1125		65				
CNRL LADYFERN B-017-I/094-H-01 002	B-017-I/094-H-01	4070	Canadian Natural Resources Limited		Provincial	3150							
CNRL LADYFERN B-047-H/094-H-01 001	B-047-H/094-H-01	4576	Canadian Natural Resources Limited		Provincial	1425							
CNRL NARRAWAY A-065-A/093-I-09 003	A-065-A/093-I-09	8619	Canadian Natural Resources Limited		Alberta								
CNRL PEGGO D-083-C/094-P-08 004	D-083-C/094-P-08	2153	Canadian Natural Resources Limited	Mole Sieve	Provincial	2817	2733			80			
CNRL POUCE COUPE (AB) 03-03-081-13 001	03-03-081-13	1242	Canadian Natural Resources Limited		Alberta								
CNRL RING C-081-I/094-H-09 002	C-081-I/094-H-09	740	Canadian Natural Resources Limited	Refrigeration	Provincial	2958	2662	129		224			
CNRL RING C-081-I/094-H-09 003	C-081-I/094-H-09	921	Canadian Natural Resources Limited										
CNRL RING C-081-I/094-H-09 008	C-081-I/094-H-09	4556	Canadian Natural Resources Limited		Provincial	1090	1005	90					
CNRL RING a-049-B/094-H-16 005	A-049-B/094-H-16	2766	Canadian Natural Resources Limited		Provincial	227	221				0	0	100
CNRL SEPTIMUS 08-22-081-19 001	08-22-081-19	7806	Canadian Natural Resources Limited		Provincial	4816	4790	143221	50774	11496		0	
CNRL STODDART 02-34-087-21 001	02-34-087-21	3164	Canadian Natural Resources Limited		Provincial	3392	2772	870			1.98	1.98	100
CNRL TOOGA B-031-I/094-P-02 001	B-031-I/094-P-02	2438	Canadian Natural Resources Limited		Provincial								
COP INGA NORTH C-011-K/094-A-12 002		26696	ConocoPhillips Canada Resources Corp.			6518	5654	1616		6523		3.9	
COPOL BRASSEY D-013-F/093-P-10 003	D-013-F/093-P-10	457	ConocoPhillips Canada Operations ULC		Provincial								
COPOL BRASSEY D-013-F/093-P-10 004	D-013-F/093-P-10	7383	ConocoPhillips Canada Operations ULC		Provincial								
CREW SEPTIMUS 12-27-081-18 001	12-27-081-18	7776	Crew Energy Inc.		Provincial	1690							
CREW WILDER 10-14-082-20 001	10-14-082-20	18074	Crew Energy Inc.		Provincial	3540	3400			950		0	
CSRI FARRELL CREEK C-093-H/094-B-01 001	C-093-H/094-B-01	7717	Canadian Spirit Resources Inc.		Provincial	33.8							
CVE ENERGY ELMSWORTH 01-08-070-11 001	01-08-070-11	443	Cenovus Energy Inc.		Alberta								
ECA SADDLEHILLS 04-08-077-13 001	04-08-077-13	7459	Encana Corporation		Alberta								
ECA SATURN 15-27-079-17 003	15-27-079-17	18260	Encana Corporation		Provincial	14590.8	13930.2	592666.6	254721.9	304369.9		0	
ECA SUNRISE 04-26-078-17 001	04-26-078-17	18051	Encana Corporation		Provincial	11327	11136	208	205.9	206		0	
ECA TOWER LAKE 03-07-081-17 001	03-07-081-17	18136	Encana Corporation		Provincial	7429	7065	343929	159931	299841		0	
ECOG MAXHAMISHLAKE D-036-I/094-O-14 001	D-036-I/094-O-14	3548	EOG Canada Oil & Gas Inc.		Provincial	676	675			7			
EXXONMOBIL RAINBOW 04-15-110-06 001	04-15-110-06	486	ExxonMobil Canada Energy		Alberta								
GSENR MAXHAMISHLAKE A-060-I/094-O-11 003	A-060-I/094-O-11	9075	GS E&R Canada Inc.		Provincial	648	566	20.4	41.9	62			
HARVEST HAYRIVER B-076-H/094-I-09 004	B-076-H/094-I-09	7633	Harvest Operations Corp.		Provincial	180							
HARVEST SHEKILIE B-024-A/094-I-16 003	B-024-A/094-I-16	7473	Harvest Operations Corp.		Provincial	250							
HARVEST SHEKILIE B-046-A/094-I-16 002	B-046-A/094-I-16	7472	Harvest Operations Corp.		Provincial	250							
HUSKY BIVOUAC 003		18330	Husky Oil Operations Limited		Alberta								
HUSKY FIRE CREEK B-099-H/094-I-08 003	B-099-H/094-I-08	7435	Husky Oil Operations Limited		Alberta								
KANATA DAIBER A-054-C/094-B-16 001	A-054-C/094-B-16	18016	KANATA Energy Group Ltd.		Provincial	794.2	770.2	45.1	20.6	8.4	0.006	0.006	0
KELT LNG INGA 02-10-088-23 002	02-10-088-23	26856	Kelt Exploration (LNG) Ltd.			3391.5	3391.5					0	
KELT NEPTUNE (AB) 10-13-086-13 001	10-13-086-13	970	Kelt Exploration Ltd.		Alberta								
KEYERA BOUGIE D-031-F/094-G-15 001	D-031-F/094-G-15	1279	Keyera Energy Ltd.	Methyldiethanolamine; Refrigeration	Provincial								
KEYERA CARIBOU C-004-G/094-G-07 003	C-004-G/094-G-07	2411	Keyera Energy Ltd.	Refrigeration	Provincial	2815		115		48	68	0	100
LEUCROTTA DOE 13-24-080-15 005	13-24-080-15	7932	Leucrotta Exploration Inc.		Provincial	2407	2320	100320	53840	470.21		0	
NORTHRIVER OPSGP AITKENCREEK D-044-L/094-A-13 007		26947	NorthRiver Midstream Operations GP Inc.										
NORTHRIVER OPSGP CABIN B-047-I/094-P-04 001		26950	NorthRiver Midstream Operations GP Inc.										

Gas Processing Plants in British Columbia

Plant	Location	Facility ID	Operator	Plant Process	Jurisdiction	Raw Gas (e3m3/d)	Sales Gas (e3m3/d)	C3 (m3/d)	C4 (m3/d)	C5 (m3/d)	Sulphur (tonnes/d)	Sulphur Emmission (tonnes/d)	Sulphur Recovery (%)
NORTHRIVER OPSGP CLARKELAKE B-084-G/094-J-10 002		26945	NorthRiver Midstream Operations GP Inc.		Provincial								
NORTHRIVER OPSGP DAWSONCREEK 11-26-078-17 003	11-26-078-17	26951	NorthRiver Midstream Operations GP Inc.										
NORTHRIVER OPSGP FORTSTJOHNSE 15-25-082-18 002	15-25-082-18	26946	NorthRiver Midstream Operations GP Inc.										
NORTHRIVER OPSGP SIKANNI B-041-I/094-G-03 006		26943	NorthRiver Midstream Operations GP Inc.		Provincial								
NORTHRIVER OPSGP SUKUNKA A-084-K/094-O-03 001		26952	NorthRiver Midstream Operations GP Inc.		Provincial								
NOVAGAS TAYLOR 10-36-082-18 001	10-36-082-18	2787	Novagas Canada Ltd.		Provincial								
NRM GP CABIN D-076-J/094-P-04 002	D-076-J/094-P-04	7812	NorthRiver Midstream G and P Canada Inc.	Amine Contactor; Stabilization	Provincial	22540							
NRM GP TUPPER CREEK 05-01-077-17 001	05-01-077-17	7808	NorthRiver Midstream G and P Canada Inc.		Provincial	11829	11489			25		1.95	
NRM GP TUPPER CREEK A-021-B/093-P-09 001	A-021-B/093-P-09	7676	NorthRiver Midstream G and P Canada Inc.		Provincial	3099	2974	36000	17000	5000		0	
NRM HOLD LTD BUCKINGHORSE A-081-H/094-G-06 002	A-081-H/094-G-06	558	NorthRiver Midstream Energy Holdings Limited	Methyldiethanolamine; Absorption	Provincial	2832					0.332	0.332	0
NorthRiver DOE 02-25-080-15 001	02-25-080-15	7652	NorthRiver Midstream Inc.		Provincial	2790							
NorthRiver HIGHWAY B-036-I/094-B-16 002	B-036-I/094-B-16	2436	NorthRiver Midstream Inc.	Refrigeration; Amine Contactor	Provincial	3100	2945	149	137	154		1.98	0
NorthRiver JEDNEY B-088-J/094-G-01 005	B-088-J/094-G-01	2267	NorthRiver Midstream Inc.	Methyldiethanolamine	Provincial	2200	1900	120		80	62.27	0.07	99.9
NorthRiver JEDNEY B-088-J/094-G-01 007	B-088-J/094-G-01	2435	NorthRiver Midstream Inc.	Refrigeration; Amine Contactor	Provincial	2265	2039	140			66.65	0.18	99.7
NorthRiver SUNRISE 15-26-078-17 002	15-26-078-17	7974	NorthRiver Midstream Inc.		Provincial	11270	10700						
OBSIDIAN CYPRESS B-075-F/094-B-15 001	B-075-F/094-B-15	7354	Obsidian Energy Ltd.		Provincial								
OBSIDIAN PARKLAND 06-29-081-15 002	06-29-081-15	1726	Obsidian Energy Ltd.		Provincial								
PACIFIC CANBRIAM ALTARES B-024-H/094-B-08 001	B-024-H/094-B-08	7834	Pacific Canbriam Energy Limited		Provincial	1416	1346	106.9	93.9	74		0	
PACIFIC CANBRIAM ALTARES B-072-A/094-B-08 001	B-072-A/094-B-08	17909	Pacific Canbriam Energy Limited		Provincial	8354	7998	24	45.9	389.5		0	
PACIFIC TUMBLER RIDGE A-074-G/093-I-15 003	A-074-G/093-I-15	303	Pacific Northern Gas (N.E.) Ltd.	Diethanolamine; Absorption	Provincial	256	225				0.007	0.007	0
PAINTED PONY BLAIR A-079-B/094-B-16 001	A-079-B/094-B-16	8649	Painted Pony Energy Ltd.		Provincial	710							
PARA (ACL) HAMBURG C-032-H/094-H-08 003	C-032-H/094-H-08	2268	Paramount Resources Ltd.		Alberta								
PARA (ACL) KOMIE B-017-I/094-P-04 004	B-017-I/094-P-04	7830	Paramount Resources Ltd.		Provincial								
PARA MASON A-030-G/094-G-07 001	A-030-G/094-G-07	438	Paramount Resources Ltd.	Absorption; Methyldiethanolamine	Provincial								
PENGL YOUNGER 02-36-082-18 002	02-36-082-18	932	1195714 Alberta Ltd.	Turbo Expander; Refrigeration (Obsolete)	Provincial	21240	18959	1947	815	283			
PENGROWTH GROUNDBIRCH 06-19-080-20 001	06-19-080-20	7795	Pengrowth Energy Corporation		Provincial	991	991	8540	3252	843			
PETRONAS ALTARES C-065-G/094-B-08 001	C-065-G/094-B-08	8651	PETRONAS Energy Canada Ltd.		Provincial	2832							
PETRONAS CARIBOU C-016-F/094-G-07 001	C-016-F/094-G-07	7966	PETRONAS Energy Canada Ltd.		Provincial	5550							
PETRONAS CLARKELAKE A-076-G/094-J-10 001	A-076-G/094-J-10	4579	PETRONAS Energy Canada Ltd.		Provincial								
PETRONAS FARRELLCREEKWEST B-088-I/094-B-01 001	B-088-I/094-B-01	7778	PETRONAS Energy Canada Ltd.		Provincial	5070							
PETRONAS JULIENNE CREEK C-042-H/094-G-02 001		26223	PETRONAS Energy Canada Ltd.			5550	5400	3.6	7.9	29.8		0	
PETRONAS LILYLAKE A-029-J/094-G-02 001	A-029-J/094-G-02	7925	PETRONAS Energy Canada Ltd.		Provincial	5550	5436	59.8	27.2	6.8	0	0	
PETRONAS TOWN B-089-J/094-B-16 001	B-089-J/094-B-16	18309	PETRONAS Energy Canada Ltd.			9910	9458	233	325	688	0	1.94	99.5
PETRONAS TOWN C-072-A/094-B-16 001	C-072-A/094-B-16	18229	PETRONAS Energy Canada Ltd.		Provincial	5550	5272	164.5	227.3	590	0	0	0
PREDATOR OIL BC HELMET D-075-A/094-P-11 003	D-075-A/094-P-11	2917	Predator Oil BC Ltd.		Provincial	3944	3380			8	0.003	0	
SAGUARO LAPRISE CREEK B-024-H/094-G-08 001	B-024-H/094-G-08	17858	Saguaro Resources Ltd.		Provincial	3965	3885	151.03	58.83	20.86		0	
SEC ELLEH A-019-F/094-I-12 001	A-019-F/094-I-12	7309	Shanghai Energy Corporation		Provincial								
SEC SIERRA A-026-K/094-I-11 002	A-026-K/094-I-11	3738	Shanghai Energy Corporation		Provincial	2500							
SHELL BRASSEY 07-34-077-19 001	07-34-077-19	7463	Shell Canada Limited		Provincial	540							
SHELL GROUNDBIRCH 04-15-080-19 001	04-15-080-19	7286	Shell Canada Limited		Provincial	282	254						
SHELL GROUNDBIRCH 04-15-080-19 003	04-15-080-19	7727	Shell Canada Limited		Provincial	3800							
SHELL GROUNDBIRCH 04-15-080-19 004	04-15-080-19	7810	Shell Canada Limited		Provincial								
SHELL MONIAS 07-14-078-22 001	07-14-078-22	7854	Shell Canada Limited		Provincial	226.5							
SHELL SATURN 03-28-080-20 001	03-28-080-20	7868	Shell Canada Limited		Provincial	6497	6497	212		229		0	
SHELL SUNDOWN B-037-B/093-P-10 003	B-037-B/093-P-10	9132	Shell Canada Limited		Provincial	250							
SHELL SUNSET PRAIRIE 13-08-080-18 001	13-08-080-18	7896	Shell Canada Limited		Provincial	5578							
SHELL SUNSETPRAIRIE 05-03-081-18 002	05-03-081-18	3479	Shell Canada Limited		Provincial	350		40					
SRL NIG CREEK B-048-G/094-H-04 001		26801	Storm Resources Ltd.			1697	1590	225	52	332		1.99	
STAR PINE 07-06-077-25 003	07-06-077-25	1593	domcan		Provincial								
SUKUNKA KWOEN D-057-G/093-P-05 002	D-057-G/093-P-05	7346	Sukunka Natural Resources Inc.		Provincial	0	0					0	
SUKUNKA PINE RIVER C-085-D/093-P-12 001	C-085-D/093-P-12	442	Sukunka Natural Resources Inc.	Sulfinol; Adsorption; M And C Tail Gas Clean-Up	Provincial	15864	12493				2000	20	99
TAQA NORTH CHINCHAGARIVER C-032-H/094-H-08 007	C-032-H/094-H-08	2889	TAQA North Ltd.		Provincial	1415				60			
TERRA PINTAIL 15-22-084-25 001	15-22-084-25	7883	Terra Energy Corp.		Provincial	1000	964	118		75.6		0	
TIDEWATER POCKETKNIFE A-059-L/094-G-07 002	A-059-L/094-G-07	9092	Tidewater Midstream and Infrastructure Ltd.		Provincial								
TIDEWATER POCKETKNIFE B-032-I/094-G-06 002	B-032-I/094-G-06	7158	Tidewater Midstream and Infrastructure Ltd.		Provincial								

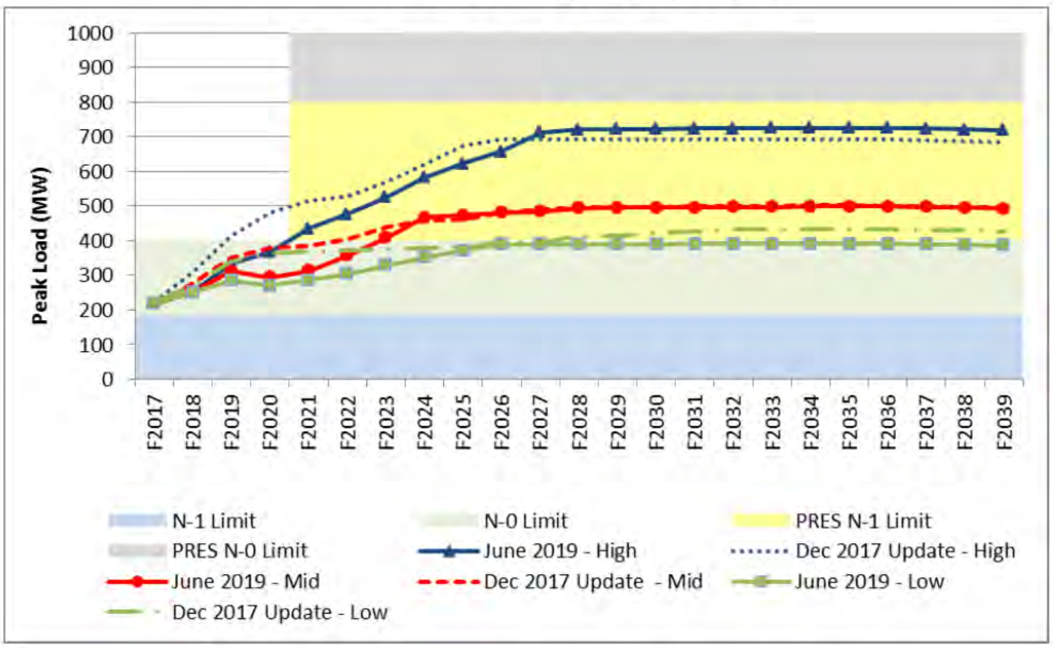
Gas Processing Plants in British Columbia

Plant	Location	Facility ID	Operator	Plant Process	Jurisdiction	Raw Gas (e3m3/d)	Sales Gas (e3m3/d)	C3 (m3/d)	C4 (m3/d)	C5 (m3/d)	Sulphur (tonnes/d)	Sulphur Emmission (tonnes/d)	Sulphur Recovery (%)
TOURMALINE DOE 02-11-080-16 001	02-11-080-16	26229	Tourmaline Oil Corp.			3957	3301.7	161694	66601	21189	1.804	0	
TOURMALINE DOE 13-25-080-16 001	13-25-080-16	7936	Tourmaline Oil Corp.		Provincial	3396	3396	225.1	191.5	695.2			
TOURMALINE GUNDY CREEK C-060-A/094-B-16 001		26427	Tourmaline Oil Corp.			11192	10140	451000	216120	76002		0	
TOURMALINE SUNRISE 03-18-080-17 001	03-18-080-17	7819	Tourmaline Oil Corp.		Provincial	2832	2036	32.2	37.8	213			
VMGPI CUTBANK C-064-A/093-P-08 002	C-064-A/093-P-08	7466	Veresen Midstream General Partner Inc.		Provincial	6088.1	6006				40	1.95	95.9
VMGPI HYTHE (AB) 11-18-076-13 001	11-18-076-13	3234	Veresen Midstream General Partner Inc.		Alberta								
WESTCOAST AITKENCREEK D-044-L/094-A-13 005	D-044-L/094-A-13	559	Westcoast Energy Inc.	Methyldiethanolamine; Refrigeration	Federal	2323	2210				0.31	0.31	0
WESTCOAST CABIN A-030-A/094-P-05 001	A-030-A/094-P-05	7193	Westcoast Energy Inc.		Federal								
WESTCOAST DAWSONCREEK 11-26-078-17 001	11-26-078-17	8645	Westcoast Energy Inc.		Federal								
WESTCOAST DRY GAS 06-07-080-13 001	06-07-080-13	1243	Westcoast Energy Inc.		Federal								
WESTCOAST FORT NELSON B-084-G/094-J-10 001	B-084-G/094-J-10	437	Westcoast Energy Inc.	Adsorption; Monoethanolamine; Modified Claus; Sulfreen	Federal	28427	24163				674	33.6	95
WESTCOAST MCMAHON 15-25-082-18 001	15-25-082-18	439	Westcoast Energy Inc.	Absorption; Adsorption; Fractionation; Monoethanolamine; Modified Claus; Refrigeration; Sulfreen	Federal	19263	17564	195	330	1055	559	8.9	98.4
WESTCOAST PATRY D-057-G/093-P-05 001	D-057-G/093-P-05	7192	Westcoast Energy Inc.		Federal								
WESTCOAST SIKANNI B-041-I/094-G-03 001	B-041-I/094-G-03	322	Westcoast Energy Inc.	Diethanolamine; Absorption	Federal	2890	2833				0.4	0.3	25
WHITECAP BOUNDARYLAKE 02-25-085-14 005	02-25-085-14	7362	Whitecap Resources Inc.		Provincial	155	0	0	0	0		0.49	0
WHITECAP BOUNDARYLAKE 07-02-085-14 002	07-02-085-14	445	Whitecap Resources Inc.	Absorption; Flexsorb; Refrigeration	Provincial	312	234	120			1	1	0

59.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix C, June 2019 update to South Peace River forecast.

In Appendix C, BC Hydro provides the following chart to illustrate the differences between the previous (May 2016) and the latest (June 2019) Load Forecast for the area to be serviced by the PRES project:

Figure C-1 South Peace Region Load Forecasts June 2019 and December 2017 Update



The chart appears to show the Mid Forecast of Peak Loads reaching around 500 MW by F2024, and the High Forecast of Peak Loads reaching around 700 MW by F2027. These are approximately the same levels as were forecast in May 2016, except that the newer High Forecast reaches a level about 20 MW higher, which BC Hydro describes as *"due to increased electrification assumptions in the Groundbirch area as a result of LNG development."*

4.59.5 What steps can BC Hydro take to electrify a higher proportion of the total work load in the PRES area? What, if any, actions is BC Hydro undertaking to accomplish this?

RESPONSE:

As discussed in BC Hydro's response to CEABC IR 1.10.4, BC Hydro Key Account Managers regularly meet with existing and prospective customers to discuss potential projects. This includes identifying the locations of existing and potential compressor stations relative to existing electrical infrastructure and assessing the timeline and costs required to connect those facilities. BC Hydro also actively assists customers through the interconnection process to manage customer in-service dates.

A customer's decision to use BC Hydro electricity supply for their project is driven by a number of factors including cost, proximity to existing electrical infrastructure, and confidence in the in-service date of the interconnection.

61.0 Reference: Exhibit B-15, 20-Year Load Forecast, page 3, expected annual load growth, and the Clean Energy Act of B.C.

The Clean Energy Act has been the law in British Columbia for about 9 years. The following objectives are excerpted from the Act:

"2. The following comprise British Columbia's energy objectives:

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the Climate Change Accountability Act;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;"

4.61.2 What does BC Hydro perceive as its role in achieving the objectives of the Clean Energy Act? How is this role being reflected in the current 20-Year Load Forecast?

RESPONSE:

As discussed in section 2.6.2 of Chapter 2 of the Application, the BCUC must consider the energy objectives in section 2 of the *Clean Energy Act* when reviewing applications made under sections 44.1, 44.2, 45 and 71 of the *Utilities Commission Act*. Consideration of the energy objectives may require trade-offs (i.e., "consider" is not synonymous with "must apply" or "must prioritize").

Accordingly, when preparing filings for the BCUC under sections 44.1, 44.2, 45 and 71 of the *Utilities Commission Act*, BC Hydro strives to provide the BCUC with sufficient evidence to consider the application in light of the various energy objectives.

Potential electricity demand related to legislation and public policy is considered and evaluated through the methodology set out in Appendix O of the Application.

BC Hydro's response to BCUC IR 4.325.2 illustrates how this plays out in the context of the CleanBC Plan.

64.0 Reference: On August 29, 2019, the Governments of Canada and B.C. announced an MOU aimed at the electrification of B.C.'s natural gas sector.

https://news.gov.bc.ca/files/MOU_Canada_BritishColumbia_Natural_Gas_Electrification.pdf

The following is an excerpt from that MOU:

Purpose

1. The purpose of this Memorandum of Understanding is to demonstrate the commitment of the Government of British Columbia and the Government of Canada to support the electrification of the natural gas sector in British Columbia.

Joint actions

2. The participants agree on the importance of supporting the electrification of the natural gas sector in British Columbia.

3. A Canada-British Columbia Clean Power Planning Committee, with senior representation from both jurisdictions, including BC Hydro will:

   a. Advance natural gas and liquified natural gas electrification, including:

      i. CleanBC Facilities Electrification Fund;

      ii. Bear Mountain to Dawson Creek Voltage Conversion project;

      iii. North Montney Power Supply project; and

      iv. Other natural gas electrification opportunities identified by the participants

   b. Explore other electrification and transmission expansion opportunities, as determined by the Committee;

   c. Improve cross-government coordination to connect existing and new funding sources to priorities, especially with respect to federal infrastructure funding; and

   d. Develop and consider new and/or alternative financing models that can advance priority transmission projects, which may include Indigenous or other private sector ownership and participation by the Canada Infrastructure Bank.

BC Hydro is named as having "*senior representation*" on the Clean Power Planning Committee that is driving this initiative.

4.64.1 Is BC Hydro's expected 1% load growth over the next 20 years consistent with the objectives stated in this Canada-B.C. MOU? If not, why not? What is BC Hydro planning to do to achieve the objectives of the MOU?

RESPONSE:

BC Hydro's June 2019 Load Forecast includes limited load growth in the natural gas sectors in the regions that could be supplied by the electrification projects referenced in the MOU (i.e., the CleanBC Facilities Electrification Fund, the Bear Mountain to Dawson Voltage Conversion project, and the North Montney Power Supply project). Please refer to BC Hydro's responses to CEABC IRs 4.65.2 and 2.41.1 which indicate that declines in natural gas prices have generally favoured self-supply over electricity supply.

BC Hydro will support the MOU by participating in the Canada-British Columbia Clean Power Planning Committee, and by continuing to work with natural gas and liquefied natural gas producers to meet their electricity needs.

64.0 Reference: On August 29, 2019, the Governments of Canada and B.C. announced an MOU aimed at the electrification of B.C.'s natural gas sector.

https://news.gov.bc.ca/files/MOU_Canada_BritishColumbia_Natural_Gas_Electrification.pdf

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   d. Develop and consider new and/or alternative financing models that can advance priority transmission projects, which may include Indigenous or other private sector ownership and participation by the Canada Infrastructure Bank.

BC Hydro is named as having "*senior representation*" on the Clean Power Planning Committee that is driving this initiative.

4.64.2 What is the "North Montney Power Supply project" identified as item 3.a.iii. in the MOU? Is this project the same as the "North Montney – Transmsission Development" project identified in the response to BCUC IR 2.254.2? To what extent are they the same or different? What are their respective objectives? How much capital has BC Hydro budgeted for these projects? When are they expected to be complete and in-service? How much additional load does BC Hydro expect to serve through these projects, and in what years is that additional load included in the June 2019 20-Year Forecast?

RESPONSE:

The “North Montney Power Supply project” identified as item 3.a.iii in the MOU is the same as the North Montney – Transmission Development project identified in BC Hydro responses to BCUC IRs 2.254.2 and 2.254.2.1.

BC Hydro’s response to BCUC IR 2.254.2 outlines the project objective and BC Hydro’s response to BCUC IR 2.254.2.1 explains that the capital budget and in-service date for this project will be available once customer commitments are confirmed and the annual capital planning process is complete.

BC Hydro expects that this project will enable new load growth in the North Montney area. As discussed in BC Hydro’s response to BCUC IR 2.254.2.1, load commitments from potential customers are being confirmed. When potential customers confirm sufficient load commitments, the project will proceed in accordance with BC Hydro’s financial approval procedures.

64.0 Reference: On August 29, 2019, the Governments of Canada and B.C. announced an MOU aimed at the electrification of B.C.'s natural gas sector.

https://news.gov.bc.ca/files/MOU_Canada_BritishColumbia_Natural_Gas_Electrification.pdf

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      ii. Bear Mountain to Dawson Creek Voltage Conversion project;

      iii. North Montney Power Supply project; and

      iv. Other natural gas electrification opportunities identified by the participants

   b. Explore other electrification and transmission expansion opportunities, as determined by the Committee;

   c. Improve cross-government coordination to connect existing and new funding sources to priorities, especially with respect to federal infrastructure funding; and

   d. Develop and consider new and/or alternative financing models that can advance priority transmission projects, which may include Indigenous or other private sector ownership and participation by the Canada Infrastructure Bank.

BC Hydro is named as having "*senior representation*" on the Clean Power Planning Committee that is driving this initiative.

4.64.3 What "Other natural gas electrification opportunities" has BC Hydro identified? How much capital and expenses are budgeted for them? When will they be completed and in-service?

How much additional load does BC Hydro expect to serve through these opportunities, and is that additional load included in the June 2019 20-Year Forecast?

RESPONSE:

There are currently no natural gas electrification opportunities identified in addition to those listed in section 3(a) of the MOU. BC Hydro will work with the other participants on the Canada-British Columbia Clean Power Committee to identify additional natural gas electrification opportunities.

65.0 Reference: Exhibit B-15, 20-Year Load Forecast, and news announcement from Petronas re its plans for LNG exports.

Petronas Canada described its plans for gas expansion activities in Northeast B.C. in this news article November 28, 2018.

https://www.alaskahighwaynews.ca/business/petronas-plans-gradual-ramp-up-electrification-in-northeast-b-c-1.23511710

The article stated that:

> "Petronas Canada plans to electrify its operations in Northeast B.C. as it reaccelerates its drilling program and brings spending to $1 billion a year by 2022…
>
> The company plans to build slowly from there in 2019, with two rigs to drill 30 wells and boosting spending to just under $500 million. By 2022, it plans to have up to six rigs in the region drilling up to 80 wells, with spending reaching $1 billion...
>
> Around 63 trillion cubic feet of Petronas' reserves are recoverable with today's technology, Deyell said. Of that, 7 tcf will be sent west to the LNG Canada project in Kitimat, in which Petronas bought a 25% share in May…
>
> Petronas has recently committed to the federal government to lead the development of an electrification plan in Northeast B.C., Deyell said. The company will be working with all levels of government, First Nations, and the public in the new year on that plan, she said."

4.65.1 What steps is BC Hydro taking to ensure that as much as possible of Petronas' gas operations in Northeast B.C. will be electrified?

RESPONSE:

The public version of the response has been redacted to maintain confidentiality over customer information. The un-redacted version of the response is being made available to the BCUC only, in order to protect the customer's commercial interests.

As referenced in the Memorandum of Understanding between the Government of Canada and the Government of British Columbia on the Electrification of the Natural Gas Sector, the advancement of activities associated with the North Montney Power Supply project and the CleanBC Facilities Electrification Fund

could help to facilitate the electrification of Petronas' operations in Northeast British Columbia.

[redacted]

65.0 Reference: Exhibit B-15, 20-Year Load Forecast, and news announcement from Petronas re its plans for LNG exports.

Petronas Canada described its plans for gas expansion activities in Northeast B.C. in this news article November 28, 2018.

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The article stated that:

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>
> The company plans to build slowly from there in 2019, with two rigs to drill 30 wells and boosting spending to just under $500 million. By 2022, it plans to have up to six rigs in the region drilling up to 80 wells, with spending reaching $1 billion...
>
> Around 63 trillion cubic feet of Petronas' reserves are recoverable with today's technology, Deyell said. Of that, 7 tcf will be sent west to the LNG Canada project in Kitimat, in which Petronas bought a 25% share in May…
>
> Petronas has recently committed to the federal government to lead the development of an electrification plan in Northeast B.C., Deyell said. The company will be working with all levels of government, First Nations, and the public in the new year on that plan, she said."

4.65.2 Given the short time frame for Petronas' activities e.g. phase one of LNG Canada is expected to be in commercial operation by 2025, how will BC Hydro meet the need for the electrification of Petronas' facilities? How much of this new load has BC Hydro included in the June 2019 Load Forecast, and in which years?

RESPONSE:

The public version of the response has been redacted to maintain confidentiality over customer information. The un-redacted version of the response is being made available to the BCUC only, in order to protect the customer's commercial interests.

BC Hydro is undertaking preliminary assessment work for the North Montney Power Supply project with a target in-service date of fiscal 2026. Where required, bridging options are also being considered.

[redacted]

[redacted]

[redacted]

[redacted]

66.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix D, Load Resource Balances, Table D-3, Demand Side Management and Other Measures.

Table D-3 now gives a picture of the 20 year outlook for DSM and other measures, but there is no discussion of how these 20 year forecasts are determined.

Under "*Existing and Committed*" measures, the table shows "*F19 DSM Portfolio Savings (F20-F21 RRA)*", which decline from 695 GWh of savings in F2021 to 401 GWh in F2039.

4.66.1 How is it that these Portfolio Savings have such a long period of decline, when most DSM programs are viewed as losing their effectiveness over no more than 10 years?

RESPONSE:

Portfolio savings includes savings from programs, rate structures, and codes and standards. As per the DSM assumptions shown on page 80 of Appendix X of the Application, some measures within certain initiatives have a longer persistence (e.g., savings from building codes and product and equipment standards). Please refer to BC Hydro's response to CEABC IR 4.66.4 where BC Hydro further explains the persistence of codes and standards savings.

66.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix D, Load Resource Balances, Table D-3, Demand Side Management and Other Measures.

Table D-3 now gives a picture of the 20 year outlook for DSM and other measures, but there is no discussion of how these 20 year forecasts are determined.

Under "*Existing and Committed*" measures, the table shows "*F19 DSM Portfolio Savings (F20-F21 RRA)*", which decline from 695 GWh of savings in F2021 to 401 GWh in F2039.

4.66.2 Are these savings based on existing programs where all the costs have already been incurred, or will new costs be incurred over the 20 year period?

RESPONSE:

The referenced savings and the persistence of the savings are based on new activities and expenditures for fiscal 2019 only, covering programs, rate structures, and codes and standards.

66.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix D, Load Resource Balances, Table D-3, Demand Side Management and Other Measures.

Also under "*Existing and Committed*" measures, the table shows "*F20+ Codes & Standards (F20-F21 RRA) plus Voltage and VAR Optimization*", which increases from 615 GWh of savings in F2021 to 3,750 GWh in F2039.

4.66.3 Please itemize each of the items that comprise this line, and provide a breakdown of the savings from each and the spending on each over the time period.

RESPONSE:

Attachment 1 to this response provides a breakdown of the new savings from codes and standards from fiscal 2020 onwards by sector at the customer meter as well as the Voltage and VAR Optimization savings and the associated system losses. The second table shows the planned expenditures for codes and standards activities. There are no expenditures associated with Voltage and VAR Optimization or system losses.

F20+ Codes & Standards (F20-F21 RRA) plus Voltage and VAR Optimization Energy Savings (GWh)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Residential	350	527	656	774	886	989	1,083	1,166	1,241	1,310	1,376	1,441	1,503	1,564	1,627	1,689	1,751	1,813	1,876
Commercial	174	300	407	502	590	665	725	781	838	902	957	1,001	1,045	1,090	1,135	1,180	1,225	1,270	1,315
Industrial	17	25	31	37	42	48	53	58	62	66	69	72	76	79	82	85	88	91	94
VVO	19	24	27	32	35	39	49	53	57	62	66	70	75	79	84	89	93	98	103
Losses	56	88	114	138	160	180	198	213	228	243	258	272	285	298	312	325	338	350	363
Total	615	964	1,235	1,482	1,713	1,920	2,108	2,271	2,427	2,584	2,726	2,856	2,982	3,110	3,239	3,367	3,494	3,622	3,750

Codes and Standards Expenditures

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
($ millions)	5.3	5.4	5.5	5.6	5.7	5.9	6.0	6.1	6.2	6.3	6.5	6.6	6.7	6.9	7.0	7.1	7.3	7.4	7.6

66.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix D, Load Resource Balances, Table D-3, Demand Side Management and Other Measures.

Also under "*Existing and Committed*" measures, the table shows "*F20+ Codes & Standards (F20-F21 RRA) plus Voltage and VAR Optimization*", which increases from 615 GWh of savings in F2021 to 3,750 GWh in F2039.

4.66.4 Please explain how these listed items are expected to produce such significant savings over such a long period.

RESPONSE:

BC Hydro's Codes and Standards initiative focuses on transforming the marketplace to energy efficient practices and products, by working with all levels of government. Please refer to page 3 of Appendix X of the Application for a description of our Codes and Standards initiative.

A key reason why codes and standards result in significant savings is that they establish a new baseline for the efficiency of technologies for the entire market. Through new codes and standards, the purchasing of higher efficiency technologies is mandated by regulation, leading to market transformation. Therefore, the persistence of codes and standards activities assumes multiple life cycles of the measure over the entire planning period as customers will be required to replace the product with the higher efficiency technology mandated by the regulation each time the product reaches end of life.

66.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix D, Load Resource Balances, Table D-3, Demand Side Management and Other Measures.

Under "*Planned*" DSM Measures, the table shows "*F20+ Rates (F20-F21 RRA)*", which increases from 381 GWh of savings in F2021 to 1,615 GWh in F2039, and it also shows "*F20+ Programs (F20-F21 RRA)*", for which the savings are more or less constant from 128 GWh in F2021 to 135 GWh in F2039.

4.66.5 Please itemize what is included in these "Rates" and "Programs" lines, describe each item, and provide a breakdown of the savings from each and the spending on each over the time period.

RESPONSE:

As noted in BC Hydro's response to AMPC IR 4.7.2, there is a labeling error in the referenced Table D-3 of Appendix D. Row 11 should be "F20+ Programs (F20-F21 RRA)" and Row 12 should be "F20+ Rates (F20-F21 RRA)".

"Rates" include the savings forecast from the Transmission Service Rate (TSR). Based on recent evaluation findings, the Residential Inclining Block Rate and the Large General Service / Medium General Service Rate no longer generate any new incremental savings in the forecast period.

"Programs" include the savings forecast from all of BC Hydro's DSM programs for the integrated system for the three customer sectors.

Attachment 1 to this response shows the energy savings at the customer meter, the associated system losses and the expenditures associated with the energy savings over time.

Cumulative Acquired Electricity Savings at Customer Meter (GWh)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Rate Structures											
Transmission Service Rate	117	131	135	131	129	127	126	125	124	124	124
System Losses	12	13	14	13	13	13	13	13	13	13	13
F20+ Rate Structures with Losses (Row 12 of Table D-3)	**128**	**144**	**149**	**145**	**142**	**140**	**139**	**138**	**137**	**137**	**137**
DSM Programs											
Residential Sector											
Low Income	13	21	29	37	44	51	57	62	67	70	73
Retail	8	13	16	19	22	24	26	28	30	32	33
Home Renovation Rebate	13	21	29	38	46	54	63	71	79	88	96
Energy Management Activities	18	28	38	47	56	62	67	70	73	74	74
Residential Sector Total	*52*	*82*	*112*	*140*	*167*	*191*	*212*	*231*	*249*	*264*	*275*
Commercial Sector											
Leaders in Energy Management - Commercial	70	109	143	175	200	222	248	272	295	316	336
New Construction	10	15	17	17	17	17	17	17	17	17	17
Commercial Sector Total	*81*	*124*	*160*	*192*	*217*	*239*	*264*	*289*	*312*	*333*	*352*
Industrial Sector											
Leaders in Energy Management - Industrial	164	218	269	330	389	448	508	564	613	663	698
Thermo-Mechanical Pulp	50	92	92	92	92	92	92	92	92	92	42
Industrial Sector Total	*214*	*310*	*361*	*422*	*481*	*539*	*600*	*656*	*705*	*755*	*741*
System Losses	*35*	*52*	*64*	*77*	*89*	*100*	*111*	*122*	*132*	*141*	*143*
F20+ Programs with Losses (Row 11 of Table D-3)	**381**	**569**	**698**	**832**	**954**	**1,070**	**1,188**	**1,298**	**1,398**	**1,493**	**1,512**

Cumulative Acquired Electricity Savings at Customer Meter (GWh)

	F2032	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Rate Structures								
Transmission Service Rate	124	123	123	123	123	122	122	122
System Losses	13	13	13	13	13	13	13	13
F20+ Rate Structures with Losses (Row 12 of Table D-3)	**137**	**136**	**136**	**136**	**136**	**135**	**135**	**135**
DSM Programs								
Residential Sector								
Low Income	75	76	78	79	80	80	81	82
Retail	34	35	36	37	37	38	38	39
Home Renovation Rebate	104	113	121	129	138	146	151	155
Energy Management Activities	72	71	70	69	68	68	68	68
Residential Sector Total	*286*	*296*	*304*	*314*	*323*	*332*	*338*	*343*
Commercial Sector								
Leaders in Energy Management - Commercial	351	366	380	387	384	375	368	362
New Construction	17	17	17	17	17	17	13	7
Commercial Sector Total	*368*	*383*	*397*	*404*	*401*	*392*	*380*	*368*
Industrial Sector								
Leaders in Energy Management - Industrial	719	734	739	745	750	750	749	747
Thermo-Mechanical Pulp	0	0	0	0	0	0	0	0
Industrial Sector Total	*719*	*734*	*739*	*745*	*750*	*750*	*749*	*747*
System Losses	*144*	*149*	*153*	*156*	*157*	*157*	*157*	*156*
F20+ Programs with Losses (Row 11 of Table D-3)	**1,517**	**1,562**	**1,592**	**1,619**	**1,631**	**1,630**	**1,624**	**1,615**

Table 5. Total BC Hydro Costs ($ Million)

	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032
Rate Structures												
Transmission Service Rate	0.5	0.5	0.5	0.5	0.8	0.5	0.5	0.5	0.5	0.5	0.8	0.5
Total Rate Structures	**0.5**	**0.5**	**0.5**	**0.5**	**0.8**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.8**	**0.5**
DSM Programs												
Residential Sector												
Low Income	6.9	7.8	8.4	8.6	8.8	9.1	9.4	9.7	9.9	10.3	10.4	10.6
Retail	2.1	2.2	2.0	1.6	1.5	1.3	1.2	1.2	1.3	1.0	1.0	1.0
Home Renovation Rebate	4.4	4.6	4.8	4.9	5.1	5.2	5.2	5.4	5.4	5.5	5.7	5.9
Energy Management Activities	4.9	5.0	5.2	5.3	5.4	5.6	5.4	5.4	5.3	5.2	5.1	5.2
Residential Sector Total	*18.3*	*19.5*	*20.4*	*20.5*	*20.9*	*21.3*	*21.2*	*21.7*	*21.9*	*22.1*	*22.3*	*22.7*
Commercial Sector												
Leaders in Energy Management - Commercial	9.1	9.2	8.8	8.7	8.6	8.1	8.4	8.5	8.3	8.5	8.8	8.8
New Construction	2.4	2.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Management Activities	6.1	6.1	6.2	6.3	6.5	6.6	6.7	6.7	6.7	6.9	7.0	7.1
Commercial Sector Total	*17.5*	*17.2*	*15.4*	*15.0*	*15.1*	*14.7*	*15.2*	*15.2*	*15.0*	*15.3*	*15.8*	*15.9*
Industrial Sector												
Leaders in Energy Management - Industrial	18.5	17.9	18.5	18.9	19.1	19.7	20.3	20.3	20.7	20.7	20.7	21.0
Thermo-Mechanical Pulp	27.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Management Activities	8.4	8.5	8.6	8.8	9.0	9.2	9.4	9.5	9.7	9.9	10.1	10.3
Industrial Sector Total	*54.1*	*26.3*	*27.2*	*27.7*	*28.1*	*28.9*	*29.7*	*29.9*	*30.4*	*30.6*	*30.8*	*31.3*
Total Programs	**89.9**	**63.1**	**62.9**	**63.2**	**64.1**	**64.9**	**66.0**	**66.8**	**67.2**	**68.0**	**68.8**	**70.0**
Supporting Initiatives												
Public Awareness	7.5	7.6	7.7	7.9	8.0	8.2	8.4	8.5	8.7	8.9	9.1	9.2
Indirect and Portfolio Enabling	7.4	7.5	7.9	8.0	8.0	8.1	8.5	9.0	8.8	9.2	9.3	9.4
Supporting Initiatives Total	**14.9**	**15.0**	**15.7**	**15.8**	**16.1**	**16.3**	**16.9**	**17.5**	**17.5**	**18.1**	**18.3**	**18.6**
Total Programs, Rates & Supporting Initiatives	**105.2**	**78.6**	**79.1**	**79.5**	**80.9**	**81.7**	**83.4**	**84.7**	**85.2**	**86.6**	**87.9**	**89.1**

Table 5. Total BC Hydro Costs ($ Million)

	F2033	F2034	F2035	F2036	F2037	F2038	F2039
Rate Structures							
Transmission Service Rate	0.5	0.5	0.5	0.5	0.8	0.5	0.5
Total Rate Structures	**0.5**	**0.5**	**0.5**	**0.5**	**0.8**	**0.5**	**0.5**
DSM Programs							
Residential Sector							
Low Income	10.0	9.9	10.1	10.4	10.5	10.7	10.9
Retail	1.0	1.0	1.2	1.0	1.0	1.1	1.1
Home Renovation Rebate	5.8	6.1	6.1	6.2	6.3	6.6	6.8
Energy Management Activities	5.0	5.1	5.1	5.2	5.2	5.0	4.8
Residential Sector Total	*21.8*	*22.0*	*22.5*	*22.8*	*23.0*	*23.3*	*23.6*
Commercial Sector							
Leaders in Energy Management - Commercial	9.2	9.3	9.3	9.5	9.8	9.9	9.7
New Construction	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Management Activities	7.3	7.3	7.5	7.6	7.8	7.9	7.9
Commercial Sector Total	*16.5*	*16.6*	*16.8*	*17.1*	*17.6*	*17.8*	*17.6*
Industrial Sector							
Leaders in Energy Management - Industrial	21.7	21.7	22.0	22.8	22.9	23.3	23.7
Thermo-Mechanical Pulp	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Management Activities	10.5	10.7	11.0	11.2	11.4	11.6	11.9
Industrial Sector Total	*32.2*	*32.4*	*33.0*	*34.0*	*34.3*	*35.0*	*35.6*
Total Programs	**70.5**	**71.0**	**72.3**	**73.9**	**74.9**	**76.2**	**76.8**
Supporting Initiatives							
Public Awareness	9.4	9.6	9.8	10.0	10.2	10.4	10.6
Indirect and Portfolio Enabling	10.3	10.3	10.4	10.9	10.9	11.1	11.6
Supporting Initiatives Total	**19.7**	**19.9**	**20.2**	**20.9**	**21.1**	**21.5**	**22.2**
Total Programs, Rates & Supporting Initiatives	**90.6**	**91.4**	**93.0**	**95.3**	**96.8**	**98.1**	**99.5**

66.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix D, Load Resource Balances, Table D-3, Demand Side Management and Other Measures.

