BC Hydro
Power smart

Chris Sandve
Chief Regulatory Officer
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September 3, 2021

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: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2021 Annual Report to the Commission

BC Hydro writes further to the August 30, 2021 submission of its Fiscal 2021 Annual Report to the Commission to provide a Consolidated Statement of Operations schedule.

BC Hydro had intended to include this schedule in Section 6, Attachment 2 of the Fiscal 2021 Annual Report; however, it was inadvertently excluded from the original submission.

For further information, please contact Joe Maloney at 604-623-4348 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Chris Sandve
Chief Regulatory Officer

cs/ma

Enclosure

Chris Sandve
Chief Regulatory Officer
Phone: 604-623-3726
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

August 30, 2021

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: British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2021 Annual Report to the Commission

BC Hydro writes pursuant to BCUC Letter Nos. L-36-94, L-14-95, L-45-15 and subsection 45(6) of the *Utilities Commission Act* to provide BC Hydro's Fiscal 2021 Annual Report to the Commission for the period April 1, 2020 to March 31, 2021.

BC Hydro's Fiscal 2021 Annual Report to the Commission includes some changes relative to the Fiscal 2020 Annual Report. Specifically:

1. A breakdown between storm restoration costs and evacuation relief costs in the Storm Restoration Costs Regulatory Account, as required by Item 5 of BCUC Order No. G-215-20 (refer to section 6, Attachment 2, Schedule 2.2, Line 39);[1]
2. A breakdown of historic actual system imports/exports into flexible and non-flexible in accordance with Directive 5 of BCUC Order No. G-187-21 (refer to Section 6, Attachment 1, Section 3);
3. Additional information on capital expenditures pursuant to sections 24 and 45 of the *Utilities Commission Act* in accordance with BCUC Letter No. L-65-20 (refer to Section 6, Attachment 1, Section 12); and
4. A Performance of Rate Schedule 1894 and 1895 appendix has been added as required by BCUC Order No. G-38-21 which directs BC Hydro to provide a brief annual report to the BCUC on the performance of these rate schedules (refer to Appendix D).

[1] Refer to Section 6, Attachment 2, Schedule 2.2, line 39.

For further information, please contact Joe Maloney at 604-623-4348 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Anthea Jubb

(for) Chris Sandve
Chief Regulatory Officer

ls/rh

Enclosure

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

April 1, 2020 to March 31, 2021

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List of Appendices

1 Declaration

I, David Wong, of 333 Dunsmuir Street, Vancouver, B.C., do hereby certify:

1. That I am the Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer of BC Hydro located at 333 Dunsmuir Street, Vancouver, B.C.
2. That I have examined the content of this report and the information set out herein is complete and accurate, to the best of my knowledge, information and belief. I have read and understand Section 106 and 109.1 to 109.8 of the *Utilities Commission Act*.

BC Hydro has also complied with the Commission's financial directives with regard to the following:[1]

- Section 6, Attachment 2: A breakdown between storm restoration costs and evacuation relief costs in the Storm Restoration Costs Regulatory Account as required by Item 5 of BCUC Order No. G-215-20 (Schedule 2.2, Line 39);
- Section 6, Attachment 1: Financial Schedules and Variance Explanations in accordance with BCUC Order No. G-187-21 (section 3 Cost of Energy Variance Explanations);
- Section 6, Attachment 1: Financial Schedules and Variance Explanations in accordance with BCUC Order No. G-313-19 (section 3.3.1);
- Section 6, Attachment 1, section 12: Financial Schedules and Variance Explanations in accordance with BCUC Letter No. L-65-20;

[1] Directive 62 of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application directed BC Hydro to file annually as part of its annual report to the BCUC, in confidence if necessary, a summary of Powertech's net income in sufficient detail to enable the BCUC to determine whether the inclusion of Powertech's net income is appropriate. On March 22, 2021, the Government of B.C. deposited Order in Council (**OIC**) No. 172, which amended Direction No. 8 to the BCUC. In accordance with the amendments to Direction No.8, BC Hydro requested that Directive 62 be rescinded. The BCUC considered BC Hydro's request and on June 28, 2021, issued Order No. G-197-21 which rescinded this directive.

- Section 6, Attachment 1, section 1: Financial Schedules and Variance Explanations – Domestic Energy Sales Variance Explanation in accordance with Directive 4 of BCUC Order No. G-246-20;
- Section 7, Attachment: Summary of Planned Capital Extension Projects and Anticipated Regulatory Filings as required by Directive 2 of BCUC Order No. G-313-19 (section 3.1.3);
- Section 10.1: Waneta Transaction Annual Report as required by Directive 4 (e) of BCUC Order No. G-130-18;
- Section 10.2: Summary Report on Volume and Pricing of Transmission Capacity Reassignments and Simultaneous Submission Window as required by BCUC Order No. G-102-09 (section 3.3.3 and 3.6.3.1);
- Appendix A: Annual Deferral Accounts Report[2] as required by Directive 8 of BCUC Order No. G-96-04;
- Appendix B: Debt Management Regulatory Account Annual Status Report as required by Directive 4 of BCUC Order No. G-42-16;
- Appendix C – Residential Service Customers Charging Zero Emission Vehicles at their Dwelling Annual Report as required by Directive 2 of BCUC Order No. G-92-19; and
- Appendix D – Performance of Rate Schedule 1894 and 1895 as required by BCUC Order No. G-38-21.

[2] BC Hydro received a Variance to Order No. G-112-14 on September 14, 2017 requiring BC Hydro to file the Deferral Accounts Report on an annual basis and include it with the BC Hydro Annual Report to the British Columbia Utilities Commission within four months following the end of the fiscal year.

Per:

David Wong

Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer,

British Columbia Hydro and Power Authority

August 30, 2021

2 Directors and Officers

Report below the name, title and business address of each director and officer, as at March 31, 2021.

Name	Business Address	Office Held
Board of Directors		
Doug Allen[1]	333 Dunsmuir St Vancouver, BC V6B 5R3	Chair
Lenard F. Boggio	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Daryl Fields	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Valerie Lambert	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Irene Lanzinger	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Nalaine Morin	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
John Nunn	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Catherine Roome	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Chris Sanderson	333 Dunsmuir St Vancouver, BC V6B 5R3	Director
Officer (Executive Team)		
Chris O'Riley	333 Dunsmuir St Vancouver, BC V6B 5R3	President and Chief Executive Officer
Janet Fraser	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, People, Customer & Corporate Affairs
Maureen Daschuk	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President, Integrated Planning
Ken Duke	333 Dunsmuir St Vancouver, BC V6B 5R3	Vice-President & General Counsel

[1] Doug Allen was appointed Chair on February 26, 2021.

Name	Business Address	Office Held
Al Leonard	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President, Capital Infrastructure Project Delivery
Charlotte Mitha	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Operations
Ken McKenzie	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Site C
Kirsten Peck	333 Dunsmuir St Vancouver, BC V6B 5R3	Senior Vice-President, Safety & Chief Compliance Officer
David Wong	333 Dunsmuir St Vancouver, BC V6B 5R3	Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer

3 Control Over Utility

If any corporation, business trust, or similar organization or combination of such organizations jointly held control over the utility at end of year, state name of controlling corporation or organization, manner in which control was held and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

Government of B.C., sole Shareholder.

4 Corporations Controlled by BC Hydro

1. Report below the names of all corporations, business trusts and similar organizations, controlled directly or indirectly by BC Hydro at any time during the year. If control ceased prior to end of year, give particulars in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name other interests.

The following table lists BC Hydro's fully operational or fully active operating subsidiary companies as of March 31, 2021.[1]

Name of Company Controlled	Kind of Business	Percent Voting Stock Owned	Footnote Reference
Powerex Corp.	Marketer of wholesale energy products and services in Western Canada and the Western United States.	100	Direct Control
Powertech Labs Inc.	Research and technology provider; services include testing, problem solving and consulting services.	100	Direct Control
BCHPA Captive Insurance Company Ltd	To assist BC Hydro in the management of its insurance program.	100	Direct Control
Tongass Power and Light Company	Company acquired by BC Hydro in 1964 as a "border accommodation" due to Hyder's remoteness from Alaska-based electrical suppliers. Tongass is connected to the BC Hydro system by a distribution line and a transfer pricing agreement formalizes the services provided.	100	Direct Control

[1] BC Hydro has not included Columbia Hydro Constructors Ltd. (**CHC**) in this list. BC Hydro considers CHC to be active but not "fully operational or fully active" in that it was not used for construction work during the year.

Definitions

1. Direct control is that which is exercised without interposition of an intermediary.
2. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
3. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other.

5 Important Changes During the Year – Fiscal 2021

Furnish particulars, including effective dates, concerning the matters indicated below:

1. Changes or additions to franchise rights.
2. Acquisition or disposal of ownership in other companies; consolidation, merger or reorganization with other companies.
3. Acquisition or disposal of an operating unit or system.
4. Important leaseholds.
5. Important extension or reduction in generation, transmission or distribution systems.
6. Estimated annual effect and nature of important wage scale changes during the year.
7. Important legal proceedings pending, in progress, or concluded during the year.

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1. None.
2. None.
3. None.
4. Important leasehold information can be found in BC Hydro's Consolidated Financial Statements of the 2020/21 BC Hydro Annual Service Plan Report as follows:
   - Leasehold information within Note 12: Right-Of-Use Assets, page 76 and *Long-term energy purchase agreements, property leases and other leases* sections within Note 19: *Lease Liabilities*, page 90;
   - *Energy Commitments and Lease and Service Agreements* sections within Note 25: *Commitments and Contingencies,* page 111; and

- Significant accounting policies for important leaseholds are disclosed in the *Leases* section within Note 3: *Significant Accounting Policies,* page 59.

A link to this report is provided: http://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html.

5. In fiscal 2021, BC Hydro placed into service the UBC Load Increase Stage 2 project, the Arnott Feeder to Tilbury Island project, and the Fort St John and Taylor Electric Supply project.

The UBC Load Increase Stage 2 project was put into service in November 2020. The project was requested by the customer (**UBC**), to increase their contracted demand from 55 MVA to 65 MVA. The project installed one indoor Gas Insulated Switchgear, two Hybrid Insulated Switchgears, and two transformers along with other 230 kV equipment. The project is currently completing deficiency and dismantling work.

The Arnott Feeder to Tilbury Island project was put into service in July 2020. The BC Hydro distribution network serving the Tilbury area of the Corporation of Delta required additional infrastructure as it did not have sufficient capacity to meet the future load growth requirements forecasted in the area. This load growth includes both general industrial growth forecast by the Corporation of Delta, as well as other forecast spot loads in the area. The project scope included the design and construction of an eight km 16-way ductbank between Arnott substation along River Road to the Tilbury Island industrial area of Delta.

The Fort St John and Taylor Electric Supply project was placed into service in October 2020. The project constructed a 138 kilovolt switchyard at the new South Bank substation located at Site C, which included the installation of six single-phase 500/138 kilovolt transformers. Two new sections of three kilometer 138 kilovolt wood pole transmission lines were constructed to connect the existing

1L360 (GMS to Taylor) and 1L374 (GMS to Fort St John) transmission lines to the new substation. This enabled the de-energization and removal of approximately 70 kilometers of existing lines between the South Bank substation and Peace Canyon, providing space on the right-of-way to construct the second Site C 500 kilovolt transmission line, 5L006. The benefits of the project are reduced line losses, improved reliability and the reinforcement of the Peace Region transmission system by the bulk 500 kilovolt transmission system.

6. Union wage scales increased 2.0 per cent effective April 1, 2020. Manager and exempt professional (**M&P**) salary scales increased 2.0 per cent effective April 1, 2020.

7. Important legal proceedings pending, in progress, or concluded during the year can be found in BC Hydro's Consolidated Financial Statements of the 2020/21 BC Hydro Annual Service Plan Report as follows:

   - *Contingencies and Guarantees* section within Note 25: *Commitments and Contingencies*, page 111.

   A link to this report is provided: http://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html.

6 Fiscal 2021 Financial Schedules and Variance Explanations

BC Hydro has provided, in Attachment 1 to this section, a detailed comparison between the fiscal 2021 Decision amounts from the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**F2020-F2021 RRA**) and fiscal 2021 actual financial results, including variance explanations. Included in Attachment 2 to this section are financial schedules which provide additional comparison details between the fiscal 2021 Decision amounts and fiscal 2021 actual financial results and which support the fiscal 2021 information and tables provided in Attachment 1.[1]

[1] Please note the amounts presented in the tables in Attachment 1 may not add due to rounding.

BC Hydro
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BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Attachment 1 to Section 6

Fiscal 2021 Financial Schedules and Variance Explanations

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List of Tables

In sections 1 through 9, variance explanations are provided for actual gross amounts in fiscal 2021 compared to the F2020–F2021 RRA decision (**Decision**) amounts. Apart from domestic energy sales variances, all explanations are provided where variances between actual and Decision amounts are greater than 10 per cent, with a minimum variance threshold of $5 million. Domestic energy sales variance explanations are provided for each customer sector.

1 Domestic Energy Sales Variance Explanations (Schedule 14.0)

This section compares fiscal 2021 actual domestic energy sales amounts in GWh with the fiscal 2021 Decision.

Table 1 Fiscal 2021 Domestic Energy Sales Variances

	(GWh)	Schedule Reference	F2021 Decision	F2021 Actual	F2021 Diff	F2021 % Diff
			1	2	3=2-1	4=3/1
1	Residential	14.0 L1	17,927	18,982	1,055	6%
2	Light Industrial and Commercial	14.0 L2	18,744	18,091	(653)	-3%
3	Large Industrial	14.0 L3	13,203	12,438	(765)	-6%
4	Other	14.0 L4:L10	2,066	1,628	(438)	-21%
5	**Total Domestic Energy Sales**	14.0 L11	**51,940**	**51,139**	(801)	-2%

Pursuant to Directive 4 of the Decision, this variance analysis includes an estimate of the extent of any variance that is attributed to and independent from the COVID-19 pandemic. Developing a precise estimate of load variance due to the COVID-19 pandemic is difficult because it involves a comparison of “what if” scenarios and forecasts, for which there are no measurable “after-the-fact” metrics. In particular, the COVID-19 Scenario A used to estimate the potential load impacts in fiscal 2021 was developed relative to the March 2020 Load Forecast whereas the F2020-F2021 RRA was based on the October 2018 Load Forecast, but then reduced by 2.6 per cent in accordance with the BCUC’s decision on that application. Since the March 2020 Load Forecast was a comprehensive forecast with updates to all input assumptions, the extent to which these assumptions differ from assumptions underpinning the F2020-F2021 RRA make it difficult to attribute variances due to the pandemic relative to the October 2018 Load Forecast.

For the purpose of responding to Directive 4, BC Hydro applied a simplified approach. We compared fiscal 2021 actual energy (GWh) consumption against fiscal 2020 actual consumption by major customer group. We then compared those differences to the net effect of COVID-19 Scenario A load impacts on the March 2020 Load Forecast for fiscal 2021. This comparison indicates that the differences between fiscal 2021 actuals and fiscal 2020 actuals are similar to the net effect of the assumed load declines reflected in the COVID-19 Scenario A on the March 2020 Load Forecast.

Following this, we assessed the variance results against our typical variance factors such as residential account growth, temperature, and specific large industrial account information to determine whether any variances can be clearly attributed to factors other than the COVID-19 pandemic.

Overall, actual domestic energy sales in fiscal 2021 were 801 GWh (or 2 per cent) lower than the fiscal 2021 Decision. This was due to:

- Line 1 - Actual residential sales were 1,055 GWh (or 6 per cent) higher than the fiscal 2021 Decision. Variances in residential sales are driven by three main factors: electricity sales per account (use per account), temperature, and number of accounts. In fiscal 2021, the residential sales variance was driven primarily by higher than expected use per account. Higher use per account variance can be driven by many different factors. While the exact drivers in this case are not known, the likely primary driver is the COVID-19 pandemic, which saw residential customers spend more time at home, working from home, and studying from home, resulting in higher consumption. The number of accounts was slightly favourable. The total number of residential accounts was 10,600 (less than 1 per cent) higher than plan and did not contribute significantly to the sales variance. There was a small offsetting variance for temperature, which was slightly unfavourable. Temperatures were close to normal, with warmer temperatures in December and January offset by colder temperatures in February and several other months of the year.

Actual fiscal 2021 sales are higher than fiscal 2020 actual sales and both the October 2018 and March 2020 Load Forecast sales expectations for fiscal 2021. Actual fiscal 2021 sales are directionally consistent with the COVID-19 Scenario A projection that residential sales would increase relative to the pre-pandemic March 2020 Load Forecast. While the net increase was not as large as projected, it was still higher relative to the fiscal 2021 Decision. Based on the above comparisons and consideration of temperature and account information, BC Hydro believes the positive fiscal 2021 sales variance can be largely attributed to the COVID-19 pandemic.

- Line 2 - Actual light industrial and commercial sales were 653 GWh (or 3 per cent) lower than the fiscal 2021 Decision. The commercial sector is comprised of a diverse group of business classes and lower energy consumption can generally be attributed to many different factors. For fiscal 2021 we expected the primary factor was closures and curtailments due to public health orders relating to the COVID-19 pandemic. To confirm this BC Hydro compared fiscal 2021 actual load to fiscal 2020 actual load. The business classes with the largest reduction in their load were offices, accommodations, food services, entertainment, recreation, shopping centers, and educational services. Actual fiscal 2021 sales are lower than fiscal 2020 actual sales and both the October 2018 and March 2020 Load Forecast sales expectations for fiscal 2021. Actual fiscal 2021 sales are directionally consistent with the COVID-19 Scenario A projection that sales would decline relative to the pre-pandemic March 2020 Load Forecast. While the net decline was not as large as projected, it was still lower relative to the fiscal 2021 Decision. Based on the above comparisons BC Hydro believes the negative fiscal 2021 sales variance is largely attributable to the COVID-19 pandemic.

- Line 3 - Actual large industrial sales were 765 GWh (or 6 per cent) lower than the fiscal 2021 Decision. Actual fiscal 2021 sales are lower than fiscal 2020 actual sales and both the October 2018 and March 2020 Load Forecast sales expectations for fiscal 2021. Actual fiscal 2021 sales are also consistent with COVID-19 Scenario A sales projections and underlying account assumptions. Based on the above comparison BC Hydro believes the negative fiscal 2021 sales variance is largely attributable to the COVID-19 pandemic.
- Line 4 – The original forecast for the Other customer sector was 1,650 GWh. As required by Directive 4 of BCUC Order G-246-20 BC Hydro increased the forecast by 25.2 percent for a revised forecast of 2,066 GWh in the fiscal 2021 Decision. Actual energy sales to the Other customer sector of 1,628 GWh were more consistent with the original forecast and were 438 GWh or 21 per cent lower than the revised forecast.