Under "*Planned*" DSM Measures, the table shows "*F20+ Rates (F20-F21 RRA)*", which increases from 381 GWh of savings in F2021 to 1,615 GWh in F2039, and it also shows "*F20+ Programs (F20-F21 RRA)*", for which the savings are more or less constant from 128 GWh in F2021 to 135 GWh in F2039.

4.66.6 Please explain how the "Rates" items are expected to produce such significant savings and to last for such a long period.

RESPONSE:

The "Rates" savings are not as significant as shown in Table D-3. As noted in BC Hydro's response to AMPC IR 4.7.2, there is a labeling error in the referenced Table D-3 of Appendix D. Row 11 should be "F20+ Programs (F20-F21 RRA)" and Row 12 should be "F20+ Rates (F20-F21 RRA)".

The savings are expected to last over time due to the continuation of the higher marginal price signal of the rate structure.

66.0 Reference: Exhibit B-15, 20-Year Load Forecast, Appendix D, Load Resource Balances, Table D-3, Demand Side Management and Other Measures.

Under "*Planned*" DSM Measures, the table shows "*F20+ Rates (F20-F21 RRA)*", which increases from 381 GWh of savings in F2021 to 1,615 GWh in F2039, and it also shows "*F20+ Programs (F20-F21 RRA)*", for which the savings are more or less constant from 128 GWh in F2021 to 135 GWh in F2039.

4.66.7 Please explain how the "Program" savings can be expected to last for 20 years without declining to zero.

RESPONSE:

As noted in BC Hydro's response to AMPC IR 4.7.2, there is a labeling error in the referenced Table D-3 of Appendix D. Row 11 should be "F20+ Programs (F20-F21 RRA)" and Row 12 should be "F20+ Rates (F20-F21 RRA)".

The "F20+ Programs" savings assumes annual investments in DSM program activities throughout the duration of the planning period (from fiscal 2020 onwards), which produce new incremental savings each year that partially offset some of the erosion of savings due to persistence. In addition, as per the DSM assumptions shown on page 80 of Appendix X of the Application, some measures within certain programs have a longer persistence.

1.0 Reference: Exhibit B-15, page 4

Table 1 Changes in Methodology and Input Assumptions between the October 2018 Load Forecast and the June 2019 Load Forecast

Sector	Input	October 2018	June 2019
Residential & Commercial	Economic Forecast	Conference Board of Canada (**CBoC**) June 2018	Same
	Energy Information Administration Data	2018	Same
	Codes and Standards Overlap	Refer to section 12 of Appendix O of the Application	Refer to section 3.1.1 below
	Calibration Period	Fiscal 2009 to Fiscal 2018	Same
	Electric Vehicles (**EVs**)	Refer to section 9 of Appendix O of the Application	Refer to section 3.1.2 below[2]
Large Industrial	Account by Account Assessment	Comprehensive Assessment[3]	Specific Customer Updates[4]
Light Industrial	GDP Forecast	BC Ministry of Finance September 2018 Q1 Report for fiscal 2019 to fiscal 2023 CBoC June 2018 for fiscal 2024 to fiscal 2039	BC Ministry of Finance February 2019 Budget for fiscal 2019 to fiscal 2023 CBoC June 2018 for fiscal 2024 to fiscal 2039
	Account by Account Assessment	Comprehensive Assessment[3]	Specific Customer Updates[4]
Adjustments	Rate Impacts[5]	2013 10 Year Rates Plan	Comprehensive Review – Phase One
	DSM Savings	Fiscal 2020-Fiscal 2022 DSM Plan	Same

4.1.1 Please confirm that BC Hydro used the 2018 Conference Board of Canada forecast and not the 2019 forecast.

RESPONSE:

Confirmed. The June 2019 Load Forecast used the 2018 Conference Board of Canada Economic Forecast as a 2019 version is not yet available.

1.0 Reference: Exhibit B-15, page 4

Table 1 Changes in Methodology and Input Assumptions between the October 2018 Load Forecast and the June 2019 Load Forecast

Sector	Input	October 2018	June 2019
Residential & Commercial	Economic Forecast	Conference Board of Canada (**CBoC**) June 2018	Same
	Energy Information Administration Data	2018	Same
	Codes and Standards Overlap	Refer to section 12 of Appendix O of the Application	Refer to section 3.1.1 below
	Calibration Period	Fiscal 2009 to Fiscal 2018	Same
	Electric Vehicles (**EVs**)	Refer to section 9 of Appendix O of the Application	Refer to section 3.1.2 below[2]
Large Industrial	Account by Account Assessment	Comprehensive Assessment[3]	Specific Customer Updates[4]
Light Industrial	GDP Forecast	BC Ministry of Finance September 2018 Q1 Report for fiscal 2019 to fiscal 2023 CBoC June 2018 for fiscal 2024 to fiscal 2039	BC Ministry of Finance February 2019 Budget for fiscal 2019 to fiscal 2023 CBoC June 2018 for fiscal 2024 to fiscal 2039
	Account by Account Assessment	Comprehensive Assessment[3]	Specific Customer Updates[4]
Adjustments	Rate Impacts[5]	2013 10 Year Rates Plan	Comprehensive Review – Phase One
	DSM Savings	Fiscal 2020-Fiscal 2022 DSM Plan	Same

4.1.2 Please provide the most recent Conference Board of Canada Economic Forecast.

RESPONSE:

The most recent Conference Board of Canada Economic Forecast is the June 2018 forecast. It was provided as an attachment to BC Hydro's response to BCUC IR 1.6.1.

1.0 Reference: Exhibit B-15, page 4

Table 1 Changes in Methodology and Input Assumptions between the October 2018 Load Forecast and the June 2019 Load Forecast

Sector	Input	October 2018	June 2019
Residential & Commercial	Economic Forecast	Conference Board of Canada (**CBoC**) June 2018	Same
	Energy Information Administration Data	2018	Same
	Codes and Standards Overlap	Refer to section 12 of Appendix O of the Application	Refer to section 3.1.1 below
	Calibration Period	Fiscal 2009 to Fiscal 2018	Same
	Electric Vehicles (**EVs**)	Refer to section 9 of Appendix O of the Application	Refer to section 3.1.2 below[2]
Large Industrial	Account by Account Assessment	Comprehensive Assessment[3]	Specific Customer Updates[4]
Light Industrial	GDP Forecast	BC Ministry of Finance September 2018 Q1 Report for fiscal 2019 to fiscal 2023 CBoC June 2018 for fiscal 2024 to fiscal 2039	BC Ministry of Finance February 2019 Budget for fiscal 2019 to fiscal 2023 CBoC June 2018 for fiscal 2024 to fiscal 2039
	Account by Account Assessment	Comprehensive Assessment[3]	Specific Customer Updates[4]
Adjustments	Rate Impacts[5]	2013 10 Year Rates Plan	Comprehensive Review – Phase One
	DSM Savings	Fiscal 2020-Fiscal 2022 DSM Plan	Same

4.1.3 Please provide a rough description of how the most recently updated Conference Board of Canada Forecast would likely affect the load forecast and provide any quantification available.

RESPONSE:

As stated in BC Hydro's response to CEC IR 4.1.1, the most recent Conference Board of Canada forecast (June 2018) was used in preparation of the June 2019 Load Forecast. The 2019 version of the Conference Board of Canada Economic Forecast has not yet been completed. However, when completed, it will be used for the next comprehensive Load Forecast update. As this is only one input into the load forecasting process, it is not possible to speculate on any changes to the forecast at this time.

2.0 Reference: Exhibit B-15 page 7 and 8

3.1.2 Electric Vehicles

The June 2019 Load Forecast uses a new methodology for EVs, to align with the CleanBC Plan for light duty electric vehicles. Specifically, the *Zero-Emission Vehicles Act* (**ZEV Act**) was enacted on May 30, 2019. The ZEV Act stipulates the percentage of new light duty car and truck sales in B.C. that must be zero emission vehicles, as follows: 10 per cent of sales by 2025; 30 per cent of sales by 2030; and 100 per cent of sales by 2040.

Accordingly, the low EV forecast in the June 2019 Load Forecast is based on these requirements and the associated incentives because, at a minimum, EV sales would be expected to reach the levels required by legislation. The high-EV scenario

assumes EV models are more available, the purchase cost declines, consumers' preferences change, and more infrastructure becomes available. In other words, the high EV forecast assumes that the natural uptake of EVs is greater than the requirements set out in the ZEV Act, resulting in a higher total EV forecast. Due to the significant level of uncertainty when developing a long-term EV forecast, BC Hydro developed its mid-EV forecast by taking the average between the high and low EV forecasts.

[1]

4.2.2 Please provide evidence as to the current proportion of zero emission light duty vehicles sold in BC.

RESPONSE:

Statistics Canada has reported that in calendar 2018 there were 225,539 new vehicles sold in B.C. and the 2018 electric Mobility Canada (EMC) report states that there were 8,449 new Electric Vehicle (EV) sold in B.C. Therefore, B.C.'s market share for new EV sales in 2018 was 3.7 per cent.

[1] Exhibit B-15, page 8

2.0 Reference: Exhibit B-15 page 7 and 8

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4.2.3 Please provide evidence as to the current rate of growth of EVs in BC.

RESPONSE:

Table 9-2 of Appendix O of the Application provides the historical number of EVs from fiscal 2013 to fiscal 2018. The annual growth rates for those years are provided in the table below.

	Historical Total EV Stock	**Total EV Stock Annual Growth Rate (%)**
F2013	**567**	
F2014	**1,157**	**104**
F2015	**2,122**	**83**
F2016	**3,869**	**82**
F2017	**6,230**	**61**
F2018	**10,803**	**73**

2.0 Reference: Exhibit B-15 page 7 and 8

3.1.2 Electric Vehicles

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4.2.4 Does the ZEV Act allow for hybrid vehicles?

RESPONSE:

Plug-in electric hybrid vehicles appear to qualify while non-plug-in hybrid electric vehicles do not qualify.

The *Zero-Emission Vehicle Act* includes the following definition of a "zero-emission vehicle" or "ZEV":

(a) a motor vehicle that

(i) is propelled by electricity or hydrogen from an external source, and

(ii) emits no greenhouse gases at least some of the time while the motor vehicle is being operated;

(b) a prescribed type of motor vehicle.

For further information on the *Zero-Emission Vehicle Act*, please refer to: http://www.bclaws.ca/civix/document/id/bills/billscurrent/4th41st:gov28-1.

Plug In BC's website clarifies: "The ZEV category includes fully electric, plug-in electric hybrids, and fuel cell vehicles….". For further information, please refer to: https://pluginbc.ca/bc-zev-mandate-electric-vehicle-buyers/.

2.0 Reference: Exhibit B-15 page 7 and 8

3.1.2 Electric Vehicles

The June 2019 Load Forecast uses a new methodology for EVs, to align with the CleanBC Plan for light duty electric vehicles. Specifically, the *Zero-Emission Vehicles Act* (**ZEV Act**) was enacted on May 30, 2019. The ZEV Act stipulates the percentage of new light duty car and truck sales in B.C. that must be zero emission vehicles, as follows: 10 per cent of sales by 2025; 30 per cent of sales by 2030; and 100 per cent of sales by 2040.

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[1]

4.2.4 Does the ZEV Act allow for hybrid vehicles?

4.2.4.1 If yes, how has BC Hydro accounted for the difference between hybrid vehicles and all electric vehicles in its modelling?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.2.4, where we describe the type of vehicles that appear to qualify as Zero-Emission Vehicles (ZEV) under the *ZEV Act*. As described in section 9.2 of Appendix O of the Application, BC Hydro's EV

[1] Exhibit B-15, page 8

model combines battery electric vehicles and plug-in hybrid vehicles rather than having a separate model and a separate forecast for each type of vehicle.

2.0 Reference: Exhibit B-15 page 7 and 8

3.1.2 Electric Vehicles

The June 2019 Load Forecast uses a new methodology for EVs, to align with the CleanBC Plan for light duty electric vehicles. Specifically, the *Zero-Emission Vehicles Act* (**ZEV Act**) was enacted on May 30, 2019. The ZEV Act stipulates the percentage of new light duty car and truck sales in B.C. that must be zero emission vehicles, as follows: 10 per cent of sales by 2025; 30 per cent of sales by 2030; and 100 per cent of sales by 2040.

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4.2.7 Please provide the range of difference between the low and high EV forecast.

RESPONSE:

The June 2019 Electric Vehicle (EV) low, mid and high energy forecast for the test period is shown below.

	Low Total Load Forecast (GWh)	Mid Total Load Forecast (GWh)	High Total Load forecast (GWh)
F2020	**77**	**77**	**77**
F2021	**219**	**226**	**234**

2.0 Reference: Exhibit B-15 page 7 and 8

3.1.2 Electric Vehicles

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4.2.11 Does BC Hydro expect to monitor the uptake of electric vehicles in order to reduce uncertainty in future forecasts?

RESPONSE:

Yes, BC Hydro will continue to monitor the uptake of Electric Vehicles (EVs) in order to develop its EV energy and peak forecasts. BC Hydro receives Battery Electric Vehicles (BHEV) and Plug-in Electric Vehicles (PHEV) registration data from ICBC on a quarterly basis for this purpose.

2.0 Reference: Exhibit B-15 page 7 and 8

3.1.2 Electric Vehicles

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4.2.11 Does BC Hydro expect to monitor the uptake of electric vehicles in order to reduce uncertainty in future forecasts?

4.2.11.1 If yes, please explain how BC Hydro will assess the status of EV uptake

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.2.11.

3.0 Reference: Exhibit B-15, Appendix B, page 1 and 5

1.1. Peak Demand is the Maximum Expected Amount of Electricity Consumed in a Single Hour

BC Hydro's peak demand is defined as the maximum expected amount of electricity consumed in a single hour under an average cold temperature assumption.

BC Hydro is a winter peaking utility, as our demand is more sensitive to colder temperatures than warmer temperatures. The total BC Hydro system typically reaches its annual peak on a cold winter day between 5:00 p.m. and 6:00 p.m. while Vancouver Island has a morning and an evening peak, as residential space heating is a larger component of Vancouver Island load. The Integrated System peak demand is the peak demand of all BC Hydro's customers as well as the peak demands from the other utilities served by BC Hydro and system transmission losses. [1]

1.3.2. Transmission Peak Methodology

The second largest component of the Peak Demand is the coincident transmission peak demand. The transmission peak demand is the total coincident peak demand of all large industrial customers connected at transmission voltage. The drivers of the Large Industrial sector energy forecast generally also apply to the development of peak forecasts. [2]

4.3.1 Please provide the proportion of industrial demand as a component of Peak Demand.

RESPONSE:

BC Hydro estimates that the industrial demand represents approximately 25 per cent of the total integrated coincident system peak demand for the Test Period.

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[1] Exhibit B-15, Appendix B page 1

[2] Exhibit B-15, Appendix B page 5

The total integrated coincident system peak demand is defined as the sum of coincident distribution and transmission customers demand, losses and exports to other utilities at the time of the system peak.

The 25 per cent is an estimate, based on the proportion of light industrial customers of the general service sales and the proportion of large industrial customers of the transmission sector.

3.0 Reference: Exhibit B-15, Appendix B, page 1 and 5

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1.3.2. Transmission Peak Methodology

The second largest component of the Peak Demand is the coincident transmission peak demand. The transmission peak demand is the total coincident peak demand of all large industrial customers connected at transmission voltage. The drivers of the Large Industrial sector energy forecast generally also apply to the development of peak forecasts. [2]

4.3.2 At what time of day does the large industrial sector peak typically occur? How does this impact BC Hydro's overall Peak Demand time?

RESPONSE:

The large industrial sector does not have a typical daily peak. The system daily peak demand time is largely driven by the residential and commercial sectors.

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[1] Exhibit B-15, Appendix B page 1

[2] Exhibit B-15, Appendix B page 5

3.0 Reference: Exhibit B-15, Appendix B, page 1 and 5

1.1. Peak Demand is the Maximum Expected Amount of Electricity Consumed in a Single Hour

BC Hydro's peak demand is defined as the maximum expected amount of electricity consumed in a single hour under an average cold temperature assumption.

BC Hydro is a winter peaking utility, as our demand is more sensitive to colder temperatures than warmer temperatures. The total BC Hydro system typically reaches its annual peak on a cold winter day between 5:00 p.m. and 6:00 p.m. while Vancouver Island has a morning and an evening peak, as residential space heating is a larger component of Vancouver Island load. The Integrated System peak demand is the peak demand of all BC Hydro's customers as well as the peak demands from the other utilities served by BC Hydro and system transmission losses. [1]

1.3.2. Transmission Peak Methodology

The second largest component of the Peak Demand is the coincident transmission peak demand. The transmission peak demand is the total coincident peak demand of all large industrial customers connected at transmission voltage. The drivers of the Large Industrial sector energy forecast generally also apply to the development of peak forecasts. [2]

4.3.3 Does the large industrial sector have a seasonal peak? Please provide and explain how this impacts BC Hydro's peaking profile.

RESPONSE:

No, the total large industrial sector does not follow a seasonal peak pattern and, as a result, it does not impact BC Hydro's annual peaking profile.

[1] Exhibit B-15, Appendix B page 1

[2] Exhibit B-15, Appendix B page 5

4.0 Reference: Exhibit B-15, Appendix B page 2

1.2. Peak Load Forecast Informs BC Hydro's Capital Planning

The peak demand forecast informs BC Hydro's capital planning cycles. As an updated peak demand forecast was not available when the fiscal 2020 to fiscal 2024 Capital Plan was being finalized and actual substation load (MVA) growth was moderating, BC Hydro reduced the overall growth related substation and distribution capital expenditures in the Fiscal 2020 to Fiscal 2024 Capital Plan, which formed the basis for the capital expenditures in the Test Period.

BC Hydro's response to BCUC IR 1.108.1.2 provided a list of projects that were deferred or cancelled as a result of the expected change in the load forecast. As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support

system expansions and reinforcements required to reliably serve new and existing customers and are not solely driven by changes in the load forecast.

4.4.1 Please provide the other drivers for system expansions.

RESPONSE:

This answer also responds to CEC IR 4.4.2.

In BC Hydro's response to BCUC IR 1.111.1 we explained and further described that, in addition to changes in the load forecast, the following categories are considered primary drivers of growth investment which may take the form of system expansions and reinforcements:

- **Growth - Customer Connections;**
- **Growth - System Expansion Driven by Other Risks; and**
- **Growth - Transfer Capacity.**

To clarify, in developing alternatives and investment solutions, BC Hydro considers the need for system expansions and reinforcements of the existing system. System expansion and reinforcements of the system are not necessarily independent; a single investment may enable service to be provided to new

customers as well as reinforce the existing system (e.g., reducing risk) which benefits existing customers. As such, system expansions and reinforcements are looked at in combination when considering categories of growth investments. As a result, BC Hydro does not track growth expenditures in categories of system expansion and reinforcement.

While an investment may be categorized by one of the above listed drivers, the majority of investments also have secondary drivers. For example, an investment undertaken for customer connection may also partially address load growth requirements.

4.0 Reference: Exhibit B-15, Appendix B page 2

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system expansions and reinforcements required to reliably serve new and existing customers and are not solely driven by changes in the load forecast.

4.4.1.1 Please provide the proportion of expenditures that are established from each of the drivers for system expansions.

RESPONSE:

This answer also responds to CEC IR 4.4.2.1

As explained in BC Hydro's response to CEC IR 4.4.1, BC Hydro does not separate growth expenditures into categories of system expansions and reinforcements. Accordingly, the table below provides the combined proportion of expenditures for system expansions and reinforcements.

Proportion of BC Hydro Growth Capital Expenditures

Primary Driver	F2020 (%)	F2021 (%)
Growth - Customer Connection	59	57
Growth - Load Forecast	29	24
Growth - System Expansion Driven by Other Risks	5	9
Growth - Transfer Capacity	7	10
	100	100

***Proportions are reflective of Gross Capital Expenditures before Customer Contributions**

4.0 Reference: Exhibit B-15, Appendix B page 2

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system expansions and reinforcements required to reliably serve new and existing customers and are not solely driven by changes in the load forecast.

4.4.1.1 Please provide the proportion of expenditures that are established from each of the drivers for system expansions.

4.4.1.1.1 Are these proportions consistent from year to year? Please explain.

RESPONSE:

While relatively consistent for the Test Period, the proportions across the primary driver categories identified in BC Hydro's response to CEC IR 4.4.1 may vary significantly from year to year depending on the investments in the portfolio and their associated expenditures. For example, investing in a new transmission line to increase transfer capacity would significantly change the proportion in this category.

4.0 Reference: Exhibit B-15, Appendix B page 2

1.2. Peak Load Forecast Informs BC Hydro's Capital Planning

The peak demand forecast informs BC Hydro's capital planning cycles. As an updated peak demand forecast was not available when the fiscal 2020 to fiscal 2024 Capital Plan was being finalized and actual substation load (MVA) growth was moderating, BC Hydro reduced the overall growth related substation and distribution capital expenditures in the Fiscal 2020 to Fiscal 2024 Capital Plan, which formed the basis for the capital expenditures in the Test Period.

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system expansions and reinforcements required to reliably serve new and existing customers and are not solely driven by changes in the load forecast.

4.4.2 Please provide the other drivers for system reinforcements.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.4.1 where we provide the drivers and explain that system expansions and reinforcements are investment solutions to address growth requirements and as such must be looked at in combination when considering drivers of growth investment.

4.0 Reference: Exhibit B-15, Appendix B page 2

1.2. Peak Load Forecast Informs BC Hydro's Capital Planning

The peak demand forecast informs BC Hydro's capital planning cycles. As an updated peak demand forecast was not available when the fiscal 2020 to fiscal 2024 Capital Plan was being finalized and actual substation load (MVA) growth was moderating, BC Hydro reduced the overall growth related substation and distribution capital expenditures in the Fiscal 2020 to Fiscal 2024 Capital Plan, which formed the basis for the capital expenditures in the Test Period.

BC Hydro's response to BCUC IR 1.108.1.2 provided a list of projects that were deferred or cancelled as a result of the expected change in the load forecast. As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support

system expansions and reinforcements required to reliably serve new and existing customers and are not solely driven by changes in the load forecast.

4.4.2.1 Please provide the proportion of expenditures that are established from each of the drivers for system reinforcements.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.4.1.1 where we provide the combined proportion of expenditures for system expansions and reinforcements and explain that system expansions and reinforcements are investment solutions to address growth requirements and as such must be looked at in combination when considering drivers of growth investment.

6.0 Reference: Exhibit B-15, Appendix B page C page 3 and

The distribution peak process starts with the historical substation data collection and analysis. Temperature adjusted peak demands are estimated for each substation. In addition, a mid forecast of peak demand from Electric Vehicles (**EVs**) is developed using the number of EVs, consistent with the mid energy forecast.

1.3.1. EV Peak Methodology

The EV peak model is a simulation model that has several inputs including the total annual number of EVs, daily distance travelled, EV efficiency, power of the charging equipment in kW and a charging time profile. These inputs are used in the simulation

4.6.1 Do BC Hydro's adjustments and models for a) peak demand and b) energy demand from EVs account for potential variation in EV uptake in various geographic regions (i.e. If EVs are more prevalent in urban centres than in rural areas)? Please explain if this is done and provide a brief description of the parameters that are included in the modelling.

RESPONSE:

BC Hydro develops its Electric Vehicle (EV) energy and peak forecasts on a total system basis, and not on a regional basis.

7.0 Reference: Exhibit B-1, Appendix B page 4

A mid guideline forecast is developed using deterministic and econometric methods with various inputs, including:

- Historical temperature normalized substation peak demands;
- Rate impacts;
- Residential account forecasts; and
- Distribution energy forecasts from BC Hydro's end use model projections.

Other adjustments are made using peak load projections for emerging sectors, including EVs, cannabis and cryptocurrency.

4.7.1 Please explain the types of adjustments made for cannabis as an emerging sector.

RESPONSE:

A number of cryptocurrency and licensed cannabis spot loads in advanced stages of interconnection to the BC Hydro system were added to the mid-distribution guideline forecast. The cryptocurrency and licensed cannabis spot loads are defined as incremental additions to the existing base load, and are not captured in the economic forecast produced by the Conference Board of Canada.

7.0 Reference: Exhibit B-1, Appendix B page 4

A mid guideline forecast is developed using deterministic and econometric methods with various inputs, including:

- Historical temperature normalized substation peak demands;
- Rate impacts;
- Residential account forecasts; and
- Distribution energy forecasts from BC Hydro's end use model projections.

Other adjustments are made using peak load projections for emerging sectors, including EVs, cannabis and cryptocurrency.

4.7.2 Please explain the types of adjustments made for cryptocurrency as an emerging sector.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.7.1.

9.0 Reference: Exhibit B-19, pages 12, 13 and 14

- Second, storm restoration costs were higher than planned in fiscal 2019 due to more severe storms, including the December 2019 storm. These costs were deferred to the Storm Restoration Costs Regulatory Account and are amortized over the test period, which increases the required recovery in fiscal 2020 and fiscal 2021.

Figure 6 Operating Costs - Fiscal 2020 Plan vs. Fiscal 2020 Update – Current View ($ millions)

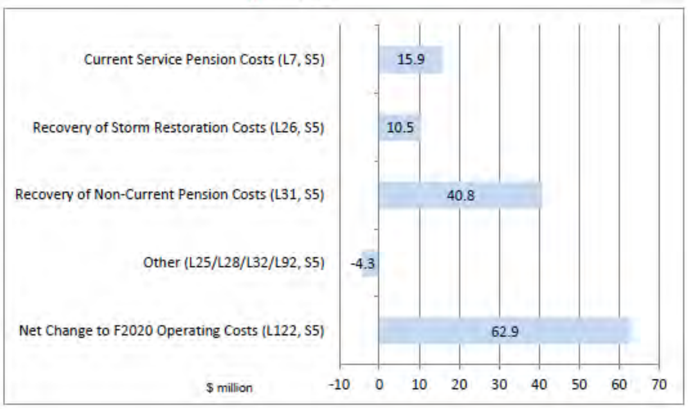
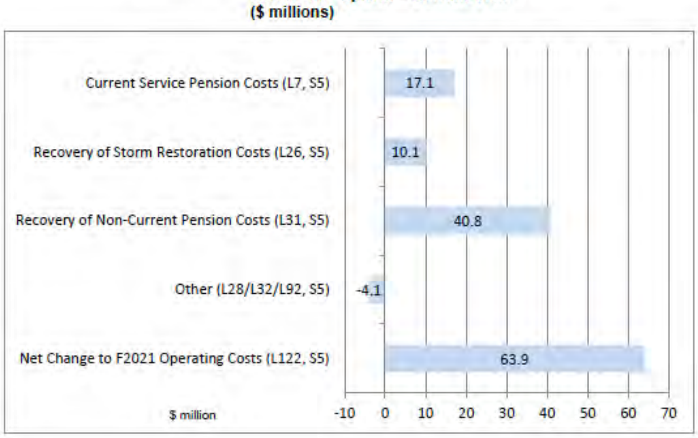


Figure 7 Operating Costs - Fiscal 2021 Plan vs. Fiscal 2021 Update – Current View ($ millions)



4.9.1 Does BC Hydro adjust its storm restoration forecasts based on recent years' costs, or are these normally averaged over a long period of time. Please explain.

RESPONSE:

This answer also responds to CEC IRs 4.9.2 and 4.9.2.1.

As discussed in BC Hydro's response to BCUC IR 2.232.4, in accordance with BCUC Order No. G-16-09 to the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, BC Hydro forecasts storm restoration costs using a five-year average of actual storm restoration costs for the five most recent normal weather years. Variances between actual and forecast storm restoration costs are deferred to the Storm Restoration Costs Regulatory Account.

In the Application, BC Hydro included the last five years of actual storm restoration costs from fiscal 2014 to fiscal 2018 in the calculation of the five-year average for the Test Period as shown in Table 7-6 of Chapter 7 of the Application.

In the Evidentiary Update, regulatory account amortization was updated to reflect fiscal 2019 actual results. This included the recovery of actual amounts deferred to the Storm Restoration Costs Regulatory Account in fiscal 2019, resulting in the increase in the recovery of the balance in the Storm Restoration Costs Regulatory Account of $10.5 million and $10.1 million in fiscal 2020 and fiscal 2021, respectively, as shown in the preamble to the question. As discussed in BC Hydro's response to BCUC IR 3.313.2, BC Hydro did not update its operating cost forecast of storm restoration costs for the Test Period based on a five-year average of the actual results from fiscal 2015 to fiscal 2019.

9.0 Reference: Exhibit B-19, pages 12, 13 and 14

- Second, storm restoration costs were higher than planned in fiscal 2019 due to more severe storms, including the December 2019 storm. These costs were deferred to the Storm Restoration Costs Regulatory Account and are amortized over the test period, which increases the required recovery in fiscal 2020 and fiscal 2021.

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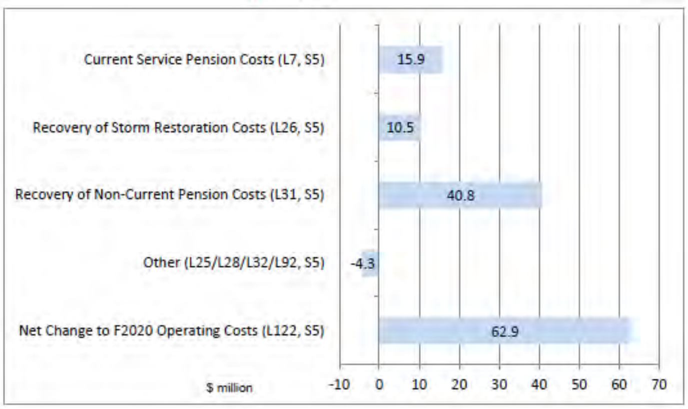
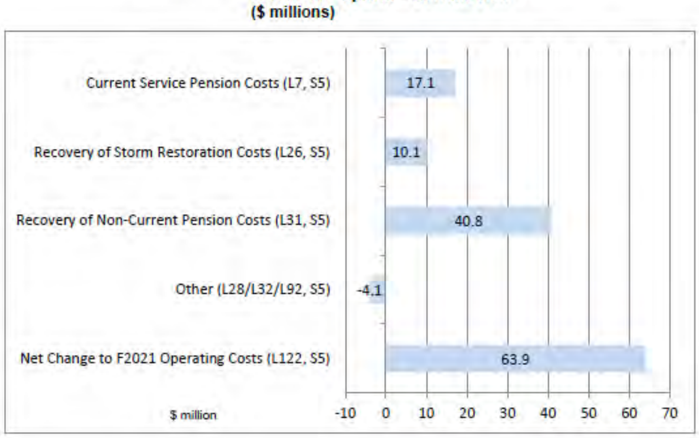


Figure 7 Operating Costs - Fiscal 2021 Plan vs. Fiscal 2021 Update – Current View ($ millions)



4.9.2 The increase in O&M for recovery of storm restoration costs appears to reflect costs from storms of fiscal 2019. If storm restoration costs are expected to continue to increase in the future due to changes in weather patterns, are these changes also included in increased operating costs? Please explain.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.9.1.

9.0 Reference: Exhibit B-19, pages 12, 13 and 14

- Second, storm restoration costs were higher than planned in fiscal 2019 due to more severe storms, including the December 2019 storm. These costs were deferred to the Storm Restoration Costs Regulatory Account and are amortized over the test period, which increases the required recovery in fiscal 2020 and fiscal 2021.

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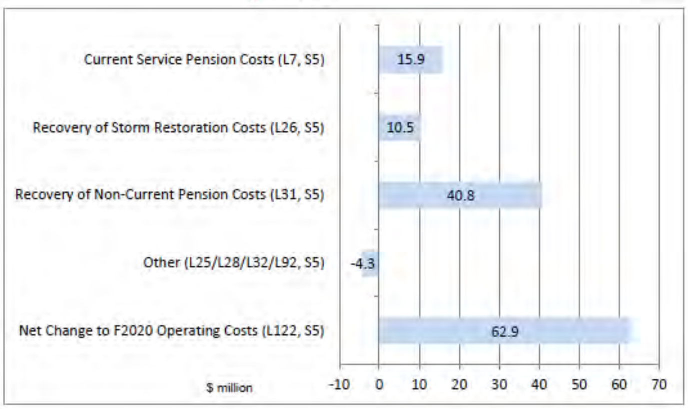
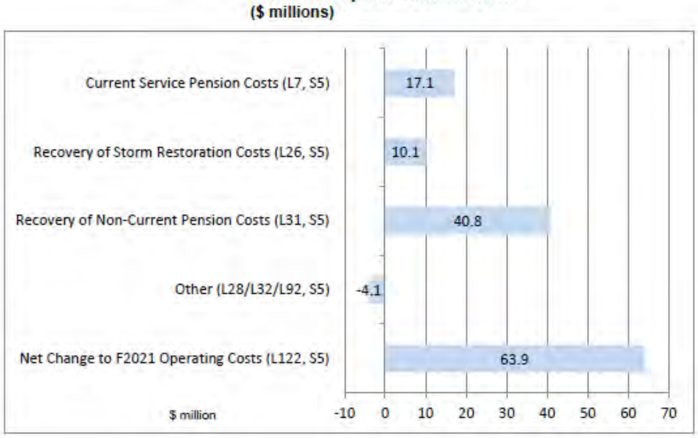


Figure 7 Operating Costs - Fiscal 2021 Plan vs. Fiscal 2021 Update – Current View ($ millions)



4.9.2 The increase in O&M for recovery of storm restoration costs appears to reflect costs from storms of fiscal 2019. If storm restoration costs are expected to continue to increase in the future due to changes in weather patterns, are these changes also included in increased operating costs? Please explain.

4.9.2.1 If yes, please provide quantification.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.9.1.

10.0 Reference: Exhibit B-19, Appendix C, pages 1 and 2 and page

One of the drivers of the change in BC Hydro's Cost of Energy forecast is 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. These dry conditions impact hydro facilities owned by Independent Power Producers (**IPPs**), as well as facilities owned by BC Hydro. This results in

and surplus sales forecast to decrease. The forecast increase in cost of Market Energy is mitigated by a decrease in costs for IPPs and Long-Term commitments and Water Rentals. Further information is provided in the sections below.

[1]

Total costs for Non-Treaty Storage and Libby Coordination Agreements are forecast to be $11.7 million higher in fiscal 2020 and $9.3 million lower in fiscal 2021, compared to the Application. Higher water releases occurred during the winter of fiscal 2019 which drew down BC Hydro's storage accounts under these agreements. As a result, BC Hydro needs to store water back into the accounts during fiscal 2020, which increases forecast costs. Higher water releases and lower costs are expected to occur in fiscal 2021.

[2]

4.10.1 Does BC Hydro consider the issue of potential climate change when assessing the expected reservoir levels and water releases? Please explain.

RESPONSE:

BC Hydro accounts for historic weather variability in its forecasts of expected reservoir levels and water releases resulting from the monthly Energy Study process.

Please refer to BC Hydro's response to CEC IR 1.17.1, where we explain that every year we add the most recent year of historic data to the modeled weather

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[1] Exhibit B-19, Appendix C, page 1 and 2

[2] Exhibit B-19, Appendix C, page 2

sequences, which allows BC Hydro to implicitly include impacts of climate change in the forecast. Furthermore, the variability in the historic record is an order of magnitude larger than the impact of climate change on the average forecast for the test period. In other words, changes to the expected (average) system operation due to climate change are small relative to changes to system operation due to weather for the Test Period.

10.0 Reference: Exhibit B-19, Appendix C, pages 1 and 2 and page

> One of the drivers of the change in BC Hydro's Cost of Energy forecast is 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. These dry conditions impact hydro facilities owned by Independent Power Producers (**IPPs**), as well as facilities owned by BC Hydro. This results in
>
> and surplus sales forecast to decrease. The forecast increase in cost of Market Energy is mitigated by a decrease in costs for IPPs and Long-Term commitments and Water Rentals. Further information is provided in the sections below.[1]
>
> Total costs for Non-Treaty Storage and Libby Coordination Agreements are forecast to be $11.7 million higher in fiscal 2020 and $9.3 million lower in fiscal 2021, compared to the Application. Higher water releases occurred during the winter of fiscal 2019 which drew down BC Hydro's storage accounts under these agreements. As a result, BC Hydro needs to store water back into the accounts during fiscal 2020, which increases forecast costs. Higher water releases and lower costs are expected to occur in fiscal 2021.[2]

4.10.2 Does the drawdown of BC Hydro's storage accounts represent a loss of capacity on BC Hydro's system? Please explain.

RESPONSE:

This answer also responds to CEC IR 4.10.2.1.

A drawdown of BC Hydro's storage accounts can be expected to primarily affect the elevation of Arrow Lakes Reservoir, and consequently may reduce maximum generation capability at the Arrow Lakes Hydro (ALH) generating station. The elevation at Arrow Lakes Reservoir is primarily affected by the Columbia River Treaty. The Non-Treaty and Libby Coordination agreements have only a secondary impact on both the elevation of Arrow Lakes Reservoir and the capacity of ALH (maximum capacity 185 MW).

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[1] Exhibit B-19, Appendix C, page 1 and 2

[2] Exhibit B-19, Appendix C, page 2

10.0 Reference: Exhibit B-19, Appendix C, pages 1 and 2 and page

One of the drivers of the change in BC Hydro's Cost of Energy forecast is 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. These dry conditions impact hydro facilities owned by Independent Power Producers (**IPPs**), as well as facilities owned by BC Hydro. This results in

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4.10.2 Does the drawdown of BC Hydro's storage accounts represent a loss of capacity on BC Hydro's system? Please explain.

4.10.2.1 If yes, how does this affect BC Hydro's ability to meet system demand?

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.10.2.

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1 Exhibit B-19, Appendix C, page 1 and 2

2 Exhibit B-19, Appendix C, page 2

10.0 Reference: Exhibit B-19, Appendix C, pages 1 and 2 and page

> One of the drivers of the change in BC Hydro's Cost of Energy forecast is 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. These dry conditions impact hydro facilities owned by Independent Power Producers (**IPPs**), as well as facilities owned by BC Hydro. This results in

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4.10.3 Is BC Hydro compensated for the higher water releases? If so, please provide details of the compensation. If not, please explain.

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.45.4 where we explain that when BC Hydro drafts from its Non-Treaty account, Bonneville Power Administration credits BC Hydro for the incremental energy valued at the Mid-C market price at the time of release.

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[1] Exhibit B-19, Appendix C, page 1 and 2

[2] Exhibit B-19, Appendix C, page 2

11.0 Reference: Exhibit B-19, Appendix C page 2

1.1 Cost of Heritage Energy

Cost of Heritage Energy is forecast to increase by $0.3 million in fiscal 2020 and decrease by $33.1 million in fiscal 2021, compared to the Application. This is largely driven by lower water rentals during the test period, and lower Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2021, partially offset by higher Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2020.

Water rental fees are calculated based on generation volumes from the prior calendar year multiplied by the current year water rental rates. Total water rentals are forecast to be $329.3 million in fiscal 2020 and $323.2 million in fiscal 2021, a decrease of $13.8 million in fiscal 2020 and $25.9 million in fiscal 2021 compared to the Application. This difference is primarily due to lower hydro generation output in fiscal 2019 and fiscal 2020 than forecast in the Application. Actual hydro generation output in fiscal 2019 was 4,027 GWh lower than the fiscal 2019 Plan, and hydro generation output in fiscal 2020 is expected to decrease by 4,894 GWh compared to the fiscal 2020 Plan in the Application. This is mainly driven by lower inflows constraining hydro generation during the winter of fiscal 2019 and fiscal 2020.

4.11.1 Please provide all the factors that contribute to generation volumes.

RESPONSE:

Actual and forecast generation volumes are driven by a number of factors which are discussed in greater detail in Chapter 4, section 4.4.2.1 of the Application. These factors include:

- **Load;**
- **IPP supply;**
- **Water inflow conditions;**
- **Electricity and gas market prices; and**
- **Generation unit availability.**

Other factors which also contribute to generation volumes at BC Hydro's heritage assets include:

- **Water licence and Water Use Plan Order requirements;**
- **Transmission system conditions; and**
- **Columbia River Treaty commitments.**

11.0 Reference: Exhibit B-19, Appendix C page 2

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4.11.2 BC Hydro states 'Water rental fees are calculated based on generation volumes from the prior calendar year multiplied by the current year water rates'. If generation volumes in a given calendar year are unusually high or low, these circumstances would appear to be perpetuated in the forecast for the following year. Please discuss and the impact of the calculations on costs.

RESPONSE:

Due to the way water rentals are billed, there is a shifting of the costs so they do not occur in the same year as the generation. Fiscal 2020 water rental costs in the Test Period are mostly based on generation outside of the Test Period, and the generation in fiscal 2021 will determine most of the costs in fiscal 2022, which is also outside of the Test Period. This can lead to variances in the unit cost of water rentals as explained in BC Hydro's response to AMPC IR 4.1.4. This billing methodology does not affect our forecast of generation in the Energy Studies.

11.0 Reference: Exhibit B-19, Appendix C page 2

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4.11.2.1 How does BC Hydro compensate for outlier years in their forecast for the next year, if at all?

RESPONSE:

The generation forecast is based on the average of 46 weather years that includes outlier years, and each weather year is considered equally likely. As a result outlier years are included in the generation forecast that forecasts the water rental fees.

Please refer to BC Hydro's response to BCUC IR 1.31.1 for an explanation of how inflows are used in the Energy Study.

11.0 Reference: Exhibit B-19, Appendix C page 2

1.1 Cost of Heritage Energy

Cost of Heritage Energy is forecast to increase by $0.3 million in fiscal 2020 and decrease by $33.1 million in fiscal 2021, compared to the Application. This is largely driven by lower water rentals during the test period, and lower Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2021, partially offset by higher Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2020.

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4.11.3 Please confirm that fiscal 2019 represents an actual figure.

RESPONSE:

Confirmed. The reference to fiscal 2019 in the preamble to the question of 4,027 GWh is the difference between Heritage Energy Water Rentals actuals for fiscal 2019 and the fiscal 2019 RRA Plan (46,368 for fiscal 2019 RRA Plan minus 42,341 for fiscal 2019 actuals).

11.0 Reference: Exhibit B-19, Appendix C page 2

1.1 Cost of Heritage Energy

Cost of Heritage Energy is forecast to increase by $0.3 million in fiscal 2020 and decrease by $33.1 million in fiscal 2021, compared to the Application. This is largely driven by lower water rentals during the test period, and lower Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2021, partially offset by higher Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2020.

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4.11.4 Please confirm that fiscal 2020 will end in March 2020.

RESPONSE:

Confirmed. BC Hydro’s 2020 fiscal year ends March 31, 2020.

11.0 Reference: Exhibit B-19, Appendix C page 2

1.1 Cost of Heritage Energy

Cost of Heritage Energy is forecast to increase by $0.3 million in fiscal 2020 and decrease by $33.1 million in fiscal 2021, compared to the Application. This is largely driven by lower water rentals during the test period, and lower Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2021, partially offset by higher Non-Treaty Storage and Libby Coordination Agreement costs in fiscal 2020.