2 Domestic Revenue Variance Explanations (Schedule 14.0)

This section compares fiscal 2021 actual domestic revenue amounts with the fiscal 2021 Decision.

Table 2 Fiscal 2021 Domestic Revenues Variances

	($ million)	Schedule Reference	F2021 Decision	F2021 Actual	F2021 Diff	F2021 % Diff
			1	2	3=2-1	4=3/1
1	Residential	14.0 L12	2,140.4	2,210.2	69.8	3%
2	Light Industrial and Commercial	14.0 L13	1,905.9	1,830.4	(75.6)	-4%
3	Large Industrial	14.0 L14	852.2	761.7	(90.5)	-11%
4	Other	14.0 L15:L21	188.9	148.2	(40.7)	-22%
5	Subtotal	14.0 L22	5,087.4	4,950.4	(137.0)	-3%
6	Revenue from Deferral Rider	14.0 L23	-	0.0	0.0	0%
7	**Total Domestic Revenues**	14.0 L24	**5,087.4**	**4,950.4**	(137.0)	-3%

Actual domestic revenues in fiscal 2021 were $137.0 million (or 3 per cent) lower than the fiscal 2021 Decision. This was primarily due to:

- Line 1 - Residential revenue was $69.8 million (or 3 per cent) higher, driven by higher sales, as described in section 1 above, partially offset by COVID-19 Relief Program grants of $37.3 million;
- Line 2 - Light industrial and commercial revenue was $75.6 million (or 4 per cent) lower, mainly due to lower sales, as described in section 1 above, as well as $6.3 million of COVID-19 Relief program waivers provided to small business customers;
- Line 3 - Large industrial customer revenue was $90.5 million (or 11 per cent) lower due to lower sales, as described in section 1, as well as a lower average rate. The lower average rate was due to $13.3 million of lower demand charges provided as COVID-19 relief and due to a different mix of customer rates than planned; and
- Other revenue was $40.7 million (or 22 per cent) lower, mainly due to the lower sales described in section 1.

3 Cost of Energy Variance Explanations (Schedule 4.0)

This section compares fiscal 2021 actual sources of energy supply and cost of energy amounts with the fiscal 2021 Decision.

Table 3 Fiscal 2021 Sources of Supply

	(GWh)	Schedule Reference	F2021 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Water Rentals	4.0 L1	44,522	49,796	5,275	12%
2	IPPs and Long-Term Commitments	4.0 L5	15,238	14,630	(608)	-4%
3	Market Electricity Purchases	4.0 L8	1,326	-	(1,326)	-100%
4	Natural Gas for Thermal Generation	4.0 L2	195	150	(46)	-23%
5	Surplus Sales	4.0 L9	(3,515)	-	3,515	-100%
6	System Imports	4.0 L10	-	999	999	0%
7	System Exports	4.0 L11	-	(9,082)	(9,082)	0%
8	Net Purchases (Sales) from Powerex	4.0 L12	(279)	-	279	-100%
9	Non-Integrated Area	4.0 L6	120	107	(13)	-11%
10	Exchange Net	4.0 L3	(250)	(355)	(105)	42%
11	**Total Sources of Supply**	4.0 L14	**57,357**	**56,245**	(1,112)	-2%

Actual fiscal 2021 sources of supply were 1,112 GWh (or 2 per cent) lower than the fiscal 2021 Decision. This was primarily due to:

- Lines 3, 5, 6, 7, and 8 – Higher net market exports[1] of 5,615 GWh driven by lower domestic load requirements and higher water inflows starting in late summer.

Partially offset by:

- Line 1 - Higher hydro generation of 5,275 GWh due to higher water inflows as mentioned above.

[1] The adoption of the 2020 TPA resulted in a change in the presentation of energy transactions (the sale and purchase of electricity) between BC Hydro and Powerex. The terms “Market Electricity Purchases” (Line 3 in Table 3), “Surplus Sales” (Line 5 in Table 3), and “Net Purchases (Sales) from Powerex” (line 8 in Table 3) were replaced by “System Imports” (line 6 in Table 3) and “System Exports” (line 7 in Table 3).

Table 4 Fiscal 2021 Cost of Energy Variances

	($ million)	Schedule Reference	F2021 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
	Heritage Energy					
1	Water Rentals	4.0 L15	323.2	333.2	10.0	3%
2	Natural Gas for Thermal Generation	4.0 L16	8.5	6.5	(2.0)	-24%
3	Domestic Transmission - Other	4.0 L17	24.4	25.5	1.1	5%
4	Non-Treaty Storage and Libby Coordination Agreements	4.0 L18	(11.7)	(49.9)	(38.1)	325%
5	Remissions and Other	4.0 L19	(26.7)	(42.0)	(15.4)	58%
6	**Subtotal**	4.0 L20	**317.7**	**273.3**	(44.4)	-14%
	Non-Heritage Energy					
7	IPPs and Long-Term Commitments	4.0 L21	1,410.8	1,404.0	(6.8)	0%
8	Non-Integrated Area	4.0 L22	30.2	26.0	(4.1)	-14%
9	Gas & Other Transportation	4.0 L23	2.5	5.3	2.7	107%
10	Water Rentals (Waneta 2/3)	4.0 L24	3.7	3.2	(0.5)	-13%
11	**Subtotal**	4.0 L25	**1,447.2**	**1,438.5**	(8.6)	-1%
	Market Energy					
12	Market Electricity Purchases	4.0 L26	43.7	0.0	(43.7)	-100%
13	Surplus Sales	4.0 L27	(165.1)	0.0	165.1	-100%
14	System Imports	4.0 L28	0.0	26.9	26.9	0%
15	System Exports	4.0 L29	0.0	(227.9)	(227.9)	0%
16	Net Purchases (Sales) from Powerex	4.0 L30	6.1	0.0	(6.1)	-100%
17	Domestic Transmission - Export	4.0 L31	17.0	11.6	(5.4)	-32%
18	**Subtotal**	4.0 L32	(98.4)	(189.4)	(91.0)	93%
19	**Total Gross Cost of Energy**	1.0 L1	**1,666.5**	**1,522.4**	(144.0)	-9%

Fiscal 2021 actual gross Cost of Energy was $144.0 million (or 9 per cent) lower than the fiscal 2021 Decision. This was primarily due to:

- Line 4 - Higher benefits associated with Non-Treaty Storage and Libby Coordination agreements of $38.1 million due to higher net water releases in the current year and more favourable prices during releases relative to forecast;
- Line 5 - Higher recoveries from remissions and other of $15.4 million due to higher water use planning remissions for the Bridge River System and John Hart Generating Station;

- Lines 12 to 16 – Lower Market Energy costs[2] of $85.7 million due to higher net market exports of 5,615 GWh (Lines 3,5,6,7 and 8 of Table 3 - Fiscal 2021 Sources of Supply) driven by lower domestic load requirements and higher inflows in fiscal 2021; and
- Line 17 – Lower domestic transmission costs of $5.4 million, reflecting the new method of allocation of point-to-point charges between BC Hydro and Powerex as a result of the 2020 Transfer Pricing Agreement (2020 TPA). In particular, there is no longer an hourly determination of whether hourly export quantities reflect domestic sales versus trade activity. The revised calculation reflects the principles of section 6.2 of the 2020 TPA to provide a reasonable allocation of the point-to-point transmission costs incurred by BC Hydro in respect of Powerex's trading activities.

Directive 5 of the BCUC's Decision on BC Hydro's Fiscal 2022 Revenue Requirements Application (BCUC Order No. G-187-21) directed BC Hydro to report on the historic actual system imports/exports divided into flexible and non-flexible (i.e., according to the format in the 2020 TPA). Table 5 provides the fiscal 2021 actual system imports/exports divided into flexible and non-flexible.

[2] The 2020 Transfer Pricing Agreement (2020 TPA) came into effect on April 1, 2020 as directed by Order in Council No. 172 (BC Reg 88/2021) and approved by the BCUC Order No. G-127-21. The adoption of the 2020 TPA resulted in a change in the presentation of energy transactions (the sale and purchase of electricity) between BC Hydro and Powerex. The terms "Market Electricity Purchases" (line 12 in Table 4), "Surplus Sales" (line 13 in Table 4), and "Net Purchases (Sales) from Powerex" (line 16 in Table 4) were replaced by "System Imports" (line 14 in Table 4) and "System Exports" (line 15 in Table 4).

Table 5 Fiscal 2021 Actual System Imports/Exports Divided into Flexible and Non-Flexible

	F2021 Actual	
	$ million	**GWh**
System Imports		
Non-Flexible imports	4.6	61
Flexible imports	22.3	938
Total System Imports	26.9	999
System Exports		
Non-Flexible exports	(12.5)	(1,182)
Flexible exports	(215.3)	(7,900)
Total System Exports	(227.9)	(9,082)
Net System Imports / (Exports)	**(201.0)**	**(8,083)**

4 Operating Costs and Provisions Variance Explanations (Schedule 5.0)

This section compares fiscal 2021 actual gross operating costs and provisions amounts with the fiscal 2021 Decision.

Table 6 Fiscal 2021 Operating Costs and Provisions Variances

	($ million)	Schedule Reference	F2021 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Integrated Planning	5.0 L1	292.0	308.8	16.7	6%
2	Capital Infrastructure Project Delivery	5.0 L2	81.1	80.8	(0.3)	0%
3	Operations	5.0 L3	244.3	265.2	21.0	9%
4	Safety	5.0 L4	57.5	55.7	(1.8)	-3%
5	Finance, Technology, Supply Chain	5.0 L5	264.8	277.3	12.5	5%
6	People, Customer, Corporate Affairs	5.0 L6	111.1	121.3	10.2	9%
7	Other	5.0 L7	(244.4)	(273.4)	(28.9)	12%
8	**Base Operating Costs**	5.0 L8	**806.4**	**835.7**	29.4	4%
9	IFRS Ineligible Capitalized Costs	5.0 L9	192.5	192.5	-	0%
10	Waneta 2/3	5.0 L10	5.9	5.8	(0.0)	-1%
11	Customer Crisis Fund	5.0 L11	5.3	2.9	(2.4)	-45%
12	**Subtotal**	5.0 L12	**203.6**	**201.2**	(2.4)	-1%
13	Deferred Account Additions	5.0 L16	-	(0.0)	(0.0)	0%
14	Regulatory Account Additions	5.0 L27	125.4	91.8	(33.6)	-27%
15	**Subtotal**		**125.4**	**91.8**	(33.6)	-27%
16	**Total Gross Operating Costs**	5.0 L27	**1,135.4**	**1,128.7**	(6.6)	-1%
17	Net Provisions & Other	5.0 L41	95.4	110.7	15.3	16%
18	Regulatory Account Additions - Provisions & Other	5.0 L49	-	53.0	53.0	0%
19	**Total Gross Provisions & Other**	5.0 L50	**95.4**	**163.7**	68.3	72%
20	**Total Gross Operating Costs and Provisions**	1.0 L2	**1,230.8**	**1,292.4**	61.7	5%

Fiscal 2021 actual gross Operating Costs and Provisions were $61.7 million (or 5 per cent) higher than the fiscal 2021 Decision. Of this amount, $53.0 million (line 18 in Table 6 above) was related to higher regulatory account additions for provisions and other, $29.4 million (line 8 in Table 6 above) was related to higher base operating costs, and $15.3 million (line 17 in Table 6 above) was related to higher net provisions and other. These amounts were partially offset by $33.6 million (line 14 in Table 6 above) related to lower regulatory account additions for operating costs.

Variances of $53.0 million related to higher regulatory account additions for provisions and other and variances of $33.6 million related to lower regulatory account additions for operating costs, netting to $19.4 million were primarily due to:

- An increase in the Environmental Provisions Regulatory Account of $51.2 million due to an increase in the Polychlorinated Biphenyl (**PCB**) provision of $20.5 million and an increase in the Asbestos Remediation provision of $30.7 million. The provisions increased due to increases in forecast PCB and Asbestos remediation costs, partially offset by reductions in the present value of future expenditures due to increases in discount rates;
- An increase in the Project Write-Off Costs Regulatory Account of $16.4 million due to $9.3 million project write-offs attributable to fiscal 2020 that was recorded prospectively in fiscal 2021 in accordance with Directive 32 of the BCUC’s Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (received in fiscal 2021) and $7.1 million project write-offs relating to fiscal 2021. Itemized project write-offs deferred to the Project Write-off Costs Regulatory Account can be found in F Appendix L of the Fiscal 2022 Revenue Requirements Application for fiscal 2020, and Appendix P of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application for fiscal 2021; and
- Other variances, totalling $0.3 million.

Partially offset by:

- Lower than planned increase in the Demand-Side Management Regulatory Account of $17.6 million due to fewer industrial customers advancing incentive projects than planned, COVID-19 restrictions impacting program operations, and shifts in completion of low carbon electrification customer projects to other fiscal years;
- A decrease in the Storm Restoration Costs Regulatory Account of $14.2 million due to:
  - ▶ $10.0 million lower than planned expenditures for storm restoration. Planned storm restoration expenditures are based on a five-year average of actual

storm restoration costs. In fiscal 2021, BC Hydro experienced relatively less storm activity (fewer and less severe wildfires, windstorms, snow events) and accordingly, actual storm restoration costs were lower than plan.

- $4.2 million reduction attributable to fiscal 2020 that was recorded prospectively in fiscal 2021 in accordance with Directive 19 of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (received in fiscal 2021) that increased the BCUC approved storm restoration cost plan by $4.2 million.

- Decrease in the Real Property Sales Regulatory Account of $10.9 million attributed to the fiscal 2020 amount that was recorded prospectively in fiscal 2021 in accordance with Directive 41 of the BCUC's on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (received in fiscal 2021); and
- Decrease in the Post-Employment Benefit (**PEB**) Current Pension Costs Regulatory Account of $5.8 million due to the increase in the discount rate from 3.33 per cent in the fiscal 2021 Decision vs 3.83 per cent in the fiscal 2021 actuals.

Variances of $29.4 million related to base operating costs were primarily due to higher than planned personnel costs, including employees unable to charge to capital/maintenance work programs as a result of the COVID-19 social distancing measures BC Hydro put in place in March 2020, additional vegetation work and expenditures to support Mandatory Reliability Standards compliance requirements, partially offset by lower costs due to maintenance work not proceeding as planned as a result of the COVID-19 pandemic.

Variances of $15.3 million related to net provisions and other were primarily due to non-recoverable amounts.

5 Taxes Variance Explanations (Schedule 6.0)

This section compares fiscal 2021 actual taxes amounts with the fiscal 2021 Decision.

Table 7 Fiscal 2021 Taxes Variances

		Schedule	F2021			
	($ million)	Reference	Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Grants in Lieu	6.0 L15	114.8	117.3	2.5	2%
2	School Taxes	6.0 L16	146.8	138.7	(8.0)	-5%
3	Waneta 2/3 Property Taxes	6.0 L17	0.6	0.8	0.2	25%
4	**Subtotal Before Regulatory Accounts**	6.0 L17	**262.2**	**256.8**	(5.4)	-2%
5	Deferred Account Additions	6.0 L	-	-	-	N/A
6	**Total Gross Taxes**	1.0 L3	**262.2**	**256.8**	(5.4)	-2%

Fiscal 2021 actual gross Taxes of $256.8 million were comparable to the fiscal 2021 Decision of $262.2 million.

6 Amortization Variance Explanations (Schedule 7.0)

This section compares fiscal 2021 actual amortization amounts with the fiscal 2021 Decision.

Table 8 Fiscal 2021 Amortization Variances

		Schedule	F2021			
	($ million)	Reference	Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Amortization of Capital Assets	7.0 L5	904.5	905.6	1.2	0%
2	IPP Capital Leases	7.0 L7	90.1	90.1	-	0%
3	Other Leases	7.0 L8	3.4	4.1	0.6	18%
4	**Subtotal Before Regulatory Accounts**		**998.0**	**999.8**	1.8	0%
5	Deferred Account Additions	7.0 L10	-	(0.3)	(0.3)	0%
6	**Total Gross Amortization**	1.0 L4	**998.0**	**999.5**	1.6	0%

Fiscal 2021 actual gross Amortization of $999.5 million was comparable to the fiscal 2021 Decision amount of $998.0 million.

7 Finance Charges Variance Explanations (Schedule 8.0)

This section compares fiscal 2021 actual finance charges amounts with the fiscal 2021 Decision.

Table 9 Fiscal 2021 Finance Charges Variances

	($ million)	Schedule Reference	F2021 Decision	F2021 Actual	F2021 Diff	F2021 % Diff
			1	2	3=2-1	4=3/1
1	Sinking Fund Income	8.0 L9	(7.7)	(8.9)	(1.2)	15%
2	Long-Term Debt Costs	8.0 L10	851.5	821.5	(29.9)	-4%
3	Short-Term Debt Costs	8.0 L11	69.6	12.4	(57.2)	-82%
4	Interest Capitalized	8.0 L12	(242.6)	(225.9)	16.7	-7%
5	Other (Income) / Loss	8.0 L13	45.1	46.2	1.0	2%
6	IPP Capital Leases	8.0 L14	46.1	46.1	-	0%
7	Accretion - Non-Deferrable	8.0 L15	1.3	1.1	(0.2)	-19%
8	Non-Current PEB	8.0 L16	(42.2)	64.0	106.2	-252%
9	Other Leases	8.0 L17	1.0	1.4	0.4	37%
10	**Subtotal Before Regulatory Accounts**	8.0 L18	**722.0**	**757.8**	35.8	5%
11	Regulatory Account Additions	8.0 L7	21.3	(506.2)	(527.5)	-2477%
12	**Total Gross Finance Charges**	1.0 L5	**743.3**	**251.6**	(491.8)	-66%

Fiscal 2021 actual gross Finance Charges were $491.8 million (or 66 per cent) lower than the fiscal 2021 Decision. This was primarily due to:

- Line 3 - Lower short-term debt costs of $57.2 million due to lower interest rates and lower outstanding short-term debt balance; and
- Line 11 - Lower regulatory account additions of $527.5 million primarily due to an increase in the fair value of future debt hedges as a result of increases in forward interest rates. Gains on future debt hedges are offset by higher interest costs when the future debt is issued.