Water rental fees are calculated based on generation volumes from the prior calendar year multiplied by the current year water rental rates. Total water rentals are forecast to be $329.3 million in fiscal 2020 and $323.2 million in fiscal 2021, a decrease of $13.8 million in fiscal 2020 and $25.9 million in fiscal 2021 compared to the Application. This difference is primarily due to lower hydro generation output in fiscal 2019 and fiscal 2020 than forecast in the Application. Actual hydro generation output in fiscal 2019 was 4,027 GWh lower than the fiscal 2019 Plan, and hydro generation output in fiscal 2020 is expected to decrease by 4,894 GWh compared to the fiscal 2020 Plan in the Application. This is mainly driven by lower inflows constraining hydro generation during the winter of fiscal 2019 and fiscal 2020.

4.11.5 Does BC Hydro have evidence that the low inflows are expected to continue? Please explain.

RESPONSE:

BC Hydro has no evidence to suggest that low inflows are expected to continue into fiscal 2021.

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12.0 Reference: Exhibit B-19, Appendix C page 2

> Total costs for Non-Treaty Storage and Libby Coordination Agreements are forecast to be $11.7 million higher in fiscal 2020 and $9.3 million lower in fiscal 2021, compared to the Application. Higher water releases occurred during the winter of fiscal 2019 which drew down BC Hydro's storage accounts under these agreements. As a result, BC Hydro needs to store water back into the accounts during fiscal 2020, which increases forecast costs. Higher water releases and lower costs are expected to occur in fiscal 2021.

4.12.1 Please provide details as to how storing water back into the storage accounts increases forecast costs.

RESPONSE:

Please refer to BC Hydro's response to CEABC IR 2.45.4 where we explain that when BC Hydro stores water into the Non-Treaty account, BC Hydro credits Bonneville Power Administration for the foregone energy valued at the Mid-C market price at the time of release.

12.0 Reference: Exhibit B-19, Appendix C page 2

> Total costs for Non-Treaty Storage and Libby Coordination Agreements are forecast to be $11.7 million higher in fiscal 2020 and $9.3 million lower in fiscal 2021, compared to the Application. Higher water releases occurred during the winter of fiscal 2019 which drew down BC Hydro's storage accounts under these agreements. As a result, BC Hydro needs to store water back into the accounts during fiscal 2020, which increases forecast costs. Higher water releases and lower costs are expected to occur in fiscal 2021.

4.12.2 Do the higher water releases and lower costs reflect a return to average conditions? Please explain.

RESPONSE:

BC Hydro assumes the term "average conditions" refers to inflows. The water releases and storage of water under the Non-Treaty and Libby Coordination Agreements are not directly impacted by inflows.

The storages and releases under the Non-Treaty Storage and the Libby Coordination Agreements are unique each year, due to the varying market price and dynamic constraints on the related storages and releases. Hence we are unable to define an "average" operation under these agreements.

As an example of the unique conditions, please refer to BC Hydro's response to AMPC IR 3.4.1, which explains that higher than planned water releases occurred during the winter of fiscal 2019 due to high market prices that were not forecast in advance.

13.0 Reference: Exhibit B-19, Appendix C, Section 1.2, page 3

1.2 Cost of Non-Heritage Energy

Cost of Non-Heritage Energy is forecast to decrease by $243.9 million in fiscal 2020 and $193.9 million in fiscal 2021, compared to the Application. This is primarily due to lower costs for IPPs and Long-Term Commitments.

Total costs for IPPs and Long-Term Commitments are forecast to be $1,294.7 million in fiscal 2020 and $1,410.8 million in fiscal 2021. This represents a decrease of $243.8 million in fiscal 2020 and $190.3 million in fiscal 2021, compared to the forecast in the Application. This reduction is due to a number of factors, such as:

- A change in accounting treatment under IFRS 16 (capital leases) for two Electricity Purchase Agreements not previously identified as capital leases (please refer to Appendix F for further discussion on the adoption of IFRS 16 and its implications);
- Lower forecast inflows for hydro IPPs due to dry weather conditions, as described above;
- Updates to historical average deliveries to incorporate the fiscal 2019 actual deliveries for operating projects, which resulted in a lower IPP forecast compared to the Application; and
- Delays in projects reaching commercial operation. [1]

4.13.1 Do the lower purchases from IPPs due to dry weather conditions create a contractual obligation for future power purchases by BC Hydro from these IPPs? Please explain and provide quantification for any changes in obligations.

RESPONSE:

No, lower purchases from IPPs due to dry weather conditions do not create a contractual obligation for future power purchases by BC Hydro.

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[1] Exhibit B-19, Appendix C, page 3

13.0 Reference: Exhibit B-19, Appendix C, Section 1.2, page 3

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- Lower forecast inflows for hydro IPPs due to dry weather conditions, as described above;
- Updates to historical average deliveries to incorporate the fiscal 2019 actual deliveries for operating projects, which resulted in a lower IPP forecast compared to the Application; and
- Delays in projects reaching commercial operation. [1]

4.13.1.1 Please provide the dollar values for any changes in IPP obligations created as a result of the current lower purchases.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.13.1.

[1] Exhibit B-19, Appendix C, page 3

13.0 Reference: Exhibit B-19, Appendix C, Section 1.2, page 3

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- Lower forecast inflows for hydro IPPs due to dry weather conditions, as described above;
- Updates to historical average deliveries to incorporate the fiscal 2019 actual deliveries for operating projects, which resulted in a lower IPP forecast compared to the Application; and
- Delays in projects reaching commercial operation. [1]

4.13.2 How often does BC Hydro update its historical average deliveries? Please explain.

RESPONSE:

BC Hydro updates the historical average deliveries annually at the end of each fiscal year by adding the actual IPP deliveries for the recently completed fiscal year to the total historical deliveries. Please also refer to BC Hydro response to BCOAPO IR 3.164.1.

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[1] Exhibit B-19, Appendix C, page 3

13.0 Reference: Exhibit B-19, Appendix C, Section 1.2, page 3

1.2 Cost of Non-Heritage Energy

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- A change in accounting treatment under IFRS 16 (capital leases) for two Electricity Purchase Agreements not previously identified as capital leases (please refer to Appendix F for further discussion on the adoption of IFRS 16 and its implications);
- Lower forecast inflows for hydro IPPs due to dry weather conditions, as described above;
- Updates to historical average deliveries to incorporate the fiscal 2019 actual deliveries for operating projects, which resulted in a lower IPP forecast compared to the Application; and
- Delays in projects reaching commercial operation. [1]

4.13.3 Over what period is the historical average delivery calculated?

RESPONSE:

Generally, the historical average deliveries are calculated for each individual EPA for the period starting from the first full month after the IPP has reached commercial operation to the end of the most recent fiscal year.

[1] Exhibit B-19, Appendix C, page 3

13.0 Reference: Exhibit B-19, Appendix C, Section 1.2, page 3

1.2 Cost of Non-Heritage Energy

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- A change in accounting treatment under IFRS 16 (capital leases) for two Electricity Purchase Agreements not previously identified as capital leases (please refer to Appendix F for further discussion on the adoption of IFRS 16 and its implications);
- Lower forecast inflows for hydro IPPs due to dry weather conditions, as described above;
- Updates to historical average deliveries to incorporate the fiscal 2019 actual deliveries for operating projects, which resulted in a lower IPP forecast compared to the Application; and
- Delays in projects reaching commercial operation. [1]

4.13.4 Please provide the previous historical average, the new historical average and the deliveries over the 'historical average' calculation period.

[1] Exhibit B-19, Appendix C, page 3

RESPONSE:

As noted in BC Hydro's response to BCUC IR 1.15.2, after one full fiscal year of commercial operation the average of each IPP project's historical energy deliveries is used to forecast its future energy deliveries.

For comparison purposes, the volumes provided below are for the same EPAs, whose future energy deliveries are based on historical energy deliveries, included in the forecast for the initial Application.

	GWh
Previous historical avg. (Initial Application)	12,517
Actual deliveries in F2019	11,606
New historical avg. (Evidentiary Update)	12,401

BC Hydro notes that not all IPP project forecasts are based on historical energy deliveries, and that in some situations historical energy deliveries where there may be an amendment to an EPA that could impact the forecast. For example, the Island Generation project is forecast based on a dispatch plan arising from the Energy Study and the Rio Tinto Alcan (RTA) project is forecast based on information as provided by RTA. For clarity, the data above excludes Island Generation, RTA, and other IPP projects where the actual deliveries for fiscal 2019 are not comparable to historical energy deliveries.

13.0 Reference: Exhibit B-19, Appendix C, Section 1.2, page 3

1.2 Cost of Non-Heritage Energy

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Total costs for IPPs and Long-Term Commitments are forecast to be $1,294.7 million in fiscal 2020 and $1,410.8 million in fiscal 2021. This represents a decrease of $243.8 million in fiscal 2020 and $190.3 million in fiscal 2021, compared to the forecast in the Application. This reduction is due to a number of factors, such as:

- A change in accounting treatment under IFRS 16 (capital leases) for two Electricity Purchase Agreements not previously identified as capital leases (please refer to Appendix F for further discussion on the adoption of IFRS 16 and its implications);
- Lower forecast inflows for hydro IPPs due to dry weather conditions, as described above;
- Updates to historical average deliveries to incorporate the fiscal 2019 actual deliveries for operating projects, which resulted in a lower IPP forecast compared to the Application; and
- Delays in projects reaching commercial operation. [1]

4.13.5 Please provide a discussion of the delays in projects reaching commercial operation.

RESPONSE:

During the development phase, BC Hydro is in contact with the IPP developing the project and we primarily rely on the information provided in the IPP's quarterly reports to BC Hydro with regard to their estimated date for reaching commercial

[1] Exhibit B-19, Appendix C, page 3

operation. This estimated date is used for forecast purposes. Generally, in our assessment, delays in reaching commercial operation are related to permitting, construction and/or financing issues.

The Application was based on information available as of October 1, 2018 and as of this date there were nine IPP projects under development which were expected to achieve their estimated commercial operation date (COD) prior to and during the Test Period. Of these nine projects, only two projects achieved COD within a month of their estimated COD and the remaining projects' estimated CODs have been revised to reflect updated information, primarily as provided by the IPP, regarding each project's estimated completion.

14.0 Reference: Exhibit B-19, Appendix C, section 1.3, page 3

Cost of Market Energy is forecast to increase by $285.5 million in fiscal 2020 and $41.4 million in fiscal 2021, compared to the Application. As discussed above, dry weather conditions during the winter of fiscal 2019 have continued into fiscal 2020, increasing the potential need for market electricity purchases and decreasing surplus sales and domestic transmission costs. [1]

4.14.1 Please explain how the purchases of market energy affect BC Hydro's Cost of Energy on a unit price basis.

RESPONSE:

BC Hydro interprets market energy in the context of this question to relate to Market Electricity Purchases.

Please refer to BC Hydro's response to BCUC IR 3.307.2 for a discussion of how the volume of Market Electricity Purchases impacts the average unit price paid.

[1] Exhibit B-19, Appendix C, page 3

14.0 Reference: Exhibit B-19, Appendix C, section 1.3, page 3

Cost of Market Energy is forecast to increase by $285.5 million in fiscal 2020 and $41.4 million in fiscal 2021, compared to the Application. As discussed above, dry weather conditions during the winter of fiscal 2019 have continued into fiscal 2020, increasing the potential need for market electricity purchases and decreasing surplus sales and domestic transmission costs. [1]

4.14.2 Does the purchase of market energy in dry conditions create any kind of upstream advantages, in the hydro electric system for BC Hydro? Please explain.

RESPONSE:

BC Hydro assumes the use of the term "upstream" is meant to refer to the large storage reservoirs at Williston, upstream of the GMS and Peace Canyon plants, and Kinbasket, which is upstream of the Mica, Revelstoke and Arrow Lakes Hydro plants.

The Market Electricity Purchases in the winter of fiscal 2019 were made to mitigate physical supply risk and ensure BC Hydro could meet its operational needs. In general, Market Electricity Purchases in dry conditions result in higher reservoir elevations, which will marginally increase the maximum generation capability at facilities and provide flexibility for meeting future demand.

[1] Exhibit B-19, Appendix C, page 3

14.0 Reference: Exhibit B-19, Appendix C, section 1.3, page 3

Cost of Market Energy is forecast to increase by $285.5 million in fiscal 2020 and $41.4 million in fiscal 2021, compared to the Application. As discussed above, dry weather conditions during the winter of fiscal 2019 have continued into fiscal 2020, increasing the potential need for market electricity purchases and decreasing surplus sales and domestic transmission costs. [1]

4.14.3 Dry weather conditions in BC do not necessarily mean dry conditions in other parts of western North America. Did the purchase of market electricity during the winter of fiscal 2019 create advantages or disadvantages for BC Hydro? Please explain why or why not.

RESPONSE:

While there may be regional differences in weather conditions across western North America, in the run up to and over the winter period of fiscal 2019, the Pacific Northwest region experienced lower-than-normal inflows.[2,3]

The advantage of the forward purchase of market electricity under the 2018 Letter Agreement between BC Hydro and Powerex was that BC Hydro was able to secure physical supply of energy to address the risks associated with evolving system requirements.

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1 Exhibit B-19, Appendix C, page 3

2 http://pweb.crohms.org/tmt/agendas/2018/1219_Ammann_2018_TMT_Year_End_Review.pdf

3 https://www.nwrfc.noaa.gov/water_supply/ws_plot.php?id=TDAO3&start_month=JAN&end_month=JUL&water_year=2019&fcst_method=BOTH

15.0 Reference: Exhibit B-19, Appendix G page 2

Actual residential sales were 250 GWh (or 1.4 per cent) lower than the fiscal 2019 RRA Plan. The residential sales forecast is based on three main variables:

- Number of accounts;
- Electricity sales per account (use per account); and
- Temperature.

The residential sales variance was related to a lower than expected usage per residential account. The lower usage per account is likely due to a number of factors including higher Demand-Side Management savings, denser housing development (more multiple unit dwellings), fewer people per account, and changes in appliance mix resulting in more efficient appliances (appliance stock turnover). The total number of residential accounts was 2,000 (or 0.1 per cent) higher than forecast in fiscal 2019 and temperatures were slightly colder than normal during the year. As such, temperature and the number of accounts do not account for the negative sales variance.

4.15.1 What steps has BC Hydro undertaken to more fully investigate the cause of the 1.4% reduction in actual usage versus expected usage?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.288.1 where a detailed explanation of this variance in residential sales is provided.

BC Hydro does not consider the variance between actual and expected usage to be significant. However, we will continue to monitor usage trends and will undertake further analysis should circumstances warrant further investigation. The fiscal 2019 actuals referenced in the preamble to the question will be incorporated into the calibration period used to develop the next load forecast.

15.0 Reference: Exhibit B-19, Appendix G page 2

Actual residential sales were 250 GWh (or 1.4 per cent) lower than the fiscal 2019 RRA Plan. The residential sales forecast is based on three main variables:

- Number of accounts;
- Electricity sales per account (use per account); and
- Temperature.

The residential sales variance was related to a lower than expected usage per residential account. The lower usage per account is likely due to a number of factors including higher Demand-Side Management savings, denser housing development (more multiple unit dwellings), fewer people per account, and changes in appliance mix resulting in more efficient appliances (appliance stock turnover). The total number of residential accounts was 2,000 (or 0.1 per cent) higher than forecast in fiscal 2019 and temperatures were slightly colder than normal during the year. As such, temperature and the number of accounts do not account for the negative sales variance.

4.15.3 Has BC Hydro accounted for the changes in use per customer in its load forecasting? Please explain.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.288.1 where a detailed explanation of this variance in residential sales and declining use per account is provided.

The historical trend of declining use per account, up to fiscal 2018, is already accounted for in the October 2018 and June 2019 Load Forecasts. The fiscal 2019 actuals referenced in the preamble to the question will be incorporated into the calibration period used to develop the next load forecast.

16.0 Reference: Exhibit B-19, appendix G page 2 and page 3

Actual light industrial and commercial sales were 108 GWh (or 0.6 per cent) higher than forecast due to higher sales in the light industrial sector. This variance in the light industrial sector reflects continued strong growth in the B.C. economy, which has been reflected in other economic indicators such as low unemployment and consistent GDP growth. The commercial sector had a small negative variance.

Actual large industrial sales were 15 GWh (or 0.1 per cent) higher than the fiscal 2019 RRA Plan.

Reference: Exhibit B-19, Appendix G page 3

Table G-2 Fiscal 2019 Domestic Revenues – Variance

($ million)	Schedule Reference	F2019 RRA	Actual	Diff	% Diff
		1	2	3 = 2 - 1	4 = 3 / 1
Residential	14.0 L11	2,067.9	2,025.2	(42.7)	-2.1%
Light Industrial and Commercial	14.0 L12	1,821.9	1,832.3	10.4	0.6%
Large Industrial	14.0 L13+L19	840.9	831.4	(9.5)	-1.1%
Other	14.0 L14 to L18	129.1	137.7	8.6	6.7%
Subtotal	14.0 L20	4,859.8	4,826.6	(33.2)	-0.7%
Revenue from Deferral Rider	14.0 L21	241.8	240.6	(1.2)	-0.5%
Total	14.0 L22	5,101.6	5,067.2	(34.4)	-0.7%

Actual domestic revenues in fiscal 2019 were $34 million (or 0.7 per cent) lower than the fiscal 2019 RRA Plan, with lower residential revenues and slightly lower large industrial revenues partially offset by higher light industrial and commercial revenue and higher other revenue. Lower residential revenue was driven by lower load, as described in section 2.1 above. Light industrial and commercial revenue was higher due to higher load, as described in section 2.1 above. Lower large industrial revenue was driven by a lower average rate, due to a different mix of customer rates than was projected in the fiscal 2019 Plan. Other revenue was higher mainly due to the adoption of IFRS 15, Revenue from Contracts with Customers, as described in section 8.13 of Chapter 8 of the Application. The adoption of IFRS 15 resulted in a higher price per MWh for sales to the City of Seattle and was partially offset by lower sales to FortisBC.

4.16.1 Please elaborate on the 'different mix' of customer rates than projected resulting in lower revenues for the large industrial customers but higher sales in GWh.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 3.99.1. Additional detail is provided below.

Sales volumes to large industrial customers in fiscal 2019 were 15 GWh (or 0.1 per cent) higher than the fiscal 2019 RRA Plan, however the revenues were lower by $9.5 million (or 1.1 per cent). This was mainly due to a different mix of customer rates, as there was a lower proportion of sales to customers on higher rates and a higher proportion of sales to customers on the lower Tier 1 rate.

As shown in the table below, the fiscal 2019 RRA Plan expected a mix of sales that included 68 per cent of sales to customers at the Tier 1 rate and 32 per cent of sales to customers on other tariff rates. Actual sales at the Tier 1 rate were 70 per cent of total sales, or 2 per cent higher than planned. This resulted in lower revenues, since the average rate for Tier 1 sales is lower.

Sales Mix at Different Rates	Actual Sales (%)	Planned Sales (%)	Variance in Sales Mix (%)	Average Actual Rate ($)
Sales at Tier 1 rate	70	68	2	60.2 / MWh
Sales at other rates	30	32	-2	69.2 / MWh
Total Sales	100	100		

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17.0 Reference: Exhibit B-19, Appendix G page 5

Table G-4 Fiscal 2019 Operating Costs and Provisions Variances

	($ million)	Schedule Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2019 % Diff
			1	2	3=2-1	4=3/1
1	Integrated Planning	5.0 L1	270.1	285.9	15.8	6%
2	Capital Infrastructure Project Delivery	5.0 L2	81.9	85.9	4.0	5%
3	Operations	5.0 L3	216.2	215.6	(0.6)	0%
4	Safety	5.0 L4	54.9	53.6	(1.3)	-2%
5	Finance, Technology, Supply Chain	5.0 L5	265.0	261.2	(3.8)	-1%
6	People, Customer, Corporate Affairs	5.0 L6	122.5	105.5	(17.0)	-14%
7	Other	5.0 L7	(251.6)	(250.5)	1.0	0%
8	F17-F19 RRA Compliance Filing Adjustment	5.0 L8	10.4	-	(10.4)	-100%
9	**Base Operating Costs**	5.0 L9	**769.5**	**757.2**	(12.2)	-2%
10	IFRS Ineligible Capitalized Costs	5.0 L10	147.7	147.7	-	0%
11	Independent Power Producer Capital Leases	5.0 L11	54.3	54.4	0.0	0%
12	Waneta 2/3	5.0 L12	–	3.7	3.7	N/A
13	Customer Crisis Fund	5.0 L13	–	4.1	4.1	N/A
14	**Net Operating Costs**	5.0 L14	**202.0**	**209.8**	7.8	4%
15	Deferred Account Additions	5.0 L18	–	(0.7)	(0.7)	N/A
16	Regulatory Account Additions	5.0 L29	197.9	198.7	0.8	0%
17	**Subtotal**		**197.9**	**198.0**	0.1	0%
18	**Total Gross Operating Costs**	5.0 L30	**1,169.4**	**1,165.1**	(4.3)	0%
19	Net Provisions & Other	5.0 L43	65.7	95.9	30.2	46%
20	Deferral Account Additions - Provisions & Other	5.0 L45	–	-	-	N/A
21	Regulatory Account Additions - Provisions & Other	5.0 L52	(14.0)	16.0	30.0	-215%
22	**Total Gross Provisions & Other**	5.0 L53	**51.7**	**111.9**	60.3	117%
23	**Total Gross Operating Costs and Provisions**	1.0 L2	**1,221.0**	**1,277.0**	56.0	5%

- Higher litigation costs of $5.2 million related to a capital project; and

4.17.1 Please briefly explain the higher litigation costs and identify the related capital project.

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 3.290.1 for a discussion of nature and status of the litigation and the reason for the higher litigation costs of $5.2 million in fiscal 2019.

18.0 Reference: Exhibit B-19, Appendix G page 6

- An increase in the Dismantling Costs Regulatory Account of $11.3 million primarily due to higher transmission and distribution work programs and the associated removal of end of life plant and equipment; and

4.18.1 Which projects experienced higher transmission and distribution work programs resulting in higher dismantling costs?

RESPONSE:

The table below provides a summary of the fiscal 2019 transmission and distribution work program capital expenditure variances which contributed to the fiscal 2019 dismantling variance. For additional information on these variances, please refer to BC Hydro's response to AMPC IR 3.16.2.

Fiscal 2019	Capital Expenditures				Dismantling		
	RRA	Actual	Difference		RRA	Actual	Difference
Distribution Capital Programs							
Customer Driven	164.6	232.4	67.8		1.6	5.4	3.8
System Expansion and Improvement -Sustain	55.1	64.3	9.2		0.9	3.2	2.3
Asset Replacements	131.0	139.0	8.0		5.2	8.2	3.0
Transmission Capital Programs							
Transmission Sustain Programs	97.8	100.5	2.7		3.2	5.4	2.2
Other Net Dismantling Variances from other Capital Expenditures							0.0
Total							**11.3**

19.0 Reference: Exhibit B-19, Appendix G page 7

Variances of $12.2 million related to base operating costs were primarily due to lower than planned expenditures on external services, and higher external recoveries from contributions to the maintenance of the power system for poles that are jointly-owned.

4.19.1 Please elaborate on, and provide quantification for, the variances related to base operating costs and the planned decrease in external expenditures. Have these costs been deferred or are they permanent reductions? Please explain.

RESPONSE:

The variance of $12.2 million in base operating costs consists of $6.5 million related to unspent, unallocated funds budgeted as part of external services, and $5.7 million attributed to higher external recoveries than planned.

Base operating cost variances are not eligible for deferral to regulatory accounts. The variances experienced in fiscal 2019 are specific to that year and are not expected to be permanent reductions, nor are they expected to drive cost pressures in the test period. There is no unallocated funds budget in fiscal 2020 or fiscal 2021.

19.0 Reference: Exhibit B-19, Appendix G page 7

> Variances of $12.2 million related to base operating costs were primarily due to lower than planned expenditures on external services, and higher external recoveries from contributions to the maintenance of the power system for poles that are jointly-owned.

4.19.2 Did, or will, BC Hydro incur additional costs internally as a result of the reduction in planned expenditures? Please explain and provide quantification where available.

RESPONSE:

Please refer to BC Hydro's response to CEC IR 4.19.1.

20.0 Reference: Exhibit B-19, Appendix G page 9 and page 31

- An increase in Site C Project expenditures based on the revised budget of $10.7 billion, including project reserve, approved by BC Hydro's Board of Directors in February 2018.

Table G-5 Fiscal 2019 Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Generation	425.0	370.3	(54.7)	-13%
Site C Project	829.2	1,116.7	287.5	35%
Waneta 2/3 Interest Acquisition	-	1,218.8	1,218.8	-
Transmission & Distribution	963.7	920.0	(43.7)	-5%
Business Support				
Technology	78.8	84.3	5.5	7%
Properties	88.3	48.4	(39.9)	-45%
Fleet/Other	39.6	58.2	18.6	47%
Total Gross	**2,424.6**	**3,816.8**	**1,392.2**	**57%**
Less: Contribution in Aid	(106.5)	(185.3)	(78.8)	74%
Total	**2,318.1**	**3,631.5**	**1,313.4**	**57%**

Contribution in Aid

Fiscal 2019 contribution in aid related to capital expenditures was $88.7 million or 111 per cent above the fiscal 2019 RRA Plan primarily due to the higher than planned expenditures for Distribution Customer Driven work, which is dependent on customer requests, as well as Contribution in Aid for several large major distribution projects being received in advance of project commencement.

Fiscal 2019 capital additions were $43.7 million or 54 per cent above the fiscal 2019 RRA Plan due to higher than planned volume for Distribution Customer Driven work.

5.6 Site C Project Capital Expenditures and Additions Variance Explanations

Site C Project fiscal 2019 capital expenditures and capital additions are presented in the tables below.

Table G-21 Fiscal 2019 Site C Project Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Total Site C	829.2	1,116.7	287.5	35%

4.20.1 Is the Site C Project still on time and on expected budget? Please explain.

RESPONSE:

BC Hydro continues to forecast achievement of the milestones for river diversion in September 2020, first power in December 2023 and the placement into service of the final generating unit in 2024, as planned.

The total approved project budget is $10.7 billion. BC Hydro reports on the project expenditure summary through Quarterly Progress Reports submitted to the BCUC.

Given the size and complexity of the project, there are scenarios that would see the total project cost exceed the approved budget. Examples of these scenarios would include if remaining procurements are materially higher than planned, or if an event occurs or a risk is realized that results in a material claim submitted by one or more contractors or if river diversion is not achieved in 2020.

In order to manage these potential impacts, BC Hydro has a robust risk management practice comprised of an integrated set of work processes, procedures and applications to plan, analyze, evaluate, treat and monitor risks related to the project. Risks are reviewed by various levels of leadership on a regular basis.

20.0 Reference: Exhibit B-19, Appendix G page 9 and page 31

- An increase in Site C Project expenditures based on the revised budget of $10.7 billion, including project reserve, approved by BC Hydro's Board of Directors in February 2018.

Table G-5 Fiscal 2019 Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Generation	425.0	370.3	(54.7)	-13%
Site C Project	829.2	1,116.7	287.5	35%
Waneta 2/3 Interest Acquisition	-	1,218.8	1,218.8	-
Transmission & Distribution	963.7	920.0	(43.7)	-5%
Business Support				
Technology	78.8	84.3	5.5	7%
Properties	88.3	48.4	(39.9)	-45%
Fleet/Other	39.6	58.2	18.6	47%
Total Gross	**2,424.6**	**3,816.8**	**1,392.2**	**57%**
Less: Contribution in Aid	(106.5)	(185.3)	(78.8)	74%
Total	**2,318.1**	**3,631.5**	**1,313.4**	**57%**

Contribution in Aid

Fiscal 2019 contribution in aid related to capital expenditures was $88.7 million or 111 per cent above the fiscal 2019 RRA Plan primarily due to the higher than planned expenditures for Distribution Customer Driven work, which is dependent on customer requests, as well as Contribution in Aid for several large major distribution projects being received in advance of project commencement.

Fiscal 2019 capital additions were $43.7 million or 54 per cent above the fiscal 2019 RRA Plan due to higher than planned volume for Distribution Customer Driven work.

5.6 Site C Project Capital Expenditures and Additions Variance Explanations

Site C Project fiscal 2019 capital expenditures and capital additions are presented in the tables below.

Table G-21 Fiscal 2019 Site C Project Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Total Site C	829.2	1,116.7	287.5	35%

4.20.2 Please elaborate on the significant reduction in Properties. Are these reductions permanent? Please explain.

RESPONSE:

The reduction in Properties Capital Expenditures in fiscal 2019 was due to project delays and deferrals and is not permanent.

As noted on pages 29 to 30 of Appendix G of the Evidentiary Update, the reason that fiscal 2019 Properties capital expenditures were $39.9 million or 45 per cent below the fiscal 2019 RRA Plan is because:

- **The Construction Services/Lower Mainland Transmission Building was deferred to fiscal 2025;**
- **The Dawson Creek Building was deferred to fiscal 2025;**
- **The Material Classification Facility Building Redevelopment was temporarily deferred during the test period which has delayed the project schedule and related spend in each year of the test period;**
- **The Chilliwack Facility was delayed due to difficulties in securing suitable land for the new office; and**
- **The Fleet Services Facility Project was deferred to fiscal 2025.**

Fiscal 2019 capital additions were comparable with the fiscal 2019 RRA Plan.

20.0 Reference: Exhibit B-19, Appendix G page 9 and page 31

- An increase in Site C Project expenditures based on the revised budget of $10.7 billion, including project reserve, approved by BC Hydro's Board of Directors in February 2018.

Table G-5 Fiscal 2019 Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Generation	425.0	370.3	(54.7)	-13%
Site C Project	829.2	1,116.7	287.5	35%
Waneta 2/3 Interest Acquisition	-	1,218.8	1,218.8	-
Transmission & Distribution	963.7	920.0	(43.7)	-5%
Business Support				
Technology	78.8	84.3	5.5	7%
Properties	88.3	48.4	(39.9)	-45%
Fleet/Other	39.6	58.2	18.6	47%
Total Gross	**2,424.6**	**3,816.8**	**1,392.2**	**57%**
Less: Contribution in Aid	(106.5)	(185.3)	(78.8)	74%
Total	**2,318.1**	**3,631.5**	**1,313.4**	**57%**

Contribution in Aid

Fiscal 2019 contribution in aid related to capital expenditures was $88.7 million or 111 per cent above the fiscal 2019 RRA Plan primarily due to the higher than planned expenditures for Distribution Customer Driven work, which is dependent on customer requests, as well as Contribution in Aid for several large major distribution projects being received in advance of project commencement.

Fiscal 2019 capital additions were $43.7 million or 54 per cent above the fiscal 2019 RRA Plan due to higher than planned volume for Distribution Customer Driven work.

5.6 Site C Project Capital Expenditures and Additions Variance Explanations

Site C Project fiscal 2019 capital expenditures and capital additions are presented in the tables below.

Table G-21 Fiscal 2019 Site C Project Capital Expenditures Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Total Site C	829.2	1,116.7	287.5	35%

4.20.3 Please elaborate on the significant increase in Fleet expenditures. Are these increases permanent? Please explain.

RESPONSE:

As shown in Table G-19 of Appendix G of the Evidentiary Update, which is re-produced below, Fleet capital expenditures comprise only a portion of the "Fleet/Other" line shown in the table provided in the preamble to the question. Specifically, fiscal 2019 Fleet capital expenditures were $6.3 million above the fiscal 2019 RRA plan.

($ million)	F2019			
	RRA	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Fleet	29.6	35.9	6.3	21%
Other	10.0	22.4	12.4	124%
Total	**39.6**	**58.2**	**18.6**	**47%**

As part of the annual capital plan update process, BC Hydro determined, based on more recent information, that the fiscal 2019 RRA plan, which was prepared in fiscal 2016, would not be sufficient for the end-of-life vehicle replacements that were required in fiscal 2019. Accordingly, BC Hydro re-directed funds from other parts of the Capital Plan in fiscal 2019 to fund the required end-of-life vehicle replacements.

The Capital Plan is reviewed on an annual basis, providing an ongoing opportunity to adjust our capital investment based on risks.

BC Hydro is also incorporating end of life replacement criteria that includes a risk rating to prioritize the replacement of our assets. BC Hydro expects fleet capital expenditures to increase over time to support end of life replacements, Clean BC emission targets and our objectives of safety and reliability.

21.0 Reference: Exhibit B-19, Appendix G page 18

Bulk System Reinforcement

Fiscal 2019 capital expenditures were $25 million or 103 per cent below the fiscal 2019 RRA Plan primarily due to a significant change in the scope of work required to interconnect LNG Canada's phase 1 project which resulted in the cancellation of the Northwest Substation Upgrade Project and the introduction of a new interconnection project, (the MIN to LNG Canada Interconnection project) with a reduced scope of work.

4.21.1 Please briefly elaborate on the change in the interconnection of the LNG project. Is the Northwest Substation Upgrade Project permanently replaced by the MIN to LNG Canada Interconnection project? Why did this occur?

RESPONSE:

Please refer to BC Hydro's response to BCUC IR 1.1.1 where we provide the current scope of work for the MIN to LNG Canada Interconnection project and explain that:

- **LNG Canada split their interconnection request to meet their development needs into two phases, with separate and distinct approvals for each phase and requested that BC Hydro only advance Phase 1; and**
- **Several earlier queue customers withdrew from the interconnection process, which meant that the previous interconnection studies for LNG Canada needed to be updated.**

These factors resulted in the scope of work to meet LNG Canada's Phase 1 development interconnection requirement being significantly less than previously determined. The reduction in the scope of work resulted in the cancellation of the Northwest Substation Upgrade project and the introduction of the MIN to LNG Canada Interconnection project.

Please also refer to BC Hydro's response to BCUC IR 2.247.2 where we explain that BC Hydro is undertaking interconnection studies for LNG Canada's Phase 2 development interconnection requirements and where we also provide the proposed scope of work associated with LNG Canada's Phase 2 interconnection requirement. The decisions on whether to implement the scope of work for the Phase 2 interconnection request will only be made once LNG Canada has made their Final Investment Decision for Phase 2 of their development.

22.0 Reference: Exhibit B-19, Appendix G page 18 and 19

Station Expansion & Modification

Fiscal 2019 capital expenditures were $36.9 million or 62 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The Mount Lehman Substation Upgrade project was $13.3 million below plan because the Identification and Definition phases were extended to study potential design alternatives due to the discovery of two species listed under the *Federal Species at Risk Act* in the planned expansion area. This discovery required additional design and field work to confirm the current plan to expand on the West side of the facility which eliminated the impact to these species;

- The Capilano Substation 25kv Conversion project was $8.7 million below plan because the Identification and Definition phases were extended to address required engineering and geotechnical studies; and

- The Westbank Substation Upgrade project was $12.5 million below plan because the Identification phase was deferred pending confirmation of the project scope.

4.22.1 Will the Mt. Lehman Substation Upgrade project experience increased or lowered costs because of the need for design changes? Please discuss and provide quantification, and identify when the costs will become additions.

RESPONSE:

The design of the Mount Lehman Substation Upgrade project was changed in the Definition phase to expand the West side of the facility rather than the East side of the facility. This change was made in response to the discovery of two species at risk on the East side of the facility.

The new design added a total of $2.0 million to the project's Implementation phase budget. Specifically, a required change to the height of the retaining wall at the perimeter of the West side of the property from 4 to 10 metres cost $1.8 million and an increase of 10,000 cubic metres of backfill cost $0.2 million.

The capital addition will occur at the project in-service date which is scheduled for fiscal 2023.

22.0 Reference: Exhibit B-19, Appendix G page 18 and 19

Station Expansion & Modification

Fiscal 2019 capital expenditures were $36.9 million or 62 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The Mount Lehman Substation Upgrade project was $13.3 million below plan because the Identification and Definition phases were extended to study potential design alternatives due to the discovery of two species listed under the *Federal Species at Risk Act* in the planned expansion area. This discovery required additional design and field work to confirm the current plan to expand on the West side of the facility which eliminated the impact to these species;

- The Capilano Substation 25kv Conversion project was $8.7 million below plan because the Identification and Definition phases were extended to address required engineering and geotechnical studies; and

- The Westbank Substation Upgrade project was $12.5 million below plan because the Identification phase was deferred pending confirmation of the project scope.

4.22.2 Will the Capilano Substation Conversion project experience increased or lowered costs overall because of the extension of the identification and definition phases? Please explain and quantify.

RESPONSE:

The 18-month extension to the Identification and Definition phases of the Capilano Substation Conversion Project added approximately $0.5 million to the overall project cost estimate.

The additional time was required to:

- **Advance further geotechnical studies into the Definition phase in order to design a ground treatment plan to address the soil conditions; and**

- **Advance certain Implementation phase engineering activities into the Definition phase in order to provide a more accurate project implementation cost and schedule.**

22.0 Reference: Exhibit B-19, Appendix G page 18 and 19

Station Expansion & Modification

Fiscal 2019 capital expenditures were $36.9 million or 62 per cent below the fiscal 2019 RRA Plan. This was primarily because:

- The Mount Lehman Substation Upgrade project was $13.3 million below plan because the Identification and Definition phases were extended to study potential design alternatives due to the discovery of two species listed under the *Federal Species at Risk Act* in the planned expansion area. This discovery required additional design and field work to confirm the current plan to expand on the West side of the facility which eliminated the impact to these species;

- The Capilano Substation 25kv Conversion project was $8.7 million below plan because the Identification and Definition phases were extended to address required engineering and geotechnical studies; and
- The Westbank Substation Upgrade project was $12.5 million below plan because the Identification phase was deferred pending confirmation of the project scope.

4.22.3 Will the Westbank Substation Upgrade project experience cost changes because of the deferral? Please explain and provide quantification.

RESPONSE:

The Westbank Substation Upgrade project schedule was deferred to allow the project team to undertake additional work to confirm the project scope.

Depending upon the outcome of this additional scoping work, the total forecast cost may increase or decrease. As this work is still underway, BC Hydro cannot quantify the impact at this time.

23.0 Reference: Exhibit B-19, Appendix G page 25 and page 27

Distribution Growth – Customer Driven

Fiscal 2019 capital expenditures were $67.8 million or 41 per cent above the fiscal 2019 RRA Plan due to an increase in distribution customer connection requests as a result of increased economic activity including housing starts and multi-year provincial infrastructure investments. This work is difficult to plan as it is dependent on customer requests and their related timing.

Fiscal 2019 capital additions were $25.5 million or 15 per cent above the fiscal 2019 RRA Plan primarily due to the increase in capital expenditures discussed above.

Contribution in Aid

Fiscal 2019 contribution in aid related to capital expenditures was $88.7 million or 111 per cent above the fiscal 2019 RRA Plan primarily due to the higher than planned expenditures for Distribution Customer Driven work, which is dependent on customer requests, as well as Contribution in Aid for several large major distribution projects being received in advance of project commencement.

Fiscal 2019 capital additions were $43.7 million or 54 per cent above the fiscal 2019 RRA Plan due to higher than planned volume for Distribution Customer Driven work.

4.23.1 Please provide the range of variation in customer driven distribution growth costs over the last 15 years and provide quantification.

RESPONSE:

Between fiscal 2005 and fiscal 2010, there were several accounting model changes that affected the presentation of customer driven distribution growth costs. As a result, consistent and comparable customer driven distribution growth costs are available from fiscal 2011 and onwards. Therefore, the table below

provides the actual customer driven distribution growth costs for the last nine fiscal years (i.e., fiscal 2011 to fiscal 2019).

($million)	F2011 Actual	F2012 Actual	F2013 Actual	F2014 Actual	F2015 Actual
Customer Driven Distribution Growth Costs	146.4	112.2	126.3	129.4	149.7

($million)	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Actual
Customer Driven Distribution Growth Costs	169.2	179.9	224.2	232.4

23.0 Reference: Exhibit B-19, Appendix G page 25 and page 27

Distribution Growth – Customer Driven

Fiscal 2019 capital expenditures were $67.8 million or 41 per cent above the fiscal 2019 RRA Plan due to an increase in distribution customer connection requests as a result of increased economic activity including housing starts and multi-year provincial infrastructure investments. This work is difficult to plan as it is dependent on customer requests and their related timing.

Fiscal 2019 capital additions were $25.5 million or 15 per cent above the fiscal 2019 RRA Plan primarily due to the increase in capital expenditures discussed above.

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Fiscal 2019 contribution in aid related to capital expenditures was $88.7 million or 111 per cent above the fiscal 2019 RRA Plan primarily due to the higher than planned expenditures for Distribution Customer Driven work, which is dependent on customer requests, as well as Contribution in Aid for several large major distribution projects being received in advance of project commencement.

Fiscal 2019 capital additions were $43.7 million or 54 per cent above the fiscal 2019 RRA Plan due to higher than planned volume for Distribution Customer Driven work.

4.23.2 Please discuss the manner in which BC Hydro undertakes to improve its estimation of customer requests.

RESPONSE:

During the preparation of capital expenditure forecasts for customer-driven work, BC Hydro considers a number of factors including:

- **Historical trends: Historical trends of customer-driven work establish the baseline of the forecast for future customer-driven work capital expenditures;**
- **Provincial economic indicators: Forecasts based on historical trends are adjusted for forward-looking provincial economic indicators such as economic growth outlook, housing starts and interest rates; and**
- **Upcoming customer-driven projects: Forecasts are further adjusted for any known large committed customer-driven projects that will move into construction phase in future years.**

Capital expenditure forecasts for customer-driven work consolidate multiple categories of customer connections, primarily Express Connections and Design Connections. Each category of customer connections uses the above noted factors to a varying degree, depending on the category type.

Express Connections is a high volume customer request category with capital expenditures that trend with housing starts.

Design Connections has a lower volume of projects with a wider range of scope and project costs that can vary from a few hundred dollars to several million dollars. Therefore, forecasts for Design Connections are correlated to provincial economic indicators, as well as changing trends of project types. For example, there is currently a shift from market driven residential subdivision projects to infrastructure projects.

23.0 Reference: Exhibit B-19, Appendix G page 25 and page 27

Distribution Growth – Customer Driven

Fiscal 2019 capital expenditures were $67.8 million or 41 per cent above the fiscal 2019 RRA Plan due to an increase in distribution customer connection requests as a result of increased economic activity including housing starts and multi-year provincial infrastructure investments. This work is difficult to plan as it is dependent on customer requests and their related timing.

Fiscal 2019 capital additions were $25.5 million or 15 per cent above the fiscal 2019 RRA Plan primarily due to the increase in capital expenditures discussed above.

Contribution in Aid

Fiscal 2019 contribution in aid related to capital expenditures was $88.7 million or 111 per cent above the fiscal 2019 RRA Plan primarily due to the higher than planned expenditures for Distribution Customer Driven work, which is dependent on customer requests, as well as Contribution in Aid for several large major distribution projects being received in advance of project commencement.

Fiscal 2019 capital additions were $43.7 million or 54 per cent above the fiscal 2019 RRA Plan due to higher than planned volume for Distribution Customer Driven work.

4.23.3 Has BC Hydro considered re-assessing its use of BC Hydro starts and infrastructure investments in its forecasting? Please explain why or why not.

RESPONSE:

BC Hydro has no immediate plans to change the forecasting methods used for customer-driven work. The current forecasting method recognizes the uncertain nature of customer forecasts and takes a conservative approach so that available capital funding is not prematurely re-directed away from other priorities. BC Hydro believes that this is a prudent approach. For further information on BC Hydro's approach to forecasting customer-driven work, please refer to BC Hydro's response to CEC IR 4.23.2.

24.0 Reference: Exhibit B-19, Appendix G page 28

Table G-14 Fiscal 2019 Business Support Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support				
Technology	112.6	64.1	(48.5)	-43%
Properties	25.5	33.0	7.6	30%
Fleet/Other	45.7	72.5	26.8	59%
Total	**183.8**	**169.6**	**(14.2)**	**-8%**

4.24.1 Please elaborate on the increases in Properties additions.

RESPONSE:

As noted in BC Hydro's response to AMPC IR 3.17.1, fiscal 2019 Properties capital additions were $7.6 million above the RRA Plan primarily due to capital expenditures for various Building Improvement projects planned for future years being advanced to fiscal 2019.

Specifically, 17 various projects were advanced including HVAC, lighting, warehouse, and resurfacing upgrades and four new projects were initiated to add/upgrade emergency generators to field offices. All of these projects were less than $1 million each.

This was also the reason why the actual fiscal 2019 capital additions for the Properties sub-category 'Building Improvements and Others' were $8.4 million above the RRA Plan.

24.0 Reference: Exhibit B-19, Appendix G page 28

Table G-14 Fiscal 2019 Business Support Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support				
Technology	112.6	64.1	(48.5)	-43%
Properties	25.5	33.0	7.6	30%
Fleet/Other	45.7	72.5	26.8	59%
Total	183.8	169.6	(14.2)	-8%

4.24.2 Please elaborate on the increases in Fleet/other additions.

RESPONSE:

As shown in Table G-20 of Appendix G of the Evidentiary Update, which is re-produced below, the Fleet/Other capital additions variance in the table provided in the preamble to the question is comprised of the following variances.