Partially offset by:

- Line 4 - Lower interest capitalized of $16.7 million due to lower work in progress balances eligible for interest during construction; and

- Line 8 - Higher non-current PEB costs of $106.2 million due to a lower liability discount rate for estimating pension plan income in actuals versus the expected long-term rate of return on pension plan assets used for the fiscal 2021 Decision.

8 Miscellaneous Revenue Variance Explanations (Schedule 15.0)

This section compares fiscal 2021 actual miscellaneous revenue amounts with the fiscal 2021 Decision.

Table 10 Fiscal 2021 Miscellaneous Revenue Variances

		Schedule	F2021			
	($ million)	Reference	Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Amortization of Contributions	15.0 L1+L8+L12	63.1	64.3	1.2	2%
2	External OATT	15.0 L4	15.9	14.1	(1.8)	-11%
3	FortisBC Wheeling Agreement	15.0 L5	5.3	5.2	(0.1)	-1%
4	Secondary Revenue (MMBU, Secondary Use, Other)	15.0 L6+L11+L28	24.2	32.4	8.3	34%
5	Interconnections	15.0 L7	2.2	8.3	6.1	278%
6	Meter/Trans Rents & Power	15.0 L14	14.9	16.4	1.5	10%
7	Smart Metering & Infrastructure	15.0 L15	1.7	1.6	(0.1)	-5%
8	Diversion Net Recoveries	15.0 L16	0.1	0.1	(0.0)	-7%
9	Other Operating Recoveries	15.0 L17	4.6	4.0	(0.6)	-12%
10	Customer Crisis Fund Rider Revenue	15.0 L18	5.3	2.9	(2.4)	-45%
11	Waneta 2/3	15.0 L24	86.9	86.5	(0.4)	0%
12	Corporate General Rents	15.0 L26	3.8	2.8	(1.0)	-25%
13	Late Payment Charges	15.0 L27	8.1	7.8	(0.3)	-4%
14	NTL Supplemental Charge	15.0 L9	2.3	2.4	0.1	3%
15	Other (Income) / Loss	15.0 L2+L19+L29	5.4	7.3	1.9	35%
16	**Subtotal Before Regulatory Accounts**	15.0 L31	**243.6**	**256.1**	12.6	5%
17	Deferral Account Additions	15.0 L33	3.5	5.0	1.5	43%
18	**Total Gross Miscellaneous Revenue**	1.0 L7	**247.0**	**261.1**	14.1	6%

Fiscal 2021 actual gross Miscellaneous Revenue was $14.1 million (or 6 per cent) higher than the fiscal 2021 Decision. This was primarily due to:

- Line 4 - Higher secondary revenue of $8.3 million, primarily due to a number of factors including higher than planned third party projects for shared assets, new customer agreement rate structure and prior year settlements, higher than planned volume of scrap sales, and higher than planned number of house moves and temporary connections; and

- Line 5 - Higher interconnections of $6.1 million, primarily due to higher than planned project revenues from feasibility, system and facilities studies.

9 Summary of Inter-Segment Revenue Variance Explanations (Schedule 3.0)

This section compares fiscal 2021 actual inter-segment revenue amounts with the fiscal 2021 Decision.

Table 11 Fiscal 2021 Inter-Segment Revenue Variances

	($ million)	Schedule Reference	F2021 Decision	Actual	Diff	% Diff
			1	2	3=2-1	4=3/1
1	Powerex - Business Support Allocation	3.0 L1	(2.9)	(2.9)	-	0%
2	Mark to Market Losses (Gains)	3.0 L2	-	90.0	90.0	0%
3	Powerex PTP Charges	3.0 L3	(34.0)	(41.7)	(7.8)	23%
4	BC Hydro PTP Charges	3.0 L4	(35.0)	(30.4)	4.7	-13%
5	**Total Inter-Segment Revenue**	1.0 L8	**(71.9)**	**15.0**	86.9	-121%

Fiscal 2021 actual Inter-Segment revenues were $86.9 million (or 121 per cent) lower than the fiscal 2021 Decision due to higher mark to market losses (line 2 in Table 11 above) of $90.0 million related to transactions under the Transfer Pricing Agreement between BC Hydro and Powerex, and higher point-to-point transmission charges of $3.1 million (line 3 and 4 in Table 11 above), primarily due to an increase in the BC Hydro Open Access Transmission Rate (**OATT**) for fiscal 2020 resulting from the BCUC's Decision on BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (BCUC Order G-246-20). The market to market losses are fully offset in Powerex's net income and have no impact on BC Hydro's consolidated net income or to ratepayers.

10 Capital Expenditures and Capital Additions Variance Explanations

The following tables and discussion provide information on the variances between fiscal 2021 actual capital expenditures and capital additions compared to the fiscal 2021 Decision amounts in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, which was based on a Currency Date of April 1, 2018.

On an annual basis, BC Hydro manages over 900 projects and programs in various phases. Capital expenditures and capital additions in a fiscal year are impacted by a number of factors that may give rise to variances from plan, including project progression and timing, potential changes in scope due to as-found equipment conditions or other factors to meet business requirements, and cost changes due to market conditions or other factors.

In addition, capital projects frequently take several years to complete, and any variances from plan in a particular year may be offset by project expenditures and additions in a subsequent year. The variances provided are against planned annual capital expenditures and additions and are not necessarily reflective of the total project cost. While year-over-year capital project cash flows may vary from annual plan amounts, overall BC Hydro is delivering its projects on budget as reported through BC Hydro's Service Plan Budget to Actual Cost performance metric.

Variances are provided for each main asset category in the tables below. The amounts presented in the tables in this section may not add due to rounding. The actual capital additions information has been presented using the same classification as the planned capital additions as presented in the tables in Chapter 6 of BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.

The COVID-19 pandemic has had an impact on the delivery of BC Hydro's capital investments in fiscal 2021, as projects and programs with construction or field work were required to incorporate new safety protocols which resulted in slowing or delaying aspects of the work. BC Hydro also made decisions to delay work to manage risk to the system in the event of a COVID outbreak. In this report we have identified significant costs and (or) schedule COVID-19 impacts known as of March 31, 2021 to the projects and programs in fiscal 2021 and provided variance explanations in each section below.

In general, explanations are provided where variances between actual and planned amounts are greater than 10 per cent, with a minimum variance threshold of $10 million.

10.1 Overall Capital Expenditures and Additions Variance Explanations

Table 12 and Table 13 below provide BC Hydro's fiscal 2021 capital expenditures and capital additions by main asset category.

Table 12 Fiscal 2021 Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Generation	435.5	300.0	(135.5)	-31%
Site C Project	1,535.5	1,725.0	189.5	12%
Transmission & Distribution	946.8	970.9	24.1	3%
Business Support				
Technology	56.0	90.8	34.8	62%
Properties	55.3	56.0	0.7	1%
Fleet	27.8	31.4	3.6	13%
Business Support - Other	47.2	23.4	(23.9)	-51%
Total Gross	**3,104.1**	**3,197.5**	**93.4**	**3%**
Less: Contribution in Aid	(148.4)	(195.7)	(47.3)	32%
Total	**2,955.7**	**3,001.8**	**46.1**	**2%**

Table 13 Fiscal 2021 Capital Additions Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Generation	297.0	102.6	(194.4)	-65%
Site C Project	189.4	220.9	31.5	17%
Transmission & Distribution	770.3	824.6	54.3	7%
Business Support				
Technology	75.5	164.9	89.4	118%
Properties	55.6	70.9	15.3	27%
Fleet	27.8	26.8	(1.0)	-4%
Business Support - Other	43.5	22.7	(20.8)	-48%
Total Gross	**1,459.1**	**1,433.4**	**(25.7)**	**-2%**
Less: Contribution in Aid	(165.8)	(180.7)	(14.9)	9%
Total	**1,293.2**	**1,252.7**	**(40.5)**	**-3%**

Fiscal 2021 capital expenditures were $93.4 million (or 3 per cent) above the Fiscal 2021 Decision, excluding contribution in aid, primarily because:

- The Site C project was $189.5 million above plan primarily due to acceleration of the main civil work to meet the river diversion milestone date and unplanned COVID-19 pandemic related costs to comply with the COVID-19 safety requirements, as discussed in section 10.6; and
- Technology was $34.8 million above plan due to scope changes and schedule extensions for various projects as discussed in section 10.5.

The increase in capital expenditures above was partially offset by the lower than planned Generation capital expenditures of $135.5 million, primarily due to schedule changes for various projects as discussed in section 10.2.

Fiscal 2021 capital additions were $25.7 million (or 2 per cent) below the fiscal 2021 Decision, excluding contribution in aid, primarily due to the following:

- Generation capital additions were below plan by $194.4 million, primarily due to schedule changes for various projects and delays which shifted the timing of placing certain assets in-service, as discussed in section 10.2.

The decrease in capital additions above was partially offset by the following:

- Technology was above plan by $89.4 million, primarily due to the Supply Chain Applications project (included in the Technology line) as the project in-service date was delayed which shifted the timing from fiscal 2020 to fiscal 2021. This delay was due to a schedule extension for the build and testing activities, as well as the delay in the project go-live training, in response to the COVID-19 pandemic;
- Transmission and Distribution capital additions were above plan by $54.3 million, primarily due to schedule changes for various projects and programs which shifted the timing of placing certain assets in-service, as discussed in section 10.3 and 10.4; and
- The Site C project was $31.5 million above plan primarily because the in-service of the outdoor portion of the Peace Canyon Gas Insulated Switchgear occurred in fiscal 2021 as discussed in section 10.6.

10.2 Generation Capital Expenditures and Additions Variance Explanations

Generation capital expenditures and capital additions in fiscal 2021 are presented in Table 14 and Table 15 below. Results exclude amounts for the Site C project, which are presented separately in section 10.6 below.

Table 14 Fiscal 2021 Generation Capital Expenditures Variances (excluding Site C Project)

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	-	0.8	0.8	100%
Redevelopment / Rehabilitation	-	9.3	9.3	100%
Dam Safety	130.0	55.8	(74.2)	-57%
Sustaining - Other	361.1	222.1	(139.0)	-38%
Total Hydroelectric Generation	491.1	288.0	(203.1)	-41%
Total Non-Integrated Areas	5.0	4.7	(0.3)	-5%
Total Thermal Generation	4.5	7.2	2.7	61%
Less: Portfolio Risk Adjustment	(65.2)	-	65.2	-100%
Total Gross	**435.5**	**300.0**	**(135.5)**	**-31%**
Less: Contribution in Aid	-	-	-	-
Total	**435.5**	**300.0**	**(135.5)**	**-31%**

Table 15 Fiscal 2021 Generation Capital Additions Variances (excluding Site C Project)

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Hydroelectric Generation				
Growth	-	0.6	0.6	100%
Redevelopment / Rehabilitation	-	9.3	9.3	100%
Dam Safety	44.4	34.1	(10.3)	-23%
Sustaining - Other	315.3	57.5	(257.8)	-82%
Total Hydroelectric Generation	359.7	101.4	(258.3)	-72%
Total Non-Integrated Areas	5.8	1.1	(4.7)	-82%
Total Thermal Generation	6.1	0.1	(6.0)	-98%
Less: Portfolio Risk Adjustment	(74.6)	-	74.6	-100%
Total Gross	**297.0**	**102.6**	**(194.4)**	**-65%**
Less: Contribution in Aid	-	-	-	-
Total	**297.0**	**102.6**	**(194.4)**	**-65%**

Growth Capital

Fiscal 2021 capital expenditures and capital additions for Generation Growth Capital were comparable to the fiscal 2021 Decision.

Redevelopment/ Rehabilitation

Fiscal 2021 capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

Dam Safety

Fiscal 2021 capital expenditures were $74.2 million (or 57 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Comox - Puntledge Flow Control Improvements project was $14.9 million below plan because the design was delayed due to greater than anticipated level of design complexity as well as delays of planned site inspections due to the COVID-19 pandemic;
- The Strathcona Upgrade Discharge project was $12.1 million below plan because the design was delayed due to the complexity of gate reliability and seismic withstand requirements;
- The Terzaghi - Spillway Chute Access Improvement project was $10.8 million below plan because of schedule delays in finalizing the Conceptual Design to appropriately balance worker risk, overall cost, and long-term maintenance;
- The W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates project was $9.8 million below plan because the project was delayed due to the addition of scope to design new stoplogs which were required to facilitate the project work;
- The John Hart Dam Seismic Upgrade project was $6.6 million below plan because design activities were completed over a longer time period, with a lower rate of spend than was assumed at the time the Plan was established. More detailed bottom up planning was completed after the Plan was established which resulted in a longer design schedule and a lower rate of spend than was assumed in the Plan;

- The Various Sites - Reservoir Booms Replacement was $5.1 million below plan because the project was initiated later than originally contemplated due to extended project planning and scheduling;
- The W.A.C. Bennett Dam Spillway Gate Upgrade project was $4.1 million below plan because of contractor delays in finalizing a contract and execution of the work;
- The Alouette Improve Headworks & Surge Tower Seismic Stability project was $4.1 million below plan because of a delay in completing the Identification Phase due to prolonged engagement and consultation with Indigenous groups and stakeholders;
- The Alouette - Environmental Flow Discharge Upgrade and LLO Sealing project was $2.2 million below plan because of schedule delays resulting from putting the project on hold for one year due to capital project investigation funding constraints;
- The Duncan Dam Replace Spillway Gates project was $2.2 million below plan because the project Implementation Phase was shifted from calendar year 2020 to calendar year 2022 to allow additional time to perform site investigations that verified the viability of gate life extension through refurbishment as the preferred alternative selection, rather than more costly gate replacements; and
- The Revelstoke Improve Left Bank Slope Stability project was $2.1 million below plan because of construction delays related to the COVID-19 pandemic.

The decrease in capital expenditures outlined above was partially offset by:

- The Revelstoke Replace Downie Slide Instrumentation project was $3.9 million above plan because of higher costs due to unforeseen complexities with accessing the remote site.

The remaining below plan variance of $4.1 million was due to smaller variances on various projects.

Fiscal 2021 capital additions were $10.3 million (or 23 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Terzaghi - Spillway Chute Access Improvement project was $12.0 million below plan because project in-service date was delayed due to the time required to finalize the Conceptual Design to appropriately balance worker risk, overall cost, and long-term maintenance;
- The Revelstoke Improve Left Bank Slope Stability project was $11.5 million below plan because the project in-service date was delayed due to construction delays related to the COVID-19 pandemic;
- The Various Sites - Reservoir Booms Replacement was $5.9 million below plan because the project was initiated later than originally contemplated due to extended planning and scheduling; and
- The MCA - Rehabilitate Vertical Movement Gauges project was $2.9 million below plan because the project in-service date was delayed due to additional time required to complete the final instrumentation connection and calibration.

The decrease in capital additions outlined above was partially offset by:

- The W.A.C. Bennett Dam Spillway Gate Upgrade project was $22.9 million above plan because the project in-service date was delayed from fiscal 2020 to fiscal 2021 due to contractor related delays in finalizing a contract and executing work.

The remaining below plan variance of $0.9 million was due to smaller variances on various projects.

When considering the non-financial impacts of these lower than planned capital expenditures and capital additions arising from schedule delays, particularly with respect to the risk position of BC Hydro's dam fleet, please refer to BC Hydro's response to BCUC Information Request 1.53.4 of the Fiscal 2022 Revenue Requirements Application. In that response, BC Hydro explained that the dynamic and complex "brown field" nature of these projects and the need to balance several competing priorities can sometimes lead to schedule delays. BC Hydro further explained that interim controls – either operational or physical – are put into place to manage any deficiency to a tolerable state until the deficiency can be addressed through the project, so that schedule delays within dam safety projects do not typically have a significant impact on the risk position of BC Hydro's dam fleet.

Sustaining – Other

Fiscal 2021 capital expenditures were $139.0 million (or 38 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior) project was $22.6 million below plan because the fiscal 2021 work program was delayed due to the restaged exterior coating scope of work;
- The Wahleach Recoat Penstock (Interior and Exterior) project was $15.5 million below plan because of a lack of Generator outage availability;
- The G.M. Shrum Upgrade HVAC System project was $15.4 million below plan because of a schedule delay due to rescoping and re-planning of the project;
- The Bridge River 2 - Strip and Recoat Penstock 2 Interior project was $8.6 million below plan because the project work was delayed due to the COVID-19 pandemic;
- The Bridge River 1 Replace Units 1-4 Generators / Governors project was $8.6 million below plan because of a schedule delay due to a procurement

strategy change and due to Directive 29 of the BCUC's Decision on BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (BCUC Order G-246-20) which directed BC Hydro to file a joint application for the Bridge River 1 Replace Units 1-4 Generators / Governors project and the Bridge River Transmission project;

- The Mica Upgrade HVAC System project was $8.5 million below plan because the project schedule and associated cashflow were revised due to design elaboration and constructability reviews during the Definition Phase;
- The Kootenay Canal Modernize Controls project was $7.2 million below plan because of longer than expected Conceptual and Feasibility Design Phases due to resource constraints, design complexities and scope confirmation;
- The Bridge River 2 Upgrade Units 5 and 6 project was $6.3 million below plan due to cost savings during construction;
- The Revelstoke Replace Fire Alarm System project was $4.7 million below plan because the construction start date changed due to an updated construction schedule from the contractor;
- The Jordan - Upgrade Governor & PRV Controls project was $4.7 million below plan because the unit outage required for construction was deferred due to design elaboration and coordination with the Jordan River - Switchyard Upgrade project to minimize outages at Jordan River substation;
- The Seton - Upgrade Unit project was $4.4 million below plan because the project was placed on hold to evaluate alternatives for a hydraulic bypass system;
- The Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior project was $4.4 million below plan because the project construction start date was delayed in order to align outages with the Bridge River 1 Replace Units 1-4 Generators /

Governors project. The scope for the two projects is separate but this approach provides efficiency and improves system water management;

- The Cheakamus Units 1 and 2 Generator Replacement project was $4.1 million below plan because the project was three months ahead of schedule and therefore part of the spend was in the prior fiscal period;
- The Mica - Intake Gantry Crane Refurbishment project was $3.8 million below plan because the project construction start date was deferred due to worker camp capacity restrictions related to the COVID-19 pandemic;
- The G.M. Shrum G1 to 10 Control System Upgrade project was $3.6 million below plan because of a schedule delay due to the COVID-19 pandemic and the Site C river diversion which deferred planned outage work;
- The Ladore - Redevelop Unit 1 project was $3.3 million below plan because the project was cancelled due to re-evaluation of the project need and timing; and
- The Mica Upgrade 600V Circuit Breakers project was $2.9 million below plan because additional time was required to complete the detailed design.

The decrease in capital expenditures outlined above was partially offset by:

- The MCA - Replace Reactors 5RX3 and 5RX4 project was $16.0 million above plan because this was an unplanned emergency replacement of failed equipment.

The remaining below plan variance of $26.4 million was due to smaller variances on many offsetting projects.

Fiscal 2021 capital additions were $257.8 million (or 82 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Bridge River 2 Upgrade Units 7 and 8 project was $54.7 million below plan because the project in-service date was delayed due to an equipment fault resulting in the delay of Unit 7 commissioning;
- The Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior) project was $31.5 million below plan because the project in-service date was delayed due to the restaged exterior coating scope of work;
- The Wahleach Recoat Penstock (Interior and Exterior) project was $26.0 million below plan because the project in-service date was delayed due to the lack of Generator outage availability;
- The Bridge River 2 - Strip and Recoat Penstock 2 Interior project was $16.6 million below plan because the project in-service date was delayed due to crew size restrictions from the COVID-19 pandemic;
- The G.M. Shrum G1 to 10 Control System Upgrade project was $15.4 million below plan because the project in-service date was delayed due to the COVID-19 pandemic and Site C river diversion which deferred planned outage work;
- The Mica Upgrade HVAC System project was $12.6 million below plan because the project in-service date was delayed due to an updated project schedule resulting from design elaboration and progression of project planning activities;
- The Mica Upgrade 600V Circuit Breakers project was $12.0 million below plan because the project in-service date was delayed due to design delays and longer manufacturing lead times than planned;
- The Hugh Keenleyside Replace Service Water Piping project was $8.8 million below plan because the project in-service date was delayed due to reprioritization of capital projects and maintenance work at Hugh Keenleyside in response to COVID-19 impacts;

- The Seven Mile Replace Unit 1-4 Exciter Transformers project was $8.6 million below plan because the project schedule was updated as a result of the design scope elaboration, project planning and early contract engagement in the Definition Phase. The forecast in-service date is updated to fiscal 2022;
- The Cheakamus Replace Units 1 and 2 Turbine Inlet Valves project was $7.3 million below plan because of a schedule delay due to defects in the turbine inlet valves cast bodies that required recasting;
- The Bridge River 2 Upgrade Units 5 and 6 project was $6.5 million below plan because of cost savings during construction and delayed reconciliation of final contractor costs;
- Various - Water License Renewal was $5.3 million below plan because the project in-service date was delayed due to the Comptroller of Water Rights requesting more time to decide on the Water Licence Renewals;
- The Waneta – Sustaining project costs were $5.2 million below plan because the project in-service dates were delayed mainly due to the Unit 3 Life Extension work Definition Phase taking longer than anticipated causing the Implementation Phase to be delayed;
- The G.M. Shrum Draft Tube Maintenance Gates Refurbishment project was $4.5 million below plan because the project in-service date was delayed due to work being delayed by the COVID-19 pandemic;
- The Peace Canyon Draft Tube Maintenance Gates Refurbishment project was $4.4 million below plan because the project in-service date was delayed due to work being delayed by the COVID-19 pandemic;
- The Mica - Recoat Intake Maintenance Gates & Draft Tube Maintenance Gates project was $4.3 million below plan because the project in-service date was delayed due to work being delayed by the COVID-19 pandemic;

- The Alouette Upgrade Station Service project was $4.3 million below plan because the project in-service date was delayed due to an additional switching study and grounding test;
- The Cheakamus Units 1 and 2 Generator Replacement project was $4.2 million below plan because of lower trailing costs due to fewer risks materializing;
- The Mica Upgrade Town Site Building Roofs project was $4.1 million below plan because the project in-service date was delayed due to a work assessment review deferring construction work and worker camp capacity restrictions related to the COVID-19 pandemic; and
- The Peace Canyon Electrical Protection Upgrade project was $4.0 million below plan because the project was delayed by two years in order to move the required outage at Peace Canyon outside of the Site C diversion period.

The remaining below plan variance of $17.5 million was due to smaller variances on many offsetting projects.

Non-Integrated Areas and Diesel and Thermal Generation

Fiscal 2021 capital expenditures and additions for Non-Integrated Areas and Diesel and Thermal Generation were comparable to the fiscal 2021 Decision.

Portfolio Risk Adjustment

The Portfolio Risk Adjustment is meant to account for the uncertainty in the schedule and cost of projects. The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical Project Delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

The Fiscal 2021 Decision Portfolio Risk Adjustment amount was $(65.2) million for capital expenditures and $(74.6) million for capital additions.

10.3 Transmission Capital Expenditures and Additions Variance Explanations

Transmission fiscal 2021 capital expenditures and capital additions are provided in Table 16 and Table 17, below.

Table 16 Fiscal 2021 Transmission Capital Expenditures Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	91.1	38.0	(53.1)	-58%
Bulk System Reinforcement	43.3	(3.5)	(46.8)	-108%
Station Expansion & Modification	22.5	30.6	8.1	36%
Feeder Positions / Section Additions	2.1	0.5	(1.6)	-77%
Generator Interconnections	3.6	4.7	1.1	32%
Transmission Load Interconnection	46.3	51.6	5.3	12%
Total Growth	208.9	121.9	(87.0)	-42%
Transmission Sustain - Stations				
Circuit Breakers	28.2	21.0	(7.2)	-26%
Other Power Equipment	104.6	99.9	(4.7)	-5%
Protection and Control	16.3	11.7	(4.6)	-28%
Stations Auxiliary Equipment	29.8	15.8	(14.0)	-47%
Stations Risk Mitigation	10.0	6.7	(3.3)	-33%
Telecommunications	25.1	18.2	(6.9)	-28%
Total Sustain - Stations	214.0	173.2	(40.8)	-19%
Transmission Sustain - Lines				
Cable Sustainment	8.9	(2.7)	(11.6)	-131%
O/H Lines Life Extension	70.1	62.4	(7.7)	-11%
O/H Lines Performance Improvement	1.4	3.9	2.5	179%
O/H Lines Risk Mitigation	3.6	6.4	2.8	77%
ROW Sustainment	9.8	9.9	0.1	1%
Third Party Requested Transmission Line Relocations	7.8	1.3	(6.5)	-83%
Total Sustain - Lines	101.6	81.1	(20.5)	-20%
Less: Portfolio Risk Adjustment	(39.0)	-	39.0	-100%
Total Gross	**485.5**	**376.3**	**(109.2)**	**-22%**
Less: Contribution in Aid	(14.8)	(9.0)	5.8	-39%
Total	**470.7**	**367.3**	**(103.4)**	**-22%**

Table 17 Fiscal 2021 Transmission Capital Additions Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Transmission Growth				
Regional System Reinforcement	58.2	97.4	39.2	67%
Bulk System Reinforcement	-	0.1	0.1	100%
Station Expansion & Modification	0.5	0.8	0.3	56%
Feeder Positions / Section Additions	0.2	-	(0.2)	-100%
Generator Interconnections	10.3	15.9	5.6	54%
Transmission Load Interconnection	16.1	41.6	25.5	158%
Total Growth	85.3	155.8	70.5	83%
Transmission Sustain - Stations				
Circuit Breakers	11.3	19.0	7.7	68%
Other Power Equipment	50.4	24.1	(26.3)	-52%
Protection and Control	13.1	2.8	(10.3)	-79%
Stations Auxiliary Equipment	26.8	6.9	(19.9)	-74%
Stations Risk Mitigation	20.0	6.4	(13.6)	-68%
Telecommunications	37.4	8.6	(28.8)	-77%
Total Sustain - Stations	159.0	67.8	(91.2)	-57%
Transmission Sustain - Lines				
Cable Sustainment	2.3	(3.4)	(5.7)	-249%
O/H Lines Life Extension	41.8	49.3	7.5	18%
O/H Lines Performance Improvement	1.4	1.7	0.3	22%
O/H Lines Risk Mitigation	10.2	6.1	(4.1)	-40%
ROW Sustainment	9.8	10.8	1.0	11%
Third Party Requested Transmission Line Relocations	9.8	0.5	(9.3)	-95%
Total Sustain - Lines	75.3	65.0	(10.3)	-14%
Less: Portfolio Risk Adjustment	(90.0)	-	90.0	-100%
Total Gross	**229.6**	**288.6**	**59.0**	**26%**
Less: Contribution in Aid	(29.2)	(8.6)	20.6	-71%
Total	**200.4**	**280.0**	**79.6**	**40%**

Transmission Growth - Regional System Reinforcement

Fiscal 2021 capital expenditures were $53.1 million (or 58 per cent) below the fiscal 2021 Decision primarily because:

- The Peace Region Electric Supply (**PRES**) project was $27.9 million below plan primarily because BC Hydro received contributions of $25 million from the Government of Canada which were not accounted for in the fiscal 2021 RRA plan. Project costs were also lower than planned;

- The East Vancouver - Substation Construction project was $9.1 million below plan because the project has been delayed for three years, following the purchase of property for the development of a West End Substation. This purchase allowed BC Hydro to proceed with the preferred project staging (i.e., constructing the West End Substation first, while delaying the construction of the East Vancouver Substation);
- The West Kelowna Transmission and Westbank Upgrade projects were $8.9 million below plan because the Transmission project returned to the Conceptual Design Stage to re-evaluate the existing alternatives and consider new alternatives in response to a higher than anticipated revised cost estimate for the Leading Alternative; and
- The Bridge River Transmission project was $8.5 million below plan because conceptual design was delayed in order to allow additional time to complete the business case and develop a regulatory application in accordance with Directive 29 of the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.

The decrease in capital expenditures outlined above was partially offset by above plan smaller variances of $1.3 million from various projects.

Fiscal 2021 capital additions were $39.2 million (or 67 per cent) above the fiscal 2021 Decision primarily because:

- The PRES project was $43.1 million above plan because the substation assets were placed in service ahead of Plan in fiscal 2021 due to their construction being completed ahead of schedule.

The increase in capital additions outlined above was partially offset by:

- The George Tripp Station Modification project was $2.7 million below plan because the project in-service date was delayed due to longer design duration as a result of resource constraints, and longer construction duration as a result of system constraints impacting the availability of required line outages; and

- $1.2 million smaller below plan variances on various projects.

Transmission Growth – Bulk System Reinforcement

Fiscal 2021 capital expenditures were $46.8 million (or 108 per cent) below the fiscal 2021 Decision primarily because:

- The Peace to Kelly Lake Capacitors project was $41.1 million below plan because the project was cancelled. Based on updated load forecast information, BC Hydro determined that the need for an increase in the transfer capability along the Peace Region to Kelly Lake transmission corridor to deliver power to the load centers in the south of the province could be delayed until after fiscal 2031. The sustainment portion of the project was grouped into a new project – the Peace to Kelly Lake Sustainment Project.

The remaining below plan variance of $5.7 million was due to smaller variances on various projects.

Fiscal 2021 capital additions were comparable to the fiscal 2021 Decision.

Transmission Growth – Transmission Load Interconnection

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $25.5 million (or 158 per cent) above the fiscal 2021 Decision primarily because:

- The UBC Load Increase Stage 2 project was $36.7 million above plan because the project was put into service in fiscal 2021, ahead of the planned fiscal 2022 in-service date as project schedule risks did not materialize and therefore the project schedule contingency was not used.

The increase in capital additions outlined above was partially offset by:

- $11.2 million below plan variances that resulted from various third-party driven customer projects due to the timing of projects being planned and put in-service.

All other line items under Transmission Growth in fiscal 2021 for both capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

Transmission Sustain-Stations

Circuit Breakers

Fiscal 2021 capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

Other Power Equipment

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $26.3 million (or 52 per cent) below the fiscal 2021 Decision. This was primarily due to the following:

- The BR1 T3 & BRT T4A Replacement project was $18.8 million below plan because the T4 portion of the project schedule was delayed during the Identification Phase to allow additional time to complete the alternative analysis and selection. The T3 portion of the project was prioritized and moved to a separate project due to the unplanned failure of BR1 T3; and
- The Peace Region to Kelly Lake - Reactor Replacement (Phase 1) project was $9.3 million below plan because the second reactor installation schedule was delayed due to the COVID-19 pandemic.

The decrease in capital additions above was partially offset by $1.8 million of smaller above plan variances on various projects.

Protection and Control

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $10.3 million (or 79 per cent) below the fiscal 2021 Decision. This was primarily because:

- The SCADA RTU Replacement - Stage 9 project was $3.5 million below plan because the project in-service date was delayed due to project design deliverables completion delays as a result of resources being shifted to the other higher priority work such as Mandatory Reliability Standards (**MRS**) compliance related projects; and
- The SCADA RTU Replacement - Stage 10 project was $3.3 million below plan because the project in-service date was delayed due to project design deliverable completion delays as a result of resources being shifted to the other higher priority work such as MRS compliance related projects.

The remaining below plan variance of $3.5 million was due to smaller variances on various projects.

Stations Auxiliary Equipment

Fiscal 2021 capital expenditures were $14.0 million (or 47 per cent) below the fiscal 2021 Decision primarily due to the following:

- The Joseph Creek (**JOE**) Substation Upgrade project was $5.7 million below plan because project was put on-hold pending the review and finalization of the Wood Pole Substations Strategy during the Identification Phase;
- The Lumby No. 2 - Substation Wood Pole Replacement project was $3.2 million below plan because the project was delayed pending the review and finalization of the Wood Pole Substations Strategy and due to resource constraints; and

- The Station Wood Pole Replacement Program - Chase (**CHS**) Substation project was $1.9 million below plan because the project start was delayed pending the review and finalization of the Wood Pole Substation Strategy.

The remaining variance of $3.2 million was due to smaller below plan variances on various projects.

Fiscal 2021 capital additions were $19.9 million (or 74 per cent) below the fiscal 2021 Decision primarily because:

- The Wood Pole Substation Replacement – Britannia Substation (**BTA**) project was $5.9 million below plan because the construction schedule was delayed due to a prolonged procurement process. A further delay occurred while the project waited for an approved customer outage for the project to resolve final construction deficiencies;
- The Wood Pole Substation Replacement Program - Chase Substation (**CHS**) project was $3.1 million below plan because the project start was delayed pending the review and finalization of the Wood Pole Substation Strategy;
- The Wood Pole Substation Replacement Program - Clinton Substation (**CLN**) project was $2.4 million below plan because the project in-service date was delayed pending the review and finalization of the Wood Pole Substation Strategy;
- The Como Lake (**COK**) Substation Cable Replacement was $1.7 million below plan because the project in-service date was delayed due to resource constraints and station outage constraints. The procurement of power cables was also delayed due to the COVID-19 pandemic; and
- The Fire Risk Program for Stations was $1.3 million below plan because the project in-service date was delayed due to change of scope and work methodology and due to the COVID-19 pandemic.

The remaining variance of $5.5 million was due to smaller below plan variances on various projects.

Station Risk Mitigation

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $13.6 million (or 68 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Oil Spill Containment - F17/F18 (ALZ / MDN) project for the Atchelitz and Meridian Substations was $7.2 million below plan because the project in-service date was delayed due to the COVID-19 pandemic.

The remaining variance of $6.4 million was due to smaller below plan variances on various projects.

Telecommunication

Fiscal 2021 capital expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions were $28.8 million (or 77 per cent) below the fiscal 2021 Decision. This was primarily due to the following:

- The Vancouver Island Radio System project was $21.5 million below plan because the project in-service date was delayed due to issues related to the supply and performance of the telecom equipment. Additional time and effort were required for procurement, testing, standardization of new equipment, and development of new system architecture; and
- The CPM MW Repeater Building Replacement project was $5.1 million below plan because the project in-service date was delayed due to the COVID-19 pandemic and due to Communication, Protection and Control resource constraints.

The decrease in capital additions above was partially offset by:

- The Copper Mountain ice mitigation project was $6.6 million above plan because the in-service date was delayed from fiscal 2020 to fiscal 2021 due to a deficiency that was required to be rectified prior to the project being put in service.

The remaining below plan variance of $8.8 million was due to smaller variances on various projects.

Transmission Sustain-Lines

Cable Sustainment

Fiscal 2021 capital expenditures were $11.6 million (or 131 per cent) below the fiscal 2021 Decision. This was primarily because:

- The Gulf Islands - Transmission Reinforcement was $5.3 million below plan because the project initiation was delayed to allow more time to complete planning activities including the identification and evaluation of additional alternatives; and
- The Asset Retirement Obligation (**ARO**) provision adjustment of ($3.4) million on the 230 kV and 138 kV Submarine Cables was re-evaluated at the fiscal 2021 year-end which resulted in an adjustment reducing the liability by $3.4 million.

The remaining below plan variance of $2.9 million was due to variances on many smaller projects.

Fiscal 2021 capital additions were comparable to the fiscal 2021 Decision.

All other line items under Transmission Sustain-Lines in fiscal 2021 for both capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

Portfolio Risk Adjustment

The Portfolio Risk Adjustment is meant to account for the uncertainty in the schedule and cost of projects. The Portfolio Risk Adjustment amount is calculated using a Monte Carlo simulation. A probability distribution is determined, based on historical Project Delivery performance information. The calculated Portfolio Risk Adjustment amount represents the difference (by fiscal year) between the expected value of the simulated portfolio forecast and the sum of individual project forecasts in the baseline Capital Plan.

The Fiscal 2021 Decision Portfolio Risk Adjustment amount was $(39.0) million in capital expenditures and $(90.0) million in capital additions.

Contribution in Aid

Fiscal 2021 Transmission Contribution in Aid expenditures were comparable to the fiscal 2021 Decision.

Fiscal 2021 Transmission Contribution in Aid additions were $20.6 million (or 71 per cent) below the fiscal 2021 Decision due to timing differences on the completion of customer work and a lower volume of third-party requests for relocations than originally planned.

10.4 Distribution Capital Expenditures and Additions Variance Explanations

Distribution fiscal 2021 actual to Fiscal 2021 Decision capital expenditures and capital additions are provided in Table 18 and Table 19, below.