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Fleet	30.2	35.7	5.5	18
Other	15.5	36.8	21.3	137
Total	45.7	72.5	26.8	59

Fiscal 2019 actual capital additions for 'Other' were $21.3 million above the fiscal 2019 RRA Plan primarily due to:

- **Communication equipment, planned as part of transmission projects, being included in 'Other" for accounting purposes;**
- **Work related to the Smart Metering Infrastructure Field Area sustainment project; and**
- **An unplanned project to replace storage racks at 24 locations to comply with new WorkSafeBC regulations.**

Fiscal 2019 actual capital additions for 'Fleet' were $5.5 million above the fiscal 2019 RRA Plan. Please refer to BC Hydro's response to CEC IR 4.20.3 for additional information on this variance.

25.0 Reference: Exhibit B-19, Appendix G page 29

> The reductions to capital additions outlined above were partially offset by emergent needs, delayed in-service dates, higher than expected storage costs, and other actual additions that were above plan amounts, totalling $40.2 million.

4.25.1 Please provide a breakdown with cost quantification of the emergent needs, delayed in-service dates, higher than expected storage cost and other additions that totaled $40.2 million.

RESPONSE:

The breakdown of emergent needs, delayed in-service dates, higher than expected storage costs and other additions that totaled $40.2 million is as follows:

- **Emergent needs – $13.0 million;**
- **Delayed in-services dates – $20.8 million;**
- **Higher than expected storage costs – $5.7 million; and**
- **Other additions – $0.7 million.**

25.0 Reference: Exhibit B-19, Appendix G page 29

> The reductions to capital additions outlined above were partially offset by emergent needs, delayed in-service dates, higher than expected storage costs, and other actual additions that were above plan amounts, totalling $40.2 million.

4.25.2 Please describe the 'emergent needs'.

RESPONSE:

Emergent investment needs are newly identified asset risks or opportunities which have resulted in a capital addition in the period.

The emergent needs, totalling $13.0 million, are categorized as follows:

- **Seven business-driven projects, totalling $6.0 million, including the Customer Mobile project ($2.9 million) and the Transmission Overhead Inspection and Quality Assurance Field Tool project ($1.3 million);**
- **Five enterprise application projects, totalling $3.3 million, including the Asset Hierarchy Foundation project ($1.1 million);**
- **Three licensing additions, totalling $3.1 million, including the Oracle Unlimited License Agreement; and**
- **Four cybersecurity additions, totalling $0.6 million.**

26.0 Reference: Exhibit B-19, Appendix G page 29

Table G-18 Fiscal 2019 Properties Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Building Development	6.7	5.9	(0.8)	-12%
Building Improvements and Others	18.8	27.1	8.4	45%
Other Properties	-	-	-	-
Total	**25.5**	**33.0**	7.6	30%

4.26.1 Please provide a brief discussion of the Building Improvements and Others that resulted in an increase of $8.4 million in additions.

RESPONSE:

Please refer to BC Hydro’s response to CEC IR 4.24.1 which provides an explanation for the fiscal 2019 increase in capital additions for the Properties sub-category ‘Building Improvements and Others’.

27.0 Reference: Exhibit B-19, Appendix G page 30 and 31

Table G-20 Fiscal 2019 Fleet/Other Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Fleet	30.2	35.7	5.5	18%
Other	15.5	36.8	21.3	137%
Total	**45.7**	**72.5**	**26.8**	**59%**

Fiscal 2019 capital expenditures for 'Other' were $12.4 million or 124 per cent above the fiscal 2019 RRA Plan primarily due to unplanned work related to the Smart Metering Infrastructure Field Area sustainment project. In addition, there was an unplanned project to replace storage racks at 24 locations to comply with new WorkSafeBC regulations.

Fiscal 2019 capital additions for 'Other' were $21.3 million or 137 per cent above the fiscal 2019 RRA Plan primarily due to the unplanned work described in the preceding paragraph and communication equipment planned as part of transmission projects but are classified as general assets for accounting purposes, instead of Technology assets where the additions were planned.

4.27.1 Please describe the unplanned work related to Smart Metering, and provide quantification.

RESPONSE:

The unplanned variance in fiscal 2019 in Capital 'Other", caused by the Smart Meter Infrastructure Field Area sustainment project was due to the responsibility of the project being moved from the Technology KBU to the Integrated Planning Business Group. As a result, capital additions of $4.5 million for this project were included in the Technology fiscal 2019 RRA Plan but the actual capital additions were recorded as 'Other' capital.

The Smart Metering Infrastructure Field Area sustainment project is an annual program to deploy additional telecommunications network equipment to connect

the smart meters installed for new customers which do not automatically connect to an existing Smart Meter Mesh network.

Connecting smart meters to the telecommunications network reduces cost and safety risks associated with manual meter reads, enables remote revenue assurance monitoring and supports automated billing, outage information and remote disconnects/reconnects for additional customers.

27.0 Reference: Exhibit B-19, Appendix G page 30 and 31

Table G-20 Fiscal 2019 Fleet/Other Capital Additions Variances

($ million)	F2019			
	RRA	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Fleet	30.2	35.7	5.5	18%
Other	15.5	36.8	21.3	137%
Total	**45.7**	**72.5**	**26.8**	**59%**

Fiscal 2019 capital expenditures for 'Other' were $12.4 million or 124 per cent above the fiscal 2019 RRA Plan primarily due to unplanned work related to the Smart Metering Infrastructure Field Area sustainment project. In addition, there was an unplanned project to replace storage racks at 24 locations to comply with new WorkSafeBC regulations.

Fiscal 2019 capital additions for 'Other' were $21.3 million or 137 per cent above the fiscal 2019 RRA Plan primarily due to the unplanned work described in the preceding paragraph and communication equipment planned as part of transmission projects but are classified as general assets for accounting purposes, instead of Technology assets where the additions were planned.

4.27.2 Please provide an update on the smart metering benefits realization.

RESPONSE:

Section 5 of BC Hydro's Smart Metering and Infrastructure Program Completion and Evaluation Report provides a summary of the estimated benefits and forecasts benefits to 2033. This report is available at the following link: https://www.bcuc.com/Documents/Proceedings/2016/DOC_48502_B-1-4_BCH-Appx-P-Update-SMI-Report.pdf.

As discussed in BC Hydro's response to CEC IRs 1.52.1 and 2.123.2, BC Hydro believes the estimates in that report remain valid.

1.0 In Appendix C - South Peace Region Forecast, on page 1 of 2, BC Hydro states: "In response to a commitment made in BC Hydro's response to BCUC IR 1.119.4, this appendix provides an update to the South Peace Region forecast for the area serviced by the Peace Region Electricity Supply Project (PRES).

4.1.8 Please provide an estimate of GHG emissions reduction for each MW of electrified load at: a) wellhead; b) gas collection/processing plants; c) pipelines; and d) other gas sector activities (if applicable).

RESPONSE:

BC Hydro does not have estimates of GHG emissions reductions for each MW of electrified load in the specific categories noted. BC Hydro has prepared high-level emission reduction estimates for electrification of gas processing, using an estimate of 560 tonnes CO2e per GWh. This estimate was derived from a study on small size gas turbine and reciprocating units carried out for BC Hydro by AMEC Foster Wheeler in 2016.

1.0 In Appendix C - South Peace Region Forecast, on page 1 of 2, BC Hydro states: "In response to a commitment made in BC Hydro's response to BCUC IR 1.119.4, this appendix provides an update to the South Peace Region forecast for the area serviced by the Peace Region Electricity Supply Project (PRES).

4.1.9 Please provide any assumptions embedded in the GHG emissions reduction estimates, as it concerns gas-to-electricity conversions.

RESPONSE:

Please refer to BC Hydro's response to GJOSHE IR 4.1.8.

1.0 In Appendix B – June 2019 Peak Forecast, in section 1.2. Peak Load Forecast Informs BC Hydro's Capital Planning, on pages 2 of 6 and 3 of 6, BC Hydro states: "As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support system expansions and reinforcements required to reliably serve new and existing customers."

Further, in response to BCUC 2.250.3 and BCUC 2.254.2, BC Hydro provides information on the North Montney Transmission Development (or the North Montney Power Supply) project (IPID 901572).

4.1.10 Please explain whether there are any changes to load growth expectations for the north Montney region, between the October 2018 Load Forecast and the June 2019 Load Forecast.

RESPONSE:

There are no changes between the October 2018 Load Forecast and the June 2019 Load Forecast for the region that would be served by the North Montney Transmission Development project.

1.0 In Appendix B – June 2019 Peak Forecast, in section 1.2. Peak Load Forecast Informs BC Hydro's Capital Planning, on pages 2 of 6 and 3 of 6, BC Hydro states: "As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support system expansions and reinforcements required to reliably serve new and existing customers."

Further, in response to BCUC 2.250.3 and BCUC 2.254.2, BC Hydro provides information on the North Montney Transmission Development (or the North Montney Power Supply) project (IPID 901572).

4.1.11 Please describe the geographical footprint of the North Montney Transmission Development project.

RESPONSE:

At this time, BC Hydro has not confirmed the geographical footprint for the North Montney Transmission Development project.

1.0 In Appendix B – June 2019 Peak Forecast, in section 1.2. Peak Load Forecast Informs BC Hydro's Capital Planning, on pages 2 of 6 and 3 of 6, BC Hydro states: "As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support system expansions and reinforcements required to reliably serve new and existing customers."

Further, in response to BCUC 2.250.3 and BCUC 2.254.2, BC Hydro provides information on the North Montney Transmission Development (or the North Montney Power Supply) project (IPID 901572).

4.1.12 Please provide the drivers for the North Montney Transmission Development project, especially as it concerns the split between wellhead (gas production), gas processing (processing plant) and compression (pipeline) load.

RESPONSE:

The drivers for the North Montney Transmission Development project are outlined in BC Hydro's response to BCUC IR 2.254.2.

A transmission expansion into the North Montney area would enable upstream natural gas processing plant owners and operators to electrify their operations using BC Hydro's clean energy instead of natural gas for production, processing, and compression for the purpose of reducing greenhouse gas emissions in British Columbia.

At this time, the split between production, processing and compression has not been determined.

1.0 In Appendix B – June 2019 Peak Forecast, in section 1.2. Peak Load Forecast Informs BC Hydro's Capital Planning, on pages 2 of 6 and 3 of 6, BC Hydro states: "As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support system expansions and reinforcements required to reliably serve new and existing customers."

Further, in response to BCUC 2.250.3 and BCUC 2.254.2, BC Hydro provides information on the North Montney Transmission Development (or the North Montney Power Supply) project (IPID 901572).

4.1.13 Please clarify whether the North Montney Transmission development project is in the vicinity of the Aitken Creek Gas Storage facility and/or the path of the North Montney portion of the Alliance Pipeline.

RESPONSE:

As stated in BC Hydro's response to GJOSHE IR 4.1.11, BC Hydro has not confirmed the geographical footprint for the North Montney Transmission Development project, at this time.

1.0 In Appendix B – June 2019 Peak Forecast, in section 1.2. Peak Load Forecast Informs BC Hydro's Capital Planning, on pages 2 of 6 and 3 of 6, BC Hydro states: "As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support system expansions and reinforcements required to reliably serve new and existing customers."

Further, in response to BCUC 2.250.3 and BCUC 2.254.2, BC Hydro provides information on the North Montney Transmission Development (or the North Montney Power Supply) project (IPID 901572).

4.1.14 Further to Gjoshe 4.13, are there any plans to electrify the existing compression and auxiliary load of the Aitken Creek Gas Storage facility? If yes, please confirm the electrical load that can be served.

RESPONSE:

The public version of the response has been redacted to maintain confidentiality over customer information. The un-redacted version of the response is being made available to the BCUC only, in order to protect the customer's commercial interests.

[redacted]

1.0 In Appendix B – June 2019 Peak Forecast, in section 1.2. Peak Load Forecast Informs BC Hydro's Capital Planning, on pages 2 of 6 and 3 of 6, BC Hydro states: "As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support system expansions and reinforcements required to reliably serve new and existing customers."

Further, in response to BCUC 2.250.3 and BCUC 2.254.2, BC Hydro provides information on the North Montney Transmission Development (or the North Montney Power Supply) project (IPID 901572).

4.1.15 Further to Gjoshe 4.13, are there any plans to electrify the existing compression load of the North Montney portion of the Alliance Pipeline? If yes, please confirm the electrical load that can be served.

RESPONSE:

The public version of the response has been redacted to maintain confidentiality over customer information. The un-redacted version of the response is being made available to the BCUC only, in order to protect the customer's commercial interests.

[redacted]

1.0 In Appendix B – June 2019 Peak Forecast, in section 1.2. Peak Load Forecast Informs BC Hydro's Capital Planning, on pages 2 of 6 and 3 of 6, BC Hydro states: "As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support system expansions and reinforcements required to reliably serve new and existing customers."

Further, in response to BCUC 2.250.3 and BCUC 2.254.2, BC Hydro provides information on the North Montney Transmission Development (or the North Montney Power Supply) project (IPID 901572).

4.1.16 Does BC Hydro have GHG emission reduction estimates associated with the electrification of the Aitken Creek Gas Storage facility load? Please discuss.

RESPONSE:

BC Hydro does not have GHG emission reduction estimates for the electrification of the Aitken Creek Gas Storage facility.

1.0 In Appendix B – June 2019 Peak Forecast, in section 1.2. Peak Load Forecast Informs BC Hydro's Capital Planning, on pages 2 of 6 and 3 of 6, BC Hydro states: "As discussed in BC Hydro's response to BCUC IR 1.111.1, growth investments support system expansions and reinforcements required to reliably serve new and existing customers."

Further, in response to BCUC 2.250.3 and BCUC 2.254.2, BC Hydro provides information on the North Montney Transmission Development (or the North Montney Power Supply) project (IPID 901572).

4.1.17 Does BC Hydro have GHG emission reduction estimates associated with the electrification of the compression load for the North Montney portion of the Alliance Pipeline? Please discuss.

RESPONSE:

BC Hydro does not have GHG emission reduction estimates for the electrification of the North Montney portion of the Alliance Pipeline.

2.0 In Section 1.2, on page 8, lines 1-5, BC Hydro states: "Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments. In addition, purchases from IPPs and Long-Term Commitments have decreased due to delayed IPP commercial operation dates and due to lower forecast IPP deliveries, based on updated historical delivery averages."

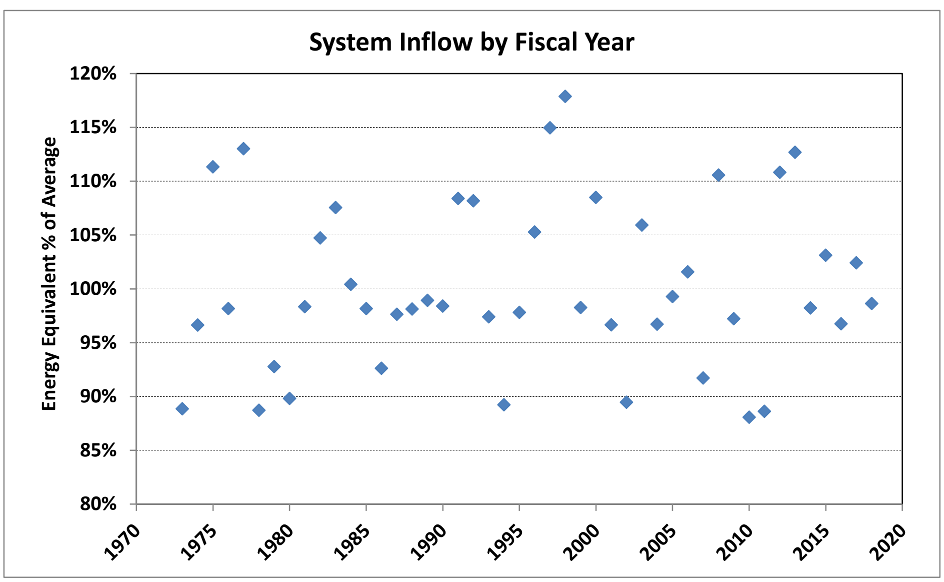
4.2.1 As it concerns planned hydroelectric generation at heritage resources, the Energy Study methodology considers historical inflow averages. Given that these averages span decades, and in light of changing expectations about future inflows, does such a methodology produce upwardly biased results?

RESPONSE:

This answer also responds to GJOSHE IR 4.2.2.

The 46 years of historic inflows used in the Energy Study, from 1973 to 2018, are currently the best information available to model both the expectation and the uncertainty in system generation through the test period.

The following chart shows the variability in inflows for fiscal years 1973 to 2018 as percent of average. There is no obvious trend, with both back-to-back wet and back-to-back dry years in the most recent 10 years shown.



Please refer to BC Hydro's response to CEC IR 1.17.1, where we explain that every year we add the most recent year of historic data to the modeled weather sequences, which allows BC Hydro to implicitly include impacts of climate change in the forecast. Furthermore, the variability in the historic record is an order of magnitude larger than the impact of climate change on the average forecast for the Test Period. In other words, changes to the expected (average) system operation due to climate change are small relative to changes to system operation due to weather for the Test Period.

The Pacific Climate Impacts Consortium completed an update of the projected hydrologic scenarios for key watersheds in British Columbia that will support assessment of possible future impacts to water supply for hydropower generation. Note that climate change in general is expected to cause slightly elevated precipitation and higher glacier melt in B.C. as described in BC Hydro's responses to CEABC IR 1.6.3, CEC IR 1.14.1, and links therein.

2.0 In Section 1.2, on page 8, lines 1-5, BC Hydro states: "Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments. In addition, purchases from IPPs and Long-Term Commitments have decreased due to delayed IPP commercial operation dates and due to lower forecast IPP deliveries, based on updated historical delivery averages."

4.2.2 To what extent looking back may no longer suffice to produce accurate expectations of future hydroelectric generation levels?

RESPONSE:

Please refer to BC Hydro's response to GJOSHE IR 4.2.1.

2.0 In Section 1.2, on page 8, lines 1-5, BC Hydro states: "Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments. In addition, purchases from IPPs and Long-Term Commitments have decreased due to delayed IPP commercial operation dates and due to lower forecast IPP deliveries, based on updated historical delivery averages."

4.2.3 What impact, if any, would continued repeated overestimation of planned hydroelectric generation, have on the balance of the Heritage Deferral Account?

RESPONSE:

If actual hydroelectric generation (and hence the associated water rental costs) is continuously lower than forecast, the favourable variance in water rental costs will be transferred to the Heritage Deferral Account thus reducing the balance of the account. The Heritage Deferral Account ensures that ratepayers only pay for actual costs.

However, assuming load remains the same, if the continuous overestimation of hydro generation causes some combination of higher market purchases, higher thermal generation or lower surplus sales, in all likelihood this will result in higher cost of energy, and therefore, a higher balance in the Heritage Deferral Account. This is because the unit cost of water rentals is generally much lower than the unit cost of these other sources of energy. Thus, the overall impact to the Heritage Deferral Account of the hypothetical posted by the question would depend on the net result of all of the variables.

2.0 In Section 1.2, on page 8, lines 1-5, BC Hydro states: “Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments. In addition, purchases from IPPs and Long-Term Commitments have decreased due to delayed IPP commercial operation dates and due to lower forecast IPP deliveries, based on updated historical delivery averages.”

In Appendix C - Updated Cost of Energy Forecast, in Section 1.1 on page 2 BC Hydro states: “This difference is primarily due to lower hydro generation output in fiscal 2019 and fiscal 2020 than forecast in the Application. Actual hydro generation output in fiscal 2019 was 4,027 GWh lower than the fiscal 2019 Plan, and hydro generation output in fiscal 2020 is expected to decrease by 4,894 GWh compared to the fiscal 2020 Plan in the Application. This is mainly driven by lower inflows constraining hydro generation during the winter of fiscal 2019 and fiscal 2020.”

4.2.4 Aside from lower inflows, are there other factors as it concerns water use at reservoirs of heritage power generating assets (i.e. use of reservoir water for other industrial, agricultural or residential purposes) of an appreciable magnitude, which may impact availability of water for power generation going forward?

RESPONSE:

Please refer to BC Hydro’s response to GJOSHE IR 4.2.5.

2.0 In Section 1.2, on page 8, lines 1-5, BC Hydro states: “Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments. In addition, purchases from IPPs and Long-Term Commitments have decreased due to delayed IPP commercial operation dates and due to lower forecast IPP deliveries, based on updated historical delivery averages.”

In Appendix C - Updated Cost of Energy Forecast, in Section 1.1 on page 2 BC Hydro states: “This difference is primarily due to lower hydro generation output in fiscal 2019 and fiscal 2020 than forecast in the Application. Actual hydro generation output in fiscal 2019 was 4,027 GWh lower than the fiscal 2019 Plan, and hydro generation output in fiscal 2020 is expected to decrease by 4,894 GWh compared to the fiscal 2020 Plan in the Application. This is mainly driven by lower inflows constraining hydro generation during the winter of fiscal 2019 and fiscal 2020.”

4.2.5 Please comment on any such factors for the Peace Region, the Interior (Columbia et al basins) and Vancouver Island generation.

RESPONSE:

BC Hydro enters into Water Use Agreements with municipalities and industrial users to use water from our reservoirs for domestic water supply and industrial uses. The agreements provide for compensation to BC Hydro for the lost power generation in order to keep ratepayers whole. We collaborate with the other users and plan our operations to accommodate their water use as needed, and in keeping with the available inflows.

On the Williston Reservoir we have three agreements for industrial use. These represent a very small volume of withdrawal in comparison to power generation.

We have no water use agreements in the Interior of B.C.

On Vancouver Island we have two agreements, one with the City of Campbell River on the John Hart Reservoir and one with the Comox Valley Regional District on the Comox Reservoir.

In the Lower Mainland we have an agreement with the Greater Vancouver Water District on the Coquitlam Reservoir.

2.0 In Section 1.2, on page 8, lines 1-5, BC Hydro states: "Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments. In addition, purchases from IPPs and Long-Term Commitments have decreased due to delayed IPP commercial operation dates and due to lower forecast IPP deliveries, based on updated historical delivery averages."

In Appendix C - Updated Cost of Energy Forecast, in Section 1.1 on page 2 BC Hydro states: "This difference is primarily due to lower hydro generation output in fiscal 2019 and fiscal 2020 than forecast in the Application. Actual hydro generation output in fiscal 2019 was 4,027 GWh lower than the fiscal 2019 Plan, and hydro generation output in fiscal 2020 is expected to decrease by 4,894 GWh compared to the fiscal 2020 Plan in the Application. This is mainly driven by lower inflows constraining hydro generation during the winter of fiscal 2019 and fiscal 2020."

4.2.6 As it concerns the Williston reservoir in the Peace Region, has BC Hydro come across any data or noticed any discernable trends with regard to the use of reservoir water for agriculture, shale gas fracking and other natural gas sector activities, mining, production of construction materials and such, that may impact estimates of heritage hydro generation output in the future?

RESPONSE:

Please refer to BC Hydro's response to GJOSHE IR 4.2.5.

2.0 In Section 1.2, on page 8, lines 1-5, BC Hydro states: "Dry conditions and lower water inflows have decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments. In addition, purchases from IPPs and Long-Term Commitments have decreased due to delayed IPP commercial operation dates and due to lower forecast IPP deliveries, based on updated historical delivery averages."

In Appendix C - Updated Cost of Energy Forecast, in Section 1.1 on page 2 BC Hydro states: "This difference is primarily due to lower hydro generation output in fiscal 2019 and fiscal 2020 than forecast in the Application. Actual hydro generation output in fiscal 2019 was 4,027 GWh lower than the fiscal 2019 Plan, and hydro generation output in fiscal 2020 is expected to decrease by 4,894 GWh compared to the fiscal 2020 Plan in the Application. This is mainly driven by lower inflows constraining hydro generation during the winter of fiscal 2019 and fiscal 2020."

4.2.7 As it concerns the Williston reservoir in the Peace Region, does BC Hydro foresee any impacts on its water use for power generation in the scenario of a full build out of LNG Canada (phases 1 and 2), including associated natural gas production, processing and transportation facilities?

RESPONSE:

BC Hydro is not anticipating any impacts to water use for power generation from the LNG Canada project or associated natural gas production, processing and transportation facilities at the Williston Reservoir. The LNG Canada project itself is located a substantial distance from the Williston Reservoir.

1 Topic: Load Resource Balance and IPP deliveries

Gjoshe Unredacted Information Request: 2.9.2

4.1 The response to Gjoshe 2.9.2 highlights that the highest period of IPP energy deliveries is during the freshet, and the lowest period being that of highest BC Hydro demand: the winter months. The RRA Evidentiary Update indicates that the expected pattern of deliveries (for F2021) has further shifted from the winter deliveries to the freshet. Please explain why the annual pattern of IPP deliveries are changing over time, and what can be done to mitigate this mismatch between IPP deliveries and seasonal BC Hydro customer demands.

RESPONSE:

The shift from winter deliveries to the freshet from 2002 to the present, reflected in the table included in BC Hydro's response to GJOSHE IR 2.9.2, which was made public in Exhibit B-20, is likely a result of the increase in BC Hydro's IPP portfolio of run-of-river projects reaching commercial operations. This increase in the number of run-of-river EPAs is largely due to the 2006 Open Call and the 2010 Clean Power Call.

To mitigate this mismatch between IPP deliveries and seasonal BC Hydro customer demands:

- **Where BC Hydro has the contractual rights, and when it makes sense to do so, BC Hydro will request an IPP to turn down its facility during the freshet season; and**
- **BC Hydro has introduced alternative rate structures designed to increase customer load during the freshet months.**

2 Reference: Twenty-Year Load Forecast October 3, 2019 – Appendix D

4.2 Tables D-1 to D-4 inclusive provide forecast energy and peak demand for the years F2021 forward. Please provide a version of each of these tables that includes 10 years of historical energy and peak actuals. At a minimum, please provide annual heritage energy production, IPP energy production, actual energy and peak demands, and the energy and peak Surplus/Deficit.

RESPONSE:

It is not appropriate to recreate Tables D-1 to D-4 based on historical heritage energy production numbers. Tables D-1 to D-4 are based on the capability of the system. A historical view is not comparable because it shows how the system was actually operated to maximize benefits to ratepayers, rather than its capability.

3 Reference: Twenty-Year Load Forecast October 3, 2019 – Appendix D

4.3 Please confirm that the length of the Forecast document is 35 pages, in contrast to the previously published BC Hydro long-term forecast which was in excess of 100 pages, and contained more methodological detail and sector-specific commentary. Is the 2019 Forecast document a summary of a more detailed document?

RESPONSE:

The length of the June 2019 Load Forecast document is 35 pages. The June 2019 Load Forecast document is not a summary of a more detailed document.

As indicated on page two of Exhibit B-15, the June 2019 Load Forecast extends and updates the October 2018 Load Forecast. Accordingly, the load forecast methodologies used to develop the October 2018 Load Forecast also apply to the June 2019 Load Forecast. Full details on these are provided in Appendix O of the Application.

Exhibit B-15 summarizes changes between the June 2019 Load Forecast and the October 2018 Load Forecast. The submission also provides a brief overview of system peak and South Peace region forecasts, which were not part of the October 2018 Load Forecast.

10 Topic: Electric Vehicles

Reference: Section 3.1.2: Twenty-Year Load Forecast October 3, 2019

"The June 2019 Load Forecast uses a new methodology for EVs, to align with the CleanBC Plan for light duty electric vehicles. Specifically, the Zero-Emission Vehicles Act (ZEV Act) was enacted on May 30, 2019. The ZEV Act stipulates the percentage of new light duty car and truck sales in B.C. that must be zero emission vehicles, as follows: 10 per cent of sales by 2025; 30 per cent of sales by 2030; and 100 per cent of sales by 2040.

Accordingly, the low EV forecast in the June 2019 Load Forecast is based on these requirements and the associated incentives because, at a minimum, EV sales would be expected to reach the levels required by legislation. The high-EV scenario assumes EV models are more available, the purchase cost declines, consumers' preferences change, and more infrastructure becomes available. In other words, the high EV forecast assumes that the natural uptake of EVs is greater than the requirements set out in the ZEV Act, resulting in a higher total EV forecast. Due to the significant level of uncertainty when developing a long-term EV forecast, BC Hydro developed its mid-EV forecast by taking the average between the high and low EV forecasts."

4.10 Is BC Hydro contemplating Time of Use rates to encourage the off-peak charging of EVs? If not, why not?

RESPONSE:

Yes. BC Hydro expects to explore optional rates and/or programs that would encourage off-peak charging of electric vehicles at residences.

In addition, please also refer to BC Hydro's responses to:

- **WILLIS IR 1.11.1 where we state that BC Hydro is examining rate designs for commercial electric vehicle public transit and fleet charging which would provide bill savings if customers charged overnight. BC Hydro filed its Fleet Electrification Rate Design Application on August 7, 2019 and it is currently being reviewed by the BCUC; and**

- **BCSEA IR 2.62.1 where we explain that the types and scope of the rates that BC Hydro may put forward for approval with regards to public fast charging will be informed by the Government of B.C.'s response to the Phase Two Report of the BCUC Inquiry into the Regulation of Electric Vehicle Charging Service.**

BC Hydro continues to develop its rate design strategy for electric vehicle charging rates and will engage customers and stakeholders as appropriate prior to making an application to the BCUC for any new rates.

11 Topic: Electric Vehicles

Reference: Section 3.1.2: Twenty-Year Load Forecast October 3, 2019

"The June 2019 Load Forecast uses a new methodology for EVs, to align with the CleanBC Plan for light duty electric vehicles. Specifically, the Zero-Emission Vehicles Act (ZEV Act) was enacted on May 30, 2019. The ZEV Act stipulates the percentage of new light duty car and truck sales in B.C. that must be zero emission vehicles, as follows: 10 per cent of sales by 2025; 30 per cent of sales by 2030; and 100 per cent of sales by 2040.

Accordingly, the low EV forecast in the June 2019 Load Forecast is based on these requirements and the associated incentives because, at a minimum, EV sales would be expected to reach the levels required by legislation. The high-EV scenario assumes EV models are more available, the purchase cost declines, consumers' preferences change, and more infrastructure becomes available. In other words, the high EV forecast assumes that the natural uptake of EVs is greater than the requirements set out in the ZEV Act, resulting in a higher total EV forecast. Due to the significant level of uncertainty when developing a long-term EV forecast, BC Hydro developed its mid-EV forecast by taking the average between the high and low EV forecasts."

4.11 Is BC Hydro contemplating an electric vehicle-specific rates to optimize the pattern of EV charging? If not, why not?

RESPONSE:

Please refer to BC Hydro's response to INCE IR 4.10 where we discuss the development of our rate design strategy with respect to electric vehicle charging rates.

12 Topic: Oil and Gas Load Forecast

Reference: Appendix C: Twenty Year Load Forecast October 3, 2019 – Figure C-1. South Peace assumptions.

4.12 Please comment on the continuing delays in realizing South Peace electrification loads, as evidenced in the most recent (June 2019) forecast relative to the previous forecast (December 2017), relative to the May 2016 Forecast and relative to the 2012 (IRP) forecast. Please indicate the drivers of these delays, including the business climate in the region and the province, environmental and First Nations issues, carbon taxes, challenges in getting pipelines constructed, the cost of electrification and low (oil and gas) commodity prices.

RESPONSE:

The changes to the South Peace load forecasts from the December 2012 Load Forecast to the June 2019 Load Forecast are generally described in BC Hydro's response to CEABC IR 2.41.1.

16 Topic: Oil and Gas Load Forecast

Reference: Appendix C: Twenty Year Load Forecast October 3, 2019 – Figure C-1. South Peace assumptions.

British Columbia Hydro & Power Authority Fiscal 2017 – Fiscal 2019 Revenue Requirements Application

Association of Major Power Customers of BC Information Request No. 2.7.6 Dated: December 16, 2016 British Columbia Hydro & Power Authority Response issued January 23, 2017

In its response to this question on the field servicing of natural gas industry hydraulic fracturing loads, BC Hydro responded that it: "…expects that we will be investigating potential opportunities for providing such service as part of our broader low-carbon electrification efforts."

4.16 Please provide an update on this progress, and how this initiative is supported within the CleanBC policy framework.

RESPONSE:

BC Hydro engages with potential natural gas industry customers that are exploring electrification for various aspects of their upstream operations.

System improvement projects recently completed or underway include the Dawson Creek Area Transmission (DCAT) and the Peace Region Electricity Supply (PRES) projects. BC Hydro continues to identify and consider potential system improvement projects that would further enable the electrification of the natural gas industry. This includes BC Hydro's participation in the Memorandum of Understanding between the Government of Canada and the Government of B.C. to support the electrification of the natural gas sector in British Columbia (https://pm.gc.ca/en/news/backgrounders/2019/08/29/memorandum-understanding-between-government-canada-and-government).

Exploring opportunities to increase the use of BC Hydro's renewable electricity by industry is also included in the Terms of Reference for Phase Two of the Comprehensive Review of BC Hydro:

> **"The objective is to develop recommendations for how BC Hydro can accomplish the provincial policy objectives laid out in the CleanBC plan, including how BC Hydro can support meeting British Columbia's legislated 2030, 2040, and 2050 greenhouse gas reduction targets in a manner that ensures BC Hydro sustainability in the future for the benefit of British Columbians."**

17 Reference: Twenty Year Load Forecast October 3, 2019

4.17 Please comment on the effect of the Oct. 24, 2019 Declaration on the Rights of Indigenous Peoples Act introduced in the BC Legislature in terms of its effect on the industrial sector load forecast, specifically whether this Act constitutes a 'veto' on all future public and private sector resource projects, including BC Hydro capital projects.

RESPONSE:

BC Hydro cannot speculate whether the B.C. Declaration on the *Rights of Indigenous Peoples Act* (the Act) will have an effect on the load forecast for the industrial sector as the Act has recently been introduced.

A Government of B.C. fact sheet regarding the Act is available at the following link:

https://www2.gov.bc.ca/assets/gov/british-columbians-our-governments/indigenous-people/aboriginal-peoples-documents/undrip_legislation_factsheet_business_final.pdf.

In planning and implementing capital projects, BC Hydro has followed, and will continue to follow, our Statement of Indigenous Principles, a copy of which can be found at the following link:

https://www.bchydro.com/community/indigenous-relations/principles.html.

21 Reference: Twenty-Year Load Forecast October 3, 2019 Section 1.1. Peak load forecast

4.21 Please provide the most recent monthly-resolution forecast of DSM Savings for both in energy and peak. Please calculate the monthly capacity factor of the savings.

RESPONSE:

BC Hydro's demand-side management (DSM) modelling software determines peak savings on an annual basis, consistent with our definition of system peak. As such, the monthly resolution forecast and the monthly capacity factor of DSM savings is not available.

22 Reference: Twenty-Year Load Forecast October 3, 2019 Section 1.1. Peak load forecast

4.22 Please provide historical monthly-resolution DSM Savings, if possible for the last 5 years, and broken down to the major DSM categories including Rates, Codes & Standards, programs, etc.

RESPONSE:

Attachment 1 to this response provides the actual cumulative acquired energy savings from the various DSM initiatives based on new activities from fiscal 2015 to fiscal 2019, allocated on a monthly basis within each year. BC Hydro's DSM model determines peak savings on an annual basis consistent with our definition of system peak. Therefore, only the actual cumulative annual peak savings have been provided.

Cumulative Acquired Electricity Savings at Customer Meter (GWh)

	F2015 Distribution of Savings by month												Total Savings for F2015
	Actual April F2015	Actual May F2015	Actual June F2015	Actual July F2015	Actual Aug F2015	Actual Sept F2015	Actual Oct F2015	Actual Nov F2015	Actual Dec F2015	Actual Jan F2015	Actual Feb F2015	Actual March F2015	Actual F2015
Codes and Standards													
Residential	1	1	2	2	3	4	6	7	9	11	9	10	65
Commercial	0	1	1	1	1	2	2	2	3	3	3	3	21
Industrial	0	0	0	0	0	0	0	0	0	0	0	1	4
Advanced DSM Strategies	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Codes and Standards	**1**	**2**	**3**	**4**	**5**	**6**	**8**	**10**	**12**	**14**	**13**	**14**	**90**
Rate Structures													
Residential Inclining Block Rate	1	1	1	1	1	1	1	1	2	1	1	1	13
General Service Rate	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Service Rate	17	18	18	18	17	17	18	17	18	18	16	18	209
Total Rate Structures	**18**	**19**	**18**	**19**	**18**	**18**	**19**	**18**	**19**	**19**	**17**	**19**	**222**
DSM Programs													
Residential Sector													
Behaviour	0	0	0	0	0	1	1	1	2	2	2	2	12
Refrigerator Buy-back	0	0	0	0	0	0	0	0	0	0	0	0	2
Low Income	0	0	0	0	0	0	0	0	0	0	0	0	2
Non Integrated Areas	0	0	0	0	0	0	0	0	0	0	0	0	0
New Home	0	0	0	0	0	0	0	0	1	1	1	0	3
Retail	0	0	0	0	0	0	1	1	1	1	1	1	7
Home Energy Retrofit Offer	0	0	0	0	0	0	0	0	0	0	0	0	1
Residential Sector Total	*0*	*0*	*1*	*1*	*1*	*1*	*2*	*3*	*4*	*4*	*4*	*4*	*26*
Commercial Sector													
Leaders in Energy Management - Commercial	0	1	1	1	2	2	2	3	4	5	5	7	33
New Construction	0	0	0	0	1	1	1	1	1	1	1	1	8
Commercial Sector Total	*1*	*1*	*1*	*2*	*2*	*3*	*3*	*4*	*5*	*6*	*6*	*8*	*41*
Industrial Sector													
Leaders in Energy Management - Transmission	0	0	0	1	4	4	5	5	9	10	10	11	60
Thermo-Mechanical Pulp	0	0	0	0	0	0	0	0	0	0	0	0	0
Leaders in Energy Management - Distribution	0	0	0	1	1	1	1	2	2	2	2	3	15
Load Displacement	0	0	0	1	1	1	1	1	1	1	1	2	12
Industrial Sector Total	*0*	*1*	*1*	*3*	*6*	*7*	*8*	*8*	*12*	*13*	*13*	*16*	*87*
Total Programs	**1**	**2**	**3**	**5**	**9**	**10**	**13**	**15**	**21**	**23**	**23**	**28**	**154**
PORTFOLIO TOTAL	**20**	**23**	**24**	**28**	**33**	**34**	**40**	**43**	**52**	**56**	**53**	**60**	**466**

Cumulative Acquired Electricity Savings at Customer Meter (GWh)

	F2016 Distribution of Savings by month												Total Savings for F2016
	Actual April F2016	Actual May F2016	Actual June F2016	Actual July F2016	Actual Aug F2016	Actual Sept F2016	Actual Oct F2016	Actual Nov F2016	Actual Dec F2016	Actual Jan F2016	Actual Feb F2016	Actual March F2016	Actual F2016
Codes and Standards													
Residential	10	10	11	12	13	15	19	22	26	29	25	25	216
Commercial	4	4	5	5	6	6	7	7	8	8	8	9	76
Industrial	1	1	1	1	1	1	1	1	1	1	1	1	12
Advanced DSM Strategies	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Codes and Standards	**14**	**15**	**16**	**18**	**20**	**22**	**27**	**30**	**35**	**39**	**34**	**35**	**304**
Rate Structures													
Residential Inclining Block Rate	1	1	1	1	1	1	1	1	2	1	1	1	13
General Service Rate	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Service Rate	18	19	18	19	18	18	19	18	19	19	17	18	220
Total Rate Structures	**19**	**20**	**19**	**20**	**19**	**19**	**20**	**19**	**20**	**20**	**18**	**20**	**233**
DSM Programs													
Residential Sector													
Behaviour	2	2	1	2	2	2	2	3	3	3	3	3	27
Refrigerator Buy-back	0	0	0	0	1	1	0	0	0	0	0	0	5
Low Income	0	0	0	0	0	0	1	1	1	1	1	1	6
Non Integrated Areas	0	0	0	0	0	0	0	0	0	0	0	0	0
New Home	0	0	0	0	0	0	0	1	1	1	1	1	5
Retail	1	1	1	1	1	1	3	3	3	3	2	2	23
Home Energy Retrofit Offer	0	0	0	0	0	0	0	1	1	1	1	1	5
Residential Sector Total	*4*	*4*	*3*	*4*	*4*	*4*	*6*	*8*	*9*	*10*	*8*	*8*	*72*
Commercial Sector													
Leaders in Energy Management - Commercial	6	7	7	8	8	8	9	10	11	12	11	13	109
New Construction	1	1	1	1	1	1	2	2	2	2	2	3	19
Commercial Sector Total	*8*	*8*	*8*	*9*	*10*	*10*	*10*	*11*	*13*	*13*	*13*	*16*	*128*
Industrial Sector													
Leaders in Energy Management - Transmission	12	13	13	14	15	16	17	17	18	18	17	19	191
Thermo-Mechanical Pulp	0	0	0	0	0	0	0	6	6	6	5	6	29
Leaders in Energy Management - Distribution	3	3	4	4	4	4	5	5	5	5	5	6	53
Load Displacement	4	4	4	4	4	4	4	4	4	4	4	6	53
Industrial Sector Total	*20*	*21*	*21*	*22*	*24*	*24*	*26*	*32*	*34*	*34*	*31*	*37*	*327*
Total Programs	**31**	**33**	**33**	**35**	**37**	**38**	**43**	**51**	**56**	**57**	**53**	**60**	**526**
PORTFOLIO TOTAL	**64**	**67**	**69**	**72**	**76**	**78**	**90**	**101**	**111**	**116**	**105**	**115**	**1,063**

Cumulative Acquired Electricity Savings at Customer Meter (GWh)

	F2017 Distribution of Savings by month												Total Savings for F2017
	Actual April F2017	Actual May F2017	Actual June F2017	Actual July F2017	Actual Aug F2017	Actual Sept F2017	Actual Oct F2017	Actual Nov F2017	Actual Dec F2017	Actual Jan F2017	Actual Feb F2017	Actual March F2017	Actual F2017
Codes and Standards													
Residential	24	23	24	25	26	29	36	40	47	50	41	41	406
Commercial	9	10	10	11	12	12	12	13	13	14	13	15	144
Industrial	1	1	1	2	2	2	2	2	2	2	2	2	20
Advanced DSM Strategies	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Codes and Standards	**34**	**35**	**35**	**37**	**40**	**42**	**50**	**54**	**62**	**66**	**56**	**58**	**569**
Rate Structures													
Residential Inclining Block Rate	1	1	1	1	1	1	1	1	2	1	1	1	13
General Service Rate	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Service Rate	16	17	16	17	16	16	17	16	16	16	15	16	195
Total Rate Structures	**17**	**18**	**17**	**18**	**17**	**17**	**18**	**17**	**18**	**18**	**16**	**18**	**208**
DSM Programs													
Residential Sector													
Behaviour	3	2	2	2	2	2	3	4	5	5	5	5	40
Refrigerator Buy-back	0	0	0	1	1	1	0	0	0	0	0	0	6
Low Income	1	1	1	1	1	1	1	1	1	1	1	1	11
Non Integrated Areas	0	0	0	0	0	0	0	0	0	0	0	0	0
New Home	0	0	0	0	0	0	0	1	1	1	1	1	5
Retail	3	2	2	2	2	3	4	4	5	5	4	4	41
Home Energy Retrofit Offer	0	0	0	0	0	0	1	1	2	2	2	1	10
Residential Sector Total	*7*	*6*	*6*	*6*	*6*	*7*	*10*	*12*	*14*	*15*	*12*	*12*	*112*
Commercial Sector													
Leaders in Energy Management - Commercial	12	13	13	15	15	15	16	16	18	18	16	19	186
New Construction	2	2	2	3	3	3	3	3	3	4	3	4	35
Commercial Sector Total	*15*	*16*	*16*	*17*	*18*	*18*	*18*	*19*	*21*	*21*	*20*	*23*	*221*
Industrial Sector													
Leaders in Energy Management - Transmission	23	26	26	26	26	26	27	26	27	30	28	31	321
Thermo-Mechanical Pulp	6	6	6	6	6	6	6	6	6	6	5	6	71
Leaders in Energy Management - Distribution	5	6	6	7	7	7	7	8	8	8	8	9	87
Load Displacement	6	6	6	6	6	6	6	6	6	6	5	6	71
Industrial Sector Total	*40*	*44*	*44*	*45*	*45*	*44*	*47*	*46*	*47*	*51*	*46*	*52*	*550*
Total Programs	**62**	**66**	**65**	**68**	**68**	**68**	**75**	**77**	**82**	**86**	**78**	**86**	**883**
PORTFOLIO TOTAL	**112**	**118**	**118**	**123**	**125**	**127**	**143**	**149**	**162**	**171**	**151**	**162**	**1,660**