The distribution system improvement portfolio is primarily comprised of small projects, with the average project size in the $1 million to $2 million range with short duration.

The System Expansion and Improvement portfolio is subject to rapidly changing priorities and the planning processes must be dynamic to respond to the emerging needs on the distribution system. This may result in variances in the timing and selection of projects in the portfolio in a given year.

Table 18 Fiscal 2021 Distribution Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	234.0	315.8	81.8	35%
System Expansion and Improvement	50.0	74.7	24.7	49%
Uneconomic Extension Assistance	0.6	-	(0.6)	-100%
Total Growth	284.6	390.5	105.9	37%
Distributon Sustain				
System Expansion and Improvement	57.2	46.3	(10.9)	-19%
Asset Replacement				
Poles	63.3	48.7	(14.6)	-23%
Overhead Equipment	15.6	30.1	14.5	93%
Underground Equipment	19.4	51.0	31.6	163%
Trouble	18.0	20.5	2.5	14%
Asset Replacement sub-total	116.3	150.3	34.0	29%
Beautification	1.1	4.5	3.4	309%
Electric Vehicle Charging Infrastructure	2.2	2.9	0.7	33%
Total Sustain	176.8	204.1	27.3	15%
Total Gross	**461.4**	**594.6**	**133.2**	**29%**
Less: Contribution in Aid	(133.7)	(186.7)	(53.0)	40%
Total	**327.7**	**407.9**	**80.2**	**24%**

Table 19 Fiscal 2021 Distribution Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Distribution Growth				
Customer Driven	239.3	273.1	33.8	14%
System Expansion and Improvement	104.3	72.9	(31.4)	-30%
Uneconomic Extension Assistance	0.6	0.2	(0.4)	-72%
Total Growth	344.2	346.2	2.0	1%
Distributon Sustain				
System Expansion and Improvement	74.1	52.3	(21.8)	-29%
Asset Replacement				
Poles	64.9	45.9	(19.0)	-29%
Overhead Equipment	15.4	22.1	6.7	44%
Underground Equipment	20.8	44.4	23.6	114%
Trouble	18.0	20.4	2.4	13%
Asset Replacement sub-total	119.1	132.9	13.8	12%
Beautification	1.1	5.1	4.0	365%
Electric Vehicle Charging Infrastructure	2.2	(0.5)	(2.7)	-121%
Total Sustain	196.5	189.8	(6.7)	-3%
Total Gross	**540.7**	**536.0**	**(4.7)**	**-1%**
Less: Contribution in Aid	(136.6)	(172.1)	(35.5)	26%
Total	**404.1**	**363.9**	**(40.2)**	**-10%**

Distribution Growth – Customer Driven

Fiscal 2021 capital expenditures were $81.8 million (or 35 per cent) above the fiscal 2021 Decision due to an increase in distribution customer driven extension activities, meter purchases for secondary connections, the Ministry of Transportation and Infrastructure relocation activities and the required design effort to support these increases. This work is difficult to plan as it is dependent on customer requests and their related timing. The increase in capital expenditures was partially offset by the increase in contributions received, as explained in the Contribution in Aid section below.

Fiscal 2021 capital additions were $33.8 million (or 14 per cent) above the fiscal 2021 Decision primarily due to the increase in capital expenditures as well as the timing of a few major customer projects going in-service in fiscal 2021.

Distribution Growth - System Expansion and Improvement

Growth-driven system expansion and improvement expenditures address existing capacity constraints to meet anticipated customer load growth. The priority of growth-driven system upgrades is influenced by new customer load connections and general load growth from existing customers. This category of expenditures is subject to year over year fluctuations from plan as a result of changes in scope, cost and schedule for projects as well as variances between forecast and actual customer load growth.

Fiscal 2021 capital expenditures were $24.7 million (or 49 per cent) above the fiscal 2021 Decision primarily because:

- The Bringing additional capacity from ARN to Tilbury project was $6.7 million above plan because of increased construction costs and duration mainly due to adverse as-found ground condition areas which resulted in unplanned spend in fiscal 2021;
- The LM-COQ-694 COK Distribution Egress Reinforcement project was $6.5 million above plan because additional time was required to complete the work and there were additional costs for water treatment plants and dewatering;
- The LM-FVW-701 - New KI2 duct bank egress & Feeder project was $5.8 million above plan due to civil cost escalations, extra cable costs, nighttime work due to a request from the Ministry of Transportation and Infrastructure and dewatering costs;
- The New MUR Circuit to Offload MUR 12F66 and MUR 12F84 project was $5.2 million above plan due to additional scope and a delay in the in-service date;

- The System Improvement Minor Capital Program was $4.4 million above plan due to higher volumes of work driven by new customer connections and general load growth from existing customers;
- The FV-CHK-018 New ALZ 25F82 to offload WAH 25F51 project was $2.7 million above plan because the project was expected to be completed in fiscal 2020. The project was delayed to fiscal 2021 due to additional reconductoring and underground work added to the project scope; and
- The HPN 12F54, 72Q, 73Q, and 324 Voltage Conversion project was $2.7 million above plan because work was delayed to fiscal 2021 by the high volume of customer vault negotiations required and slower than expected permitting for underground work;

The increase in capital expenditures above was partially offset by:

- The Three new MLE Feeders to offload CBN project was $7.3 million below plan because the project completion date was delayed due to the timing of MLE feeder positions being available in the substation which is currently being upgraded in a separate project;
- The Two Fleetwood feeders to offload McLellan project was $6.9 million below plan because the project completion date was delayed due to scope changes;

The remaining above plan variance of $4.9 million was due to smaller variances on various projects.

Fiscal 2021 capital additions were $31.4 million (or 30 per cent) below the fiscal 2021 Decision primarily due to the following:

- The Two Fleetwood feeders to offload McLellan project was $13.2 million below plan because the project completion date was delayed due to scope changes;

- The HPN 77Q, 323, 326 and 327 Voltage Conversion Preparation project was $10.0 million below plan because the project completion date was delayed due to a high volume of customer vault negotiations;
- The Three new MLE Feeders to offload CBN project was $8.7 million below plan because the project completion date was delayed due to the timing of MLE feeder positions being available in the substation which is currently being upgraded in a separate project;
- The 12F51 & 53 HPN Voltage Conversion project was $8.0 million below plan because the project completion date was delayed due to customer equipment procurement delays;
- The New MUR Circuit to Offload MUR 12F66 and MUR 12F84 project was $7.3 million below plan because the project completion date was delayed due to additional scope for a duct bank;
- The Voltage Conversion Prep for RIM Substation project was $7.3 million below plan because the project completion date was delayed due to removal of scope from the project;
- The Lower Mainland - George Dickie Feeder Voltage Conversion project was $5.0 million below plan because the project completion date was delayed to accommodate the customers’ conversion schedules. There were also fewer poles replaced than planned; and
- The LM-VAN-076 West End Voltage Conversion project was $3.4 million below plan because the project completion date was delayed due to delays in customer vault negotiations.

The decrease in capital additions above was partially offset by:

- The Bringing additional capacity from ARN to Tilbury project was $28.5 million above plan because the project in-service date was delayed from fiscal 2020 to fiscal 2021 due to increased construction duration mainly due to as-found ground conditions in the area; and

- Above plan variances of $3.0 million from various smaller projects.

Uneconomic Extension Assistance

Fiscal 2021 capital expenditures and capital additions were comparable to the Fiscal 2021 Decision.

Distribution Sustain - System Expansion and Improvement

System expansion and improvement sustaining expenditures maintain and improve distribution system performance including addressing customer reliability, safety risks and meeting regulatory, legal or environmental requirements.

Fiscal 2021 capital expenditures were $10.9 million (or 19 per cent) below the Fiscal 2021 Decision primarily because:

- The Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown was $10.6 million below plan because of delays in the City of Vancouver’s approval of designs.

The remaining below plan variance of $0.3 million was due to smaller variances on various projects.

Fiscal 2021 capital additions were $21.8 million (or 29 per cent) below the Fiscal 2021 Decision primarily due to the following:

- The Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown was $11.6 million below plan because the in-service date was delayed to fiscal 2022 mainly due to delay related to the City of Vancouver’s approval of designs;

- The New DGR Circuit for Customer Vaults at Pacific and Howe project was $5.5 million below plan because the project in-service date was delayed due to the COVID-19 pandemic and City of Vancouver traffic permit restrictions;
- The New DGR Circuit for Customer Vaults at Drake and Howe project was $8.8 million below plan because the project in-service date was delayed as the construction schedule for the project was sequenced to be after the New DGR Circuit for Customer Vaults at Pacific and Howe project, which was delayed, as explained above;
- The Merritt - New Merritt 25F114 Douglas Lake Ranch project was $2.3 million below plan because of a delay in the resolution of property access issues; and
- The Primary Metering Kit Replacement project was $2.2 million below plan because the project in-service date was delayed as a result of procurement delays for PCB metering kits.

The decrease in capital additions above was partially offset by:

- The H-Frame Elimination - Chinatown project was $8.4 million above plan because the project was placed in-service in fiscal 2021 instead of fiscal 2020, as originally forecasted; and
- Above plan variances of $0.2 million from various smaller projects.

Distribution Sustain - Asset Replacement

Distribution Asset replacements are planned and adjusted as an entire program based on inspections and changes in the prioritization of different assets.

Fiscal 2021 capital expenditures were $34 million (or 29 per cent) above the fiscal 2021 Decision primarily due to higher volumes of underground and overhead replacements; partially offset by lower volume of joint-use pole replacements and true-up of the third-party recoveries received.

Fiscal 2021 capital additions were $13.8 million (or 12 per cent) above the fiscal 2021 Decision primarily due to higher volumes of underground replacements and overhead replacements.

Contribution in Aid

Fiscal 2021 Distribution Contribution in Aid expenditures were $53.0 million (or 40 per cent) above the fiscal 2021 Decision primarily due to higher than planned distribution customer driven extension activities.

Fiscal 2021 Distribution Contribution in Aid additions were $35.5 million (or 26 per cent) above fiscal 2021 Decision primarily due to the increase in capital expenditures as explained above.

10.5 Business Support Capital Expenditures and Additions Variance Explanations

Business Support includes capital expenditures and additions for Technology, Properties, Fleet, and Other categories. Business Support Fiscal 2021 capital expenditures and capital additions are presented by category in the tables below.

Table 20 Fiscal 2021 Business Support Capital Expenditures Variances

($ million)	F2021			
	Decision	**Actual**	**Diff**	**% Diff**
	1	2	3=2-1	4=3/1
Business Support				
Technology and other Technology (Tables 21 and 27)	56.0	90.8	34.8	62%
Properties	55.3	56.0	0.7	1%
Fleet	27.8	31.4	3.6	13%
Business Support - Other	47.2	23.4	(23.9)	3%
Total	**186.3**	**201.6**	**15.3**	**8%**

Table 21 Fiscal 2021 Business Support Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support				
Technology and other Technology (Tables 22 and 28)	75.5	164.9	89.4	118%
Properties	55.6	70.9	15.3	27%
Fleet	27.8	26.8	(1.0)	-4%
Business Support - Other	43.5	22.7	(20.8)	-48%
Total	**202.4**	**285.3**	**82.9**	**41%**

Technology

Table 22 Fiscal 2021 Technology Capital Expenditures Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	55.5	89.6	34.1	61%
Total	**55.5**	**89.6**	**34.1**	**61%**

Table 23 Fiscal 2021 Technology Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Technology	75.0	164.9	89.9	120%
Total	**75.0**	**164.9**	**89.9**	**120%**

Fiscal 2021 capital expenditures were $34.1 million (or 61 per cent) above the fiscal 2021 Decision. This was primarily due to the following:

- The Supply Chain Applications project was $7.9 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The schedule was extended to complete the build and testing activities, due to a combination of increased project complexity and the COVID-19 pandemic. The COVID-19 pandemic also resulted in additional cost to rework and deliver the training remotely;

- The Information Technology Service Management Toolset project was $4.3 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The impact to schedule and costs was due to additional project design considerations and complexity, as well as a change to the accounting treatment for license purchases;
- The Windows 10 PC OS Upgrade project was $4.2 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The impact to schedule and cost was primarily due to additional deployment activities and security controls;
- The Microsoft Exchange 2010 to 2016 Upgrade project was $4.1 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The impact to schedule and cost was due to BC Hydro's decision to leverage Microsoft's cloud solution for its email application following a change to *BC's Freedom of Information and Protection of Privacy Act*;
- The Energy Management System 3.3 Upgrade project was $3.0 million above plan because the project was not in the fiscal 2021 Decision. BC Hydro reprioritized this project to begin in the test period, in order to maintain operational stability and continue to maintain compliance with MRS requirements;
- The Customer Connect Web-Enablement Project was $2.4 million above plan because the project was planned for completion in fiscal 2020 with no planned fiscal 2021 expenditures. The schedule was extended due to project complexity and resource availability issues;
- The PowerOn 4.3 Upgrade project was $2.3 million above plan because the project was not in the fiscal 2021 Decision. BC Hydro reprioritized this project to

begin in the test period, in order to maintain operational stability and vendor support.

The remaining above plan variance of $5.9 million was due to variances on many smaller projects.

Fiscal 2021 capital additions were $89.9 million (or 120 per cent) above the fiscal 2021 Decision. This was primarily because:

- The Supply Chain Applications project was $67.5 million above plan primarily due to the in-service date being delayed to fiscal 2021 as a result of a schedule extension for the build and testing activities as well as a delay in the project go-live training due to the COVID-19 pandemic.

The remaining above plan variance of $22.4 million was due to the portfolio adjustment of ($10.5) million in the Fiscal 2021 Plan, and variances of $11.9 million from various smaller projects.

Properties

Table 24 Fiscal 2021 Properties Capital Expenditures Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Building Development	39.7	14.4	(25.3)	-64%
Building Improvements and Others	15.6	41.6	26.0	167%
Total	**55.3**	**56.0**	**0.7**	1%

Table 25 Fiscal 2021 Properties Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Building Development	40.0	23.5	(16.5)	-41%
Building Improvements and Others	15.6	47.4	31.8	204%
Total	**55.6**	**70.9**	15.3	27%

BC Hydro's approach is to manage the Properties' Building Improvements projects and Building Development projects as a combined Building Projects portfolio to meet the annual plan. As some projects are delayed, others are advanced, based on changing priorities which may include asset condition or operational requirements.

Fiscal 2021 capital expenditures for Properties' Building Projects were comparable to the fiscal 2021 Decision.

Fiscal 2021 capital additions for Properties' Building Projects were $15.3 million (or 27 per cent) above the fiscal 2021 Decision. This is primarily because of the following:

- A reprioritization of Building Improvement projects within the portfolio resulted in $31.8 million of additions above Plan, reflecting the shorter time for these projects to come into service as compared to the larger Building Development projects;
- Long Beach Field Building Redevelopment project was $8.7 million above Plan due to the in-service date moving to fiscal 2021 due to delays in obtaining two building permits; and
- Materials Management Building Redevelopment project was $2.4 million above Plan because the as-found conditions on the renovation part of this project resulted in additional permitting and construction costs.

The increase in capital additions above was partially offset by:

- The Chilliwack Facility Building Redevelopment project was $28.2 million lower than Plan as it was delayed due to the challenges in acquiring suitable land for the new field office.

The remaining above plan variance of $0.6 million was due to smaller variances on various projects.

Fleet

Table 26 Fiscal 2021 Fleet Capital Expenditures Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Fleet	27.8	31.4	3.6	13%
Total	**27.8**	**31.4**	**3.6**	**13%**

Table 27 Fiscal 2021 Fleet Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Fleet	27.8	26.8	(1.0)	-4%
Total	**27.8**	**26.8**	**(1.0)**	**-4%**

Fiscal 2021 capital expenditures and capital additions for Fleet were comparable to the fiscal 2021 Decision.

Business Support - Other and Other Technology

Table 28 Fiscal 2021 Business Support –Other and Other Technology Capital Expenditures Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support - Other	47.2	23.4	(23.9)	-51%
Other Technology	0.5	1.2	0.7	-60%
Total	**47.7**	**24.6**	**(23.2)**	**-49%**

Table 29 Fiscal 2021 Business Support –Other and Other Technology Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Business Support - Other	43.5	22.7	(20.8)	-48%
Other Technology	0.5	-	(0.5)	-100%
Total	**44.0**	**22.7**	**(21.3)**	**-48%**

Business Support - Other

Business Support – Other is comprised of capital expenditures such as security equipment, field tools and minor equipment.

Fiscal 2021 capital expenditures for Business Support - Other were $23.9 million (or 51 per cent) below the Fiscal 2021 Decision primarily because:

- The Squamish Area Reinforcement Property Acquisition project (Project B in Appendix I of the F2020-F2021 RRA) was $10.4 million below plan because the project was cancelled. The decision was based on an updated load forecast, and it was determined that the additional capacity in the area will not be required until approximately 2040;
- The Oil Management Department Tank Farm Upgrade was $6.2 million below plan because of the scale and complexity of the design work resulting in delays and a revised project schedule; and
- The Learning & Development – Energized Training Substation was $6.0 million below plan because the project was cancelled due to shifting priorities and uncertainty with regard to the site location.

The remaining below plan variance of $1.3 million was due to variances on various smaller projects.

Fiscal 2021 capital additions for Business Support - Other were $20.8 million (or 48 per cent) below the fiscal 2021 Decision primarily because:

- The Squamish Area Reinforcement Property Acquisition project (Project B in Appendix I of the F2020-F2021 RRA) was $10.4 million below plan because the project was cancelled, as explained above; and
- The Oil Management Department Tank Farm Upgrade was $8.5 million below plan because the project was delayed due to a revised project schedule.

The remaining below plan variance of $1.9 million was due to variances on various smaller projects.

Other Technology

Fiscal 2021 capital expenditures and capital additions were comparable to the fiscal 2021 Decision.

10.6 Site C Project Capital Expenditures and Additions Variance Explanations

Site C Project fiscal 2021 capital expenditures and capital additions are presented in the tables below.

Table 30 Fiscal 2021 Site C Project Capital Expenditures Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Total Site C	**1,535.5**	**1,725.0**	**189.5**	**12%**

Table 31 Fiscal 2021 Site C Project Capital Additions Variances

($ million)	F2021			
	Decision	Actual	Diff	% Diff
	1	2	3=2-1	4=3/1
Total Site C	**189.4**	**220.9**	**31.5**	17%

Fiscal 2021 capital expenditures were $189.5 million (or 12 per cent) above the fiscal 2021 Decision. Variances were primarily due to:

- Unplanned COVID-19 monthly premiums related to contractor costs to comply with COVID-19 safety requirements;
- Acceleration of main civil work to meet river diversion milestone date;
- Higher than planned costs for highway re-alignment and quarry work; and

- Reservoir clearing expenditures originally planned for fiscal 2020 that were incurred in fiscal 2021.

These were partially offset by a slowdown of generating and spillway work to essential work due to the COVID-19 pandemic earlier in the fiscal year and the timing of property acquisitions.

Further detail on the reasons for these variances are provided in BC Hydro's Site C quarterly progress reports to the BCUC.

Fiscal 2021 capital additions were $31.5 million (or 17 per cent) above the fiscal 2021 Decision primarily due to:

- In-service of the outdoor portion of the Peace Canyon Gas-Insulated Switchgear (part of the Transmission-related assets) originally planned for fiscal 2020 that occurred in fiscal 2021; and
- Higher than planned costs for the first transmission line that was placed in-service in fiscal 2021.

11 Capital Projects and Programs: First Full Funding Amount vs Estimate at Completion

In compliance with BCUC Order No. G-313-19,[3] Table 32 below provides a comparison of the First Full Funding (**FFF**) amount and estimate at completion (**EAC**) for all projects and programs of projects that meet the following criteria:

- Achieved final in-service date between April 1, 2020 and March 31, 2021; or final in-service date achieved prior to this fiscal year and where the remaining capital expenditures have increased 25 per cent or more and a minimum

[3] BCUC Order G-313-19 from the Review of the Regulatory Oversight of Capital Expenditures and Projects proceedings, page 27, "The final, actual cost for completed capital projects and programs above a materiality threshold."

amount of $0.5 million compared to the estimated remaining capital expenditures when previously reported;[4] and

- Met a materiality threshold of total capital expenditures of at least $20 million for Power System and Building projects and programs, and $10 million for Technology projects and programs. These align with the thresholds for inclusion in Appendix J in future revenue requirements applications; and
- Were not recurring projects and programs that were financially authorized at a group, program or other aggregated level. This ensures consistency with the information provided in the Attachment to Section 7.

[4] The increase of 25 per cent and a minimum amount of $0.5 million compared to amounts previously reported criteria will be used going forward as this is the first time providing this report.

Table 32 includes the variance between the EAC[5] and the FFF[6] amount and provides a brief explanation for any variance greater than or equal to 10 per cent.

Table 32 Projects and Programs with Final In-Service Dates between April 1, 2020 to March 31, 2021

($ million)

A	B			C	D	E	F		G	H	I	J	K	
Planning ID	Name of Project	BCUC Application Reference -if applicable (Note 1)	F20-F21 RRA Appendix J Reference	Actual In-Service Date (Note 2)	Financially Closed (Note 3)	First Full Funding Amount (Note 4)	Appendix I Authorized Amount (Note 5)	BCUC Application Approved Amount (Note 1)	LTD Costs (Note 6)	Estimate At Completion (Note 7)	Variance [H-E]	Diff (%) [I/E]	Variance Explanation (>=10 percent)	BCUC Application Progress Reports Reference (Note 1)
94003	UBC Load Increase Stage 2	N/A	N/A	F2021	N	51.6	55.2	N/A	49.8	55.0	3.4	7%		N/A
92525	Fort St. John and Taylor Electric Supply	N/A	Page 67	F2021	N	46.6	53.1	N/A	50.9	52.0	5.4	12%	A	N/A
G000656	W.A.C. Bennett Dam Spillway Gate Upgrade	N/A	Page 5	F2021	N	42.5	47.5	N/A	31.1	35.1	(7.4)	-17%	B	N/A
900749	Bringing additional capacity from ARN to Tilbury (FV-FVW-057)	N/A	N/A	F2021	N	22.0	23.7	N/A	29.7	30.1	8.1	37%	C	N/A
T001127	Supply Chain Applications	N/A	Page 121	F2021	N	61.1	-	N/A	67.5	69.0	7.9	13%	D	N/A
YT-00708	ITSM Tool	N/A	N/A	F2021	N	1.7	-	N/A	17.4	17.4	15.7	924%	E	N/A

Note 1	BCUC Application refers to CPCN or Section 44.2 Applications
Note 2	Actual in-service date refers to the final project in-service date achieved
Note 3	Financally closed is when the project has completed all project closing procedures, no additional incremental costs are expected, and project has been closed in the financial system
Note 4	First Full Funding refers to the total capital cost of the project (excluding project reserve) when it was first approved for full Implementation Phase by BC Hydro
Note 5	Authorized Amount refers to the total capital cost of the project, including project reserve, included in the F20-21 RRA Appendix I
Note 6	LTD costs refer to the life-to-date capital costs as of March 31, 2021
Note 7	Estimate at Completion refers to the forecasted capital cost when the project is expected to be financially closed

Note A: The Fort St. John and Taylor Electric Supply project was $5.4 million (or 12 per cent) above plan because the substation civil construction costs and general site costs were higher than the estimate.

Note B: The W.A.C. Bennett Dam Spillway Gate Upgrade project was $7.4 million (or 17 per cent) below plan because the project team worked with the Design-Build contractor to re-plan and optimize construction work which reduced on-site duration and costs.

5 The estimate at completion (**EAC**) is the forecast of capital expenditures for the project or program at financial close. It includes the actual capital cost of the project or program at the in-service date plus any estimated trailing costs to address deficiencies or to otherwise complete the project or program and achieve financial close.

6 The First Full Funding (**FFF**) amount includes actual capital expenditures incurred during the Identification and Definition Phases plus the estimate of capital expenditures for the Implementation Phase approved before the Implementation Phase. Approval of First Full Funding is required to start the Implementation Phase.

Note C: The Bringing additional capacity from ARN to Tilbury project was $8.1 million (or 37 per cent) above plan because the work methodology was changed for a portion of the civil construction which led to higher cost than the estimate.

Note D: The Supply Chain Applications project was $7.9 million (or 13 per cent) above plan because there were project schedule extensions and additional costs associated with the build and testing activities due to a combination of increased project complexity and the COVID-19 pandemic. The COVID-19 pandemic also resulted in additional cost to re-work and deliver the training remotely.

Note E: The Information Technology Service Management Toolset (**ITSM**) project was $15.7 million (or 924 per cent) above plan because the prepaid and future software subscription license costs, which were originally expected to be operating costs, were determined to be eligible for capitalization. There were also cost increases due to project complexity and additional design considerations.

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Attachment 2 to Section 6

Financial Schedules

1 Financial Schedules[1]

[1] These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (**IFRS**) as issued by the International Accounting Standards Board (**IASB**).

Consolidated Statement of Operations
($ million)

Line		Column Reference	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	REVENUES				
	Domestic				
1	Residential	14.0 L12	2,140.4	2,210.2	69.8
2	Light industrial and commercial	14.0 L13	1,905.9	1,830.4	(75.6)
3	Large industrial (includes LNG revenues)	14.0 L14+L20	852.2	761.7	(90.5)
4	Other energy sales	14.0 L15:L18+L21	153.0	118.2	(34.8)
5	Seattle City Light	14.0 L19	35.9	30.0	(5.9)
6	Revenue from Deferral Rider	14.0 L23	0.0	0.0	0.0
7	Miscellaneous	15.0 L34	247.0	261.1	14.1
8	Subtotal		5,334.5	5,211.5	(123.0)
9	Intersegment revenues	3.0 L5	71.9	(15.0)	(86.9)
10	**TOTAL REVENUES**	L8+L9	**5,406.4**	**5,196.5**	**(209.9)**
	EXPENSES				
11	Domestic energy costs	1.0 L1	1,666.5	1,522.4	(144.1)
12	Operating costs	1.0 L2	1,230.8	1,292.4	61.7
13	Depreciation and amortization	1.0 L4	998.0	999.5	1.6
14	Taxes	1.0 L3	262.2	256.8	(5.4)
15	Finance charges	1.0 L5	743.3	251.6	(491.8)
16	Subtotal	L11:L15	4,900.7	4,322.7	(578.0)
17	**DOMESTIC INCOME (LOSS) BEFORE TRANSFER**	L10-L18	**505.7**	**873.8**	**368.1**
18	**POWEREX NET INCOME**	1.0 L17	**176.3**	**386.4**	**210.2**
19	**POWERTECH NET INCOME (LOSS)**	1.0 L18	**3.7**	**(0.9)**	**(4.6)**
20	**TOTAL INCOME (LOSS) BEFORE TRANSFER**	L17:L19	**685.6**	**1,259.3**	**573.7**
21	Heritage Deferral Account	2.1 L3:L6	225.6	364.9	139.3
22	Non-Heritage Deferral Account	2.1 L10:L15	111.3	(358.2)	(469.4)
23	Trade Income Deferral Account	2.1 L19:L22	107.9	(52.9)	(160.8)
24	Load Variance	2.1 L26:L30	(213.9)	109.6	323.5
25	Biomass Energy Program Variance	2.1 L34:L39	-	(14.3)	(14.3)
26	Demand-Side Management Reg. Account	2.2 L3:L6	(8.7)	(25.4)	(16.7)
27	First Nation Costs Regulatory Account	2.2 L10:L13	(15.8)	(15.6)	0.3
28	First Nation Settlement Provisions Reg. Acct.	2.2 L17:L19	4.9	5.9	0.9
29	Site C Regulatory Account	2.2 L23:L25	16.5	15.0	(1.6)
30	Foreign Exchange Gains/Losses Reg. Account	2.2 L29:L30	(1.0)	(10.8)	(9.8)
31	Pre-1996 Customer Contributions Reg. Acct.	2.2 L34	(5.1)	(5.1)	-
32	Storm Restoration Regulatory Account	2.2 L38:L41	(29.0)	(43.7)	(14.7)
33	Capital Project Investigation Costs Reg. Acct.	2.2 L45	(5.2)	(5.2)	0.0
34	Amortization of Capital Additions Reg. Acct.	2.2 L49:L51	(9.2)	(9.3)	(0.0)
35	Total Finance Charges Regulatory Account	2.2 L55:L56	(10.1)	(71.8)	(61.7)
36	Smart Metering and Infrastructure Reg. Acct.	2.2 L60:L64	(21.7)	(22.4)	(0.7)
37	Non-Current Pension Costs Reg. Account	2.2 L69:L73	(51.4)	60.2	111.6
38	Environmental Provisions Regulatory Account	2.2 L77:L82	(40.0)	16.0	56.0
39	Rock Bay Remediation Regulatory Account	2.2 L86:L88	10.3	10.2	(0.1)
40	IFRS Property Plant & Equipment Reg. Account	2.2 L92:L93	(8.6)	(8.6)	(0.0)
41	IFRS Pension Regulatory Account	2.2 L97	(38.2)	(38.2)	0.0
42	Remediation Regulatory Account	2.2 L101:L104	15.4	7.8	(7.6)
43	Real Property Sales Regulatory Account	2.2 L108:L110	1.4	(9.5)	(10.9)
44	Debt Management Regulatory Account	2.2 L114:L115	12.4	(504.2)	(516.6)
45	Dismantling Costs Regulatory Account	2.2 L119:L121	(24.1)	(28.4)	(4.2)
46	PEB Current Pension Regulatory Account	2.2 L126:L129	0.9	(5.0)	(5.8)
47	Customer Crisis Fund Regulatory Account	2.2 L133:L137	(0.4)	39.1	39.5
48	Mining Customer Payment Plan	2.2 L141:L144	-	7.3	7.3
49	Project Write-off Costs	2.2 L148:L150	-	16.7	16.7
50	Electric Vehicle Costs	2.2 L154:L158	2.6	4.4	1.8
51	**TOTAL TRANSFER TO/(FROM) DEFERRAL**	1.0 L12+L16	**26.4**	**(571.8)**	**(598.2)**
52	**TOTAL NET INCOME**	L20+L51	**712.0**	**687.5**	**(24.5)**

Revenue Requirements Summary
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
1	**Cost of Energy**		4.0 L33	1,666.5	1,522.4	(144.0)
2	**Operating Costs**		5.0 L51	1,230.8	1,292.4	61.7
3	**Taxes**		6.0 L20	262.2	256.8	(5.4)
4	**Amortization**		7.0 L12	998.0	999.5	1.6
5	**Finance Charges**		8.0 L1	743.3	251.6	(491.8)
6	**Return on Equity**		9.0 L12	712.0	687.5	(24.5)
7	**Miscellaneous Revenue**		15.0 L34	(247.0)	(261.1)	(14.1)
8	**Inter-Segment Revenue**		3.0 L5	(71.9)	15.0	86.9
	Deferral Accounts					
9	Deferral Account Additions		2.1 L47	3.5	393.3	389.8
10	Interest on Deferral Accounts		2.1 L48	4.0	9.0	5.0
11	Deferral Account Recoveries		2.1 L49	(238.3)	(451.4)	(213.1)
12	Total			(230.8)	(49.1)	181.7
	Other Regulatory Accounts					
13	Regulatory Account Additions		2.2 L186	(144.7)	381.2	525.9
14	Interest on Regulatory Accounts		2.2 L187	(30.0)	(27.2)	2.8
15	Regulatory Account Recoveries		2.2 L188	379.2	266.9	(112.3)
16	Total			204.4	620.9	416.5
	Subsidiary Net Income					
17	Powerex Trade Income			**(176.3)**	**(386.4)**	(210.2)
18	Powertech Net Income			**(3.7)**	**0.9**	4.6
19	Total			(179.9)	(385.5)	(205.6)
20	**Less Other Utilities Revenue**		14.0 L19	(35.9)	(30.0)	5.9
21	**Less Liquefied Natural Gas Revenue**		14.0 L20	0.0	0.0	0.0
22	**Less Deferral Account Rate Rider**		14.0 L23	0.0	(0.0)	(0.0)
23	**Total Rate Revenue Requirement**			5,051.6	4,920.4	(131.1)

BC Hydro Schedule 2.1
F21 actual RRA Page 2

Deferral Accounts
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Heritage Deferral Account					
1	Beginning of Year			(225.6)	(300.1)	(74.5)
2	Adjustment to Opening Balance			0.0	0.0	0.0
3	Additions		Line 53	0.0	77.8	77.8
4	Additions - F20 Compliance				60.6	
5	Interest			(4.0)	(3.0)	0.9
6	Recovery			229.5	229.5	0.0
7	End of Year			0.0	64.8	64.8
	Non-Heritage Deferral Account					
8	Beginning of Year			(111.3)	204.7	316.0
9	Adjustment to Opening Balance			0.0	0.0	0.0
10	Transfer to Load Variance				0.0	0.0
11	Additions		Line 54	0.0	(112.7)	(112.7)
12	Additions - F20 Compliance				(351.6)	(351.6)
13	Additions - Waneta 2/3		15.0 L33	(3.5)	(5.0)	(1.5)
14	Interest			(2.1)	(5.7)	(3.6)
15	Recovery			116.8	116.8	0.0
16	End of Year			(0.0)	(153.4)	(153.4)
	Trade Income Deferral Account					
17	Beginning of Year			(107.9)	(173.7)	(65.8)
18	Adjustment to Opening Balance			0.0	(0.0)	(0.0)
19	Additions		Line 55	0.0	(210.2)	(210.2)
20	Additions - F20 Compliance				55.7	55.7
21	Interest			(1.9)	(3.5)	(1.6)
22	Recovery			109.8	105.1	(4.7)
23	End of Year			(0.0)	(226.7)	(226.7)
	Load Variance					
24	Beginning of Year			214.0	0.0	(214.0)
25	Adjustment to Opening Balance			0.0	0.0	0.0
26	Transfer from NHDA				0.0	
27	Additions		Line 56	0.0	85.8	85.8
28	Additions - F20 Compliance		Line 56		20.3	20.3
29	Interest			3.9	3.5	(0.4)
30	Recovery			(217.8)	0.0	217.8
31	End of Year			0.0	109.6	109.6
	Biomass Energy Program Variance					
32	Beginning of Year			0.0	0.0	0.0
33	Adjustment to Opening Balance			0.0	0.0	0.0
34	Additions - Cost of Energy		Line 57	0.0	(14.7)	(14.7)
35	Additions - Revenue		Line 58	0.0	1.7	1.7
36	Additions - COE (F20 Compliance)		Line 57		(4.3)	(4.3)
37	Additions - Revenue (F20 Compliance)		Line 58		3.2	3.2
38	Interest			0.0	(0.3)	(0.3)
39	Recovery			0.0	0.0	0.0
40	End of Year			0.0	(14.3)	(14.3)
	End of Year Balances					
41	Heritage		Line 7	0.0	64.8	64.8
42	Non-Heritage		Line 16	(0.0)	(153.4)	(153.4)
43	Trade Income		Line 23	(0.0)	(226.7)	(226.7)
44	Load Variance		Line 31	0.0	109.6	109.6
45	Biomass Energy Program Variance		Line 40	0.0	(14.3)	(14.3)
46	Total			0.0	(220.0)	(220.0)

Deferral Accounts
($ million)

Line		Reference Column	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	Summary				
47	Deferral Account Additions		(3.5)	(393.3)	(389.8)
48	Interest on Deferral Accounts		(4.0)	(9.0)	(5.0)
49	Deferral Account Recoveries		238.3	451.4	213.1
50	Adjustment to Opening Balance	L2+L9+L18	0.0	(0.0)	(0.0)
51	Deferral Account Net Transfers		230.8	49.1	(181.7)
52	**Interest Rate**	8.0 L24	3.73%	3.38%	(0.35%)
	Summary of Items Subject to Deferral				
53	Cost of Heritage Energy	4.0 L44	219.0	296.9	77.8
54	Cost of Non-Heritage Energy	4.0 L57	1,370.7	1,258.0	(112.7)
55	Trade Income	1.0 L17	(176.3)	(386.4)	(210.2)
56	Load Variance	14.0 L29	(5,036.3)	(4,950.5)	85.8
57	Biomass Energy Program Variance - COE	4.0 L58	80.7	66.0	(14.7)
58	Biomass Energy Program Variance - Revenue	14.0 L30	(15.2)	(13.5)	1.7