Cumulative Acquired Electricity Savings at Customer Meter (GWh)

	F2018 Distribution of Savings by month												Total Savings for F2018
	Actual April F2018	Actual May F2018	Actual June F2018	Actual July F2018	Actual Aug F2018	Actual Sept F2018	Actual Oct F2018	Actual Nov F2018	Actual Dec F2018	Actual Jan F2018	Actual Feb F2018	Actual March F2018	Actual F2018
Codes and Standards													
Residential	39	38	38	39	42	44	55	61	70	75	61	60	623
Commercial	14	16	16	18	18	18	19	19	21	21	20	22	222
Industrial	2	2	2	2	2	2	2	2	3	3	2	3	28
Advanced DSM Strategies	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Codes and Standards	**56**	**56**	**56**	**59**	**62**	**65**	**76**	**83**	**93**	**99**	**84**	**85**	**874**
Rate Structures													
Residential Inclining Block Rate	1	1	1	1	1	1	1	1	2	1	1	1	13
General Service Rate	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Service Rate	9	9	9	9	9	9	9	9	9	9	8	9	110
Total Rate Structures	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**11**	**11**	**10**	**10**	**123**
DSM Programs													
Residential Sector													
Behaviour	4	3	3	3	3	3	4	6	7	7	6	6	57
Refrigerator Buy-back	0	0	0	1	1	1	0	0	0	0	0	0	6
Low Income	1	1	1	1	1	1	1	2	2	2	2	1	16
Non Integrated Areas	0	0	0	0	0	0	0	0	0	0	0	0	0
New Home	0	0	0	0	0	0	0	1	1	1	1	1	5
Retail	5	4	4	4	4	5	6	6	7	7	5	5	62
Home Energy Retrofit Offer	1	0	0	0	0	0	1	2	3	3	2	2	15
Residential Sector Total	*11*	*9*	*9*	*9*	*9*	*10*	*14*	*17*	*20*	*20*	*17*	*15*	*160*
Commercial Sector													
Leaders in Energy Management - Commercial	18	19	19	19	20	19	20	20	21	21	20	22	237
New Construction	4	4	4	4	4	4	4	5	5	5	5	6	53
Commercial Sector Total	*22*	*22*	*22*	*23*	*24*	*23*	*24*	*24*	*26*	*26*	*25*	*28*	*290*
Industrial Sector													
Leaders in Energy Management - Transmission	31	33	33	34	34	33	34	33	34	32	34	38	404
Thermo-Mechanical Pulp	6	6	6	6	6	6	6	6	6	6	5	6	71
Leaders in Energy Management - Distribution	8	8	8	8	9	9	10	10	10	10	10	11	112
Load Displacement	6	6	6	6	6	6	6	6	6	6	5	6	71
Industrial Sector Total	*51*	*53*	*52*	*55*	*54*	*53*	*56*	*55*	*57*	*55*	*55*	*62*	*657*
Total Programs	**83**	**85**	**84**	**87**	**87**	**87**	**94**	**96**	**102**	**101**	**96**	**105**	**1,108**
PORTFOLIO TOTAL	**149**	**151**	**150**	**157**	**159**	**161**	**180**	**189**	**206**	**211**	**190**	**200**	**2,104**

Cumulative Acquired Electricity Savings at Customer Meter (GWh)

	F2019 Distribution of Savings by month												Total Savings for F2019
	Actual April F2019	Actual May F2019	Actual June F2019	Actual July F2019	Actual Aug F2019	Actual Sept F2019	Actual Oct F2019	Actual Nov F2019	Actual Dec F2019	Actual Jan F2019	Actual Feb F2019	Actual March F2020	Actual F2019
Codes and Standards													
Residential	57	55	55	56	59	63	77	85	97	104	84	82	874
Commercial	22	24	25	27	27	27	28	29	30	31	29	33	331
Industrial	3	3	3	3	3	3	3	3	3	4	3	4	38
Advanced DSM Strategies	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Codes and Standards	**81**	**82**	**82**	**86**	**89**	**93**	**108**	**117**	**131**	**138**	**117**	**118**	**1,243**
Rate Structures													
Residential Inclining Block Rate	1	1	1	1	1	1	1	1	2	1	1	1	13
General Service Rate	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Service Rate	11	11	11	11	11	11	11	11	11	11	10	11	134
Total Rate Structures	**12**	**12**	**12**	**12**	**12**	**12**	**13**	**12**	**13**	**13**	**12**	**13**	**147**
DSM Programs													
Residential Sector													
Behaviour	5	5	4	4	4	5	6	7	9	9	8	8	75
Refrigerator Buy-back	0	0	0	1	1	1	0	0	0	0	0	0	6
Low Income	1	1	1	1	1	2	2	2	3	3	2	2	22
Non Integrated Areas	0	0	0	0	0	0	0	0	0	0	0	0	0
New Home	0	0	0	0	0	0	0	1	1	1	1	1	5
Retail	5	5	5	4	5	5	6	7	8	7	6	5	68
Home Energy Retrofit Offer	1	0	0	0	0	0	2	3	4	5	3	3	21
Residential Sector Total	*13*	*12*	*11*	*11*	*11*	*12*	*17*	*21*	*25*	*25*	*20*	*19*	*196*
Commercial Sector													
Leaders in Energy Management - Commercial	21	22	22	22	22	22	23	23	24	24	23	25	273
New Construction	5	5	5	6	6	5	6	6	6	6	6	6	68
Commercial Sector Total	*26*	*27*	*27*	*28*	*28*	*27*	*28*	*29*	*30*	*30*	*28*	*31*	*341*
Industrial Sector													
Leaders in Energy Management - Transmission	35	34	34	35	34	35	36	35	37	37	34	37	422
Thermo-Mechanical Pulp	6	6	6	6	6	6	11	10	15	15	13	15	115
Leaders in Energy Management - Distribution	10	10	10	11	11	11	12	12	13	13	12	13	139
Load Displacement	6	6	6	6	6	6	6	6	6	6	5	6	71
Industrial Sector Total	*57*	*57*	*56*	*58*	*57*	*58*	*65*	*63*	*70*	*70*	*64*	*71*	*746*
Total Programs	**97**	**96**	**94**	**97**	**96**	**98**	**110**	**113**	**124**	**125**	**113**	**121**	**1,283**
PORTFOLIO TOTAL	**190**	**190**	**188**	**195**	**198**	**202**	**231**	**242**	**269**	**277**	**241**	**252**	**2,673**

Cumulative Associated Capacity Savings at Customer Meter (MW)

	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Actual
Codes and Standards					
Residential	16	54	101	153	214
Commercial	3	11	20	31	46
Industrial	0	1	2	3	4
Advanced DSM Strategies	0	0	0	0	0
Total Codes and Standards	**19**	**66**	**123**	**186**	**265**
Rate Structures					
Residential Inclining Block Rate	3	3	3	3	3
General Service Rate	0	0	0	0	0
Transmission Service Rate	24	26	23	13	16
Total Rate Structures	**27**	**28**	**25**	**15**	**18**
DSM Programs					
Residential Sector					
Behaviour	2	5	8	11	15
Refrigerator Buy-back	0	1	1	1	1
Low Income	1	2	3	5	7
Non Integrated Areas	0	0	0	0	0
New Home	1	2	2	2	2
Retail	2	7	12	19	20
Home Energy Retrofit Offer	0	2	4	5	8
Residential Sector Total	*6*	*18*	*30*	*43*	*52*
Commercial Sector					
Leaders in Energy Management - Commercial	5	16	27	35	41
New Construction	1	3	5	8	10
Commercial Sector Total	*6*	*18*	*32*	*43*	*50*
Industrial Sector					
Leaders in Energy Management - Transmission	7	22	37	47	49
Thermo-Mechanical Pulp	0	3	8	8	13
Leaders in Energy Management - Distribution	2	7	12	15	19
Load Displacement	1	6	8	8	8
Industrial Sector Total	*10*	*39*	*66*	*79*	*90*
Total Programs	**22**	**76**	**127**	**165**	**192**
PORTFOLIO TOTAL	**68**	**170**	**276**	**366**	**475**

24 Reference: Twenty-Year Load Forecast October 3, 2019 Section 1.1. Peak load forecast

4.24 Please note that the calculated load factor after DSM is somewhat worse (lower) than as calculated before-DSM. Does this imply that BC Hydro's DSM programs are primarily focused on energy savings, whereas BC Hydro's provided load-resource balance indicates that new capacity is the more immediate need?

RESPONSE:

BC Hydro's current DSM plan is energy-focused. The DSM plan is not developed to target a specific load factor. Rather, the load factor is a result of the relative mix of activities within the plan and the ratio of energy savings to associated capacity savings of those activities.

BC Hydro continues to pilot and develop capacity-focused DSM programs that will inform future resource options. The 2021 Integrated Resource Plan will inform BC Hydro's energy and capacity-focused DSM plans going forward.

25 Reference: Twenty-Year Load Forecast October 3, 2019 Section 1.1. Peak load forecast

4.25 Within the attached spreadsheet, please check and comment on the calculated capacity factors of IPP generation and IPP renewals (rows 123 and 125). The high numbers imply that the seasonal energy production from these resources is a mismatch to BC Hydro's load shape – i.e. cumulatively that IPP deliveries are energy rich and capacity poor.

RESPONSE:

The capacity factor values provided in rows 123 and 125 of the spreadsheet attached to the information request are not correct and it appears the calculation used has incorrect data inputs (e.g., effective load carrying capability was used instead of installed capacity).

Capacity factor is a measure used to determine how much a resource is used (i.e., annual energy generation amounts) relative to its installed capability (assuming the facility operates at its installed capacity in every hour of the year). Hence, by definition, it is generally not possible to have a capacity factor greater than 100 per cent. In addition, BC Hydro notes that a high or low capacity factor does not necessarily lead to a conclusion that seasonal energy production is a mismatch with load shape.

26 Reference: Twenty-Year Load Forecast October 3, 2019: Table 1

4.26 Please confirm that the econometric forecast(s) used in the current Residential and Commercial customer sector forecasts was not updated from the October, 2018 Forecast.

RESPONSE:

Confirmed. The June 2019 Load Forecast used the same economic forecast as the October 2018 Load Forecast.

27 Reference: Twenty-Year Load Forecast October 3, 2019: Section 3.3 Light Industrial

4.27 Please confirm that the GDP forecast was updated for the Light Industrial forecast. Please provide a table comparing the econometric inputs in the Evidentiary Update (BC Ministry of Finance September 2018 Q1 Report for fiscal 2019 to fiscal 2023), to the new October 3rd Forecast (BC Ministry of Finance February 2019 Budget for fiscal 2019 to fiscal 2023). Please provide GDP, exchange ($US/Cdn) and interest rate projections from both forecasts.

RESPONSE:

Confirmed.

For the table comparing the GDP growth rate from the B.C. Ministry of Finance September 2018 Q1 Report and the B.C. Ministry of Finance February 2019 Budget, please refer to BC Hydro's response to BCOAPO IR 4.178.1.

BC Hydro does not use the exchange rate and interest rate projections as a direct input into the development of the Light Industrial Forecast.

28 Reference: Twenty-Year Load Forecast October 3, 2019: Section 3.3.1: Codes and Standards: DSM-Load Forecast Overlaps

4.28 Please provide the 2019 Navigant Report on DSM-Load Forecast overlaps.

RESPONSE:

No formal report was provided by Navigant on their work regarding Codes and Standards overlap. For a discussion of the results of Navigant's work and the impact to the load forecast, please refer to BC Hydro's response to INCE IR 1.8.6.

29 Reference: Twenty-Year Load Forecast October 3, 2019: Section 3.3.1: Codes and Standards: DSM-Load Forecast Overlaps

4.29 Please confirm the reason for an upwards adjustment to the Evidentiary Update load forecast is that DSM savings formerly attributed by BC Hydro were already embedded in the base load forecast – before DSM savings.

RESPONSE:

BC Hydro notes that:

- **The reference for this question should be section 3.1.1, not section 3.3.1; and**
- **The June 2019 Load Forecast was provided for information purposes only and was not part of the Evidentiary Update. The calculation of the Test Period revenue requirements, as updated by the Evidentiary Update, uses actual financial results for April 2019 and May 2019 and the October 2018 Load Forecast for the remainder of fiscal 2020 and all of fiscal 2021.**

As shown in Figure 2 of Exhibit B-15, the revised Codes and Standards overlap assessment results in an increase in the June 2019 Load Forecast relative to the October 2018 Load Forecast (estimated to be 28 GWh in fiscal 2020 and 44 GWh in fiscal 2021).

30 Reference: Twenty-Year Load Forecast October 3, 2019: Section 3.3.1: Codes and Standards: DSM-Load Forecast Overlaps

4.30 Please provide a high-level summary of the categories of end-use overlaps identified in the Navigant Report.

RESPONSE:

For a discussion of the results of Navigant's work and the impact to the load forecast, please refer to BC Hydro's response to INCE IR 1.8.6.

31 Reference: British Columbia Utilities Commission Information Request No. 3.296.3 Dated: September 19, 2019 British Columbia Hydro & Power Authority Response issued October 10, 2019

4.31 Please confirm that in Scenario H, as proposed in David Ince Information Request: 3.2, the forecast cumulative Five-Year Net Bill Impact is 4.4%, which is lower than the 6.2% cumulative rate impact proposed by BC Hydro.

RESPONSE:

Confirmed. Please refer to BC Hydro's response to BCUC IR 3.296.3, where BC Hydro explains why BC Hydro considers Scenario H to be less preferable than BC Hydro's proposal in the Evidentiary Update.

32 Reference: British Columbia Utilities Commission Information Request No. 3.296.3 Dated: September 19, 2019 British Columbia Hydro & Power Authority Response issued October 10, 2019

4.32 Please provide the rate impact (annual $/year) of adopting the BC Hydro cumulative rate proposal of 6.2% versus the 4.4% that would result from adopting Ince Scenario H.

RESPONSE:

BC Hydro typically presents rate impacts as percentage changes in rates or bill impacts. Please refer to the table below, which summarizes information from the Evidentiary Update and BC Hydro's response to BCUC IR 3.296.3 in respect of Scenario H.

Annual Bill Impact - Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Per Scenario H, as per BC Hydro's Response to BCUC IR 3.296.3	1.76	0.64	0.64	0.64	0.64
Per Evidentiary Update	1.76	(0.99)	2.69	(0.26)	2.95
Difference	-	1.62	(2.05)	0.90	(2.32)

Cumulative Bill Impact - Per Cent Increase / (Decrease)	F2020	F2021	F2022	F2023	F2024
Per Scenario H, as per BC Hydro's Response to BCUC IR 3.296.3	1.76	2.41	3.06	3.71	4.37
Per Evidentiary Update	1.76	0.75	3.46	3.19	6.24
Difference	-	1.65	(0.41)	0.52	(1.87)

As the question asks for the rate impact in annual dollar amounts per year, we have interpreted the question to be asking what the difference in the revenue requirements is between BC Hydro's rate proposal in the Evidentiary Update and Scenario H in BC Hydro's response to BCUC IR 3.296.3.

The annual revenue requirements associated with Scenario H, as compared to BC Hydro's Evidentiary Update, are shown in the table below.

Forecast Revenue Requirements ($ million)	F2020	F2021	F2022	F2023	F2024	Total
Per Scenario H, as per BC Hydro's Response to BCUC IR 3.296.3	5,224	5,284	5,311	5,375	5,503	26,697
Per Evidentiary Update	5,224	5,198	5,332	5,348	5,601	26,703
Difference in Revenue Requirements	0	85	(21)	27	(98)	(7)

As shown in the table above, the cumulative difference in revenue requirements between Scenario H and BC Hydro's proposal in the Evidentiary Update is $7 million over the fiscal 2020 to fiscal 2024 period.

In its response to BCUC IR 3.296.3, BC Hydro outlined its principles for proposing the rate increases as well as why BC Hydro considers its proposal in the Evidentiary Update to be preferable to Scenario H. Specifically, in that response, BC Hydro noted that:

- **As a cost of service utility, BC Hydro should collect its revenue requirements in each Test Period. Scenario H will result in BC Hydro collecting more than its revenue requirements from ratepayers in the Test Period; and**
- **We do not consider it advisable to smooth rates beyond the Test Period, or to use assumed future test period costs and revenues to determine a smoothed bill increase that impacts the current Test Period, as would be required in Scenario H.**

34 Reference: British Columbia Utilities Commission Information Request No. 3.296.3 Dated: September 19, 2019 British Columbia Hydro & Power Authority Response issued October 10, 2019

4.34 Please confirm that Scenario H produces the lowest cumulative five-year rate impact of all 14 of the scenarios investigated and summarized in the response to BCUC 3 296.3.

RESPONSE:

Confirmed. Please refer to BC Hydro's response to BCUC IR 3.296.3, where BC Hydro explains why BC Hydro considers Scenario H to be less preferable than BC Hydro's proposal in the Evidentiary Update.

35 Reference: Response to Ince Information Request 3.10.

4.35 Please explain an almost 10% negative variance in July and August F2020 sales in the Large Industrial category relative to the Evidentiary Update load forecast. In BC Hydro's response to Ince Information Request 3.10, BC Hydro indicated that it was too early to establish a variance trend. Is a trend clearer now with September actuals?

RESPONSE:

The reasons for the variance in large industrial sales are provided in BC Hydro's response to INCE IR 3.10.0. In that response, BC Hydro's states that it is too early to determine a trend with regards to the residential and commercial sectors, not the large industrial sector.

36 Reference: Response to Ince Information Request 3.10.

4.36 Please provide September variances in a format similar to BC Hydro's response to Ince IR 3.10.

RESPONSE:

The table below provides the requested information based on accrued actual and forecast sales.

	F2020 September			
(GWh)	**EU**	**Actual**	**Diff**	**% Diff**
	1	2	3 = 2 -1	4 = 3 / 1
Residential	1,147	1,125	(22)	-1.9%
Light Industrial and Commercial	1,482	1,456	(26)	-1.7%
Large Industrial	1,225	1,029	(196)	-16.0%
Other	85	145	60	70.5%
Total	3,939	3,756	(183)	-4.6%

For further discussion, please refer to BC Hydro's response to INCE IR 3.10.0.

38 Reference: 20 Year Load Forecast section 3.1.1

4.38 Please confirm that BC Hydro's electricity conservation (DSM) forecast is essentially a (negative) load forecast.

RESPONSE:

Not confirmed. BC Hydro's DSM Plan forecast is an estimate of the future energy and associated capacity savings to inform BC Hydro's long-term planning. As a primary objective of DSM is to promote electricity conservation and efficiency, the DSM Plan forecast has the effect of reducing the load forecast before DSM.

39 Reference: 20 Year Load Forecast section 3.1.1

4.39 Please confirm that BC Hydro has been making adjustments to its load forecast for a number of years due to overlaps between its forecast of DSM savings, and its forecast of electricity demand growth - without DSM.

RESPONSE:

BC Hydro has been making an adjustment to its load forecast to reflect codes and standards overlap for a number of years.

41 Reference: 20 Year Load Forecast section 3.1.1

4.41 Please confirm the need for close integration between the processes and approaches in preparing each of the load forecasts, to ensure that there is minimal double counting or undercounting of future DSM savings.

RESPONSE:

This answer also responds to INCE IR 4.48.0.

BC Hydro agrees that there is a need to consider integration issues between the Load Forecast and DSM in the processes and approaches used to prepare each of the forecasts.

One process that is in place to consider these issues is the internal DSM-Load Forecast Integration working group that meets to discuss projects and initiatives that impact both areas. With respect to the codes and standards overlap adjustment, the working group also reviews the overlap adjustment during each load forecast update and adjusts as necessary.

42 Reference: 20 Year Load Forecast section 3.1.1

4.42 Please confirm that the adjustments made to the load forecast over the last several forecast issuances has been to increase the forecast electricity demand in the net forecast due to over-counting of DSM savings that would have naturally occurred (natural conservation).

RESPONSE:

BC Hydro assumes that the question is referring to the effect of the codes and standards overlap adjustment described in section 3.1.1 of Exhibit B-15 on the net load forecast.

The application of the codes and standards overlap adjustment has the effect of increasing the net load forecast. This is appropriate because there are energy savings from codes and standards reflected in both the DSM Plan and the U.S. EIA assumptions included in the SAE model. If this adjustment was not made, it would have the effect of overstating the energy savings and understating the net load forecast.

43 Reference: 20 Year Load Forecast section 3.1.1

4.43 Please provide examples of trends in natural conservation, particularly historical use rates for lighting, home electronics (televisions), home computers, home entertainment/gaming systems and electric space and water heating.

RESPONSE:

BC Hydro's 2017 Residential End Use Study suggests increasing penetrations of efficient technologies across a number of end uses over time, including:

- **Lighting: The percentage of households with at least one LED bulb has grown from 14 per cent in 2010 to 61 per cent in 2017. Conversely, the percentage of households with at least one incandescent bulb has dropped from 91 per cent in 2010 to 78 per cent in 2017;**
- **Televisions: The percentage of households with conventional colour (CRT) televisions has dropped from 63 per cent in 2010 to 10 per cent in 2017. The penetration of LCD and LED televisions has increased from 51 per cent in 2010 to 85 per cent in 2017;**
- **Home computers: The percentage of households with desktop computers has dropped from 65 per cent in 2010 to 43 per cent in 2017. The penetration of laptop computers has increased from 58 per cent to 71 per cent;**
- **Electric space heating: the percentage of electrically heated households with a heat pump (air source or ground source) has increased from 8 per cent to 12 per cent, while electrically heated households with a forced air furnace and/or electric baseboards has decreased from 80 per cent to 73 per cent; and**
- **Electric water heating: the percentage of electrically water-heated households with a heat pump water tank increased from 0.8 per cent to 1.6 per cent between 2014 and 2017.**

These changes over time are likely a result of multiple factors, including DSM programs, codes and standards, natural conservation or other market factors.

44 Reference: 20 Year Load Forecast section 3.1.1

4.44 Please comment on the domestic trends in building shell efficiencies, particularly due to changing insulation standards.

RESPONSE:

For new construction, the B.C. Building Code was updated in December 2014 to include more stringent requirements, specifically around insulation. The impact of this was to improve the efficiency of residential building envelopes. We do not expect new codes to be enacted within the test period that will impact the efficiency of building envelopes in new construction. Going forward, as municipalities and local governments adopt more stringent codes in line with the BC Energy Step Code, it is reasonable to expect that this will improve the performance of building envelopes over time.

For existing homes, BC Hydro’s 2017 Residential End Use Study suggests that 17 per cent of homes have made improvements to their home envelope over the past two years (at least one upgrade including windows, doors, window frames, and insulation).

45 Reference: 20 Year Load Forecast section 3.1.1

4.45 Please provide examples of offsetting trends – in terms of increased electricity use due to either new end-uses, or end-uses with increased penetration in the household (such as the increasing numbers of electronic devices and chargers).

RESPONSE:

Examples of trends that could result in increased electricity use, based on BC Hydro's 2017 Residential End Use Study include:

- **Air conditioning: the percentage of households with an air conditioner has increased from 26 per cent in 2010 to 34 per cent in 2017;**
- **Space heating: the percentage of households that use electricity as their primary heating fuel has increased from 40 per cent in 2010 to 44 per cent in 2017; and**
- **Electronics: the percentage of homes with tablets has increased from 17 per cent in 2012 to 54 per cent in 2017, and the average number of tablets per home has increased from 1.2 to 1.5 over the same time period.**

46 Reference: 20 Year Load Forecast section 3.1.1

4.46 Please provide the 2019 Navigant report on the overlap in codes and standards savings.

RESPONSE:

No formal report was provided by Navigant on their work regarding Codes and Standards overlap. For a discussion of the results of Navigant's work and the impact to the load forecast, please refer to BC Hydro's response to INCE IR 1.8.6.

47 Reference: 20 Year Load Forecast section 3.1.1

4.47 As per the Navigant report, please provide a summary of the codes & standards categories that have been primarily responsible for BC Hydro's DSM double-counting.

RESPONSE:

For a discussion of the results of Navigant's work and the impact to the load forecast, please refer to BC Hydro's response to INCE IR 1.8.6.

48 Reference: 20 Year Load Forecast section 3.1.1

4.48 Please comment on the internal forecasting processes in place to ensure that DSM over-counting is minimized.

RESPONSE:

Please refer to BC Hydro's response to INCE IR 4.41.0.

51 Reference: 20 Year Load Forecast Section 1.3 Distribution Peak methodology

4.51 Please provide the obligations of BC Hydro for servicing FortisBC Electric peak loads – in terms of seasonal obligations and magnitude (MW). Please comment on the advance notice required of and/or provided by FortisBC such that BC Hydro can plan for and then dispatch required peak-period electricity.

RESPONSE:

Under the Power Purchase Agreement (PPA) between BC Hydro and FortisBC Electric, BC Hydro is committed to providing up to 1,752 GWh of energy per year, at a delivery rate of up to 200 MW in any hour[1]. By June 30 each year FortisBC Electric is required to provide BC Hydro with an Annual Energy Nomination for the following Contract Year that commences October 1. FortisBC Electric may only change its Annual Energy Nomination by +/- 20 per cent compared to the prior Contract Year.

Additionally, FortisBC Electric is obligated to provide a 10-year forecast of its service area load and expected PPA purchases for the purpose of facilitating BC Hydro's resource planning.

1 **https://www.bcuc.com/Documents/Proceedings/2014/DOC_41321_05-06-2014_BCH_PPA-RS%203808-TS-No-2-and-3_Decision.pdf** **See page (i) of the Executive Summary.**

52 Reference: 20 Year Load Forecast Section 1.3 Distribution Peak methodology

4.52 Are negotiations underway to increase the maximum peak allocation provided by BC Hydro to FortisBC Electric consistent with population and load growth in the BC Southern interior?

RESPONSE:

Negotiations are not under way to increase the maximum Contract Demand of the Power Purchase Agreement between BC Hydro and FortisBC Electric nor are there negotiations under way with regards to any other agreement with FortisBC Electric in relation to services provided to the South Okanagan.

6.0 TOPIC: EXHIBIT B-15, OCTOBER 3 2019 20-YEAR LOAD FORECAST

IMPACT OF MUNICIPAL AND REGIONAL CLIMATE INITIATIVES

4.6.1 Please confirm that municipal and regional governments have the authority to adopt standards and codes concerning the selection of energy resources for developments within their jurisdictions, which are independent of provincial or federal initiatives and which may extend beyond provincial or federal initiatives.

RESPONSE:

The authority of Local Governments is established through provincial legislation such as the *Local Government Act*, *Vancouver Charter*, *Community Charter*, and *Building Act*. While local governments may adopt targets with respect to fuel selection that differ from provincial or federal targets, they may or may not have the authority to enact regulations that will enable their jurisdiction to reach those targets. This would depend on the specific targets and nature of the regulations that need to be changed within a given municipality or region to achieve the target.

Movement of United Professionals Information Request No. **4.6.2** Dated: **October 18, 2019** British Columbia Hydro & Power Authority Response issued **November 14, 2019**	Page 1 of 1
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-23**

6.0 TOPIC: EXHIBIT B-15, OCTOBER 3 2019 20-YEAR LOAD FORECAST

IMPACT OF MUNICIPAL AND REGIONAL CLIMATE INITIATIVES

4.6.2 Please list the municipal and regional governments in British Columbia that have declared a “climate emergency” as of October 1 2019.

RESPONSE:

BC Hydro is aware, through media reports, that a number of municipal and regional governments in British Columbia have declared a climate emergency. However, BC Hydro does not have a list of the municipal and regional governments in British Columbia that have declared a “climate emergency” as of October 1, 2019.

Further, BC Hydro is aware that, in September 2019, the Union of B.C. Municipalities (UBCM) endorsed convention resolution B139, “Call to Action on Global Climate Emergency”. The resolution states:

> **“Therefore be it resolved that UBCM supports a call to action and asks all orders of Government (including local government) to adopt climate emergency motions and to take dramatic steps toward the protection of biodiversity and to accelerate the reduction in greenhouse gas emissions, which are a primary cause of this climate emergency.”**

6.0 TOPIC: EXHIBIT B-15, OCTOBER 3 2019 20-YEAR LOAD FORECAST

IMPACT OF MUNICIPAL AND REGIONAL CLIMATE INITIATIVES

4.6.3 Please file the City of Vancouver April 2019 Climate Emergency Response Report (https://council.vancouver.ca/20190424/documents/cfsc1.pdf) and Climate Emergency Response Final Motion (https://vancouver.ca/files/cov/climate-emergency-response-council- amendments.pdf).

RESPONSE:

The City of Vancouver April 2019 Climate Emergency Response Report is provided as Attachment 1 to this response. The Climate Emergency Response Final Motion is provided as Attachment 2 to this response.

CITY OF VANCOUVER

ADMINISTRATIVE REPORT

Report Date:	April 16, 2019
Contact:	Matt Horne
Contact No.:	604.673.8331
RTS No.:	12978
VanRIMS No.:	08-2000-20
Meeting Date:	April 24, 2019

TO: Standing Committee on City Finance and Services

FROM: General Manager of Planning, Urban Design and Sustainability and General Manager of Engineering Services

SUBJECT: Climate Emergency Response

RECOMMENDATIONS

A. THAT Council adopt a new City-wide long-term climate target of being carbon neutral before 2050 as a complement to the target of 100 per cent of the energy used in Vancouver coming from renewable sources before 2050.

B. THAT Council adopt the target that by 2030, 90 per cent of people live within an easy walk/roll of their daily needs, and direct staff to report back by Fall 2020 with a strategy to achieve the target (“Big Move #1”).

C. THAT Council accelerate the existing sustainable transportation target by 10 years, so that by 2030, two thirds of trips in Vancouver will be by active transportation and transit, and direct staff to report back by Fall 2020 with a strategy to achieve the target (“Big Move #2”).

D. THAT Council adopt the target that by 2030, 50 per cent of the kilometres driven on Vancouver’s roads will be by zero emissions vehicles, and direct staff to report back by Fall 2020 with a strategy to achieve the target (“Big Move #3”).

E. THAT Council adopt the new target that by 2025, all new and replacement heating and hot water systems will be zero emissions, and direct staff to report back by Fall 2020 with a strategy to achieve the target (“Big Move #4”).

F. THAT Council adopt the target that by 2030, the embodied emissions in new buildings and construction projects will be reduced by 40 per cent compared to a 2018 baseline, and direct staff to report back by Fall 2020 with initial actions to achieve this target including recommendations to remove regulatory barriers to mass timber construction and initial requirements for embodied emissions reductions (“Big Move #5”).

G. THAT Council adopt the target that by 2030, restoration work will be completed on enough forest and coastal ecosystems in Vancouver and the surrounding region to remove one million tonnes of carbon pollution annually by 2060, and direct staff to report back by Fall 2020 with initial actions to achieve the target, including potential partnership opportunities (“Big Move #6”).

H. THAT Council direct staff to begin implementing the Accelerated Actions as described in Appendix A and report back to Council with an overall progress report by May 2020.

I. THAT Council direct staff to proceed with the development of a carbon budgeting and accountability framework for corporate and city-wide carbon pollution that meets the objectives described in this report.

J. THAT Council direct staff to proceed with the formation of the Climate and Equity Working Group according to the objectives, process, timelines, participants and budget described in this report.

K. THAT Council direct staff to proceed with the development of Vancouver’s next environmental plan, Greenest City 2050, which will incorporate the work from this Climate Emergency Response report, as well as broader environmental sustainability objectives, and report back on the recommended strategy that will be integrated and coordinated with the City-wide Plan.

L. THAT Council direct staff to integrate the six (6) Big Moves in this report into the development of the City-wide Plan recognizing there will be further development and refinement of the Big Moves which will be informed by and coordinated with City-wide planning.

REPORT SUMMARY

In January 2019, Vancouver City Council unanimously approved a motion recognizing the climate emergency that the planet faces; acknowledging that Vancouver needs to do more to reduce carbon pollution in response to that emergency; and asking staff for recommendations on how to ramp up the City’s climate actions in line with efforts to limit global warming to 1.5°C. The 1.5°C limitation is a guiding target in the Paris Agreement, and it represents a level of global warming that would avoid the worst impacts of climate change and avoid overwhelming society’s capacity to adapt.

To ramp up the City’s actions to align with 1.5°C, this report offers two complementary approaches:

1. A set of six (6) “Big Moves” that would guide the City of Vancouver’s work in response to the climate emergency. The Big Moves are intended to direct staff to pursue the City’s key opportunities to meet the objective of limiting warming to 1.5°C. While they are all intended to be technically achievable, they will push the limits of what staff think can be accomplished in the next decade and staff realize that there will likely be political, financial and “pace-of-change” challenges to their implementation. If staff are directed to

pursue the Big Moves, any identified challenges, along with possible solutions, will be included in the reports being brought back for Council's consideration.

Walkable city

Active transportation and transit

Zero emissions vehicles

Heat pumps

Embodied carbon

Negative emissions

If Council endorses the Big Moves, staff will begin the analysis and engagement that is required to understand the challenges and opportunities with each, and to develop a comprehensive implementation and funding strategy. Depending on the nature of the challenges that emerge, and what we learn from our engagement process, staff may explore potential adjustments to the Big Moves, so long as they maintain consistency with the 1.5°C objective.

2. A package of 53 Accelerated Actions that build on the climate action the City has taken to date are also outlined in the report appendices. These are aligned with the Big Moves, as most will help move towards them. The reason for having these accelerated actions is, in part, to have some quick-starts to move forward on while the planning work on the Big Moves proceeds.

   To further align with Vancouver's efforts of limiting warming to 1.5°C, this report also recommends an updated 2050 target and a set of objectives for the City's carbon budgeting and accountability framework. Lastly, this report recommends an approach for a new Climate and Equity Working Group that will help to ensure that equity has a central place in the City's climate emergency and sustainability work.

COUNCIL AUTHORITY/PREVIOUS DECISIONS

On January 16, 2019, Council approved a motion recognizing climate change as an emergency and directed staff to:

- Review the City's climate change targets in the context of the latest research from the Intergovernmental Panel on Climate Change and the objective of limiting global warming to 1.5°C.
- Establish a carbon budgeting approach for the City that is consistent with the 1.5°C objective.
- Establish a Climate and Equity Working Group to provide guidance and support for the City's efforts to respond to the climate emergency.
- Add new actions to reduce carbon pollution that align the City's efforts with the 1.5°C objective.

This report provides the staff response to the January 16, 2019, climate emergency motion.

The recommendations in this report build on a long history of climate planning and action at the City of Vancouver. Highlights include:

- Clouds of Change (1990)
- Transportation Plan (1997)
- The Climate-Friendly City (2005)
- EcoDensity (2008)
- Greenest City Action Plan (2011)
- Transportation 2040 (2012)
- The Strategic Approach to Neighbourhood Energy (2012)
- Healthy City Action Plan (2014)
- The Renewable City Strategy (2015) and Renewable City Action Plan (2017)
- The Zero Emissions Building Plan (2016)
- The Electric Vehicle Ecosystem Strategy (2016)
- The Zero Waste Strategy (2018)
- The Climate Change Adaptation Strategy (developed in 2012 and updated in 2018)

The climate emergency response directly supports the forthcoming Resilient Vancouver Strategy, which recommends objectives and actions to build resilience to major shocks and stresses impacting Vancouver now and in the future. Many of the impacts of those shocks and stresses (e.g., floods and extreme weather) are the result of inadequate mitigation actions.

CITY MANAGER'S/GENERAL MANAGER'S COMMENTS

The City Manager recommends approval of the foregoing.

REPORT

Context

a. The Risks of Climate Breakdown

The threat of climate breakdown has been clearly documented by the world's scientists. Vancouver is already experiencing the impacts of 1°C of warming, including more severe storms, flooding, and forest fire smoke. Every degree of warming will increase those impacts and make it increasingly difficult, and eventually impossible, to adapt.

Even half a degree is significant. The Intergovernmental Panel on Climate Change (IPCC) compared the impacts from climate change in a world with 2°C of warming to one with 1.5°C and found the following:

- As many as 457 million more people exposed to climate risks and related poverty.
- Twice as many people suffering from water scarcity.
- Twice as many plants and three times as many insects losing their habitat.
- An ice-free Arctic every 10 years instead of every 100 years.
- The exposure of 2.6 times as many people to extreme heat at least every five years.
- Double the decline in global fisheries.

The impacts of climate change do not plateau at 2°C, so any warming beyond that would mean even more severe impacts. For context, even if the commitments made by Paris-signatory countries to date were being met, the world would be on track for more than 3°C of warming by the end of this century. That degree of warming would cause a worldwide economic, environmental and social catastrophe.

b. Limiting Global Warming to 1.5°C

The signatory countries to the Paris Agreement (including Canada) have committed to keeping global warming below 2°C, and as close to 1.5°C as possible. In October 2018, the Intergovernmental Panel on Climate Change (IPCC) released a major report making a clear case to strive for 1.5°C. The IPCC report also laid out the actions required to achieve that objective.

To limit global warming to 1.5°C, the necessary changes to global energy and economic systems will be immense and will require an unprecedented degree of technological change and cooperation. Global net carbon emissions will need to be reduced to 45 per cent below 2010 levels by 2030, net zero by 2050, and net negative in the second half of the century.

Cutting carbon pollution that quickly will require rapid and far-reaching transitions in energy systems, land use, transportation and buildings. Fossil fuels will ultimately need to be replaced through significant improvements in energy efficiency and a rapid shift to renewable energy and other zero emissions energy sources. In addition to reducing emissions, large quantities of carbon will need to be removed from the atmosphere (e.g., through reforestation projects, projects that enhance carbon storage in aquatic ecosystems, and projects that capture and store carbon from wood waste combustion).

In addition to reducing and removing emissions (mitigation), governments also need to better prepare for the anticipated impacts of climate change (adaptation). While both mitigation and adaptation are critical responses, this report is focused on mitigation, as per the guidance in Council's climate emergency motion. Through the course of developing this report, several new priority adaptation actions were identified. They are included in Appendix B and progress will be reported as part of the City's Adaptation Strategy.

c. Growing Number of Climate Emergency Declarations

In Canada and around the world, there is a growing movement of hundreds of local governments recognizing the emergency that climate change represents, accelerating their own actions, and calling on provincial/state and national governments to also ramp up their responses. Given the world's increasingly urbanized population is on the front lines of the fight against climate change, the world's urban population will disproportionately experience the effects of global warming. Collectively we have the ability to influence the directions that senior governments take in responding to the climate emergency. As a leading city within this movement, Vancouver is well positioned to help define next steps for those cities, so that we are all well aligned with the objective of limiting warming to 1.5°C.

For a list of cities declaring a climate emergency see Appendix C.

d. Government of BC Ramping Up Climate Action

In December 2018, BC released its new climate plan, CleanBC. Phase one of the plan is designed to put the province on track for 75 per cent of the reductions it needs to meet its 2030 target (a 40 per cent reduction below 2007 levels). The specific policies in CleanBC are leading examples in North America and globally, and they provide an excellent foundation for Vancouver to align its efforts with.

In launching CleanBC, Premier Horgan emphasized the need to work together to transition away from fossil fuels to renewable energy. With the work Vancouver is doing on buildings, transportation and waste, the City is well positioned to play a leading role in that effort.

To learn more about CleanBC and supportive policies from the Government of Canada, see Appendix D.

e. Local and Regional Governments Ramping Up Climate Action

Metro Vancouver (Metro) is in the process of developing Climate 2050, which is intended to be the regional response to climate change—both in terms of reducing carbon pollution and preparing for the impacts of climate change. Metro is also beginning work on the next phase of the Regional Growth Strategy, and TransLink is embarking on an update of the Regional Transportation Strategy (RTS), which will both guide how people live, work and move around the region. Local governments across the region and province continue to adopt climate policies of their own (e.g., the Energy Step Code and electric vehicle-readiness requirements for new construction).

The updates to those regional plans will continue to impact Vancouver directly through the expectations they set for the City, and indirectly through the expectations they set for other local governments within the region. Vancouver's response to the climate emergency is an opportunity to help take a leadership role and shape that regional picture. The higher the degree of alignment between the City and the region, the more likely the collective regional response to the climate emergency will align with the objective of limiting global warming to 1.5°C.

f. Reducing Carbon Pollution has Multiple Benefits

There is no question that carbon pollution needs to be rapidly reduced and reach net negative levels by the second half of the century to effectively fight climate change. No single jurisdiction can solve the problem on their own, so success depends on everyone contributing to the solution. That said, fighting climate change is not the only reason to reduce carbon, as most of the solutions being pursued in an urban context offer multiple benefits including improved heath and air quality, greater community resilience, economic development and reduced costs. See Appendix E for a more detailed discussion.

Aligning Vancouver Targets with 1.5°C (Recommendation A)

Council's climate emergency motion directed staff to "increase targets and accelerate timelines for actions in line with the IPCC call for 45 per cent reductions in GHG emissions over 2010 levels by 2030, net zero emissions by 2050". This section focuses on aligning the targets.

a. Scope 1 and 2 Emissions

Vancouver's efforts to fight climate change have focused on addressing the sources of carbon pollution the City has the greatest influence over: residential and commercial buildings, the vehicles on our roads, and our landfill. These sources (also referred to as scope 1 and scope 2 emissions) are reported in the City's annual emissions inventory and accounted for 2.6 million tonnes of carbon pollution in Vancouver in 2017 (the latest year for which data is available). The scope of Vancouver's inventory aligns with the priority sectors in the Global Protocol for Cities (a globally recognized carbon accounting standard used by hundreds of cities).

For buildings, transportation and solid waste, the City's current targets for reducing carbon emissions and using renewable energy are as follows:

	2020	2030	Before 2050
Percentage of energy from renewable sources (including hydro power)	No target	55%	100%
Reduction in carbon pollution (relative to 2007)	33%	50%	At least 80%

Vancouver's 2030 carbon target (50 per cent below 2007) is largely consistent with the global reductions needed to limit warming to 1.5°C (45 per cent below 2010). Converting Vancouver's target to the same base year for consistency, the City's 2030 target is equivalent to 49 per cent below 2010 levels. Based on the City's experiences and economic modelling, achieving the 50 per cent target by 2030 is achievable yet very challenging.

For 2050, the IPCC research points to a need for zero net carbon emissions on a global basis. Vancouver's current 2050 carbon target is "at least 80 per cent below 2007". While this looks like a 20 per cent difference from the IPCC research, the actual gap is expected to be smaller because the City will need to exceed the 80 per cent carbon reduction target in order to achieve the 100 per cent renewable energy target. Staff anticipate that transitioning to 100 per cent renewable energy will result in carbon pollution being reduced by approximately 75 per cent in 2040 and more than 95 per cent in 2050.

Staff recommend maintaining the 2030 targets and modifying Vancouver's 2050 target to be "carbon neutral" instead of "at least 80 per cent below 2007 levels". If approved, the actions needed to achieve this revised target would be included within Big Move 6.

b. Beyond 2050 to Negative Emissions

In addition to reaching net zero carbon emissions by 2050, the IPCC research concludes that global net negative emissions will be necessary in the second half of the century. Examples of how negative emissions could be achieved include reforestation projects, projects that enhance carbon storage in aquatic ecosystems, and projects that capture and store carbon from wood waste combustion.

The sixth Big Move in this report (recommendation G) is intended to begin Vancouver's work on negative emissions such that the City is helping to sequester approximately 1 million tonnes of carbon pollution annually by 2060. Based on initial analysis of the IPCCs research, the 1 million tonnes is aligned with the objective of limiting global warming to 1.5°C.

c. Beyond Scope 1 and 2 to Embodied Carbon

The City also bears some responsibility for the emissions that are released through the production and transportation of goods and materials used in Vancouver (referred to as scope 3 emissions). Based on the City's analysis of these additional sources of carbon pollution, priority opportunities include transitioning to lower-carbon building and construction materials, and encouraging residents and restaurants to shift to more plant-based diets, which are less carbon intensive to produce.

To begin addressing Vancouver's scope 3 carbon emissions, Big Move #5 is focused on the embodied emissions in new buildings and construction projects, including a target that by 2030, those sources be reduced by 40 per cent as compared to 2018 typical practice. The Big Move is supported by a number of specific projects in the accelerated actions.