BC Hydro
F21 actual RRA
Other Regulatory Accounts
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Demand-Side Management					
1	Beginning of Year			920.3	906.6	(13.7)
2	Adjustment to Opening Balance			0.0	0.0	0.0
3	Additions		5.0 L17 - Line 4	89.1	77.0	(12.0)
4	Additions - Low Carbon Electrification			9.7	4.1	(5.6)
5	Amortization on Existing			(107.4)	(106.5)	0.9
6	Amortization on Additions			0.0	0.0	0.0
7	End of Year			911.7	881.2	(30.4)
	First Nations Costs					
8	Beginning of Year			71.4	69.5	(1.9)
9	Adjustment to Opening Balance			0.0	0.0	0.0
10	Additions		5.0 L18	2.4	1.9	(0.5)
11	Transfer from Provision		Line 19	13.1	13.3	0.3
12	Interest			2.3	2.3	(0.0)
13	Recovery			(33.7)	(33.1)	0.5
14	End of Year			55.5	53.9	(1.7)
	First Nations Settlement Provisions					
15	Beginning of Year			423.0	426.0	3.0
16	Adjustment to Opening Balance			0.0	0.0	0.0
17	Additions - Operating		5.0 L44	0.0	1.2	1.2
18	Additions - Accretion		8.0 L4	18.0	18.0	0.0
19	Transfer to Negotiation Costs			(13.1)	(13.3)	(0.3)
20	End of Year			427.9	431.9	4.0
	Site C Project					
21	Beginning of Year			508.4	508.4	0.0
22	Adjustment to Opening Balance			0.0	0.0	0.0
23	Additions		5.0 L19+8.0 L20	(2.4)	(2.2)	0.1
24	Interest			18.9	17.2	(1.7)
25	Recovery			0.0	0.0	0.0
26	End of Year			524.9	523.3	(1.6)
	Foreign Exchange Gains/Losses					
27	Beginning of Year			9.0	16.6	7.5
28	Adjustment to Opening Balance			0.0	0.0	0.0
29	Additions			(1.5)	(10.7)	(9.2)
30	Recovery			0.5	(0.1)	(0.6)
31	End of Year			8.0	5.7	(2.3)

Other Regulatory Accounts
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Pre-1996 Customer Contributions					
32	Beginning of Year			78.2	78.2	0.0
33	Adjustment to Opening Balance			0.0	0.0	0.0
34	Recovery			(5.1)	(5.1)	0.0
35	End of Year			73.1	73.1	0.0
	Storm Restoration Costs					
36	Beginning of Year			29.0	20.8	(8.3)
37	Adjustment to Opening Balance			0.0	0.0	0.0
38	Additions – Storm Restoration Costs		5.0 L20 - Line 39	0.0	(14.2)	(14.2)
39	Additions - Evacuation Relief			0.0	0.0	0.0
40	Interest			0.5	0.0	(0.5)
41	Recovery			(29.5)	(29.5)	(0.0)
42	End of Year			0.0	(22.9)	(22.9)
	Capital Project Investigation					
43	Beginning of Year			5.2	5.2	(0.0)
44	Adjustment to Opening Balance			0.0	0.0	0.0
45	Recovery			(5.2)	(5.2)	0.0
46	End of Year			0.0	0.0	0.0
	Amortization of Capital Additions					
47	Beginning of Year			9.2	8.9	(0.4)
48	Adjustment to Opening Balance			0.0	0.0	0.0
49	Additions		13.0 L32	0.0	0.1	0.1
50	Interest			0.2	0.0	(0.1)
51	Recovery			(9.4)	(9.4)	(0.0)
52	End of Year			(0.0)	(0.4)	(0.4)
	Total Finance Charges					
53	Beginning of Year			10.1	11.1	0.9
54	Adjustment to Opening Balance			0.0	0.0	0.0
55	Additions		8.0 L19	0.0	(61.7)	(61.7)
56	Recovery			(10.1)	(10.1)	0.0
57	End of Year			(0.0)	(60.8)	(60.8)
	Smart Metering & Infrastructure					
58	Beginning of Year			195.5	195.4	(0.1)
59	Adjustment to Opening Balance			0.0	0.0	0.0
60	Additions - Deferred Operating			0.0	0.0	0.0
61	Additions - DSMD Write-Off			0.0	0.0	0.0
62	Additions - Miscellaneous Revenue			0.0	0.0	0.0
63	Interest			6.8	6.2	(0.5)
64	Recovery			(28.5)	(28.6)	(0.2)
65	End of Year			173.8	173.0	(0.8)

BC Hydro **Schedule 2.2**
F21 actual RRA **Page 6**
Other Regulatory Accounts
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Non-Current Pension Cost					
66	Beginning of Year			364.1	210.1	(154.0)
67	Adjustment to Opening Balance			0.0	0.0	0.0
68	OCI Deferral			0.0	(156.3)	(156.3)
69	Additions			0.0	0.0	0.0
70	Recovery - Operating			(51.4)	(46.0)	5.4
71	Recovery - Finance Charges			0.0	106.2	106.2
72	Transfer to PEB Current Pension-Addition			0.0	0.0	0.0
73	Transfer to PEB Current Pension-Recovery			0.0	0.0	0.0
74	End of Year			312.7	114.0	(198.7)
	Environmental Provisions					
75	Beginning of Year			236.2	305.1	68.8
76	Adjustment to Opening Balance			0.0	0.0	0.0
77	Additions - Deferred Operating		5.0 L45	0.0	51.2	51.2
78	Additions - Accretion		8.0 L5	4.8	2.9	(1.9)
79	Transfer to Rock Bay			0.0	0.0	0.0
80	Transfer to Remediation (Asbestos)			(18.8)	(8.0)	10.8
81	Transfer to Remediation (PCB)			(26.0)	(30.1)	(4.1)
82	Recovery					0.0
83	End of Year			196.2	321.0	124.8
	Rock Bay Remediation					
84	Beginning of Year			(10.3)	(10.4)	(0.1)
85	Adjustment to Opening Balance			0.0	0.0	0.0
86	Transfer from Environmental			0.0	0.0	0.0
87	Interest			(0.2)	(0.2)	(0.1)
88	Recovery			10.4	10.4	(0.0)
89	End of Year			(0.0)	(0.2)	(0.1)
	IFRS PP&E					
90	Beginning of Year			1,079.2	1,079.2	(0.0)
91	Adjustment to Opening Balance			0.0	0.0	0.0
92	Additions - Deferred Operating		5.0 L21	22.4	22.4	(0.0)
93	Recovery			(31.0)	(31.0)	(0.0)
94	End of Year			1,070.6	1,070.6	(0.0)
	IFRS Pension					
95	Beginning of Year			458.9	458.9	0.0
96	Adjustment to Opening Balance			0.0	0.0	0.0
97	Recovery			(38.2)	(38.2)	0.0
98	End of Year			420.6	420.6	0.0

BC Hydro
F21 actual RRA
Other Regulatory Accounts
($ million)

Line		Reference	F2021 RRA	F2021 Actual	F2021 Diff
	Column		1	2	3 = 2 - 1
	Remediation				
99	Beginning of Year		(15.4)	(34.3)	(18.8)
100	Adjustment to Opening Balance		0.0	0.0	0.0
101	Transfer from Env. Prov. (Asbestos)	Line 80	18.8	8.0	(10.8)
102	Transfer from Env. Prov. (PCB)	Line 81	26.0	30.1	4.1
103	Interest		(0.3)	(1.2)	(0.9)
104	Recovery		(29.2)	(29.2)	(0.0)
105	End of Year		(0.1)	(26.5)	(26.4)
	Real Property Sales				
106	Beginning of Year		50.9	56.2	5.3
107	Adjustment to Opening Balance		0.0	0.0	0.0
108	Additions	5.0 L23+L46	0.0	(10.9)	(10.9)
109	Interest		1.4	1.4	(0.0)
110	Recovery		0.0	0.0	0.0
111	End of Year		52.3	46.7	(5.6)
	Debt Management				
112	Beginning of Year		276.5	952.9	676.4
113	Adjustment to Opening Balance		0.0	0.0	0.0
114	Additions	8.0 L6	0.0	(516.6)	(516.6)
115	Recovery		12.4	12.4	0.0
116	End of Year		288.9	448.6	159.8
	Dismantling Cost				
117	Beginning of Year		24.1	16.0	(8.2)
118	Adjustment to Opening Balance		0.0	0.0	0.0
119	Additions		0.0	(3.8)	(3.8)
120	Interest		0.4	(0.1)	(0.5)
121	Recovery		(24.6)	(24.6)	(0.0)
122	End of Year		(0.0)	(12.4)	(12.4)
	PEB Current Pension Costs				
123	Beginning of Year		(0.9)	(1.8)	(0.9)
124	Adjustment to Opening Balance		0.0	0.0	0.0
125	OCI Deferral		0.0	0.0	0.0
126	Additions	5.0 L22	0.0	(5.8)	(5.8)
127	Recovery - Operating		0.9	0.9	(0.0)
128	Transfer from Non-Current Pension-Addition	Line 72	0.0	0.0	0.0
129	Transfer from Non-Current Pension-Recovery	Line 73	0.0	0.0	0.0
130	End of Year		0.0	(6.7)	(6.7)

BC Hydro Schedule 2.2
F21 actual RRA Page 8
Other Regulatory Accounts
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Customer Crisis Fund					
131	Beginning of Year			(2.9)	(5.3)	(2.4)
132	Adjustment to Opening Balance			0.0	0.0	0.0
133	Additions - CCF		5.0 L24	(0.3)	0.9	1.2
134	Additions - COVID-19 Relief operating costs			0.0	0.0	0.0
135	Additions - COVID-19 Residential Grants		14.0 L26	0.0	37.3	37.3
136	Interest			(0.1)	1.0	1.1
137	Recovery			0.0	0.0	0.0
138	End of Year			(3.3)	33.8	37.1
	Mining Customer Payment Plan					
139	Beginning of Year			0.0	0.0	0.0
140	Adjustment to Opening Balance			0.0	0.0	0.0
141	Additions			0.0	0.7	0.7
142	Additions - COVID-19 SGS Waivers		14.0 L27	0.0	6.3	6.3
143	Interest			0.0	0.2	0.2
144	Recovery			0.0	0.0	0.0
145	End of Year			0.0	7.3	7.3
	Project Write-off Costs					
146	Beginning of Year			0.0	0.0	0.0
147	Adjustment to Opening Balance			0.0	0.0	0.0
148	Additions		5.0 L48	0.0	16.4	16.4
149	Interest			0.0	0.2	0.2
150	Recovery			0.0	0.0	0.0
151	End of Year			0.0	16.7	16.7
	Electric Vehicle Costs					
152	Beginning of Year			2.3	0.0	(2.3)
153	Adjustment to Opening Balance			0.0	0.0	0.0
154	Additions - Operating Costs		5.0 L25	1.7	3.3	1.6
155	Additions - Cost of Energy		4.0 L37	0.3	0.3	0.1
156	Additions - Depreciation		7.0 L15	0.5	0.7	0.2
157	Interest			0.1	0.1	(0.1)
158	Recovery			0.0	0.0	0.0
159	End of Year			4.9	4.4	(0.6)

BC Hydro
F21 actual RRA
Other Regulatory Accounts
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	End of Year Balances					
160	Demand-Side Management		Line 7	911.7	881.2	(30.4)
161	First Nations Costs		Line 14	55.5	53.9	(1.7)
162	First Nations Settlement Provisions		Line 20	427.9	431.9	4.0
163	Site C Project		Line 26	524.9	523.3	(1.6)
164	Foreign Exchange Gains/Losses		Line 31	8.0	5.7	(2.3)
165	Pre-1996 Customer Contributions		Line 35	73.1	73.1	0.0
166	Storm Restoration Costs		Line 42	0.0	(22.9)	(22.9)
167	Capital Project Investigation		Line 46	0.0	0.0	0.0
168	Amortization of Capital Additions		Line 52	(0.0)	(0.4)	(0.4)
169	Total Finance Charges		Line 57	(0.0)	(60.8)	(60.8)
170	Smart Metering & Infrastructure		Line 65	173.8	173.0	(0.8)
171	Non-Current Pension Cost		Line 74	312.7	114.0	(198.7)
172	Environmental Provisions		Line 83	196.2	321.0	124.8
173	Rock Bay Remediation		Line 89	(0.0)	(0.2)	(0.1)
174	IFRS PP&E		Line 94	1,070.6	1,070.6	(0.0)
175	IFRS Pension		Line 98	420.6	420.6	0.0
176	Remediation		Line 105	(0.1)	(26.5)	(26.4)
177	Real Property Sales		Line 111	52.3	46.7	(5.6)
178	Debt Management		Line 116	288.9	448.6	159.8
179	Dismantling Cost		Line 122	(0.0)	(12.4)	(12.4)
180	PEB Current Pension Costs		Line 130	0.0	(6.7)	(6.7)
181	Customer Crisis Fund		Line 138	(3.3)	33.8	37.1
182	Mining Customer Payment Plan		Line 145	0.0	7.3	7.3
183	Project Write-off Costs		Line 151	0.0	16.7	16.7
184	Electric Vehicle Costs		Line 159	4.9	4.4	(0.6)
185	Total			4,517.7	4,495.9	(21.8)
	Summary					
186	Regulatory Account Additions			144.7	(381.2)	(525.9)
187	Interest on Regulatory Accounts			30.1	27.2	(2.9)
188	Regulatory Account Recoveries			(379.2)	(266.9)	112.3
189	Adjustments to Opening Balances			0.0	0.0	0.0
190	OCI Deferral (Pension)			0.0	(156.3)	(156.3)
191	Regulatory Account Net Transfers			(204.4)	(777.2)	(572.8)
192	**Interest Rate**		8.0 L24	3.73%	3.38%	(0.35%)

Reconciliation of Current and Gross Views
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Inter-Segment Revenue					
1	Powerex - Business Support Allocation		3.1 L14	(2.9)	(2.9)	0.0
2	Mark to Market Losses (Gains)		3.1 L15	0.0	90.0	90.0
3	Powerex PTP Charges		3.4 L18	(34.0)	(41.7)	(7.8)
4	BC Hydro PTP Charges		3.4 L19	(35.0)	(30.4)	4.7
5	Total			(71.9)	15.0	86.9

Note 1: These revenues relate to an allocation of corporate costs to Powerex and are eliminated against Trade Income.

Note 2: Commodity Risk of $90.0 million consists of mark-to-market gains/losses on intercompany transactions that are offset by corresponding transactions in the TIDA. There is no net impact on the combined NHDA and TIDA balances due to these transactions.

Note 3: These transmission revenues relate to an allocation of BC Hydro’s cost of purchases of point-to-point transmission with B.C. for export and some import transactions. These revenues are eliminated against trade cost of energy on consolidation. The variance is deferred to the NHDA.

Note 4: These transmission revenues relate to an allocation of BC Hydro’s cost of purchases of point-to-point transmission relating to BC Hydro’s Skagit Valley Treaty commitment and Domestic Exports. These revenues are eliminated against domestic cost of energy on consolidation. This variance is deferred in the NHDA.

Cost of Energy

Line		Reference Column	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	Sources of Supply (GWh)				
	Heritage Energy				
1	Water Rentals		44,522	49,796	5,275
2	Natural Gas for Thermal Generation		195	150	(46)
3	Exchange Net		(250)	(355)	(105)
4	Total		44,467	49,591	5,124
	Non-Heritage Energy				
5	IPPs and Long-Term Commitments		15,238	14,630	(608)
6	Non-Integrated Area		120	107	(13)
7	Total		15,358	14,737	(621)
	Market Energy				
8	Market Electricity Purchases		1,326	0	(1,326)
9	Surplus Sales		(3,515)	0	3,515
10	System Imports			999	999
11	System Exports			(9,082)	(9,082)
12	Net Purchases (Sales) from Powerex		(279)	0	279
13	Total		(2,467)	(8,083)	(5,616)
14	**Total Sources of Supply**	L4+L7+L13	57,357	56,245	(1,112)
	Cost of Energy ($ million)				
	Heritage Energy				
15	Water Rentals		323.2	333.2	10.0
16	Natural Gas for Thermal Generation		8.5	6.5	(2.0)
17	Domestic Transmission - Other		24.4	25.5	1.1
18	Non-Treaty Storage and Libby Coordination Agreements		(11.7)	(49.9)	(38.1)
19	Remissions and Other		(26.7)	(42.0)	(15.4)
20	Total		317.7	273.3	(44.4)
	Non-Heritage Energy				
21	IPPs and Long-Term Commitments		1,410.8	1,404.0	(6.8)
22	Non-Integrated Area		30.2	26.0	(4.1)
23	Gas & Other Transportation		2.5	5.3	2.7
24	Water Rentals (Waneta 2/3)	15.0 L22	3.7	3.2	(0.5)
25	Total		1,447.2	1,438.5	(8.6)
	Market Energy				
26	Market Electricity Purchases		43.7	0.0	(43.7)
27	Surplus Sales		(165.1)	0.0	165.1
28	System Imports			26.9	26.9
29	System Exports			(227.9)	(227.9)
30	Net Purchases (Sales) from Powerex		6.1	0.0	(6.1)
31	Domestic Transmission - Export		17.0	11.6	(5.4)
32	Total		(98.4)	(189.4)	(91.0)
33	**Total Gross COE**	L20+L25+L32	1,666.5	1,522.4	(144.0)
	Items Subject to HDA				
34	Heritage Energy	Line 20	317.7	273.3	(44.4)
35	Market Electricity Purchases	Line 26	43.7	0.0	(43.7)
36	Surplus Sales	Line 27	(165.1)	0.0	165.1
37	Electric Vehicle Costs Additions		(0.3)	(0.3)	(0.1)
38	Domestic Transmission - Export	Line 31	17.0	11.6	(5.4)
39	Costs in Operating/Amortization		12.5	12.5	0.0
40	Notional Water Rentals		(1.8)	0.0	1.8
41	Skagit and Ancillary Revenue	14.0 L19	(35.9)	(30.0)	5.9
42	Deferred Operating HDA	5.0 L14	0.0	(1.5)	(1.5)
43	Other		31.2	31.2	0.0
44	Total		219.0	296.9	77.8