Further, Project 13.b in the table of Accelerated Actions will begin work on the emissions associated with food consumption in Vancouver, and the City's efforts to shift to active transportation and transit will reduce the embodied emissions in vehicles, if the number of vehicles in the City declines. At this point, staff are not recommending targets for other sources of embodied carbon, such as those associated with food and vehicles.

d. Helping Developing Jurisdictions Transition to Renewable Energy

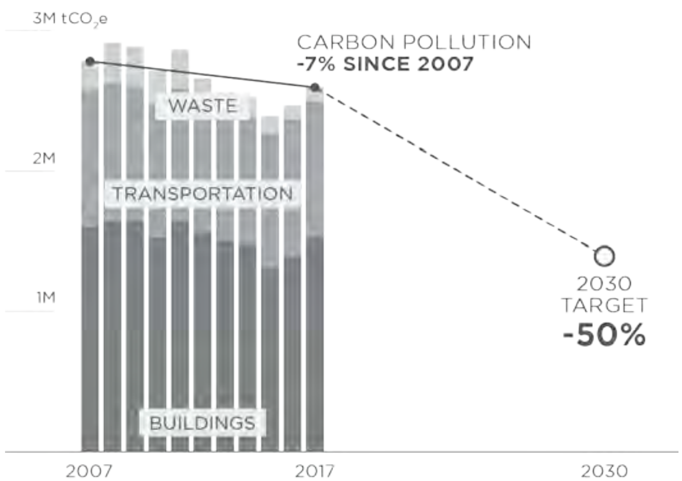
To fully be aligned with 1.5°C, jurisdictions that are wealthy by global standards (including Vancouver) need to support emissions reductions in jurisdictions without the same resources to improve energy efficiency and transition to renewable energy. Without a willingness to provide this support, it is highly unlikely that developing jurisdictions will have the resources to transition fast enough.

The underlying rationale for wealthier jurisdictions providing support is that we continue to have much higher per capita emissions, and we have accumulated a great deal of our wealth through the burning of fossil fuels since the beginning of the last century. Developing jurisdictions have contributed comparatively little to global emissions and are the least equipped to reduce emissions and prepare for its impacts.

What Vancouver's role could be in helping developing jurisdictions transition to renewable energy is not well defined. Project 14.i in the accelerated actions is intended to begin the work of figuring out what that role could be.

Vancouver Needs to Accelerate Progress to Align with 1.5°C

While the City's 2030 target is aligned with the objective of limiting global warming to 1.5°C, our progress towards the target is not. As shown in the following chart, Vancouver's emissions from buildings, transportation and solid waste have declined by an average of 19,000 tonnes per year over the past decade. Though we are moving in the right direction (while accommodating significant population and economic growth), progress needs to be accelerated significantly.



To get on track for the City's 2030 target, Vancouver's emissions need to drop by 1.2 million tonnes. That's an average of 92,000 tonnes per year over the next decade—a five-fold increase from the past decade. For context, approximately 92,000 tonnes of reductions could be achieved individually by each of the examples below:

- Switching 15 per cent of vehicle trips per year on Vancouver's roads to active transportation and transit.
- Replacing 35,000 gasoline cars owned by Vancouver residents with electric cars.
- Replacing 22,000 furnaces with heat pumps.
- Switching the downtown district energy system to renewable energy.

To reduce city-wide carbon pollution by 92,000 tonnes every year, the City will need to pursue all of these opportunities and more. The City actions needed to pursue these opportunities are presented later in the report and are covered by Recommendations B to H.

Ramping Up Vancouver's Actions to Align with 1.5°C

To ramp up the City's actions to align with 1.5°C, this report offers two complementary approaches, a set of six Big Moves and a package of Accelerated Actions. The Big Moves and Accelerated Actions are intended to use the range of tools available to the City, which can be grouped into investment tools, regulatory tools, and advocacy tools:

- *Regulatory Tools*: Where the City uses its authorities under the Vancouver Charter to establish the rules that guide resident and business decisions that support zero emissions outcomes. These would typically have minimal direct cost for the City.

- *Investment Tools*: Where the City invests directly in equipment and infrastructure to reduce carbon pollution, and where the City provides financial incentives to encourage residents and businesses to choose zero emissions options.
- *Advocacy Tools*: Where the City works with other governments and utilities to encourage them to apply their regulatory and investment tools to support zero emissions outcomes.

It is important to consider the full range of tools because the selection will depend on the barrier that is being addressed, and it will have implications for how costs and benefits are distributed. These tools are discussed in Appendix F.

a. The Big Moves (Recommendations B to G)

The Big Moves are intended to pursue the key opportunities where the City's tools will be critical and the reductions are adequate to align the City's work with the objective of limiting warming to 1.5°C. The objectives are also intended to be easier to understand than traditional climate targets like a 50 per cent cut in carbon pollution. They are all intended to be achievable, while pushing to the limits of what staff think can be accomplished in the next decade in partnership with other levels of government.

Big Moves #1 through #4 will accelerate and expand the City's existing work on buildings and transportation, Big Move #5 will begin important work on reducing the embodied emissions from building and construction materials, and Big Move #6 will begin the work of establishing the City's role in pursuing negative emissions.

In terms of the 1.2 million tonnes of reductions targeted for 2030 from buildings, transportation and solid waste, Big Moves #1 through #4 would achieve 1.1 million tonnes.[1] The remaining 0.1 million tonnes plus a 0.1 million tonne buffer would be addressed by two key provincial policies that are reducing the carbon intensity of transportation fuels and the gas grid:

- The Renewable Gas Standard will require 15 per cent of the gas in FortisBC's distribution network to come from renewable sources by 2030, which will help reduce an additional 135,000 tonnes of carbon pollution in Vancouver. Depending on how it is designed, this Standard could also help the district energy systems in Vancouver convert to renewable heating options. The City is helping to support meeting this requirement by using renewable gas in its facilities and looking for opportunities to generate more renewable gas.
- The Low Carbon Fuel Standard will require a 20 per cent cut in the carbon intensity of transportation fuels in BC by 2030, which will help reduce an additional 38,000 tonnes of carbon pollution in Vancouver. The City is helping to support meeting this requirement by using renewable fuels in our fleet, and exploring opportunities to be a producer of such fuels.

If the Big Moves are approved by Council, staff will begin the analysis and engagement that is required to understand the challenges and opportunities with each, and to develop the detailed plans, policies, and funding strategies they will need. As part of that work, staff will assess the costs and benefits in greater detail and develop high-level financial strategies. Depending on the nature of the challenges that emerge and what we learn from our engagement process, staff

[1] The emissions targeted by Big Move #5 are scope 3 emissions, so while they are important contributions, they do not count directly against the 1.2 million tonnes targeted for 2030. Big Move #6 is not expected to be sequestering material amounts of carbon pollution in 2030.

may explore potential adjustments to the Big Moves, so long as they maintain consistency with the 1.5°C objective. All of this information would come back to Council for further consideration.

The following pages describe each Big Move, including the objective staff will work toward, an initial estimate of carbon reduction potential, key actions that will likely be required for the Big Move to be successful, how the Big Move links to existing City work, and which departments will lead the work.

Big Move #1 	**A walkable city** By 2030, 90% of people live within an easy walk/roll* of their daily needs. *(Recommendation B)* **Walking or other pedestrian-scale mobility devices like wheelchairs.*
Carbon Reduction Potential	By making it easier for people to walk/roll instead of driving, 153,000 tonnes/year of carbon pollution could be reduced by 2030 (13% of the targeted reductions).
Description	Success for this Big Move will mean more “complete neighbourhoods” that have daily destinations, such as shops, services, jobs, parks, schools and community centres, within walking/rolling distance of where people live. For context, approximately 45% of residents live within an easy walk/roll of their daily needs today. Achieving this goal will require sensitively introducing more housing choices and essential amenities to neighbourhoods across the city. To create truly walkable neighbourhoods that are livable, compact and complete, the streets and pathways linking these daily needs will need to be safe, comfortable and attractive for walking, rolling and cycling, and supported by good access to frequent transit. Complete neighbourhoods will support local businesses, a diversity of households, healthier lifestyles, more social interaction, and reduced energy use and carbon emissions.
Links to Existing Work	The City has a long history of planning for complete and compact communities where it is easy to walk/roll between home and most daily destinations. Many of our most desirable communities, such as the West End, Southeast False Creek, Kitsilano, and Grandview-Woodlands, provide a rich mix of land uses and safe, connected and comfortable streets and pathways. Upcoming planning initiatives, such as the City-wide Plan, the Broadway Plan and Jericho Lands, provide opportunities to expand our approach to creating and enhancing walkable communities and pilot new strategies to accelerate our transition to a truly walkable city. Walkable and complete communities will also support the City’s resilience work because people can more easily help each other and access resources during emergencies. It also supports and enhances efforts to create more diverse and affordable housing choices.
Responsible Departments	• Led by Planning, Urban Design and Sustainability • Supported by Engineering and Development, Buildings and Licensing

Big Move #2	**Safe and convenient active transportation and transit**
	By 2030, two thirds of trips in Vancouver will be by active transportation and transit, which would be 10 years earlier than currently planned. *(Recommendation C)*
Carbon Reduction Potential	By making it safer and more convenient for people to choose active transportation and transit to move around the city, 141,000 tonnes/year of carbon pollution could be reduced by 2030 (12% of the targeted reductions). This would be in addition to the 153,000 tonnes in Big Move #1.
Description	Success for this Big Move will require a significantly improved transit capacity and efficiency, better-connected active transportation networks city-wide, and continued expansion of high-quality reliable transit across the city and region. Efforts will continue to focus on increasing affordable and safe transportation choices with access for all, and addressing gaps in the network, particularly in underserved areas. Achieving this will necessitate investment in a spectrum of improvements, from local upgrades throughout the city, to completing major projects, such as the Broadway Subway to UBC, 41st Avenue B-Line and the Granville Bridge greenway. Through this work, the number of trips people need to take in cars will decline as will the length of many vehicle trips. New policy tools will also be important with mobility pricing providing a good example because of its ability to encourage fewer vehicle trips during our most congested times of day and to provide the funds needed to expand and improve the transit and active transportation networks. While this Big Move is focused on trips that originate in Vancouver, it will provide an opportunity to engage with partners across the region to help shape Metro Vancouver's Climate 2050 plan and the Regional Transportation Strategy.
Links to Existing Work	The City has a long history of prioritizing active transportation and transit for a mix of reasons, such as enhanced livability, reduced congestion, affordability, improved air quality, more active lifestyles, and reduced carbon pollution. Pursuing this move will build upon Transportation 2040, which was approved in 2012 and has helped the City succeed in seeing 50% of daily trips by active transportation or transit. These efforts reduce needs for cars which can also enhance affordability of daily living in Vancouver.
Responsible Departments	• Led by Engineering • Supported by Planning, Urban Design and Sustainability

Big Move #3 — Pollution-free cars, trucks and buses

By 2030, 50% of the kilometres driven on Vancouver's roads will be by zero emissions vehicles.

(Recommendation D)

Carbon Reduction Potential

The rapid transition to electric and other zero emissions vehicles would reduce Vancouver's carbon pollution by 283,000 tonnes per year by 2030 (24% of the targeted reductions).

Description

Success for this Big Move will mean almost all new light-duty vehicles will need to be zero emissions towards the end of next decade. For light-duty fleets where vehicles are replaced more frequently (e.g., taxis, car shares, ride-hailing, etc.), almost all of these vehicles will need to be zero emissions by 2030. The transition for medium- and heavy-duty vehicles will be slower, but rapid progress will still be needed in some key market segments (e.g., in transit, where TransLink has already made a commitment for all new buses to be zero emissions by 2025).

To achieve this scale of transition, there are at least three tools the City will likely need to rely on heavily: 1) expanding residential, commercial and public charging infrastructure, 2) parking policies that encourage and eventually require zero emissions vehicles, and 3) zero emissions zones that discourage and eventually ban polluting vehicles from specific areas or corridors. The timing for any zero emissions vehicle requirements and how those would be phased in for different types of vehicles would need to be explored. The City could also require any remaining gas stations to transition to zero emissions charging/fueling stations between 2030 and 2040.

As the City considers these types of parking policies and zero emissions areas, it will be important to ensure that all residents and businesses have equitable access to zero emissions transport choices, and convenient and robust charging or fueling infrastructure for vehicles.

This Big Move also introduces a challenge for Big Move #2 because it will result in a significant decline in gas tax revenue, which is a primary source of financing transit in the region. The work to support this Big Move will include developing a better understanding and forecasting of this challenge, exploring potential solutions that secure long term transit funding (e.g. congestion charging), and working with senior governments and partners to implement those solutions.

Links to Existing Work

This Big Move would accelerate and expand upon Vancouver's Electric Vehicle Ecosystem Strategy, which has guided investments in public charging infrastructure and ensured that new buildings are ready for electric vehicles. It would also link well to the City's efforts to electrify its own fleet, which has resulted in the largest electric vehicle fleet in Canada. Given that this links to the City's support of TransLink's Low Carbon Strategy towards fossil-free buses, it will be important to consider the people moving capacity of zero emission vehicles and buses as we monitor this Big Move.

Responsible Departments

- Led by Engineering
- Supported by Development, Buildings and Licensing; Planning, Urban Design and Sustainability Park Board; and Real Estate and Facilities Management

Big Move #4 — Zero emissions space and water heating

By 2025, all new and replacement heating and hot water systems will be zero emissions.

(Recommendation E)

Carbon Reduction Potential

Ensuring that new and replacement space and water heating systems are zero emissions will reduce Vancouver's carbon pollution by 552,000 tonnes/year in 2030 (46% of the targeted reductions).

Description

Success for this Big Move will mean that by 2025, all space and water heating in new buildings and those replaced in existing buildings would be zero emissions. Heat pumps are expected to be an important solution is this transition. They are over 200% efficient at capturing heat from the air, ground or waste sources. They also cool buildings, which will be especially important as climate change causes hotter summers. The City's Neighbourhood Energy Utility will also need to get 100% of its energy from renewable sources by 2030 (currently 70%).

For this Big Move to succeed, the Zero Emissions Building Plan for new construction will need to be sped up. New construction is critical because one quarter of the floor space in 2030 will be built over the next decade. Building that new floor space with zero emissions space and water heating starting as early as 2021 avoids the need to retrofit in the future.

For existing buildings, the City will need to develop a Zero Emissions Retrofit Strategy to transition space and hot water heating to zero emissions. Furnaces and boilers last 15–25 years, while hot water heaters last closer to 10 years. Every time they are replaced is an opportunity to upgrade to zero emissions.

A successful Retrofit Strategy will include sustained incentives (potentially through a Vancouver Climate Trust) and investments in industry capacity-building to support voluntary adoption of zero emissions space and water heating before 2025. Ultimately, there will need to be regulations that require zero emissions heating equipment when it is replaced (in the same way higher efficiency furnaces are already required when an old one is replaced).

While 2025 is the key date to meaningfully bend the emissions reduction curve, moving this quickly will have implications on factors such as costs and business' ability to adapt to new opportunities. Success will depend on understanding where there are concerns and finding effective ways of addressing them. Also critical will be a jobs transition roadmap. In addition, careful consideration and analysis of the use of incentives is required in order to preserve affordability and avoid displacement of existing residents, particularly in aging rental buildings.

Links to Existing Work

Implementation of Zero Emissions Building Plan (2016) is ongoing. The City continues to require energy efficiency upgrades when a building is retrofitted, which help make the switch to zero emissions heating more affordable. The Neighborhood Energy Utility has been providing low-carbon heat and hot water to customer base in Southeast False Creek since 2010, and expansion is underway to parts of Mount Pleasant, North East False Creek and the False Creek Flats. The City has transitioned boilers to heat pumps at a growing number of its own facilities, including City Hall. This Big Move also supports the Vancouver Housing Strategy by ensuring homes are healthier and have lower energy costs.

Responsible Departments

- Led by Planning, Urban Design and Sustainability
- Supported by Development, Buildings and Licensing; Engineering; and Real Estate and Facilities Management

Big Move #5	Lower carbon construction materials and designs
	By 2030, the embodied emissions in new buildings and construction projects will be reduced by 40% compared to a 2018 baseline. *(Recommendation F)*
Carbon Reduction Potential	By reducing the embodied carbon emissions in new construction projects, 78,000 tonnes/year of carbon pollution could be reduced by 2030. This reduction does not count against the 1.2 million tonnes the City is targeting because nearly all embodied emissions are not included in the City's current inventory.
Description	Success for this Big Move will mean a shift in construction practices to: use more mass timber and low carbon concrete, rely more on prefabricated and modular construction, eliminate spray foam insulation with high-carbon blowing agents, and use more recycled aggregate and asphalt. Further, a shift in design practices to less underground parking and the retention or re-use of existing materials will also be outcomes of this Big Move. In addition to reducing carbon pollution, these outcomes have the potential to support BC's sustainable forest sector and our economy, improve seismic resilience, and open up more affordable construction options, specifically around mass timber and reduced parking. The first phases of implementation of the Zero Emissions Building Plan have resulted in a significant reduction in operational GHG emissions for new construction. However, the embodied emissions of a new building are significant and can typically be equivalent to (and sometimes two times greater than) the operational emissions from that same building. Initial work towards this Big Move is expected to include removing regulatory barriers to increased mass timber construction and introducing requirements for lower embodied emissions. As with the Zero Emissions Building Plan, the work to achieve the target cannot depend on regulations alone. To recognize the steep learning curve for many designers, developers and building occupants, the work will include incentives for early adopters, industry capacity-building and City leadership. The City will need to work with regional, provincial, national and international partners to improve standards and protocols for embodied emissions accounting in order for this work to be successful.
Links to Existing Work	Embodied carbon in construction is a relatively new area of consideration for the City. The most recent update to the Green Building Policy for Rezoning requires developers to report embodied carbon in their projects and the City has been using lower-carbon concrete and higher rates of aggregate and asphalt recycling.
Responsible Departments	• Led by Planning, Urban Design and Sustainability and Engineering • Supported by Development, Buildings and Licensing; and Real Estate and Facilities Management

Big Move #6	Restored forests and coasts
	By 2030, restoration work will be completed on enough forest and coastal ecosystems in Vancouver and the surrounding region to remove one million tonnes of carbon pollution annually by 2060. *(Recommendation G)*
Carbon Reduction Potential	Through reforestation and coastline rehabilitation, the materials planted will be capable of removing and sequestering at least one million tonnes of CO2 per year by 2060. The reductions will be minimal in 2030 because ecosystems take time to recover and grow once any planting is complete.
Description	Conserving, restoring, and creating forest and coastal ecosystems will remove large amounts of carbon from the atmosphere and sequester it as vegetation and in the soil as organic matter. Natural shorelines also increase resilience to sea level rise associated with climate change. In addition to carbon sequestration benefits, forests and coastal ecosystems (e.g., eelgrass meadows and salt marshes) play an important role in supporting cultural practices and providing ecosystem services and resilience to people and wildlife, both in Vancouver and in the surrounding areas. Success for this Big Move will mean: • Increasing Vancouver's tree canopy, especially in underserved communities. • Collaborating with the Musqueam, Squamish and Tsleil-Waututh Peoples to restore lands. • Partnering with Environment and Climate Change Canada, Fisheries and Oceans Canada, BC Ministry of Environment, Metro Vancouver, Port of Vancouver, Vancouver Aquarium, and others to conserve and restore coastal ecosystems, such as the eelgrass meadows of Spanish Banks. • Improving water quality of receiving waterbodies to a standard that supports marine life water quality objectives. • Large-scale restoration of shorelines and subtidal zones along False Creek, the Fraser River, English Bay, Burrard Inlet and Trout Lake. • Conservation of large tracts of coastal forest, such as the Coastal Douglas Fir Biogeoclimatic Zone, which is a rare local forest ecosystem.
Links to Existing Work	The City has some experience in these types of carbon sequestration projects through the Greenest City Action Plan, although carbon has never been a primary reason for the projects (e.g., tree canopy goals and the New Brighton Park Shoreline Habitat Restoration Project). The Rain City Strategy, Urban Forest Strategy, Climate Change Adaptation Strategy, Resilient Vancouver Strategy, and Biodiversity Strategy also support actions related to this Big Move. This Big Move would be a significant expansion of scale of the City's work in this field.
Responsible Departments	• Led by Planning, Urban Design and Sustainability • Supported by Park Board and Engineering.

b. The Accelerated Actions (Recommendation H)

The climate emergency will not pause while the Big Moves take time with engagement to develop into robust strategies. In order to respect that urgency, staff have also developed a set of Accelerated Actions that build on existing work and can move forward without delay.

Many of the Accelerated Actions are expected to become important elements in the Big Moves as they develop, but they can be safely initiated concurrent with that work. They may need to be strengthened to adequately support a Big Move and they may need to be complemented with other actions. This work can be seen as 'no-regrets' as it is very unlikely that any of the Accelerated Actions would stop making sense even after the Big Moves are developed.

Several of the Accelerated Actions address sources of carbon pollution not covered by any of the Big Moves. Of note are Accelerated Actions 12.a and 13.b, which relate to the emissions from our food system. Growing, processing and transporting our food are material sources of carbon emissions, but at this time, staff do not have a clear enough picture of how much they can be reduced or what the most appropriate roles are for the City to articulate a meaningful Big Move for food consumption. Staff will continue to monitor and pursue this opportunity as these plans are reviewed and updated.

The full list of Accelerated Actions is contained in Appendix A. Each action includes a short description of the action and how it reduces carbon pollution, information on whether the action is a next step or a new action, what the next milestone in the project would be, and which departments are responsible for the action.

Given the large number of Accelerated Actions, the next milestone for most of them is a report back to Council to provide a more thorough opportunity to understand and discuss them. Some of those reports will be for single Accelerated Actions, and in other cases staff will bundle Accelerated Actions into logical groupings or the Big Moves.

Carbon Budgeting (Recommendation I)

In January 2019, Council directed staff to "establish a remaining carbon budget for corporate and community emissions commensurate with limiting warming to 1.5°C, re-evaluate how to best measure such emissions, and report annually on the expenditure of the City of Vancouver's remaining carbon budget".

The field of carbon budgeting is nascent and definitions vary by jurisdictional context. A review of existing national and sub-national carbon budgets showed two main groups of approaches:

a. Remaining Carbon Budgeting

These approaches focus on total present and future GHGs in the atmosphere, rather than reductions from chosen "baselines". They typically look at the remaining amount of carbon "room" left in the atmosphere before there is an unacceptable risk of a global temperature threshold being exceeded. This room is continuously decreasing due to the carbon we emit, leading to approaches that budget the remaining allowable carbon. In practice, a jurisdiction takes a portion of that global room and sets immediate and medium-term multi-year budgets, leading eventually to their maximum allowable carbon limit.

Examples: UK, London, Australia, New Zealand

An advantage of multi-year budgets is that they focus on efforts to reduce long-term accumulation of emissions in the atmosphere, rather than fluctuations in the rate of emissions due to near-term factors (e.g., weather; economic and investment cycles).

> *A cumulative multi-year goal is a commitment to reduce, or control the increase of, cumulative emissions over a target period to a fixed absolute quantity. Cumulative multi-year goals are often referred to as "carbon budgets." This type of multi-year goal is framed as a fixed-level goal because it is not defined in reference to a base year or baseline scenario.*
>
> *- Mitigation Goal Standard, World Resources Institute*

b. Carbon Reduction Accounting

These approaches add up carbon-reduction contributions (likened to GHG "spending") to achieve a cumulative reduction against a chosen target. They focus on transparency in investments, programs and policies that lead to emissions reductions.

Examples: Oslo, London, British Columbia (TBD)

To achieve this, they can be broken down by sector or program, and include such information as time period, cost, contributions to carbon goals, and responsibility. Because they are additive, an advantage is that any gap in achieving the necessary reductions against the target becomes visible, demanding a response.

> *[Oslo's] climate budget is a tool to convert a city's climate goals into concrete, annual, measurable action. It establishes a maximum GHG emissions level for the budget year, based on the city's emissions goal. The budget details the city's proposed short-term, emissions-reduction actions to stay within the maximum amount, their projected impact, and cost. It is a distinct part of the city's overall budget and moves through the city's usual budgeting process, from proposal to adoption, implementation, and after-action assessment.*
>
> *- Game Changers Report, Carbon Neutral Cities Alliance*

Overall, carbon targets reframed as maximum "budgets" can help enforce more rigorous approaches to managing carbon. They can list carbon impacts and ownership line-by-line. They can allocate and transfer carbon between different sources to balance out the big picture (see the Improved Accountability section). Reassessed, a carbon budget periodically gives opportunities for course corrections where necessary. Carbon budgets can help clearly communicate the impact of carbon-reduction efforts to the public, the City organization, and stakeholders. While more transparent, any budget requires accountability on implementation, with potentially some form of consequence (and mechanism to redress) if budgets are not met.

Objectives for Vancouver Approach

Staff will work to develop carbon budgets for Vancouver's corporate and community emissions. Final approaches may draw elements from both approaches discussed previously. A carbon budget is only useful if it helps to guide appropriate, agile, and accountable effort to reduce emissions. As such, any shift to a budget approach for Vancouver's City-corporate and community emissions should aim to meet the following objectives:

- Improved Transparency
- Better Data
- Better Forecasting
- CleanBC Alignment
- Improved Accountability

These objectives are detailed in Appendix G, along with sample considerations to be resolved in developing a carbon budget approach.

Next Steps

If approved, an approach for corporate emissions will be developed and implemented first, to confirm the objectives are being met, and to test if it can be replicated for community emissions. Developing the corporate approach now aligns well with the forthcoming Green Operations Plan refresh. If multi-year budgets are set, the first budget cycle (e.g., 2019–2022) can be used to refine carbon budget approaches.

Nearly all City departments will be involved (e.g., Planning, Urban Design and Sustainability; Finance, Risk and Supply Chain Management; Engineering Services; Real Estate and Facilities Management; Technology Services). Staff will report back with an update on the carbon budget approaches to Council, in line with the progress update on climate emergency measures in 2020.

Climate and Equity Working Group (Recommendation J)

Climate change shocks and stresses do not affect all groups in our community equally. Those that have been affected by systemic vulnerabilities and inequity are often at greater risk from the impacts of climate change and often have the fewest resources to respond and adapt. In Vancouver, climate change impacts, such as extreme heat and poor air quality from wildfires, are already being felt disproportionately.

In parallel, we know that it's critical to engage with and support systemically excluded and low-income populations as we transition from fossil fuels to renewable energy. That transition can be undertaken in ways that improve social equity and affordability, while alleviating issues such as "energy poverty". For example, convenient public transit helps reduce carbon emissions and air pollution while also supporting affordable mobility for all residents.

In the U.S., a growing number of cities are advancing equity in parallel with their climate action work, using input from Climate and Equity Committees. Portland, Seattle, and Washington, D.C., have each applied an equity lens to their climate work, to minimize the impacts of climate change on systemically excluded populations and ensure that new policies do not negatively impact vulnerable populations, while also identifying ways to support greater equity through climate action. Similarly, the Canadian Urban Sustainability Network recently completed a study that identified the significant extent of energy poverty across the country and highlighted the need for equity considerations in climate plans.

Social Policy is currently developing an Equity Framework to formalize the City's equity-focused work and to promote access, inclusion, cultural safety, and public participation for all staff and residents, and across all City areas of business. Creating a Climate and Equity Working Group would provide an early opportunity to use the tools of the Equity Framework to engage with systemically excluded and low-income residents on the City's climate and sustainability work, ensuring that the actions put forward in Greenest City 2050 and ongoing response to the climate emergency improve social equity.

The Climate and Equity Working Group will coordinate with the City-wide Plan effort regarding equity conversations as both programs develop. It will also be an important opportunity to incorporate a gendered intersectional lens into the City's climate actions and the Climate Adaptation Strategy.

More details of the Climate and Equity Work group can be found in Appendix H.

Greenest City 2050 (Recommendations K and L)

Vancouver's current environmental strategy, the Greenest City Action Plan, extends to 2020. All ten of the goal areas are relevant for Vancouver's Climate Emergency Response. The ten goals are:

1. Climate and Renewables
2. Green Buildings
3. Green Transportation
4. Zero Waste
5. Access to Nature
6. Clean Water
7. Local Food
8. Clean Air
9. Green Economy
10. Lighter Footprint

Because of the strong links between the climate emergency and the City's broader sustainability work, the climate emergency response will be most effective if it is embedded within the next phase of the Greenest City Action Plan and integrated with the upcoming City-wide Plan. To enable this coordination, staff are seeking approval from Council to begin the creation of Vancouver's next environmental action plan, Greenest City 2050.

If approved, staff will report back on the Greenest City 2050 in coordination with the City wide Plan reporting structure. Further, staff will integrate the six Big Moves in this report into the development of the City-wide Plan which will address a broad diversity of policy areas including land-use, transportation, economy, social, environment, parks, culture, sustainability, climate change, infrastructure, and place-making/urban design with lenses of reconciliation, resiliency and equity. The City-wide Plan will provide an "umbrella" for integrated, long-range strategic policy across these areas and a framework to support more detailed implementation strategies in specific areas such as climate change. This framework would enable a coordinated system of progress monitoring, investment, policy review and adaptation over time to achieve community, Council and corporate goals.

Climate Emergency Engagement

Within the 90-day window kicked off by Council's climate emergency motion on January 19, 2019, engagement efforts have focused internally and on organizations where the City has established relationships. The internal engagement included meetings and workshops with staff from Planning, Urban Design and Sustainability; Engineering; Development, Buildings and Licensing; Real Estate and Facilities Management; Social Policy; Park Board; Legal Services; Finance; and Intergovernmental Relations.

The primary external engagement was a half-day workshop on February 25, which was attended by 112 individuals from local businesses, environmental non-governmental organizations, community associations, labour organizations, academia, and other levels of government. During the event, staff collected nearly 900 ideas during sixteen breakout sessions, which focused on new and existing buildings, neighbourhood energy systems, zero emissions vehicles, active transportation and transit, the City's corporate leadership, embodied carbon, and climate equity.

Implications/Related Issues/Risk

Financial

Should Council approve the recommendations of the Climate Emergency Response, staff will report back by the Fall of 2020 with a comprehensive implementation and financial strategy for the recommended Big Moves and Accelerated Actions. When developing the strategy, staff will strive to optimize the City's regulatory, financial and advocacy tools, considering the City's financial and operational capacity within the context of the City's service planning, capital planning and budget framework and the financial impacts (costs and savings) for the City's residents and businesses, utilities, and other levels of government.

If any of the Big Moves is ready for Council's consideration before the Fall of 2020, staff will report back with an implementation and financial strategy that contemplates any links to the Big Moves still under development. Any Accelerated Actions brought forward in advance of the comprehensive implementation and financial strategy will be supported by a similar evaluation, including a consolidated assessment of any initiative proposed as part of the 2020 budget.

Human Resources

The Accelerated Actions can start to be advanced to their next milestones with existing staff capacity. Depending on the proposed next steps at those milestones, there may be staff implications, and staff will include any required staff resource as part of the annual budget process.

Advancing the Big Moves from their current form to robust implementation strategies will be a significant undertaking that transects across departments. It will also require additional engagement with the public, other governments, utilities, business, labour, academia and NGOs to ensure a wide variety of perspectives are reflected as the Big Moves are developed. Additional or reallocated staff will likely be required and as the Big Moves are developed staffing needs will be brought for approval as necessary.

Legal

Staff will engage Legal Services to confirm, if necessary, the legal authority for the City to implement any of the Big Moves, Accelerated Actions or any specific step or activity contemplated in either one. If the City does not have the legal authority under the Vancouver Charter to implement one or more of the foregoing, and if at such time the City still wishes to pursue such action, staff will engage Legal Services to work collaboratively with the Province for the specific legal authority under the Vancouver Charter.

Conclusion

The world is at a tipping point between a climate disaster and a renewable, more equitable future. By choosing to act, Vancouver is choosing optimism and hope over despair and darkness. The transition will take time and will be challenging, but many cities around the world and even some Vancouver neighbourhoods are already thriving as low carbon communities. Through a thoughtful transition Vancouver can continue to move toward a healthier, more communal, more secure, greener and more affordable future and in doing so be a beacon for other cities to follow.

* * * * *

Appendix A – Accelerated Actions

Category		Accelerated Action		How this Action Reduces Carbon Pollution	New Action vs. Next Step	Next Milestone	Department Lead(s)
1	City-wide Planning Use city-wide planning and quick-start housing actions to advance green buildings and sustainable transportation objectives.	a.	Sustainable Mode Splits: Expand policies and actions that lead to communities with very low motor vehicle reliance (e.g., 15–20% of daily trips) by ensuring: a) most daily household destinations are within walking or biking distance and/or within walking distance of rapid transit; b) requirements for parking reflect this; and c) that the allocation of public space supports walking, cycling and transit. Pilot this approach on major development sites and planning areas, such as the Jericho Lands and Broadway Area Plan, by setting neighbourhood-specific mode-split targets and showcasing integrated multi-modal land use and transportation planning that can be learned from and replicated throughout the City.	Compact, livable communities not only produce healthier and happier residents, but reduce costs and greatly reduce dependence on fossil fuels through a reduction in vehicle ownership and kilometres travelled by vehicle.	Next Step	Report back to Council on progress. Target Q4 2020.	PDS, ENG
		b.	Infill Pilot Program: Investigate feasibility and details of a pilot program in RS and RT zones to incentivize new types of infill housing that reduce climate change impacts and improve unit accessibility. The pilot will be based on the Character Homes Incentive Program as a model for introducing housing choice and meeting public interest objectives.	To be eligible for incentives, the infill housing would need to be near-zero emissions, and there could also be an opportunity to reduce embodied emissions.	New Action	Study feasibility. Report back to Council with details and process (summer 2019).	PDS
		c.	Small Townhouse Pilot Program: Investigate feasibility and details of a townhouse pilot program on large lots in low-density areas to demonstrate construction and design approaches that reduce climate change impacts and improve unit accessibility.	To be eligible for the pilot program, the townhomes would need to be near-zero emissions, and there could also be an opportunity to reduce embodied emissions.	New Action	Study feasibility. Report back to Council with details and process (summer 2019).	PDS

Category	Accelerated Action	How this Action Reduces Carbon Pollution	New Action vs. Next Step	Next Milestone	Department Lead(s)
	d. Barriers to Low Embodied Carbon: Review existing zoning regulations and design guidelines to identify how the existing regulatory framework requires and incentivizes the construction of low-density buildings with high embodied carbon (e.g., lots of concrete), and investigate how those requirements and incentives could be removed to enable low-carbon building construction. Examples include regulations and guidelines that limit above-grade floor area and therefore require or encourage below-grade living space (basements) and underground parking, both of which require more concrete.	The embodied emissions from building materials, such as concrete and foam plastics, can be significant in the overall life-cycle emissions of a building. By identifying and removing incentives for construction with high embodied carbon and enabling construction methods with low levels of embodied carbon, the City can help to reduce those emissions sources.	New Action	Study feasibility. Report back to Council with details and process (summer 2019).	PDS, DBL
	e. City-wide and Area-Specific Plans: At the time of their development or during review, city-wide and area-specific plans should make provisions to advance near-zero emissions buildings. This could include considerations such as articulating access to sunlight for neighbouring buildings at the block scale, allowances for simplified low-carbon building forms, and roof alignment and design allowances to enable solar energy.	Large-scale planning exercises can foster community expectations and create opportunities for low-carbon building forms and features, such as high levels of insulation, mass-timber, and roof top solar. Mass timber may also be a key to more affordable multi-unit residential buildings.	New Action	Report back to Council by Q4 2020.	PDS, DBL

Category		Accelerated Action	How this Action Reduces Carbon Pollution	New Action vs. Next Step	Next Milestone	Department Lead(s)
		f. Expanded Goals for Design Guidelines: Gather data and expand the factors considered in the development of design guidelines so that in addition to livability and neighbourhood impacts, we consider cost, climate change mitigation, and seismic resilience, if/when warranted. Pilot this approach by integrating consideration of data and these other factors into the development of new or revised design guidelines for a specified form/development type. Initially constraining this to a specific set of guidelines will reduce the variables and support higher quality data. The resultant guidelines could include alternate approaches to built form, incentives, or conditional approval paths for projects that are designed to achieve near-zero building standards in addition to livability and affordability outcomes.	Design guidelines for new developments are established to maintain livability for both new and existing residents, but can lead to complex building forms that may have significant implications for construction cost, energy efficiency, and embodied carbon.	New Action	Report back to Council by Q4 2020.	PDS, DBL
2	Zero Emissions Areas Explore zero emissions transformational areas.	a. Zero Emissions Areas: Begin engaging residents and businesses on zero emissions areas, where access by combustion engine vehicles are restricted or deterred, and active transportation and zero emissions transit are encouraged, in order to explore innovative emissions reduction programs. Identify areas of the City where these approaches can be explored, and identify replicable lessons for city-wide implementation.	Zero emissions areas encourage a broader shift to zero emissions vehicles, including for goods movement. They can also be designed to encourage active transportation. The areas also offer air quality, health and noise benefits for residents.	New Action	Report back to Council on initial engagement by Q4 2020.	PDS, ENG, DBL, CEC

	Category		Accelerated Action	How this Action Reduces Carbon Pollution	New Action vs. Next Step	Next Milestone	Department Lead(s)
3	<u>Land Use Incentives for Green Buildings</u> Use land-use tools to encourage zero emissions buildings, zero emissions space/water heating equipment, and low-carbon materials.	a.	Time-limited pre-regulatory Density Bonus incentives for Zero Emission buildings: Explore defining buildings that deliver near-zero operational and/or low embodied carbon emissions as an amenity, so that they can be subject to the density bonus provision under Section 165.2(1) of the Vancouver Charter. If Council defines these buildings as an amenity, this would allow staff to explore and report back on specific opportunities to allow time-limited density bonuses for a wider range of green buildings, including zero emissions commercial and institutional buildings, and buildings with low embodied carbon. Incentives would be in place until equivalent regulatory requirements come into effect. Staff would ensure that any recommended short-term bonus programs are aligned with provision of rental and non-market housing and other community goals.	The early stages of transformational change often involve higher costs and uncertainties than continuing with conventional approaches. In order to gain experience and drive down these costs, incentives are temporarily required while new practices and products are normalized. Defining low-carbon buildings as an amenity would allow staff to introduce time-limited pre-regulatory policies and amendments to the Zoning and Development Bylaw that would allow for modest density bonuses for a wider range of green buildings, including zero emissions commercial and institutional buildings and buildings with low embodied carbon.	New Action	Report back to Council (Q2 2019).	PDS, DBL
		b.	Deep Emissions Retrofits: Explore land-use tools that help property owners and managers undertake deep emissions retrofits of existing buildings. This could include revised district schedules that would allow increased usable space in existing buildings in exchange for the deep emissions, and possibly for seismic resilience retrofit.	This would better ensure an equitable distribution of the health, comfort, resilience and operational cost savings of low-carbon buildings. Careful consideration and analysis of the use of increases in usable space to encourage retrofits are needed to preserve affordability and avoid displacement of existing residents.	New Action	Report back to Council by Q2 2020.	PDS, DBL

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	c. Improved Floor Space Incentives for Zero Emissions: Explore floor space exclusion for near zero emissions detached and small multifamily buildings that is streamlined and enhanced relative to City's current approach. Current wall-thickness and mechanical-space exclusions for near zero emissions buildings require additional work for small builders and staff. Simplifying this with a temporary outright exclusion would simplify the process and would allow for consideration of modest additional floor space for early adopters of near zero emissions design approaches.	The early stages of transformational change often involve higher costs and uncertainties than continuing with conventional approaches. In order to gain experience and drive down these costs, incentives are temporarily required while new practices and products are normalized. While this approach is already being used by other local governments in the region, careful consideration is required to ensure this does not undermine efforts to increase housing supply in traditional single family neighbourhoods.	Next Step	Report back to Council with recommendations by Q4 2019.	PDS, DBL
4 Financial Incentives for Zero Emissions Buildings and Equipment Implement incentives to make it easier and more affordable to advance zero emissions new buildings and zero emissions space/water	a. **Financial Incentives for Existing Building Energy Retrofits:** Explore options for deep energy retrofits of existing City and private buildings in connection with Council's motion to allocate $5 million of Capital Plan funding. Options will include: 1) accelerate the transition of existing City buildings to near zero and zero emissions; 2) enhance the capacity of for non-profit housing operators to access significant provincial and federal capital improvement funding; and 3) through a new collaborative approach, leverage provincial funding and energy utility administrative capacity to effectively provide additional resources to Vancouver homeowners and building operators to make deep emission reduction retrofits to their buildings. This includes pilot projects in partnership with the provincial government to retrofit affordable market rental housing and non-market housing.	Meaningful energy retrofits of existing buildings are more challenging than implementing similar measures in new construction, necessitating the provision of financial incentives. Measures are in place and will be strengthened to ensure retrofit incentives do not result in the displacement of existing residents.	New Action	Report back to Council by Q2 2019.	PDS, REFM, FIN

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heating equipment.	b. **Climate Trust:** Explore the creation of a Vancouver Climate Trust, which would have the objective of providing ongoing investments to reduce emissions from existing buildings. The Trust will continue the work started in 4a and coordinate with the Low Carbon Cities Canada initiative announced in the 2019 federal budget. Staff will evaluate potential funding streams as part of the exploration process, including the possibility of a one-time charge on new developments in the City that would be proportional to their anticipated emissions.	Staff will need to explore the balance of decreasing maximum allowed emissions limits, the introduction of embodied emissions limits, and the impacts of a potential charge to offset any remaining emissions to ensure that existing housing affordability or the viability of new developments is not materially impacted. In addition, staff will need to ensure that any new investment minimizes the displacement of existing residents.	New Action	Report back to Council by Q2 2020 in conjunction with recommended updates to Green Building Policy for Rezoning.	PDS, FIN, DBL
	c. **Heat Pump Permits:** Make it more affordable and easier to get a permit for heat pumps. Options to explore include reducing the permit fee to a fixed and nominal amount (as is currently done for solar permits), moving to an online permitting system where feasible, allowing heat pumps to be installed in front yards, and publishing a list of heat pumps that meet the City's noise limits. The applicability of successful solutions to other key zero emissions technologies, such as electric vehicle charging and solar panels, will be considered.	Electric heat pumps are typically over 200% efficient, result in almost no carbon emissions due to the nearly 100% renewable electrical grid in BC, and can provide both heating and cooling, thereby increasing resilience to climate changes. Because heat pumps are a new technology for most existing homes, installations and the permitting process can be more complex. Simplifying the process is essential to accelerate the voluntary installation of heat pumps.	Next Step	Report back to Council by Q1 2020 if required.	PDS, DBL

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5	Zero Emissions Building Standards Accelerate the implementation of the Zero Emissions Building Plan.	a.	New Zero Emissions Buildings: Explore opportunities to set lower carbon emissions limits for new construction faster than laid out in the Zero Emissions Building Plan. Any proposed changes to those limits would be based on the appropriate research and consultation, and would work within established timelines for policy and bylaw updates. To continue encouraging the development of Passive House buildings, that standard would continue to be a recognized compliance option.	Every building built to zero emissions today means one less building requiring expensive retrofits in the future. Accelerating this work will save carbon emissions and money.	Next Step	Report back as part of recommended updates to VBBL and Green Building Policy for Rezoning by Q2 2020.	PDS, DBL
		b.	Improved Compliance: Develop the tools, processes, and resources to ensure that the carbon emissions limits for new detached and multi-family residential buildings are being complied with and that developers and builders have support to meet them. One key option to be explored is a requirement for a heating permit for new detached homes and low-rise buildings (an approach used in other Lower Mainland municipalities).	The City does not currently review or inspect the sizing, performance specification or quality of installation of many of the mechanical systems that are essential to reducing GHG emissions in new construction. New policy or regulation without compliance only punishes responsible developers and builders.	New Action	Report back as part of recommended updates to VBBL by Q2 2020.	PDS, DBL

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6	Neighbourhood Energy Transition the City-owned Neighbourhood Energy Utility to 100% renewable energy and expand the system.	a.	Renewable Energy Supply: Transition the Neighbourhood Energy Utility (NEU) to 100% renewable energy before 2030. This could include a mix of expanded sewer heat recovery, waste heat recovered from data centres, thermal energy storage, bio-fuels (e.g., renewable natural gas), hydrogen, or other renewable energy sources. Currently, 70% of the NEU's energy comes from renewable sources, and opportunity exists to transition to a higher blend of renewable energy in future years.	By transitioning to 100% renewable energy, NEU-connected buildings will not need to rely on fossil-based natural gas for space and water heating. Factoring in the long-term growth of the utility, transitioning to a 100% renewable energy target could eliminate an additional ~10,000 tonnes of CO2 per year by the mid 2030s, above and beyond the current 70% renewable energy target for the NEU (current 70% target would net ~24,000 tonnes per year reduction at build-out of the customer base).	Next Step	Adoption of 2030 100% renewable target subject to evaluation using the NEU's existing investment decision framework and competitivenes s with other low carbon energy options for buildings	ENG
		b.	Expand Service Area: Evaluate feasibility for expansion of the City-owned NEU service area. Opportunity areas include areas of the Central Broadway Corridor adjacent to SE False Creek, Jericho Lands and False Creek South.	To be determined, following establishment of proposed land uses and densities for these areas (needed to inform business case analysis for expansion).	Next Step	Report back to Council in 2021 (timing dependent on timing of area plan completion).	ENG
7	Active Transportation and Transit Infrastructure Accelerate the development of infrastructure to make it easier to choose walking, cycling	a.	Improved Bus Service: Accelerate transit priority implementation on key routes, such as 41st Avenue, Georgia Street, Main Street and Hastings Street, as part of the ongoing bus speed and reliability program. A quick win would be further extension of bus lane hours beyond current peak hours.	Enabling improved bus service makes it a more efficient and attractive option for residents. Articulated buses generate 25% of the carbon emissions per person relative to a single occupancy vehicle, which can be improved to 5% with the use of electric buses.	Next Step	Report back to Council on engagement. Target Q2 2020.	ENG

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and transit.	b. Active Transportation Network: Explore opportunities to accelerate the completion of accessible and equitable active transportation networks, and close key gaps, including the Granville Bridge pathway.	Providing safe, equitable active transportation infrastructure encourages walking and cycling, decreasing reliance on private vehicles and the associated carbon emissions.	Next Step	Report back to Council on opportunities. Target Q3 2020.	ENG
	c. E-Bike Share: Add 500 electric-assist bicycles (e-bikes) and 50 electrified stations to the public bike share (PBS) system. E-bikes have been shown to provide mobility to those with physical limitations that prohibit cycling, increase ridership among currently underrepresented groups and enable longer trips for a greater variety of trip purposes.	Replacing higher carbon (private motor vehicle, taxi, transit) emissions trips with lower emissions ones, like PBS with e-bikes. Currently about 47% of PBS trips replace higher carbon modes. E-bikes have at least doubled the number of rides per bike per day compared to the current system in other cities. Compared to other systems, expected usage will be at least 4.5 rides per bike per day. Average trip distance is expected to be 3.5 km, so 500 bikes are expected to replace over 1,380,000 km of polluting trips annually (conservative estimate, NYC has shown 5x more usage per bike than this estimate).	Next Step	Report back to Council on opportunities. during 2019.	ENG

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8	Transportation Demand Management Enhanced transportation demand management to support walking, cycling and transit.	a. City-wide Transportation Demand Management Program: Encourage shifting travel behaviour from driving to sustainable modes. Coordinate, track, and monitor existing cross-branch activities (including efforts with School Active Travel, Walk + Bike + Roll promotions, and new developments) to leverage existing infrastructure investments. Complete gap analysis and develop programming to encourage mode shift and address under-targeted markets, such as major employers and institutions.	Encourage behaviour change to travel by sustainable modes. Promote efficient use of existing infrastructure.	Next Step	Report back to Council on progress. Target Q3 2020.	ENG
		b. Support for electric bikes: Explore options to encourage the safe use of electric bikes and electric cargo bikes, especially for longer commutes, steeper terrain and for those with limited physical capacity. As part of this work, staff will explore options of partnering with the provincial government to extend CleanBC incentives for electric vehicles to electric bikes.	A switch to electric bikes or cargo bikes from private vehicle trips reduces gasoline and diesel use. They also make that switch possible for longer trips, trips with kids or a heavy load, and for people who might not be able to travel by a non-electric bike.	New Action	For consideration in service planning for 2020 .	ENG
		c. Transportation Pricing: Undertake a comprehensive City-focused transportation pricing review to explore equitable and comprehensive applications for all modes (e.g., road and curb pricing) that would help curtail vehicle emissions and support zero emissions mobility. To be aligned with regional mobility pricing work.	Pricing road and curb space is a powerful tool for decreasing congestion resulting in high concentrations of emissions and discouraging vehicle travel. Revenue from mobility pricing can also be directed towards supporting sustainable travel.	New Action	Report back to Council on progress. Target Q3 2020.	ENG, PDS

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	d. Parking Requirements: Update the Parking Bylaw to: 1) expand the transportation demand management (TDM) options available to developments outside of the downtown core and allow for elimination or reduction of parking stall requirements in those developments (except for accessible and visitor parking), and 2) explore design standards that enable parking stalls to be repurposed in the future if they aren't needed for parking (e.g., flat floor plates and over-height ceilings). This work would be in addition to the planned monitoring of the effectiveness TDM program for new developments.	How a city prioritizes parking clearly signals its priorities around livability and sustainability. Successful and livable cities support parking and driving for those who need it, and ensure other modes are readily available to the rest. With limited space and money, parking should be a low priority when designing an affordable, green city. Reduced parking also helps to reduce the embodied emissions in new construction if less concrete is needed, and it can also lead to reduced embodied emissions from vehicles as car ownership declines.	Next Step	Report back to Council on progress. Target Q3 2020.	ENG
	e. On-Street Car Share Parking: Update bylaws and create agreements to allow car share vehicles to end trips and have stopovers at on-street metered parking spaces.	It has been estimated that households participating in two-way car share programs (e.g., Modo, Zipcar) reduce their annual vehicle-related GHGs by up to 54% on average. For households participating in one-way car share programs (car2go, Evo), vehicle-related GHG emissions declined by up to 15% on average. Car sharing is also a proven way to reduce vehicle ownership, vehicle kilometres travelled and transportation costs for residents utilizing car sharing.	New Action	Report to Council Q2 2019.	ENG

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9	<u>Goods Movement and Fleets</u> Reduce carbon emissions from freight and private fleets operating in Vancouver.	a.	Urban Freight and Fleets: Develop an urban freight and fleets strategy to identify the needs for regional and longer-distance goods movement, and the opportunities for lower-impact goods movement, deliveries, and servicing in the urban environment. The strategy will also address the transition of private fleets to zero emissions vehicles (including light-, medium- and heavy-duty vehicles). Elements of the strategy could include increasing the use of cargo bikes for freight, provision of logistics hubs, time-of-day and loading zone policies, commercial vehicle licensing policies, and leveraging rail or other modes to reduce truck travel.	Reduces greenhouse gas emissions of goods movement by decreasing the distance travelled by trucks, transitioning to zero emissions vehicles, and supporting modes with lower GHG emissions, such as rail and bikes.	Next Step	Report back to Council on progress. Target Q3 2020.	ENG, PDS
		b.	Curbside Zone Management: Update the management and enforcement of on-street curbside zones (e.g., commercial loading zones) so that they more effectively encourage efficient use of street space and encourage the transition to zero emissions commercial vehicles.	Effective pricing of curbside zones would encourage vehicles to load and vacate the space quickly, making it available for the next user. This would reduce greenhouse gas emissions due to circling and reduce congestion caused by double-parking. Curbside management could also be used to directly encourage the transition to zero emissions vehicles by offering preferential access to the zones.	New Action	Report back to Council in Q2 of 2020.	ENG, PDS, DBL

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10	<u>Electric Charging Network</u> Increase the public charging network for electric vehicles and other needs, such as film and food trucks.	a. Neighbourhood Charging: Develop a neighbourhood charging strategy for vehicles and electric bikes, with a focus on providing charging in areas of the city where residents do not have access to off-street home charging. Possible locations include on-street (including light-pole charging), and lower-use parking areas, such as parks and schools, particularly where overnight access is possible. The neighbourhood charging strategy would also help provide charging options for shared mobility companies helping to accelerate their transition to zero emissions vehicles.	Access to home charging is considered a key enabler for electric vehicle uptake. It also reduces reliance on higher-powered, short-term public charging that is necessarily more expensive to use and operate. For the thousands of Vancouver residents without access to off-street parking, including many renters, this strategy will seek to enable access to convenient, more equitable near-home charging.	Next Step	Report back to Council in Q2 of 2020 with completed strategy. Early actions to also be included for consideration in service planning for 2020.	ENG, PDS
		b. Film, Food Trucks and Special Events: Develop a power supply plan for film, food trucks, and special events to help them transition off of diesel and propane generators, which are also significant contributors to noise and air pollution. Installing power drops for filming at Larwill Park will be one quick-start action. A capital project is currently underway to develop improvements to the public charging network as part of the Electric Vehicle Ecosystem Strategy. The Larwill Park initiative will be funded by the existing capital program. To help finance additional power drops at key areas, staff will implement a diesel generator permit for film and special events.	By enabling film operations, food trucks and special events to connect to the grid at key areas, such as frequent filming locations and farmers markets, they can reduce their reliance on diesel and propane use. These actions also help to reduce local air pollution and noise.	New Action	Report back to Council in Q2 of 2020 with completed plan. Early actions to also be included for consideration in service planning for 2020.	ENG, PDS
		c. Commercial Buildings: Update electric-vehicle readiness requirements for new commercial buildings to close a gap for workplace charging and other commercial uses. In recognition of the range of uses for commercial buildings and parking, the requirements will be based on a points system (similar to the City's TDM approach), where developers can choose from a menu of EV-readiness options.	For many EV drivers, the ability to charge a vehicle at work will allow them to transition to an EV, either by extending their range for long commutes or by having access to charging when not available at their home parking spot.	Next Step	Report back to Council in Q1 2020.	PDS, DBL, ENG

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	d.	Fast-Charging Network: Complete phase 1 of the City's DC fast-charging network for electric vehicles by end of 2020, instead of 2021. This will put a fast-charging hub within a 10-minute drive of anywhere in the City.	A 10-minute drive to a fast-charging hub, located at a convenient amenity, was rated by a majority of Vancouver residents as a solution that would make it more likely for them to switch to an electric vehicle.	Next Step	Selection of vendor.	ENG, PDS
	e.	Home Charging in Rental Buildings: Explore options to encourage the installation of home charging in existing buildings, with a focus on rental buildings and non-market housing, which have not been as well supported as stratas by existing provincial government programs. Options to explore include providing a top-up to the Government of BC's CleanBC incentives, which were expanded in the 2019 provincial budget.	Access to home charging is a key enabler for switching to electric vehicles. Renters face a significant barrier to adding home charging if their building is not already equipped with charging infrastructure, and cost has been flagged as the greatest barrier to adding charging in multi-family buildings.	Next Step	For consideration in service planning for 2020.	PDS
	f.	Electric Tour Buses: Provide charging service for electric tour buses as a pilot project at up to three locations in 2019/2020. This would build on the site identification work already completed, and provide a clear path to getting priority sites up and running to be responsive to industry leaders and help inform the freight and fleets strategy. Access to the charging locations would be determined through a market process. A capital project is currently underway to develop improvements to the public charging network as part of the Electric Vehicle Ecosystem Strategy. The Electric Tour Buses initiative will be funded by the existing capital program.	Private medium- and heavy-duty vehicles are a significant part of transportation emissions, and also significant contributors to local air pollution. Central parking and charging opportunities help reduce the barriers for tour bus operators, who may lose half their range by charging out of the city and driving in.	Next Step	Request for expressions of interest for site access.	ENG, PDS
11 Electric Vehicle Incentives Implement incentives to accelerate the	a.	Parking for Zero Emissions Car-Share Vehicles: Update the Transportation Demand Management requirements in the Parking Bylaw to: 1) require all new car-share vehicles to be zero emissions with dedicated level 2 charging if electric, and 2) include points for micro-mobility charging including e-bikes.	Encourages shift to electric vehicles and other sustainable modes of transportation.	Next Step	Report back to Council by Q2 2020.	ENG, PDS

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	transition to electric vehicles.	b.	Car Share Parking Rates: For zero emissions vehicles, waive the fee for permits issued to car-share organizations that allow those vehicles to park in areas restricted to residents-only parking. Waivers granted would expire in five years subject to an evaluation of the incentive.	Encourages shift to electric vehicles.	New Action	Report back to Council by Q2 2020.	ENG, PDS
12	Solid Waste Reduce solid waste and use it to reduce fossil fuel use.	a.	Reducing Wasted Food: Identify and pursue opportunities to advance community actions to reduce wasted food across Vancouver, in partnership with local food businesses and food industry, with a dual focus to avoid wasted food in the supply chain and divert surplus food to people.	The production, processing and movement of food results in carbon emissions. By reducing the amount of wasted food, those food-related emissions can also be reduced.	Next Step	Identified opportunities to be considered as part of service planning for 2020.	ENG
		b.	Renewable Gas Supply: Assess the business case of converting waste organic materials into renewable natural gas at the Vancouver Landfill. This would be additional to the project the City is already advancing with FortisBC to upgrade landfill gas into renewable natural gas.	Renewable natural gas can be directly substituted for fossil natural gas, which eliminates the carbon emissions associated with extracting, processing, transmitting and combusting the fossil gas.	Next Step	Complete business case analysis by 2019 year-end.	ENG
		c.	Construction and Demolition Waste: Explore the business case of producing a biofuel from waste construction and demolition materials received at the Vancouver Landfill, which could potentially be used to replace coal for the local production of cement.	Construction and demolition waste can be processed into a biofuel, thereby reducing the emissions associated with mining, transporting and burning coal, for example.	Next Step	Complete business case analysis by 2019 year-end.	ENG
		d.	Recycled asphalt and aggregate: Explore the business case of investing in existing infrastructure to enable an increased proportion of recycled asphalt and aggregates in City construction projects.	By increasing the proportion of recycled asphalt and aggregates in City projects, we can reduce the need for new asphalt and aggregate and the emissions associated with producing it.	Next Step	Complete business case analysis by 2019 year-end.	ENG

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13	Food and Beverage Reduce emissions from Vancouver's food and beverage industry.	a.	Restaurants and Breweries: Engage with local restaurants and breweries to help reduce emissions and transition to renewable energy. The project will work with the food and beverage industry to explore their options to reduce their emissions, as well as the possible roles that businesses and the City can play to accelerate change. Areas of interest include alternatives to standard cooking facilities and patio heaters.	Carbon emissions would be reduced by transitioning off of fossil natural gas and propane to solutions such as renewable natural gas, induction stoves, heat pump water heaters, electric patio heaters and blankets.	New Action	Report back with action plan by end of 2019.	PDS, DBL, ENG
		b.	Diets that are Healthy for People and the Planet: Convene a Solutions Lab to accelerate movement toward diets that are healthy for people and the planet. The Solutions Lab will bring together City staff, partners, and community members to understand a complex challenge and rapidly prototype and test solutions. Staff will also investigate the City's potential role in supporting emissions reduction from the food system and identify best practices for ensuring that policy approaches are equity-based.	In Vancouver, 20% of consumption-based carbon emissions come from food (EcoCity Footprint Tool Pilot), therefore food can play an important role in taking climate action. Given that limited food production occurs within city limits, the City's role in supporting food system emissions reduction will likely focus on residents' eating habits and institutional food provision.	New Action	Begin convening Solutions Lab in Q2 2019. Report back with potential actions for consideration in Q1 2020.	PDS, ACCS
14	City Leadership Updating the City's Green Operations Plan to reflect the urgency of the climate emergency.	a.	Facilities Capital Maintenance: The City is working towards all City buildings having 100% renewable energy and 100% reduction in carbon emissions by 2040. All new City-owned buildings are being built to zero emissions standards (since 2018). Going forward, all capital maintenance projects on energy using equipment in City buildings will transition from gas to high efficiency electric options where viable. As part of this work, several additional gas-to-electric heat pump projects will be completed in 2019/2020.	The City owns and operates more than 600 buildings and when a major upgrade is required for a boiler, furnace, or domestic hot water heaters it is proposed that zero emissions solutions are used, subject to meeting operational requirements. This action will address carbon reduction opportunities in existing buildings.	Next Step	Ongoing annual reporting.	REFM, PDS

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	b. Embodied Carbon: Adopt a strategy that all new City facilities will explore opportunities for significant reductions in embodied emissions. To support this strategy, staff will continue to develop capacity and metrics, and create simple tools for decision-making and reporting. Staff will also work with private, public and non-profit sector partners to build awareness and encourage leadership commitments in this emerging opportunity.	By shifting materials and construction practices for new buildings to lower-carbon options, the City will be able to reduce the embodied carbon it is responsible for and help private, public and non-profit sector partners achieve similar outcomes.	New Action	Embodied carbon policy defined and included in all City-owned facilities development 2019/20.	REFM, PDS
	c. City Fleet: By 2023, transition all non-emergency City fleet sedans to zero emissions vehicles, replace an additional batch of heavy-duty trucks with electric vehicles, and support additional operational improvements using GPS and telematics.	The identified City fleet projects would reduce carbon pollution by reducing the overall volume of fossil fuels used. It is likely this would be on the order of 1,500 tonnes of CO_2e.	Next Step	Detailed analysis will be considered as part of service planning for 2020.	ENG
	d. Fleet Charging: Develop a charging infrastructure strategy for the City's electric vehicles to support the accelerated sedan transition and the addition of medium- and heavy-duty electric vehicles to the fleet.	To support the planned transition to electric, a comprehensive charging strategy will allow for effective and efficient installation of the required charging infrastructure.	Next Step	For consideration as part of service planning for 2020.	ENG
	e. Manitoba Works Yard Energy Hub: As part of the planning process for the redevelopment of the Manitoba Works Yard, set an objective of establishing the yard as a renewable energy hub for the community. This could include solar PV electricity generation, generation of RNG from organic waste, and EV charging and RNG/HDRD refueling for City vehicles and private fleets and vehicles.	Establishing a renewable energy hub would support quicker transition of the City and private fleets to renewable sources, while also increasing demand, driving further maturation of the local market for these energy technologies.	New Action	Detailed plan as part of 2019–2023 Manitoba Works Yard Master Plan.	REFM, ENG

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	f. Small Equipment: Develop a strategy to transition small mobile equipment (e.g., mowers and leaf blowers) to electric or zero emissions technologies. Use that experience to consider city-wide approaches to phase out fossil fuels in that equipment.	A transition of small mobile equipment to electric has the potential to reduce emissions by 800 tonnes of CO_2e.	New Action	For consideration as part of service planning for 2020.	ENG
	g. Sustainable Commuting: Update the Sustainable Commuting Program to accelerate long-term shifts towards City staff commuting by walking, cycling, transit, or zero emissions vehicles. A secondary objective will be to provide a leading standard for City facilities as an example to other employers and commercial landlords in Vancouver. The first phase of work will focus on policies to enhance City employee electric vehicle charging and bicycle end-of-trip facilities at City buildings. A second phase will include a comprehensive review of the City's Sustainable Commuting Program and identify additional actions beyond end-of-trip facilities that will accelerate a shift to zero-carbon commuting.	As a leading employer, the City can both enable our own employees to switch to zero emissions options for commuting, as well as influence other employers in applying best practices to encourage zero emissions commuting. Active transportation, transit, electric vehicles and telecommuting all reduce commuting carbon emissions relative to a commute via an internal combustion private vehicle.	Next Step	Complete project charter in Q2 2019; develop first phase of policy by Q3 2019.	PDS, REFM, ENG, HR
	h. Online Services: Explore all available options to provide services online in order to reduce the number of trips that applicants need to make to the Development and Building Services Centre.	The City receives about 45,000 in-person visits a year to the Development and Building Services Centre at 525 W 12th Avenue. Moving more services online helps to reduce the carbon footprint of these trips. In addition, most applicants need to provide multiple printed copies of site plans and construction plans. Moving to online plan submission and review has a further benefit in reducing paper use.	Next Step	Develop detailed implementation plans for online service delivery.	DBL, IT

Category		Accelerated Action		How this Action Reduces Carbon Pollution	New Action vs. Next Step	Next Milestone	Department Lead(s)
		i.	Support for Cities in Developing Countries: Explore options to help cities in developing countries grow their economies without relying on fossil fuels to the extent that Canada and other developed countries have. Options could include contributing to the UNFCCC's Green Climate Fund, partnering with specific cities in developing countries to support transition to renewable energy, advocating for increased federal and/or private sector contributions, etc.	Cities in developing countries often do not have the financial resources and technical knowledge needed to rapidly transition to renewable energy and adapt to climate change, while also growing their economy. By providing support, wealthier jurisdictions that have long benefited from fossil fuels can help them achieve those objectives.		Report back to Council on options by end of 2020.	PDS, CMO, VEC
15	Intergovernmental Relations and Community Engagement	a.	Intergovernmental Relations: Develop a list of policy, legislative, and regulatory changes and investment funding priorities (coordinated with other City corporate priorities) to work with other governments and related organizations in order to implement and support the City's climate emergency work. These include the federal and provincial governments; Metro Vancouver; other municipal governments across BC, Canada and internationally; FCM; UBCM; TransLink; Port of Vancouver; BC Hydro; and FortisBC. Examples of these changes and priorities include mobility pricing (as a tool to limit congestion and raise funds for transit), right-to-charge rules for electric vehicle owners in multi-unit residential buildings, ride-hailing legislation that aligns with zero emissions principles and complements sustainable travel, supporting the All On Board campaign, accelerated transit electrification, a bold vision for the Regional Transportation Strategy, energy performance benchmarking for buildings, counting district energy systems with heat from renewable energy as a contributor towards the targets in BC's new renewable gas standard, and electricity pricing that supports electrification.	As discussed in the report, the City has a number of important tools it can use to reduce carbon pollution. However, achieving the City's objectives will rely on a broader set of tools that require senior levels of government, the region, and utilities moving in similar directions.	Next Step	Report back to Council on recommended priorities by June 2019.	CMO, PDS, ENG

Category	Accelerated Action	How this Action Reduces Carbon Pollution	New Action vs. Next Step	Next Milestone	Department Lead(s)
	b. Community Engagement: Develop and implement an action-oriented community education and awareness strategy to increase residents' literacy on the urgency of climate change, local impacts, and opportunities for individual and collective action. Working with community partners, local businesses, and stakeholders, examples could include campaigns, strategic communication on City assets (fleet and buildings), presence at community events, side events during relevant local conferences—with an emphasis on those groups who are typically harder to engage, including youth and new Canadians.	Based on research conducted by Mustel Group in 2017 and 2018, the City has an opportunity, through trusted partners, to educate on the types of renewable energy, to engage on opportunities to take action, and to address specific concerns and uncertainties voiced by those who participated in the research. This will not only build continued support for climate-related policy and City action, but is foundational for resident action.	Next Step	Complete hiring of new staff and develop strategy.	PDS, CEC, VEC
	c. Partner Engagement: Develop and implement a strategy to further build relationships and expand engagement and collaboration with diverse groups involved in advancing climate action in Vancouver. Examples could include further developing the annual Renewable City stakeholder event, supporting program ambassadors, managing existing and initiating new topic-specific working groups, and coordinating collaboration between partner organizations working toward priority outcomes.	With dedicated capacity and a focused strategy, the City can better coordinate and leverage the efforts of partner organizations. This type of joint action will be essential in successfully delivering many of the actions outlined in this report.	Next Step	Complete hiring of new staff and develop strategy.	PDS, VEC

Appendix B – Adaptation Actions

The adaptation actions in the following table were identified through the process of preparing the climate emergency response.

Action	Description	How this Actions Supports Adaptation	Next Milestone
Pilot clean air shelters	In the summer of 2019, City staff will collaborate to provide “clean air rooms” in up to five (5) cooling centres. Portable HEPA filters—the VCH recommended filtration level—will be used in designated areas and rooms to provide refuge for the public during extended daytime hours during poor air quality days. Level of use, challenges and lessons will be evaluated to inform a more permanent program.	Between 2015 and 2017 there were 27 days of air quality alerts issued for the Lower Mainland due to particulate matter from wildfires burning outside the region and from ground-level ozone. The summer of 2018 also included several extended air quality alerts. Exposure to ozone and fine particulate matter is particularly a concern for infants, the elderly and those who have underlying medical conditions, such as lung disease, heart disease, diabetes or asthma. Feedback from frontline staff throughout the city suggests addressing this impact from climate change is a priority in the short term. This action targets those most vulnerable to poor air quality.	Report back to Council with pilot results and next steps.
Temporary cooling in non-market housing	Provide temporary cooling measures during summer heat to the non-market housing buildings identified as overheating during the last few summers.	As summers have been getting hotter, it is widely recognized that older buildings and certain building designs do not cool down well at night and thermal comfort during the day declines. In Vancouver, a high proportion of vulnerable people reside in areas identified as urban heat islands, and many live in older, poorly ventilated buildings. In 2018, temporary cooling was provided in four cooling rooms in City-owned non-market housing buildings that were found to be overheating. This summer, the effort will be expanded to up to six sites and to provide better cooling results.	See below

Action	Description	How this Actions Supports Adaptation	Next Milestone
Long-term cooling of non-market housing	Recognizing the limitations and costliness of continued temporary cooling in non-market housing, REFM and Non-market Housing Operations (ACCS) are collaborating to investigate options to provide long-term cooling for non-market housing buildings prone to over-heating. A consultant study of specific sites will be undertaken to recommend actions.	Investing in cooling (whether passive or active) where populations most vulnerable to heat illness are identified is a priority step in managing climate change impacts.	Report back to Council with study recommendations and related actions.
Amendment to existing street trees	Provide an amendment to existing tree pits in locations around the city to improve drought and pest tolerance.	The soil amendment will provide improved drought and pest tolerance for street trees as well as improving tree health generally. With warmer winters and summers, increasing pests are anticipated. Hotter summers are already putting stress on our trees. The GCAP goal of increasing tree canopy in the city is important for mitigating urban heat island effect, which is worsening with hotter weather, and also for stormwater benefits.	Report back to Council with results and next steps.

Appendix C – Other Climate Emergency Declarations

Examples of other cities and regions that have declared climate emergencies include:

- In BC: Richmond, New Westminster, Victoria, the Capital Regional District, the Islands Trust Area, and Powell River.
- The BC Assembly of First Nations also passed a motion recognizing the climate change emergency in March 2019.
- Across Canada, the list includes Halifax, Mahone Bay, Moncton, Sackville (NB), Edmundston, Kingston, and Hamilton, and in Québec there are over 200 communities including Québec City and Montréal.
- International cities include London, Edinburgh, Los Angeles, Berkeley, and Oakland.

Appendix D – CleanBC Commitments with Greatest Relevance for Vancouver

The policies and investments in phase one of BC's new climate plan (CleanBC) that are of greatest relevance to Vancouver include:

- A zero emissions vehicle standard that will require an increasing percentage of the light-duty vehicles sold in BC to be zero emissions. The specific targets are 10 per cent of sales by 2025, 30 per cent of sales by 2030, and 100 per cent of sales by 2040. The policy will ensure that there are more electric vehicles available when residents and businesses are ready to purchase a new vehicle.
- A strengthened Low-Carbon Fuel Standard, which will require the carbon intensity of transportation fuels of 20 per cent below 2010 levels by 2030. The current requirement is 10 per cent below 2010 levels by 2020. This policy will support the transition to electric vehicles and increase the supply of renewable diesel and gasoline.
- A renewable gas standard that will require 15 per cent of FortisBC's gas supply to come from renewable sources by 2030 (there is currently less than one per cent renewable content in the gas grid). This policy will help reduce carbon pollution from buildings and some transportation in the city, and will help advance renewable natural gas supply projects.
- The 2019 provincial budget included $902 million to support the implementation of CleanBC from 2019 through 2021. This includes new funding for electric vehicles and charging infrastructure, heat pumps, and building energy efficiency upgrades.

In addition to these provincial actions, the federal government has been in the process of implementing several important climate policies of its own through the Pan-Canadian Framework on Clean Growth and Climate Change. These include the Carbon Pollution Pricing Benchmark, the Clean Fuel Standard and the Coal-Fired Power Phase-Out. All of these policies will help Canada reduce emissions, but in a BC context, they are largely overlapping with provincial climate policies.

Appendix E – Multiple Benefits of Reducing Carbon Pollution

Health and air quality benefits
The vast majority of solutions the City is pursuing to reduce carbon pollution also lead to better health outcomes. Zero emissions buildings have better indoor air quality. Electric vehicles produce less air pollution than their gasoline and diesel counterparts. Walking and cycling are pollution-free and they help people stay active.

Improved resilience
Many of the solutions that help to reduce carbon pollution also help residents and businesses become more resilient. A zero emissions building provides a good example: in addition to emitting no carbon pollution, the improved ventilation helps limit air quality impacts from forest fire smoke, and high levels of insulation mean that it can stay comfortable in hot or cold weather in the event of a power outage and more extreme weather events. A second example is a resilient transportation network, which provides a range of mobility options that can meet diverse daily needs and respond to and recover from changing circumstances.

Reduced costs
The costs of reducing emissions fast enough to limit warming to 1.5°C are much less than the costs that will be incurred if more warming is allowed to happen. That said, it is understandable that many residents and businesses are focused on more immediate cost implications to them as individuals. In some cases, those solutions already represent a net savings for Vancouver residents and businesses (e.g., improved energy efficiency requirements in new buildings, and safer and more convenient active transportation and transit choices).

In other cases, there are currently cost premiums that most residents will not recover through energy savings (e.g., electric vehicles and heat pumps). In these cases, the City (and governments more generally) can play an important role of helping to make those solutions more affordable in the near term and building demand for them so that costs come down.

Based on economic modelling the City commissioned with BC Hydro in 2017, the transition to 100 per cent renewable energy can help achieve modest cost savings for residents and businesses. For example, average per capita expenditures on energy and the associated capital equipment decline by nine per cent between 2015 and 2050.

Economic development
Going “green” is good for business and great for the local economy. This can be measured in a variety of ways, including job creation, job transition, innovation, process efficiencies, increased sales/revenues, etc. In Vancouver, the green economy employs 1 in 15 workers, well above any other North American city and this is growing at 7.8% per year on average for the past three years. The carbon intensity of Vancouver’s economy (tonnes of carbon pollution per dollar of GDP) has fallen by 29 per cent since 2007.

Establishing effective policies that address climate change can accelerate innovation in cleantech, green building technologies, advanced materials, local food, solid waste and transportation options. When Vancouver City Council passed the Zero Emissions Building Plan and the Government of BC established the BC Energy Step Code for new construction, the Vancouver Economic Commission (VEC) identified a $3.3 billion market opportunity for the local green building and construction sector over the next decade.

The environmental ethos and world-renowned recognition of Vancouver as a “green” city has also translated into a US$31.7 billion brand. In a global economy where cities are competing for talent, this is an important quality and advantage that Vancouver possesses to help it attract the best and brightest to Vancouver’s thriving economy in all sectors.

Appendix F – Regulatory, Investment and Advocacy Tools to Reduce Carbon Pollution

The following table lists the primary regulatory and investment tools (with examples) that Vancouver can use to reduce carbon pollution. Advocacy tools are discussed below the table.

Tool	Examples
Land-use planning	• Designing complete and compact communities that allow people to live close to transit and other services and amenities
Allocating public space	• Widening sidewalks • Creating parks and plazas • Dedicating road space for transit • Reserving parking for electric vehicles • Creating protected bike lanes
Regulating buildings and equipment	• Limiting carbon emissions in new construction • Adding electric-vehicle readiness requirements in new construction • Supporting transportation demand management requirements in new construction
Investing in infrastructure	• Improving walking and cycling networks • Increasing public electric vehicle chargers
Supplying renewable energy	• Developing and expanding the Neighbourhood Energy Utility • Providing landfill gas for heat and power generation
Providing financial and land-use incentives	• Topping up Government of BC incentives for heat pumps • Incentivizing carbon reductions in heritage homes • Allowing buildings that are taller or have bigger footprints in exchange for higher environmental performance • Pricing curb space to manage parking demand and reduce congestion
Capacity building	• Partnering with institutional and professional organizations to provide skills training • Establishing the Zero Emissions Buildings Centre of Excellence
Demonstrating corporate leadership	• Transitioning the City's fleet to electric vehicles and renewable fuels • Heating the City's buildings with heat pumps and renewable energy sources

Advocacy Tools

In addition to the regulatory and investment tools that the City directly controls, we can also work with other governments and utilities to use their tools to pursue shared climate objectives. Climate change is too big of a problem to be tackled without close collaboration and learning from other jurisdictions. Examples include:

- The Government of BC's jurisdiction includes critical policies, such as requirements for the percentage of renewable energy in the gas and electric grids. The City continues to actively work with the Government of BC on the development and implementation of its climate plan (CleanBC).
- The amount of renewable energy supplied by BC Hydro and FortisBC, and the rate structures they set to connect to and use their energy influences the business cases for switching to renewable energy, such as electric vehicles, heat pumps and renewable natural gas.
- Metro Vancouver, TransLink and neighbouring local governments have similar tools to Vancouver that can help transform regional markets that make it easier for Vancouver to achieve its targets (e.g., the broader adoption of EV-readiness requirements in new construction will help accelerate EV adoption across the region). Updating transit fare policy and providing additional transit service region-wide can support Vancouver's sustainable transportation goals.
- Vancouver is also an active member in a number of regional, national and international networks of cities working collaboratively to reduce carbon emissions. Examples include the Union of BC Municipalities (UBCM) and Federation of Canadian Municipalities (FCM), the EV Peer Network, the BC Energy Step Code Peer Network, Carbon Neutral Cities Alliance, C40 Cities, and 100 Resilient Cities.

Appendix G – Carbon Budgeting Objectives

Improved Transparency
A carbon budget should be accessible to the public. It should show:

- The components ("sub-budgets") that add up to the overall budget (e.g., energy use reductions in buildings, transportation; waste management).
- The links to anticipated carbon reductions.
- The links to financial budgets to show that they are funded.
- The City departments responsible for development and implementation.
- Any remaining carbon reductions necessary to achieve targets, but not currently attributable.

How targets for the "sub-budgets" are equitably set, and mechanisms for rebalancing between them if necessary, remains a question. Cost-effective, impactful technologies and reduction pathways may be available to different sectors and departments at different times. There is also the issue of evaluating program efficacy. Initiatives with manifold or indirect effects may be especially complicated, and the ability to measure, estimate, or forecast carbon impacts varies greatly.

Other considerations include delayed carbon reduction impacts and the permanence of those impacts. In these instances where the carbon impact may not be clear, secondary metrics within a forthcoming indicators framework for the Renewable City Action Plan can help track progress. Finally, any gaps between indicated components and reduction targets will inform additional carbon reduction or removal programs as required to meet the budget targets. Underpinning all of these is the need to improve data quality.

Better Data
The carbon budget should track our emissions with enough accuracy and precision to properly assess our progress.

Better data helps us better determine whether we have the right current and planned measures to achieve our targets. Calculating Vancouver's community emissions to date has relied on estimates, which has been enough to show overall trends in total emissions. A carbon budget requires more detailed, "policy-sensitive" data to show clear links between program impacts and measured emissions.

As an example, reported transportation emissions have relied partially on fuel-sales data. This can show an overall trend in vehicle activity, but it is influenced by too many external factors to directly show the impact of Vancouver's progress of mode split, resident vehicle-distances driven, and active transportation initiatives. Another example is methane emissions from the natural gas distribution system and the Vancouver Landfill. A number of studies have pointed to scientific uncertainty regarding the amount of methane released from these sources, and efforts to reduce that uncertainty help the City make better decisions about programs and policies.

Better Forecasting
The carbon budget should allow us to forecast emissions with reasonable confidence, and course-correct as necessary.

Better data also allows improved forecasting for future budgets. Budget levels should be adjusted as progress is made (or not), as costs and availability of carbon-reduction and removal technologies change, and as global climate projections are updated. Regular budget-adjustment milestones should be set: four-year periods would align with Council terms and fulfil Council's directive to "create interim four-year targets and goals".

CleanBC Alignment
The carbon budget should align with the Government of BC's CleanBC plan where appropriate.

A new CleanBC accountability framework is currently in development. The CleanBC report mentions carbon budgets with respect to maintaining a "commitment to transparency on use of carbon tax revenue", undertaking an "independent review of proposed climate action against climate budgets", and tabling "an annual report of GHG spending, program results and anticipated reductions in GHG emissions". These all point to similar objectives around transparency already discussed above. Vancouver's data analysis and forecasting approaches can align where possible with provincial approaches, to ensure similar measures are accounted for, as long as carbon measurements continue to be policy-sensitive at the city level.

Improved Accountability
The carbon budget should enable some mechanism for addressing exceedances.

Targets may be missed. Carbon budgeting approaches can help drive analysis into the causes of exceedance, which drives the development of ways to address them. Tracking carbon expenditures within a budget also allows accounting processes to be applied, such as the ability to carry forward budget surpluses to future years, to borrow surplus "room" if overspent, or to accrue carbon-removal impacts to the years they actually come into effect. Frequent budget reporting (Council direction is for annual reporting) decreases the risk of complacency and delayed action.

Likewise, accountability can lead to the notion of carbon "debt": if a carbon budget is missed in one year, does that incur a deficit that should be addressed in the following year? Meanwhile, at this time, no common approach exists for consequences. For example, New Zealand's Emissions Trading Scheme allows exceedances to be offset with carbon removals. The District of Saanich's Carbon Fund makes departments accountable by requiring them to pay into a fund for corporate-emissions reduction projects, based on their emissions levels. Staff will continue to research and develop an approach in consultation with City departments.

Appendix H – Carbon and Equity Working Group

Objectives and Process

The objectives of Vancouver's Climate and Equity Work Group will be to:

1. Help City staff to better centre the voices of Vancouver black, Indigenous, and people of colour in climate and sustainability work, and to understand systemic discrimination and climate-related risks faced by low-income residents.
2. Review proposed Greenest City 2050 actions over a number of goal areas, including this Climate Emergency Response, to identify potential impacts (positive and negative) and opportunities where implementation could benefit systemically excluded populations.
3. Propose new relevant actions to be considered for inclusion in climate plans, including the City's Climate Change Adaptation Strategy.

An ancillary objective of the Climate and Equity Working Group will be to serve as a potential model for meaningfully engaging with black, Indigenous, and people of colour, as well as low-income communities, using the tools and guidance provided by the City's Equity Framework. The Climate and Equity Working Group will be a learning experience and one that could build trust and capacity for other City-led initiatives. It will also be an important opportunity to incorporate a gendered intersectional lens into the City's climate actions and the Climate Adaptation Strategy.

In terms of process, it is anticipated that the Climate and Equity Working Group participants will attend a series of 2–3 hour workshops over the course of 12–18 months, starting in the fall of 2019. To avoid power imbalance, the workshops will be facilitated by a non-City staff person with a depth of experience in equity. The workshops will be organized and attended by staff from Sustainability working in collaboration with Social Policy. Other City staff will attend based on the topic area of discussion at each meeting. The working structure of the group will be co-created with working group participants, to ensure that it delivers meaningful outcomes while building trust amongst participants and City staff.

Participants

The group will consist of 10–15 representatives from local community-based organizations (or their citizen designates). An intersectional approach will be used. The working group will include Indigenous representation and the City will strive to include a diversity of racial and ethnic backgrounds, ages, gender identities, and sexual orientations. The City will strive to ensure the group has a majority of black, Indigenous, and people of colour among participants. Applicants who identify as black, Indigenous, people of colour, and LGBTQ2S+ who may also identify as gender non-binary will be strongly encouraged to apply. A public call for applications for organizations that are willing to participate will be made.

Budget

The proposed budget to create the Climate and Equity Working Group is $50,000, which will cover up to eight workshops with an external facilitator and includes compensation for working group participants at Vancouver's living wage, provision of childcare during meetings, and transportation costs. The proposed budget would also enable the facilitator to do a high-level scan of the City's climate and sustainability plans (e.g., GCAP 2020) to identify equity gaps and opportunities. Staff have identified funding for the creation of this group from within existing budgets and may bring back a budget proposal for an ongoing working group for Council's consideration.

CLIMATE EMERGENCY RESPONSE
FINAL MOTION AS APPROVED

A. THAT Council adopt a new City-wide long-term climate target of being carbon neutral before 2050 as a complement to the target of 100 per cent of the energy used in Vancouver coming from renewable sources before 2050.

B. THAT Council adopt a “complete communities” target that by 2030, 90 per cent of people live within an easy walk/roll of their daily needs, and direct staff to report back by Fall 2020 with a strategy and budget to achieve the target (“Big Move #1”).

C. THAT Council accelerate the existing sustainable transportation target by 10 years, so that by 2030, two thirds of trips in Vancouver will be by active transportation and transit, and direct staff to report back by Fall 2020 with a strategy and budget to achieve the target (“Big Move #2”), including a plan to work toward cheaper or free transit for lower income people as council agreed to in the All on Board motion.

D. THAT Council adopt the target that by 2030, 50 per cent of the kilometers driven on Vancouver’s roads will be by zero emissions vehicles, and direct staff to report back by Fall 2020 with a strategy and budget to achieve the target (“Big Move #3”).

E. THAT Council adopt the new target that by 2025, all new and replacement heating and hot water systems will be zero emissions, and direct staff to report back by Fall 2020 with a strategy and budget to achieve the target (“Big Move #4”).

F. THAT Council adopt the target that by 2030, the embodied emissions in new buildings and construction projects will be reduced by 40 per cent compared to a 2018 baseline, and direct staff to report back by Fall 2020 with initial actions and budget to achieve this target including recommendations to remove regulatory barriers to mass timber construction and initial requirements for embodied emissions reductions (“Big Move #5”).

G. THAT Council direct staff to report back by fall 2020 with 2030 GHG emission reductions targets that can be achieved by the “negative emission” restoration of natural forest and coastal ecosystems in the City of Vancouver. That the report also indicate opportunities to work with local First Nations, Metro Vancouver and other local municipalities to set a GHG emission reductions target and budgets for 2060 to "remove the appropriate amount of carbon pollution annually to deal with the regional negative emission requirements as per the IPCC report” (“Big Move #6”).

H. THAT Council direct staff to begin implementing the Accelerated Actions as described in Appendix A of the Administrative Report dated April 16, 2019, entitled “Climate Emergency Response”, and report back to Council with an overall progress report by May 2020; and

FURTHER THAT City staff be directed to engage with the City of Vancouver’s respective Union Locals, who represent our 10,000 plus employees, to work jointly on industry best practices for accelerated actions under ‘Sustainable Commuting’ in the immediate and medium term.

I. THAT Council direct staff to proceed with the development of a carbon budgeting and accountability framework for corporate and city-wide carbon pollution that meets the objectives described in the Administrative Report dated April 16, 2019, entitled “Climate Emergency Response”.

J. THAT Council direct staff to proceed with the formation of the Climate and Equity Working Group according to the objectives, process, timelines, participants and budget described in the Administrative Report dated April 16, 2019, entitled “Climate Emergency Response”.

K. THAT Council direct staff to proceed with the development of Vancouver’s next environmental plan, Greenest City 2050, which will incorporate the work from the Administrative Report dated April 16, 2019, entitled “Climate Emergency Response”, as well as broader environmental sustainability objectives, and report back on the recommended strategy that will be integrated and coordinated with the City-wide Plan.

L. THAT Council direct staff to integrate the six (6) Big Moves as described in the Administrative Report dated April 16, 2019, entitled “Climate Emergency

Response” into the development of the City-wide Plan recognizing there will be further development and refinement of the Big Moves which will be informed by and coordinated with City-wide planning.

M. THAT Council direct staff to develop local renewable energy targets and accelerated actions, including for solar hot water and photovoltaic solar panels that can reduce energy costs of heat pumps and mitigate risks of hydro-electricity outages.

N. THAT Council acknowledge the necessity of working with partners and stakeholders, including non-profit organizations and industry leaders, to achieve the ambitious targets recommended in the Administrative Report dated April 16, 2019, entitled “Climate Emergency Response” and “6 Big Moves;”

FURTHER THAT Council direct staff to consult with and work with these groups to discuss any implications and impacts, including budgetary; and

FURTHER THAT Council acknowledge the possibility that some of the resources may need to be reprioritized or adjusted and targets recommended in the “6 Big Moves”, contained in the above-noted report, to respond to issues including affordability and/or livability in the midst of the City of Vancouver’s Emergency Response to the overdose crisis and the housing and affordability crisis.

O. THAT Council direct staff to incorporate robust resident engagement on the Climate Emergency Response framework and its Big Moves components as part of the upcoming City-wide planning process, in order to support livability and vibrant and complete communities.

P. THAT Council direct staff to share the Administrative Report dated April 16, 2019, entitled “Climate Emergency Response” and recommendations with Metro Vancouver, the Vancouver Park Board and Vancouver School Board for the purpose of asking them to formally express support for the strategy, and consider ways that the respective bodies can support the Big Moves and recommendations.

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6.0 TOPIC: EXHIBIT B-15, OCTOBER 3 2019 20-YEAR LOAD FORECAST

IMPACT OF MUNICIPAL AND REGIONAL CLIMATE INITIATIVES

4.6.4 Please confirm that Vancouver City Council approved the Final Motion by a unanimous vote.

RESPONSE:

Confirmed. In January 2019, Vancouver City Council unanimously approved the Climate Emergency Response Final Motion, provided as Attachment 2 to BC Hydro's response to MOVEUP IR 4.6.4.

6.0 TOPIC: EXHIBIT B-15, OCTOBER 3 2019 20-YEAR LOAD FORECAST

IMPACT OF MUNICIPAL AND REGIONAL CLIMATE INITIATIVES

Reference: Climate Emergency Response Final Motion Item "E":

THAT Council adopt the new target that by 2025, all new and replacement heating and hot water systems will be zero emissions, and direct staff to report back by Fall 2020 with a strategy and budget to achieve the target ("Big Move #4").

4.6.5 Does BC Hydro expect that the adoption of Item "E" will have an immediate impact upon energy-resource decisions of real estate developers in the City of Vancouver who are planning or contemplating future developments? If not please explain why not.

RESPONSE:

This answer also responds to MOVEUP IR 4.6.6.

BC Hydro expects that real estate developers consider existing and forthcoming local government regulations in their project planning.

While there may be an impact over the longer term, at this point, without the accompanying plans, regulations and requirements, it is too early for BC Hydro to know how the adoption of a target relating to zero emissions hot water and heating systems will impact the immediate decisions of the real estate development community in the City of Vancouver, or other local governments that may adopt such targets.

6.0 TOPIC: EXHIBIT B-15, OCTOBER 3 2019 20-YEAR LOAD FORECAST

IMPACT OF MUNICIPAL AND REGIONAL CLIMATE INITIATIVES

Reference: Climate Emergency Response Final Motion Item "E":

THAT Council adopt the new target that by 2025, all new and replacement heating and hot water systems will be zero emissions, and direct staff to report back by Fall 2020 with a strategy and budget to achieve the target ("Big Move #4").

4.6.6 Does BC Hydro expect that similar impacts will be felt in other municipalities as they adopt policies, programs and standards aimed at limiting climate change?

RESPONSE:

Please refer to BC Hydro's response to MOVEUP IR 4.6.5.

8.0 TOPIC: EXHIBIT B-15, OCTOBER 3 2019 20-YEAR LOAD FORECAST

IMPACT OF CONSERVATION RATE DESIGN OVER TIME

4.8.1 What assumptions does BC Hydro make of the persistence of the load impact of conservation-based residential rate design over time? What evidence does BC Hydro rely upon to arrive at these assumptions?

RESPONSE:

On a go forward basis, BC Hydro has not made any assumptions on the persistence of the energy savings that result from structuring the Residential Inclining Block (RIB) rate into two tiers.

This is because the April 2018 Evaluation report on the Residential Inclining Block Rate (Fiscal 2013 to Fiscal 2017) concluded that there are no new incremental savings resulting from the rate structure.

Any historical savings from the rate structure of the RIB rate are embedded within the actual sales and as such will have been captured in the calibration period used to estimate the load forecast models.

1 Reference: Twenty-Year Load Forecast, October 3, 2019
Table 2, Page 11, F2021
Appendix D, Table D-1, Demand for F2021

In Table 2, the June 2019 Load Forecast indicates a Total Domestic Sales Forecast after DSM of 53,652 GWh for F2021. Table D-1 indicates a Demand – Integrated System of 60,738 GWh and DSM, Code savings of 1,310 GWh giving a net demand of 60,731 – 1,310 = 59,421 GWh.

4.1 Why is there such a difference between the Sales Forecast in Table 2 of 53,652 GWh and the Planned View value in Table D-1 of 59,421 GWh.

RESPONSE:

The values provided in Table 2 represent Total Domestic Sales, after Demand-Side Management Savings and Rate impacts, not including BC Hydro own use. The values in Table D-1 represent Total Integrated Gross System Requirements, including exports, BC Hydro own use, losses, and non-integrated requirements.

Figure 2-1 on page 10 of Appendix O of the Application shows the build-up of the Total Integrated Gross System Requirements that are provided in Table D-1 in Exhibit B-15.

2 Reference: Appendix B, Section 1.3.1 EV Peak Methodology

"The EV peak model is a simulation model that has several inputs including the total annual number of EVs, daily distance travelled, EV efficiency, power of the charging equipment in kW and a charging time profile."

4.2 In the above reference, there was no mention of special rates that would encourage EV owners to charge their EVs during off peak hours. Pacific Gas and Electric do have an EV rate where deep rate discounts are provided for charging during off-peak times like 3:00 to 6:00 am. Considering the large increase in EVs that are expected and the impact that this could have on capacity in distribution regions, is BC Hydro considering rates that will encourage charging during off-peak periods.

RESPONSE:

BC Hydro is examining time-of-use rates for electric vehicles to encourage charging during off-peak hours. BC Hydro does not expect any changes to peak demand related to time of use rates within the Test Period.

64.0 Topic: Changes in Methodology and Input Assumptions

Reference: Exhibit B-15 (Twenty-Year Load Forecast), Table 1, page 4.

Regarding the changes in methodology between October 2018 and June 2019 Load Forecast, BC Hydro states, in note 4 on page 4 of the Twenty-Year Evidentiary Update for the Large Industrial Sector:

Primarily from customer information and market research. No formal update to third-party expert information.

4.64.2 What is the status of the Comprehensive Review - Phase Two, and have any of its conclusions, recommendations or action items been incorporated into the June 2019 Load Forecast?

RESPONSE:

This answer also responds to ZONE II RPG IRs 4.64.2.1 and 4.64.2.2.

The Ministry of Energy, Mines and Petroleum Resources initiated Phase Two of the Comprehensive Review in July 2019. An interim report is expected to be made public at the end of 2019 for comment. A final report with recommendations is expected to be completed in spring 2020.

The June 2019 Load Forecast does not include any recommendations from Phase Two of the Comprehensive Review. The recommendations from Phase Two of the Comprehensive Review will inform the load forecast developed by BC Hydro following the release of the final report for the Comprehensive Review.

64.0 Topic: Changes in Methodology and Input Assumptions

Reference: Exhibit B-15 (Twenty-Year Load Forecast), Table 1, page 4.

Regarding the changes in methodology between October 2018 and June 2019 Load Forecast, BC Hydro states, in note 4 on page 4 of the Twenty-Year Evidentiary Update for the Large Industrial Sector:

Primarily from customer information and market research. No formal update to third-party expert information.

4.64.2 What is the status of the Comprehensive Review - Phase Two, and have any of its conclusions, recommendations or action items been incorporated into the June 2019 Load Forecast?

4.64.2.1 If yes, please provide details on the impact to the June 2019 Load Forecast, with specific reference to NIA customers.

RESPONSE:

Please refer to BC Hydro’s response to ZONE II RPG IR 4.64.2.

64.0 Topic: Changes in Methodology and Input Assumptions

Reference: Exhibit B-15 (Twenty-Year Load Forecast), Table 1, page 4.

Regarding the changes in methodology between October 2018 and June 2019 Load Forecast, BC Hydro states, in note 4 on page 4 of the Twenty-Year Evidentiary Update for the Large Industrial Sector:

Primarily from customer information and market research. No formal update to third-party expert information.

4.64.2 What is the status of the Comprehensive Review - Phase Two, and have any of its conclusions, recommendations or action items been incorporated into the June 2019 Load Forecast?

4.64.2.2 If no, please explain why not and if so when the implications of the Comprehensive Review - Phase Two will be incorporated in the load forecast and if this new load forecast will be available publicly.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 4.64.2.

65.0 Topic: Variances

Reference: Exhibit B-15 (Twenty-Year Forecast), page 5.

On page 5, BC Hydro states:

> BC Hydro is not proposing any further adjustments to the revenue forecast provided in the Evidentiary Update. Any variances between forecast and actual revenue would be deferred in the normal course for future recovery from, or refund to, ratepayers.

4.65.1 Identify the mechanism for deferring or refunding any variances to ratepayers, including how and when such refunds will be determined and calculated.

RESPONSE:

Variances between forecast and actual domestic revenues are deferred to the Non-Heritage Deferral Account, in accordance with BCUC Order No. G-16-09. Please refer to BC Hydro's response to BCUC IR 3.301.4 for further information on the deferral of these variances and how the amounts are determined.

As noted in section 7.7.1.1 of Chapter 7 of the Application, BC Hydro expects to propose to return to the Deferral Account Rate Rider (DARR) table mechanism approved by the BCUC in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application in the subsequent test period starting in fiscal 2022. This means that the balance in the account would be recovered from or returned to ratepayers via the DARR.

66.0 Topic: Codes and Standards

Reference: Exhibit B-15 (Twenty-Year Forecast), page 7;
Exhibit B-1 (Application), Appendix O, page 129 of 170.

From Appendix O of the Application, BC Hydro states:

> For the non-lighting code items that were considered to be an overlap, BC Hydro applied 50 per cent of the forecast of DSM savings of these various codes and standards which overlapped with the EIA. These estimates were then used as the adjustments to the SAE model projections.

On page 7 of the Twenty-Year Forecast, BC Hydro states:

> The review reconciled codes and standards set out by legislation in British Columbia and Canada, which are reflected in BC Hydro's DSM Plan, with the U.S. federal codes and standards reflected in the EIA projects. The review found that there were additional end uses technologies which overlapped between the EIA and DSM plan relative to previous assumptions reflected in the October 2018 Load Forecast. Accordingly, an updated adjustment was made for Codes and Standards in the June 2019 Load Forecast. The change in codes and standards estimates relative to the October 2018 Load Forecast is less than 50 GWh per year for fiscal 2020 and fiscal 2021.

4.66.1 Confirm, or explain otherwise, whether BC Hydro applied the 50% forecast of DSM savings to adjust the Statistically Adjusted End Use (SAE) model projections for the additional end uses technologies which overlapped between the EIA and DSM plan relative to previous assumptions reflected in the October 2018 Load Forecast.

RESPONSE:

Confirmed. This approach of applying only 50 per cent of the identified overlap between the EIA and DSM plan is consistent with the methodology described in Appendix O of the Application.

67.0 Topic: Electric Vehicles

Reference: Exhibit B-15 (Twenty-Year Forecast), page 8.

On page 8 of the Twenty-Year Forecast, BC Hydro states:

> The June 2019 Load Forecast uses a new methodology for EVs, to align with the CleanBC Plan for light duty electric vehicles. Specifically, the Zero-Emission Vehicles Act (ZEV Act) was enacted on May 30, 2019.
>
> ……
>
> Accordingly, the low EV forecast in the June 2019 Load Forecast is based on these requirements and the associated incentives because, at a minimum, EV sales would be expected to reach the levels required by legislation.

4.67.1 Confirm, or explain otherwise, that BC Hydro does not incorporate the possibility that the targets in the ZEV Act will not be met in the June 2019 Forecast.

RESPONSE:

Confirmed. The June 2019 EV low energy forecast assumes that light duty electric EV sales reach the levels required by the *Zero-Emission Vehicles Act* (ZEV Act).

As shown in BC Hydro's response to CEC IR 4.2.7, for fiscal 2021 the difference between the high and low EV forecasts is 15 GWh.

As discussed in section 3.3.6 of Chapter 6 of the Application, it is challenging to predict the trajectory of electric vehicles. While the introduction of the ZEV Act provides legislative certainty, the actual EV load growth may be higher or lower than the EV uncertainty bands in the June 2019 Load Forecast.

BC Hydro continues to monitor EV market development and actual sales growth and will be incorporating that information as part of future load forecast updates.

67.0 Topic: Electric Vehicles

Reference: Exhibit B-15 (Twenty-Year Forecast), page 8.

On page 8 of the Twenty-Year Forecast, BC Hydro states:

> The June 2019 Load Forecast uses a new methodology for EVs, to align with the CleanBC Plan for light duty electric vehicles. Specifically, the Zero-Emission Vehicles Act (ZEV Act) was enacted on May 30, 2019.
>
> ……
>
> Accordingly, the low EV forecast in the June 2019 Load Forecast is based on these requirements and the associated incentives because, at a minimum, EV sales would be expected to reach the levels required by legislation.

4.67.2 Confirm or explain otherwise whether BC Hydro will offer incentive factors, such as EV rate options, rebates, etc., to encourage EV usage to meet the targets in the ZEV Act.

RESPONSE:

BC Hydro is currently working in partnership with the Government of B.C. and FortisBC (Electric) to deliver the CleanBC Go Electric EV Charger Rebate Program. Charging has been identified as a barrier to electric vehicle adoption, and this program is designed to help address this barrier by encouraging customers to install electric vehicle charging in homes and workplaces.

BC Hydro will continue to work with the Government of B.C. with regards to BC Hydro's role under the CleanBC Plan.

Please refer to BC Hydro's response to INCE IR 4.10.0 for information with regards to BC Hydro's rate design strategy for electric vehicle charging.

67.0 Topic: Electric Vehicles

Reference: Exhibit B-15 (Twenty-Year Forecast), page 8.

On page 8 of the Twenty-Year Forecast, BC Hydro states:

> The June 2019 Load Forecast uses a new methodology for EVs, to align with the CleanBC Plan for light duty electric vehicles. Specifically, the Zero-Emission Vehicles Act (ZEV Act) was enacted on May 30, 2019.
>
> ……
>
> Accordingly, the low EV forecast in the June 2019 Load Forecast is based on these requirements and the associated incentives because, at a minimum, EV sales would be expected to reach the levels required by legislation.

4.67.2 Confirm or explain otherwise whether BC Hydro will offer incentive factors, such as EV rate options, rebates, etc., to encourage EV usage to meet the targets in the ZEV Act.

4.67.2.1 If so, please specify the implications, if any, of these incentive factors during the Test Period.

RESPONSE:

The impact on the load forecast during the Test Period from the specific activities identified in BC Hydro's response to ZONE II RPG IR 4.67.2 cannot be quantified at this time. However, some of the potential impact resulting from these types of activities is reflected, as outlined in BC Hydro's response to BCUC IR 4.324.1.

BC Hydro does not believe that light electric vehicle charging rate design options will be developed and approved in time to have a material impact during the Test Period. Likewise, the impact of the rebate program described in BC Hydro's response to ZONE II RPG IR 4.67.2 is not likely to be material relative to the overall size of the load forecast during the Test Period.

68.0 Topic: Other

Reference: Exhibit B-15 (Twenty-Year Forecast), page 9.

On page 9, BC Hydro states:

> Forecast sales to the other sub-sector over the Test Period have decreased, primarily due to delays and reduced load expectations for cryptocurrency customers.

4.68.1 Provide specific details on the reasons for the reduction in load expectations for cryptocurrency customers.

RESPONSE:

A cryptocurrency customer that was at an advanced stage of the interconnection process and had a high likelihood of proceeding ultimately reduced its load request in January 2019. The revised request resulted in a reduction of the cryptocurrency load included in the June 2019 Load Forecast relative to the October 2018 Load Forecast for the Test Period.

This customer is now connected and taking service from BC Hydro.

68.0 Topic: Other

Reference: Exhibit B-15 (Twenty-Year Forecast), page 9.

On page 9, BC Hydro states:

> Forecast sales to the other sub-sector over the Test Period have decreased, primarily due to delays and reduced load expectations for cryptocurrency customers.

4.68.2 Explain the residential sales variance by providing further details on the four factors listed above, including any data in support, by region and integrated and non-integrated areas.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 3.62.1.

69.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-19 (Evidentiary Update), Appendix A, Schedule 4.0, line 6, 19 and 30, page 39 of 81; Exhibit B-17 (Responses to Round 3 Information Requests on Evidentiary Update), Zone II Ratepayers Group IR 3.56.1.

On line 6 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

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

On line 19 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Line		F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Unit Costs ($/MWh)									
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On line 30 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

Line		Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	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	(186.6)	1,576.3	1,332.4	(243.9)	1,641.1	1,447.2	(193.9)

BC Hydro's response to Zone II Ratepayers Group IR 3.56.1, stated that:

> The $42.1/MWh difference between the unit costs in the fiscal 2019 forecast ($238.9/MWh) and the fiscal 2019 results ($281.0/MWh) is primarily due to the following factors:
>
> - The fiscal 2019 forecast incorrectly included 13 GWh of energy from BC Hydro's Clayton Falls generating facility which should not have been included within a Non-Heritage Energy Cost….This factor represents approximately $31.8/MWh of the difference in unit costs;

……

- The fiscal 2019 forecast for the Non-Integrated Area included understated costs of approximately $0.3 million for one NIA-IPP. This factor represents approximately $2.6/MWh of the difference in unit costs; and

  The remaining difference in unit costs, about $7.7/MWh, is largely due to higher than forecast diesel generation costs.

4.69.1 Provide an explanation for the decrease in Non-Integrated Area Sources of Supply (GWh) from F2019 RRA (120 GWh) to Actual (103 GWh), as shown in line 6 of the table.

RESPONSE:

As discussed in BC Hydro's response to ZONE II RPG IR 4.69.2, the F2019 RRA GWh should be 110 GWh, not 120 GWh. The remaining 7 GWh difference between the corrected 2019 RRA energy value and the 2019 Actual value is a result of overall lower load than forecast for the Non-Integrated Areas.

69.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-19 (Evidentiary Update), Appendix A, Schedule 4.0, line 6, 19 and 30, page 39 of 81; Exhibit B-17 (Responses to Round 3 Information Requests on Evidentiary Update), Zone II Ratepayers Group IR 3.56.1.

On line 6 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

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

On line 19 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Line	Unit Costs ($/MWh)									
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	238.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On line 30 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

Line		Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
				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's response to Zone II Ratepayers Group IR 3.56.1, stated that:

> The $42.1/MWh difference between the unit costs in the fiscal 2019 forecast ($238.9/MWh) and the fiscal 2019 results ($281.0/MWh) is primarily due to the following factors:
>
> - The fiscal 2019 forecast incorrectly included 13 GWh of energy from BC Hydro's Clayton Falls generating facility which should not have been included within a Non-Heritage Energy Cost….This factor represents approximately $31.8/MWh of the difference in unit costs;

……

- The fiscal 2019 forecast for the Non-Integrated Area included understated costs of approximately $0.3 million for one NIA-IPP. This factor represents approximately $2.6/MWh of the difference in unit costs; and

  The remaining difference in unit costs, about $7.7/MWh, is largely due to higher than forecast diesel generation costs.

4.69.2 Provide an explanation for the decrease in Non-Integrated Unit Costs, F2019 Actual ($281.0/MWh) to F2020 Update ($259.1/MWh), as shown in line 19 of the table.

RESPONSE:

This answer also responds to ZONE II RPG IRs 4.69.3, 4.69.4, 4.69.5 and 4.69.6.

BC Hydro has reproduced Schedule 4.0 for the Non-Integrated Area. The first table below (Table 1) reflects the amounts in Schedule 4.0 as filed in the Evidentiary Update. The second table (Table 2) is an updated Schedule 4.0 to reflect certain corrections which are described below. These changes are shown in red font in Table 2.

BC Hydro's responses to the ZONE II RPG IRs 4.69.1 through 4.69.6 are based on the updated figures presented in Table 2 below.

Cost of Energy
($ million)

Table 1 Non-Integrated Area As reported in Schedule 4.0		F2019			F2020			F2021			Difference - F2020 Update vs. F2019 Actual
Line		RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff	
		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10 = 5 - 2
	Sources of Supply (GWh)										
	Non-Heritage Energy										
6	Non-Integrated Area	120	103	(17)	118	118	0	120	120	1	15
	Unit Costs ($/MWh)										
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)	(21.9)
	Cost of Energy ($ million)										
	Non-Heritage Energy										
30	Non-Integrated Area	31.1	28.9	(2.2)	31.6	30.5	(1.0)	33.6	30.2	(3.4)	1.6

Table 2 Non-Integrated Area Updated table, after corrections		F2019			F2020			F2021			Difference - F2020 Update vs. F2019 Actual
Line		RRA	Actual	Diff	Plan	Update	Diff	Plan	Update	Diff	
		1	2	3 = 2 - 1	4	5	6 = 5 - 4	7	8	9 = 8 - 7	10 = 5 - 2
	Sources of Supply (GWh)										
	Non-Heritage Energy										
6	Non-Integrated Area	**110**	103	(7)	**107**	**107**	1	**108**	**109**	1	4
	Unit Costs ($/MWh)										
19	Non-Integrated Area	258.9	281.0	22.1	**296.1**	**274.6**	(21.6)	**310.3**	**264.8**	(45.5)	(6.5)
	Cost of Energy ($ million)										
	Non-Heritage Energy										
30	Non-Integrated Area	28.4	28.9	0.5	31.6	**29.5**	(2.1)	33.6	**28.9**	(4.7)	0.5

The following corrections are reflected in Table 2 above:

- **Line 6 of the fiscal 2020 Plan and fiscal 2020 Update, and the fiscal 2021 Plan and fiscal 2021 Update included energy (GWh) from BC Hydro's Clayton Falls generating facility. The costs and volumes are accounted for outside of the Non-Integrated Area. While Clayton Falls is not part of the integrated grid, it provides electricity service to the Non-Integrated Area of Bella Bella and nearby communities. The values on Line 6 of Table 2 have been adjusted to remove the volumes associated with Clayton Falls.**

  For clarity, Clayton Falls' volumes are accounted for in Line 1 of Schedule 4.0 while its costs are accounted for in Line 23 of Schedule 4.0.

- **Line 30 of the fiscal 2020 Update and fiscal 2021 Update were revised for the following items:**

  - **Fuel costs for three NIA-diesel generating stations were overestimated in the fiscal 2020 Update and fiscal 2021 Update. These costs, totalling $1.3 million for fiscal 2020 and $1.6 million for fiscal 2021 have been adjusted on Line 30 of Table 2; and**

  - **Costs for one Non-Integrated Area IPP were understated in the fiscal 2020 Update and the fiscal 2021 Update. These costs, totalling $0.3 million per year for fiscal 2020 and fiscal 2021 have been adjusted on Line 30 of Table 2.**

After correcting the above items, the revised Non-Integrated Area unit cost for the fiscal 2020 Update and fiscal 2021 Update are shown on Line 30 of Table 2.

Despite the revisions provided above, ratepayers only pay the actual costs incurred as any variances resulting from incorrect forecasts are deferred to the Cost of Energy Variance Accounts and recovered from ratepayers in subsequent test periods.

The following provides responses to ZONE II RPG IRs 4.69.2 through 4.69.6 based on the updated table.

- **ZONE II RPG IR 4.69.2: The decrease in Non-Integrated Area unit costs between fiscal 2019 actuals and the fiscal 2020 Update is $6.5/MWh as shown on Line 19, Column 10 of Table 2. This decrease is primarily due to factors such as an assumed reduction in unit costs related to IPP renewals, partially offset by expected increases in diesel fuel prices between fiscal 2019 and fiscal 2020;**

- **ZONE II RPG IR 4.69.3: The decrease in Non-Integrated Area unit costs between the fiscal 2020 Plan and the fiscal 2020 Update is $21.6/MWh as**

shown on Line 19, Column 6 of Table 2. This is primarily due to lower forecast for diesel fuel prices in the Evidentiary Update as compared to the fiscal 2020 Plan;

- **ZONE II RPG IR 4.69.4: The decrease in Non-Integrated Area unit costs between the fiscal 2021 Plan and the fiscal 2021 Update is $45.5/MWh as shown on Line 19, Column 9 of Table 2. This is primarily due to lower forecast for diesel fuel prices in the Evidentiary Update as compared to the fiscal 2021 Plan;**

- **ZONE II RPG IR 4.69.5: BC Hydro notes that the information request asks for an explanation for the increase in Non-Integrated Area unit costs. Line 30 of Table 2 provides the fiscal 2019 Actual dollars and the fiscal 2020 Update dollars. The Non-Integrated Area costs are $0.5 million higher in the fiscal 2020 Update as compared to the fiscal 2019 Actuals due to expected increases in overall Non-Integrated Area load, as partially offset by decreases in Non-Integrated Area unit costs (as explained in the response to ZONE II RPG IR 4.69.2 above); and**

- **ZONE II RPG IR 4.69.6: The Non-Integrated Area Cost of Energy is $2.1 million lower in the fiscal 2020 Update as compared to the fiscal 2020 Plan, and is $4.7 million lower in the fiscal 2021 Update as compared to the fiscal 2021 Plan. This is mainly due to lower market forecast diesel fuel prices used in the fiscal 2020 Update and the fiscal 2021 Update as compared to the fiscal 2020 Plan and the fiscal 2021 Plan, respectively.**

69.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-19 (Evidentiary Update), Appendix A, Schedule 4.0, line 6, 19 and 30, page 39 of 81; Exhibit B-17 (Responses to Round 3 Information Requests on Evidentiary Update), Zone II Ratepayers Group IR 3.56.1.

On line 6 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

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

On line 19 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Line		F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Unit Costs ($/MWh)									
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On line 30 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

Line		Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
				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's response to Zone II Ratepayers Group IR 3.56.1, stated that:

> The $42.1/MWh difference between the unit costs in the fiscal 2019 forecast ($238.9/MWh) and the fiscal 2019 results ($281.0/MWh) is primarily due to the following factors:
>
> - The fiscal 2019 forecast incorrectly included 13 GWh of energy from BC Hydro's Clayton Falls generating facility which should not have been included within a Non-Heritage Energy Cost….This factor represents approximately $31.8/MWh of the difference in unit costs;

……

- The fiscal 2019 forecast for the Non-Integrated Area included factor represents approximately $2.6/MWh of the difference in unit costs; and The remaining difference in unit costs, about $7.7/MWh, is largely due to higher than forecast diesel generation costs.

4.69.3 Provide an explanation for F2020 decrease in Non-Integrated Area Unit Costs ($/MWh) Update versus Plan, from $268.4/MWh (Plan) to $259.1/MWh (Update), as shown in line 19 of the table.

RESPONSE:

Please refer to BC Hydro's response to ZONE II RPG IR 4.69.2.

69.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-19 (Evidentiary Update), Appendix A, Schedule 4.0, line 6, 19 and 30, page 39 of 81; Exhibit B-17 (Responses to Round 3 Information Requests on Evidentiary Update), Zone II Ratepayers Group IR 3.56.1.

On line 6 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

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

On line 19 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Line		F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Unit Costs ($/MWh)									
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On line 30 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

Line		Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	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	2.6	(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's response to Zone II Ratepayers Group IR 3.56.1, stated that:

> The $42.1/MWh difference between the unit costs in the fiscal 2019 forecast ($238.9/MWh) and the fiscal 2019 results ($281.0/MWh) is primarily due to the following factors:
>
> - The fiscal 2019 forecast incorrectly included 13 GWh of energy from BC Hydro's Clayton Falls generating facility which should not have been included within a Non-Heritage Energy Cost….This factor represents approximately $31.8/MWh of the difference in unit costs;

……

- The fiscal 2019 forecast for the Non-Integrated Area included understated costs of approximately $0.3 million for one NIA-IPP. This factor represents approximately $2.6/MWh of the difference in unit costs; and
  The remaining difference in unit costs, about $7.7/MWh, is largely due to higher than forecast diesel generation costs.

4.69.4 Provide an explanation for the F2021 decrease in Non-Integrated Area Unit Costs ($/MWh) Update versus Plan, from $280.9/MWh (Plan) to $250.7/MWh (Update), as shown in line 19 of the table.

RESPONSE:

Please refer BC Hydro’s response to ZONE II RPG IR 4.69.2.

69.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-19 (Evidentiary Update), Appendix A, Schedule 4.0, line 6, 19 and 30, page 39 of 81; Exhibit B-17 (Responses to Round 3 Information Requests on Evidentiary Update), Zone II Ratepayers Group IR 3.56.1.

On line 6 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

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

On line 19 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Line		F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Unit Costs ($/MWh)									
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On line 30 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

Line		Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	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)	16.0 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's response to Zone II Ratepayers Group IR 3.56.1, stated that:

> The $42.1/MWh difference between the unit costs in the fiscal 2019 forecast ($238.9/MWh) and the fiscal 2019 results ($281.0/MWh) is primarily due to the following factors:
>
> - The fiscal 2019 forecast incorrectly included 13 GWh of energy from BC Hydro's Clayton Falls generating facility which should not have been included within a Non-Heritage Energy Cost….This factor represents approximately $31.8/MWh of the difference in unit costs;

……

- The fiscal 2019 forecast for the Non-Integrated Area included understated costs of approximately $0.3 million for one NIA-IPP. This factor represents approximately $2.6/MWh of the difference in unit costs; and

The remaining difference in unit costs, about $7.7/MWh, is largely due to higher than forecast diesel generation costs.

4.69.4.1 Does BC Hydro expect the factors resulting in decreased Unit Costs for F2020 and F2021 to extend beyond the Test Period. Please provide details.

RESPONSE:

It is not certain whether Unit Costs will decrease or increase beyond the Test Period. Please refer to BC Hydro's response to ZONE II RPG IR 3.56.1.1.

Zone II Ratepayer Group Information Request No. **4.69.5** Dated: **October 30, 2019** British Columbia Hydro & Power Authority Response issued **November 14, 2019**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-23**

69.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-19 (Evidentiary Update), Appendix A, Schedule 4.0, line 6, 19 and 30, page 39 of 81; Exhibit B-17 (Responses to Round 3 Information Requests on Evidentiary Update), Zone II Ratepayers Group IR 3.56.1.

On line 6 of Appendix A (Schedule 4.0), BC Hydro provides the following:

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)											
	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)
	Non-Heritage Energy											
5	IPPs and Long-Term Commitments			15,199	14,248	(951)	15,449	13,949	(1,500)	16,040	15,238	(802)
6	Non-Integrated Area			120	103	(17)	118	118	0	120	120	1
7	Total			15,320	14,351	(968)	15,566	14,067	(1,500)	16,159	15,358	(801)

On line 19 of Appendix A (Schedule 4.0), BC Hydro provides the following:

	Unit Costs ($/MWh)								
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On line 30 of Appendix A (Schedule 4.0), BC Hydro provides the following:

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)		16.0 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's response to Zone II Ratepayers Group IR 3.56.1, stated that:

> The $42.1/MWh difference between the unit costs in the fiscal 2019 forecast ($238.9/MWh) and the fiscal 2019 results ($281.0/MWh) is primarily due to the following factors:
>
> - The fiscal 2019 forecast incorrectly included 13 GWh of energy from BC Hydro's Clayton Falls generating facility which should not have been included within a Non-Heritage Energy Cost….This factor represents approximately $31.8/MWh of the difference in unit costs;

……

- The fiscal 2019 forecast for the Non-Integrated Area included understated costs of approximately $0.3 million for one NIA-IPP. This factor represents approximately $2.6/MWh of the difference in unit costs; and

  The remaining difference in unit costs, about $7.7/MWh, is largely due to higher than forecast diesel generation costs.

4.69.5 Provide an explanation for increase in Non-Integrated Unit Costs, F2019 Actual ($28.9 Million) to F2020 Update ($30.5 Million), as shown in line 30 of the table.

RESPONSE:

Please refer to BC Hydro’s response to ZONE II RPG IR 4.69.2.

69.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-19 (Evidentiary Update), Appendix A, Schedule 4.0, line 6, 19 and 30, page 39 of 81; Exhibit B-17 (Responses to Round 3 Information Requests on Evidentiary Update), Zone II Ratepayers Group IR 3.56.1.

On line 6 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

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

On line 19 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Line	Unit Costs ($/MWh)	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	238.9	281.0	42.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On line 30 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

Line		Column	Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
				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's response to Zone II Ratepayers Group IR 3.56.1, stated that:

> The $42.1/MWh difference between the unit costs in the fiscal 2019 forecast ($238.9/MWh) and the fiscal 2019 results ($281.0/MWh) is primarily due to the following factors:
>
> - The fiscal 2019 forecast incorrectly included 13 GWh of energy from BC Hydro's Clayton Falls generating facility which should not have been included within a Non-Heritage Energy Cost….This factor represents approximately $31.8/MWh of the difference in unit costs;

……

- The fiscal 2019 forecast for the Non-Integrated Area included understated costs of approximately $0.3 million for one NIA-IPP. This factor represents approximately $2.6/MWh of the difference in unit costs; and
  The remaining difference in unit costs, about $7.7/MWh, is largely due to higher than forecast diesel generation costs.

4.69.6 Provide explanations for the decrease in Non-Integrated Area Cost of Energy for F2020 and F2021 Update versus Plan, as shown in line 30.

RESPONSE:

Please refer to BC Hydro’s response to ZONE II RPG IR 4.69.2.

69.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-19 (Evidentiary Update), Appendix A, Schedule 4.0, line 6, 19 and 30, page 39 of 81; Exhibit B-17 (Responses to Round 3 Information Requests on Evidentiary Update), Zone II Ratepayers Group IR 3.56.1.

On line 6 of Appendix A (Schedule 4.0), BC Hydro provides the following:

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)										
	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)
	Non-Heritage Energy										
5	IPPs and Long-Term Commitments		15,199	14,248	(951)	15,449	13,949	(1,500)	16,040	15,238	(802)
6	Non-Integrated Area		120	103	(17)	118	118	0	120	120	1
7	Total		15,320	14,351	(968)	15,566	14,067	(1,500)	16,159	15,358	(801)

On line 19 of Appendix A (Schedule 4.0), BC Hydro provides the following:

	Unit Costs ($/MWh)								
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On line 30 of Appendix A (Schedule 4.0), BC Hydro provides the following:

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)	16.0 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's response to Zone II Ratepayers Group IR 3.56.1, stated that:

> The $42.1/MWh difference between the unit costs in the fiscal 2019 forecast ($238.9/MWh) and the fiscal 2019 results ($281.0/MWh) is primarily due to the following factors:
>
> - The fiscal 2019 forecast incorrectly included 13 GWh of energy from BC Hydro's Clayton Falls generating facility which should not have been included within a Non-Heritage Energy Cost….This factor represents approximately $31.8/MWh of the difference in unit costs;

……

- The fiscal 2019 forecast for the Non-Integrated Area included understated costs of approximately $0.3 million for one NIA-IPP. This factor represents approximately $2.6/MWh of the difference in unit costs; and

  The remaining difference in unit costs, about $7.7/MWh, is largely due to higher than forecast diesel generation costs.

4.69.6.1 Does BC Hydro expect the factors resulting in decreased Cost of Energy for Non-Integrated Area costs to extend beyond the Test Period. Please specify.

RESPONSE:

It is uncertain whether the Cost of Energy will decrease or increase beyond the Test Period. Please refer to BC Hydro's response to ZONE II RPG IR 3.56.1.1.

69.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-19 (Evidentiary Update), Appendix A, Schedule 4.0, line 6, 19 and 30, page 39 of 81; Exhibit B-17 (Responses to Round 3 Information Requests on Evidentiary Update), Zone II Ratepayers Group IR 3.56.1.

On line 6 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

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

On line 19 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Line		F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Unit Costs ($/MWh)									
16	Water Rentals	7.7	8.6	0.9	7.8	8.4	0.6	7.8	7.3	(0.5)
17	Natural Gas for Thermal Generation	45.9	40.0	(6.0)	42.4	41.8	(0.6)	44.3	43.7	(0.6)
18	IPPs and Long-Term Commitments	94.7	87.5	(7.2)	99.6	92.8	(6.8)	99.8	92.6	(7.2)
19	Non-Integrated Area	258.9	281.0	22.1	268.4	259.1	(9.3)	280.9	250.7	(30.2)
20	Market Electricity Purchases	38.5	61.4	23.0	26.6	41.5	14.8	28.1	32.9	4.8
21	Surplus Sales	(28.6)	(51.6)	(23.0)	(40.3)	(5.0)	35.3	(36.1)	(47.0)	(10.9)
22	Total Weighted Cost	33.5	29.0	(4.5)	35.2	36.2	1.0	36.1	32.6	(3.5)

On line 30 of Appendix A (Schedule 4.0), BC Hydro provides the following:

Cost of Energy
($ million)

Line		Reference	F2019 RRA	F2019 Actual	F2019 Diff	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	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's response to Zone II Ratepayers Group IR 3.56.1, stated that:

> The $42.1/MWh difference between the unit costs in the fiscal 2019 forecast ($238.9/MWh) and the fiscal 2019 results ($281.0/MWh) is primarily due to the following factors:
>
> - The fiscal 2019 forecast incorrectly included 13 GWh of energy from BC Hydro's Clayton Falls generating facility which should not have been included within a Non-Heritage Energy Cost….This factor represents approximately $31.8/MWh of the difference in unit costs;

……

- The fiscal 2019 forecast for the Non-Integrated Area included understated costs of approximately \$0.3 million for one NIA-IPP. This factor represents approximately \$2.6/MWh of the difference in unit costs; and

  The remaining difference in unit costs, about \$7.7/MWh, is largely due to higher than forecast diesel generation costs.

4.69.7 Confirm, or explain otherwise, if the errors noted in the response to Zone II Ratepayers Group IR 3.56.1 are contributing factors to the changes in the Cost of Energy in the Evidentiary Update. If so, please provide details.

RESPONSE:

Not confirmed. The errors noted in BC Hydro's response to ZONE II RPG IR 3.56.1 are not contributing factors to the changes in the Cost of Energy in the Evidentiary Update. The Evidentiary Update was based on updated Cost of Energy information, rather than the correction of those errors.

70.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-9 (Evidentiary Update), Appendix A, Schedule 4.0, lines 52 and 54, page 40 of 81.

On lines 52 and 54 of Appendix A (Schedule 4.0), BC Hydro provides the following:

	Total Current COE by Function									
52	Generation	274.3	242.8	(31.4)	109.6	282.8	173.2	77.0	59.8	(17.3)
53	Distribution	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Customer Care	1,677.6	1,666.5	(11.0)	1,625.4	1,406.3	(219.1)	1,691.2	1,553.1	(138.1)
55	Total	1,951.8	1,909.4	(42.5)	1,735.1	1,689.1	(45.9)	1,768.2	1,612.9	(155.4)

4.70.1 Provide an explanation for the significant changes in line 52 (Generation) for F2020 and F2021 Update versus Plan.

RESPONSE:

The cost components comprising line 52 are shown in the table below.

	in $ million	App. A Reference	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Heritage Energy							
1	Water Rentals	4.0 L23	343.1	329.3	(13.8)	349.1	323.2	(25.9)
2	Natural Gas for Thermal Generation	4.0 L24	8.1	7.5	(0.6)	8.5	8.5	(0.0)
3	Domestic Transmission - Other	4.0 L25	22.5	24.5	2.0	22.4	24.4	2.0
4	Non-Treaty Storage and Libby Coordination Agreements	4.0 L26	3.3	15.0	11.7	(2.5)	(11.7)	(9.3)
5	Remissions and Other	4.0 L27	(26.1)	(25.2)	0.9	(26.8)	(26.7)	0.1
	Market Energy							
6	Market Electricity Purchases	4.0 L34	40.0	211.6	171.5	18.2	43.7	25.4
7	Surplus Sales	4.0 L35	(97.1)	(0.4)	96.7	(111.4)	(97.0)	14.4
8	Domestic Transmission - Export	4.0 L37	17.4	1.1	(16.3)	21.0	17.0	(4.0)
9	**HDA Recoveries**	4.0 L49	(201.6)	(280.6)	(79.0)	(201.6)	(221.6)	(20.0)
10	**Current COE - Generation**	4.0 L52	109.6	282.8	173.2	77.0	59.8	(17.3)

The $173.2 million increase in the fiscal 2020 Update compared to Plan is primarily driven by higher forecast market electricity purchases (shown in line 6 in the table above) and lower forecast surplus sales (shown in line 7 in the table above). The higher forecast market electricity purchases and lower forecast surplus sales are both attributable to dry weather conditions observed in the summer of 2019,

which are forecast to result in lower hydro generation on a full fiscal year basis. In order to meet domestic load requirements, more market purchases are forecast to be required and less surplus energy is forecast to be available for sale. These effects are forecast to be partially offset by higher Heritage Deferral Account (HDA) refunds (shown in line 9 in the table above).

The $17.3 million decrease in the fiscal 2021 Update compared to Plan is as a result of a combination of lower forecast water rentals due to lower forecast hydro generation in fiscal 2020 (water rentals costs are based on generation in the prior year) and higher HDA refunds, partially offset by higher market electricity purchases and lower forecast surplus sales.

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British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-23**

70.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-9 (Evidentiary Update), Appendix A, Schedule 4.0, lines 52 and 54, page 40 of 81.

On lines 52 and 54 of Appendix A (Schedule 4.0), BC Hydro provides the following:

	Total Current COE by Function									
52	Generation	274.3	242.8	(31.4)	109.6	282.8	173.2	77.0	59.8	(17.3)
53	Distribution	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Customer Care	1,677.6	1,688.5	(11.0)	1,625.4	1,406.3	(219.1)	1,691.2	1,553.1	(138.1)
55	Total	1,951.8	1,909.4	(42.5)	1,735.1	1,689.1	(45.9)	1,768.2	1,612.9	(155.4)

4.70.1.1 Explain whether or not these factors will extend beyond the Test Period.

RESPONSE:

BC Hydro has no evidence to suggest that low water inflows, which were the primary factor that led to the changes between the Plan and Evidentiary Update for Generation Cost of Energy (as explained in BC Hydro's response to ZONE II RPG IR 4.70.1), are likely to continue beyond the Test Period.

For further information on BC Hydro's perspective on inflow trends, please refer to our response to GJOSHE IR 4.2.1.

70.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-9 (Evidentiary Update), Appendix A, Schedule 4.0, lines 52 and 54, page 40 of 81.

On lines 52 and 54 of Appendix A (Schedule 4.0), BC Hydro provides the following:

	Total Current COE by Function									
52	Generation	274.3	242.8	(31.4)	109.6	282.8	173.2	77.0	59.8	(17.3)
53	Distribution	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Customer Care	1,677.6	1,666.5	(11.0)	1,625.4	1,406.3	(219.1)	1,691.2	1,553.1	(138.1)
55	Total	1,951.8	1,909.4	(42.5)	1,735.1	1,689.1	(45.9)	1,768.2	1,612.9	(155.4)

4.70.2 Provide an explanation for the significant decreases in line 54 (Customer Care) for F2020 and F2021 Update versus Plan.

RESPONSE:

The cost components comprising line 54 of Appendix A are shown in the table below.

	in $ million	App. A Reference	F2020 Plan	F2020 Update	F2020 Diff	F2021 Plan	F2021 Update	F2021 Diff
	Non-Heritage Energy							
1	IPPs and Long-Term Commitments	4.0 L29	1,538.5	1,294.7	(243.8)	1,601.1	1,410.8	(190.3)
2	Non-Integrated Area	4.0 L30	31.6	30.5	(1.0)	33.6	30.2	(3.4)
3	Gas & Other Transportation	4.0 L31	2.8	3.7	0.9	2.7	2.5	(0.1)
4	Water Rentals (Waneta 2/3)	4.0 L32	3.5	3.5	0.0	3.7	3.7	0.0
	Market Energy							
5	Net Purchases (Sales) from Powerex	4.0 L36	(0.5)	33.1	33.6	0.5	6.1	5.6
6	**NHDA Recoveries**	4.0 L50	49.6	40.8	(8.8)	49.6	99.9	50.2
7	**Current COE - Customer Care**	4.0 L54	1,625.4	1,406.3	(219.1)	1,691.2	1,553.1	(138.1)

The $219.1 million decrease in the fiscal 2020 Update compared to Plan is primarily due to $243.8 million lower forecast purchases from Independent Power Producers (IPP) (shown in line 1 in the table above) resulting from lower deliveries from hydro projects due to low water inflows and a change in accounting treatment due to the adoption of IFRS 16 as explained in Appendix F of the Evidentiary Update. This was partially offset by higher forecast net purchases

from Powerex of $33.6 million (shown in line 5 of the table above) due to higher forecast Mid-C prices in the fiscal 2020 Update compared to Plan.

The $138.1 million decrease in the fiscal 2021 Update compared to Plan is primarily due to $190.3 million lower forecast IPP purchases (shown in line 1 of the table above), partially offset by $50.2 million higher Non-Heritage Deferral Account (NHDA) recoveries (shown in line 6 of the table above).

The $190.3 million lower IPP purchases are comprised of:

- **$88 million due to a change in accounting treatment for some energy purchase agreements as the result of the adoption of IFRS 16 which is explained in Appendix F of the Evidentiary Update;**
- **$46 million due to lower forecast purchases from an IPP; and**
- **$61 million due to lower forecast volumes as a result of updating historical averages that became available since the Application.**

The $50.2 million higher NHDA recoveries are comprised of:

- **$82.8 million due to an opening balance adjustment to the NHDA as a result of the adoption of IFRS 16. This additional amount results in higher NHDA recoveries during the Test Period; and**
- **Reallocation of NHDA recovery amounts between fiscal 2020 and fiscal 2021 in order to keep the bill increase in fiscal 2020 in the Evidentiary Update the same as in the Application (1.76 per cent).**

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British Columbia Hydro & Power Authority **Fiscal 2020 to Fiscal 2021 Revenue Requirements Application**	**Exhibit:** **B-23**

70.0 Topic: Appendix A (Cost of Energy Financial Schedules)

Reference: Exhibit B-9 (Evidentiary Update), Appendix A, Schedule 4.0, lines 52 and 54, page 40 of 81.

On lines 52 and 54 of Appendix A (Schedule 4.0), BC Hydro provides the following:

	Total Current COE by Function									
52	Generation	274.3	242.8	(31.4)	109.6	282.8	173.2	77.0	59.8	(17.3)
53	Distribution	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
54	Customer Care	1,677.6	1,666.5	(11.0)	1,625.4	1,406.3	(219.1)	1,691.2	1,553.1	(138.1)
55	Total	1,951.8	1,909.4	(42.5)	1,735.1	1,689.1	(45.9)	1,768.2	1,612.9	(155.4)

4.70.2.1 Explain whether or not these factors will extend beyond the Test Period.

RESPONSE:

BC Hydro has no evidence to suggest that the low energy deliveries from Independent Power Producers due to low water inflows in fiscal 2020 are likely to continue beyond the Test Period. As discussed in BC Hydro's response to GJOSHE IR 4.2.1, there is no visible trend in system inflows, and based on the assumption that inflows to hydro IPPs are correlated with BC Hydro's own inflows, this would apply to hydro-based IPP inflows as well. The impact due to the accounting change as a result of the adoption of IFRS 16 is expected to extend beyond the Test Period.