Cost of Energy

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Items Subject to NHDA					
45	Non-Heritage Cost of Energy		Line 25	1,447.2	1,438.5	(8.6)
46	Less: Water Rentals (Waneta 2/3)		Line 24	(3.7)	(3.2)	0.5
47	Net Purchases (Sales) from Powerex		Line 30	6.1	0.0	(6.1)
48	System Imports				26.9	26.9
49	System Exports				(227.9)	(227.9)
50	Commodity Risk			0.0	90.0	90.0
51	Notional Water Rental		Line 40	1.8	0.0	(1.8)
52	Revenue Variance			0.0	0.0	0.0
53	Deferred Operating NHDA		5.0 L15	0.0	1.5	1.5
54	Deferred Amortization NHDA		7.0 L9	0.0	(0.3)	(0.3)
55	Other			0.0	(1.6)	(1.6)
56	Less: IPP subject to Biomass Energy Program Variance			(80.7)	(66.0)	14.7
57	Total			1,370.7	1,258.0	(112.7)
58	**Biomass Energy Program Variance Reg. Acct.**			80.7	66.0	(14.7)

Operating Costs and Provisions - Total Company
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Operating Costs by Business Group					
1	Integrated Planning			292.0	308.8	16.7
2	Capital Infrastructure Project Delivery			81.1	80.8	(0.3)
3	Operations			244.3	265.2	21.0
4	Safety			57.5	55.7	(1.8)
5	Finance, Technology, Supply Chain			264.8	277.3	12.5
6	People, Customer, Corporate Affairs			111.1	121.3	10.2
7	Other			(244.4)	(273.4)	(28.9)
8	**Base Operating Costs**			806.4	835.7	29.4
9	IFRS Ineligible Capitalized Costs			192.5	192.5	0.0
10	Waneta 2/3			5.9	5.8	(0.0)
11	Customer Crisis Fund			5.3	2.9	(2.4)
12	**Subtotal**			203.6	201.2	(2.4)
13	**Net Operating Costs**		L8+L12	1,010.0	1,037.0	27.0
	Deferral Account Additions					
14	Transfers to HDA			0.0	(1.5)	(1.5)
15	Transfers to NHDA			0.0	1.5	1.5
16	Total			0.0	(0.0)	(0.0)
	Regulatory Account Additions					
17	Demand-Side Management			98.8	81.1	(17.6)
18	First Nations Costs			2.4	1.9	(0.5)
19	Site C Project			0.3	0.3	0.0
20	Storm Restoration			0.0	(14.2)	(14.2)
21	IFRS Capitalized Overhead			22.4	22.4	(0.0)
22	PEB Current Pension Costs			0.0	(5.8)	(5.8)
23	Real Property Sales			0.0	1.1	1.1
24	Customer Crisis Fund			(0.3)	0.9	1.2
25	Electric Vehicle Costs			1.7	3.3	1.6
26	Mining Customer Payment Plan				0.7	0.7
27	Total			125.4	91.8	(33.6)
28	**Total Gross Operating Costs**		L13+L16+L27	1,135.4	1,128.7	(6.6)
	Net Provisions & Other					
29	Integrated Planning			36.7	40.9	4.1
30	Capital Infrastructure Project Delivery			0.0	3.2	3.2
31	Operations			4.4	5.5	1.1
32	Safety			0.0	0.1	0.1
33	Finance, Technology, Supply Chain			0.0	(12.1)	(12.1)
34	People, Customer, Corporate Affairs			0.0	13.9	13.9
35	Other			11.2	6.0	(5.2)
	Dismantling Expense					
36	Integrated Planning			34.8	34.8	0.0
37	Capital Infrastructure Project Delivery			0.3	0.3	0.0
38	Operations			7.8	7.8	0.0
39	Finance, Technology, Supply Chain			0.2	0.2	0.0
40	Real Property Sales			0.0	10.0	10.0
41	Total			95.4	110.7	15.3
	Deferral Account Additions - Provisions & Other					
42	Transfers to NHDA			0.0	0.0	0.0
43	Total			0.0	0.0	0.0

Operating Costs and Provisions - Total Company
($ million)

			F2021		
		Reference	RRA	Actual	Diff
Line		Column	1	2	3 = 2 - 1
	Regulatory Account Additions - Provisions & Other				
44	First Nations Provisions		0.0	1.2	1.2
45	Environmental Provisions		0.0	51.2	51.2
46	Real Property Sales		0.0	(12.0)	(12.0)
47	Dismantling Expense		0.0	(3.8)	(3.8)
48	Project Write-Off Costs		0.0	16.4	16.4
49	Total		0.0	53.0	53.0
50	**Total Gross Provisions & Other**	L41 + L43 + L49	95.4	163.7	68.3
51	**Total Gross Operating and Provisions & Other**	L28 + L50	1,230.8	1,292.4	61.7

Taxes
($ million)

Line		Column / Reference	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	Generation				
1	Grants in Lieu		27.9	27.4	(0.5)
2	School Taxes		18.3	17.7	(0.6)
3	Total		46.3	45.2	(1.1)
	Transmission				
4	Grants in Lieu		65.7	68.9	3.2
5	School Taxes		98.0	95.8	(2.2)
6	Total		163.7	164.7	1.0
	Distribution				
7	Grants in Lieu		8.9	8.9	0.0
8	School Taxes		24.0	20.7	(3.3)
9	Total		32.9	29.6	(3.3)
	Customer Care				
	Waneta 2/3				
10	Teck portion of property taxes	15.0 L23	0.6	0.8	0.2
11	Total		0.6	0.8	0.2
	Business Support				
12	Grants in Lieu		12.2	12.0	(0.2)
13	School Taxes		6.5	4.6	(1.9)
14	Total		18.7	16.6	(2.1)
	Total Before Regulatory Accounts				
15	Grants in Lieu	L1+L4+L7+L12	114.8	117.3	2.5
16	School Taxes	L2+L5+L8+L13	146.8	138.7	(8.0)
17	Waneta 2/3 Property Taxes	L10	0.6	0.8	0.2
18	Total		262.2	256.8	(5.4)
	Deferral Account Additions				
19	Transfers to NHDA		0.0	0.0	0.0
20	**Total Gross Taxes**	L18 + L19	262.2	256.8	(5.4)

Depreciation and Amortization
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Amortization of Capital Assets					
1	Generation			266.8	270.2	3.4
2	Transmission			230.8	230.5	(0.3)
3	Distribution			216.5	217.1	0.5
4	Business Support			190.4	187.9	(2.5)
5	Total			904.5	905.6	1.2
	IPP Capital Leases					
6	IPP Capital Leases			90.1	90.1	0.0
7	Total			90.1	90.1	0.0
	Other Leases					
8	Amortization			3.4	4.1	0.6
	Deferral Account Additions					
9	Transfers to NHDA			0.0	(0.3)	(0.3)
10	Total			0.0	(0.3)	(0.3)
11	Less: Electric Vehicle Costs - Ineligible stations			(0.0)		0.0
12	**Total Gross Amortization**			998.0	999.5	1.6
	Deferral Account Additions					
13	Transfers to NHDA			0.0	0.3	0.3
	Transfer to Regulatory Account					
14	Amortization on Additions Variance		13.0 L32	0.0	(0.1)	(0.1)
15	Electric Vehicle Costs Additions			(0.5)	(0.7)	(0.2)
16	Transfer to Regulatory Account			(0.5)	(0.8)	(0.3)

Finance Charges
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
1	**Total Gross Finance Charges**		L7 + L18	743.3	251.6	(491.8)
	Regulatory Account Additions					
2	FX Gains/Losses			**(1.5)**	**(10.7)**	(9.2)
3	Deferred IPP Capital Leases (Total Finance Charge Reg. Account Additions)			**0.0**	**0.2**	0.2
4	Accretion - First Nations			**18.0**	**18.0**	0.0
5	Accretion - Environmental			**4.8**	**2.9**	(1.9)
6	Debt Management			**0.0**	**(516.6)**	(516.6)
7	Total			21.3	(506.2)	(527.5)
8	**Adj. for Regulatory Account Additions**			722.0	757.8	35.8
	Total Before Regulatory Accounts					
9	Sinking Fund Income			(7.7)	(8.9)	(1.2)
10	Long-Term Debt Costs			851.5	821.5	(29.9)
11	Short-Term Debt Costs			69.6	12.4	(57.2)
12	Interest Capitalized			(242.6)	(225.9)	16.7
13	Other (Income) / Loss			**45.1**	**46.2**	1.0
14	IPP Capital Leases			**46.1**	**46.1**	0.0
15	Accretion - Non-Deferrable			**1.3**	**1.1**	(0.2)
16	Non-Current PEB			**(42.2)**	**64.0**	106.2
17	Other Leases			**1.0**	**1.4**	0.4
18	Total			722.0	757.8	35.8
19	Total Finance Charge Regulatory Acct. Additions			0.0	61.7	61.7
20	Site C Project (IFRS 14 IDC impact)			**2.7**	**2.6**	(0.1)
	Weighted Average Cost of Debt (WACD) Rate					
21	Total Gross Finance Charges		Line 1	743.3	251.6	(491.8)
22	WACD Adjustment			**165.4**	**619.1**	453.8
23	Finance Charges for WACD			908.7	870.7	(38.0)
24	Weighted Average Cost of Debt (WACD) Rate			3.73%	3.38%	(0.35%)

Return on Equity
($ million)

Line		Column	Reference	F2021 RRA	F2021 Actual	F2021 Diff
				1	2	3 = 2 - 1
	Deemed Equity					
1	Rate Base		10.0 L5	23,335.6	23,098.9	(236.7)
2	Pre-1996 Customer Contns		2.2 L35	(73.1)	(73.1)	0.0
3	Powerex & Powertech Assets			**67.3**	**97.8**	30.6
4	Allowance for Working Capital			**250.0**	**250.0**	0.0
5	Total			23,579.8	23,373.6	(206.1)
6	Deemed Equity Percentage			**30.0%**	**30.0%**	0.0%
7	Year-End Deemed Equity			7,073.9	7,012.1	(61.8)
8	Mid-Year Deemed Equity			7,011.9	6,957.9	(53.9)
9	Achieved ROE				9.88%	
10	Allowed ROE / Derived ROE (F18-F21)			10.15%		
11	Return on Equity			**712.0**	687.5	(24.5)
12	Gross Return on Equity			712.0	687.5	(24.5)

Rate Base
($ million)

Line		Reference Column	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	Total				
1	Net Assets in Service	12.0 L11	24,281.7	24,143.7	(138.0)
2	Less: Electric Vehicle Costs Assets		(2.4)	0.0	2.4
3	Net Contributions	11.0 L12	(1,855.4)	(1,926.1)	(70.6)
4	Net DSM	2.2 L7	911.7	881.2	(30.4)
5	Total		23,335.6	23,098.9	(236.7)
6	Mid-Year		23,132.2	22,924.7	(207.5)

Contributions
($ million)

Line		Reference Column	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	Contributions in Aid - Total				
1	Gross Contns - Beginning of Year		2,692.5	2,700.8	8.3
2	IFRS Opening Balance Adjustment		0.0	0.0	0.0
3	Additions		148.5	195.7	47.2
4	Retirements & Transfers		(4.5)	(15.0)	(10.4)
5	Gross Contns - End of Year		2,836.4	2,881.5	45.1
6	Accum Amort - Beginning of Year		927.5	915.5	(12.0)
7	Amortization		58.6	59.0	0.4
8	Amortization of Pre-96 CIAC		(5.1)	(5.1)	0.0
9	Retirements & Transfers		0.0	(9.7)	(9.7)
10	IFRS amortization reclassification		0.0	(4.3)	(4.3)
11	Accum Amort - End of Year		981.0	955.4	(25.6)
12	Net Contributions - End of Year		1,855.4	1,926.1	70.6

Assets - Total (Excluding DSM and IPP Capital Leases)
($ million)

Line		Reference Column	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	Gross Assets in Service				
1	Opening Balance		26,303.4	26,123.6	(179.8)
2	Adjustment to Opening Balance		0.0	14.2	14.2
3	Capital Additions	13.0 L19	1,459.0	1,433.4	(25.7)
4	Retirements & Transfers		(46.8)	(66.6)	(19.9)
5	Closing Balance		27,715.7	27,504.6	(211.1)
	Accumulated Amortization				
6	Opening Balance		2,529.5	2,494.5	(35.0)
7	Amortization on Existing Assets		823.7	824.8	1.1
8	Amortization on Additions	13.0 L32	80.7	80.8	0.1
9	Retirements & Transfers		0.0	(39.2)	(39.2)
10	Closing Balance		3,434.0	3,360.9	(73.0)
11	**Net Assets in Service (Year-End)**		24,281.7	24,143.7	(138.0)

Capital Expenditures and Additions
($ million)

Line		Reference Column	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	Capital Expenditures				
1	Generation Growth		0.0	0.8	0.8
2	Generation Sustaining		435.5	299.2	(136.3)
3	Transmission Growth		198.9	121.9	(77.0)
4	Transmission Sustaining		286.5	254.4	(32.1)
5	Distribution Growth		284.6	390.5	105.9
6	Distribution Sustaining		176.9	204.1	27.2
7	Site C Project		1,535.5	1,725.0	189.5
8	Technology		56.0	90.8	34.8
9	Properties		55.3	54.8	(0.5)
10	Fleet & Other		75.1	56.0	(19.1)
11	Total		3,104.2	3,197.5	93.3
	Total Capital Additions				
12	Generation		296.9	102.6	(194.3)
13	Transmission		229.5	288.5	59.0
14	Distribution		540.7	536.0	(4.7)
15	Site C Project		189.4	220.9	31.5
16	Technology		75.5	164.9	89.4
17	Properties		55.6	70.9	15.3
18	Fleet & Other		71.3	49.5	(21.9)
19	Total		1,459.0	1,433.4	(25.7)
	Unfinished Construction				
20	Beginning of Year		6,150.7	6,373.4	222.8
21	Adjustments		0.0	(9.0)	(9.0)
22	Change in Unfinished		1,645.2	1,764.1	118.9
23	End of Year		7,795.8	8,128.5	332.7
24	Mid-Year Balance		6,973.2	7,251.0	277.8
	Amortization on Additions				
25	Generation		11.4	9.8	(1.6)
26	Transmission		7.7	8.6	0.9
27	Distribution		18.5	19.2	0.7
28	Site C Project		1.7	2.3	0.5
29	Technology		34.0	32.1	(1.9)
30	Properties		2.5	2.0	(0.4)
31	Fleet & Other		4.9	6.9	1.9
32	Total		80.7	80.8	0.1

Domestic Energy Sales and Revenue

Line		Reference Column	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	Domestic Energy Sales (GWh)				
1	Residential		17,927	18,982	1,055
2	Light Industrial and Commercial		18,744	18,091	(653)
3	Large Industrial		13,203	12,438	(765)
4	Irrigation		99	63	(37)
5	Street Lighting		291	213	(78)
6	New Westminster & Tongass		591	457	(134)
7	Fortis		695	584	(111)
8	Seattle City Light		388	311	(78)
9	Liquefied Natural Gas		0	0	0
10	Other		0	0	0
11	Total		51,940	51,139	(801)
	Domestic Revenues ($ million)				
12	Residential		2,140.4	2,210.2	69.8
13	Light Industrial and Commercial		1,905.9	1,830.4	(75.6)
14	Large Industrial		852.2	761.7	(90.5)
15	Irrigation		7.8	5.8	(2.0)
16	Street Lighting		55.9	42.1	(13.8)
17	New Westminster & Tongass		39.9	30.7	(9.2)
18	Fortis		49.4	39.6	(9.8)
19	Seattle City Light		35.9	30.0	(5.9)
20	Liquefied Natural Gas		0.0	0.0	0.0
21	Other			0.0	0.0
22	Subtotal		5,087.4	4,950.4	(137.0)
23	Revenue from Deferral Account Rate Rider		0.0	0.0	0.0
24	Total		5,087.4	4,950.4	(137.0)
25	**Deferral Account Rate Rider**		0.0%	0.0%	
	Baseline				
26	COVID-19 Residential Grants to CCF		0.0	(37.3)	(37.3)
27	COVID-19 SGS Waivers to MCPP		0.0	(6.3)	(6.3)
28	Skagit and Ancillary Revenue to HDA		35.9	30.0	(5.9)
29	Load Variance		5,036.3	4,950.5	(85.8)
30	Biomass Energy Program Variance		15.2	13.5	(1.7)
31	Total		5,087.4	4,950.4	(137.0)

Miscellaneous Revenue
($ million)

Line		Reference Column	F2021 RRA	F2021 Actual	F2021 Diff
			1	2	3 = 2 - 1
	Generation				
1	Amortization of Contributions		0.2	0.3	0.0
2	Other		1.7	2.3	0.7
3	Total		1.9	2.6	0.7
	Transmission				
4	External OATT		15.9	14.1	(1.8)
5	FortisBC Wheeling Agreement		5.3	5.2	(0.1)
6	Secondary Revenue		6.2	7.3	1.1
7	Interconnections		2.2	8.3	6.1
8	Amortization of Contributions		15.0	15.3	0.3
9	NTL Supplemental Charge		2.3	2.4	0.1
10	Total		46.8	52.6	5.8
	Distribution				
11	Secondary Use Revenue & Other		14.1	20.4	6.3
12	Amortization of Contributions		47.9	48.7	0.8
13	Total		62.0	69.1	7.1
	Customer Care				
14	Meter/Trans Rents & Power Factor Surcharges		14.9	16.4	1.5
15	Smart Metering & Infrastructure Impact		1.7	1.6	(0.1)
16	Diversion Net Recoveries		0.1	0.1	(0.0)
17	Other Operating Recoveries		4.6	4.0	(0.6)
18	Customer Crisis Fund Rider Revenue		5.3	2.9	(2.4)
19	Other		3.0	4.0	0.9
	Waneta 2/3				
20	Lease revenue from Teck		76.7	76.7	0.0
21	Teck portion of operating costs		5.9	5.8	(0.0)
22	Teck portion of water rentals		3.7	3.2	(0.5)
23	Teck portion of property taxes		0.6	0.8	0.2
24	Subtotal		86.9	86.5	(0.4)
25	Total		116.4	115.5	(0.9)
	Business Support				
26	Corporate General Rents		3.8	2.8	(1.0)
27	Late Payment Charges		8.1	7.8	(0.3)
28	MMBU Secondary Revenue		3.8	4.8	1.0
29	Other		0.7	1.0	0.3
30	Total		16.4	16.3	(0.0)
31	**Total Before Regulatory Accounts**		243.6	256.1	12.6
	Deferral Account Additions				
32	Waneta 2/3				
32	Teck portion of capital expenditures		3.5	5.0	1.5
33	Subtotal		3.5	5.0	1.5
34	**Total Gross Miscellaneous Revenue**		247.0	261.1	14.1

7 Planned Capital Extension Projects and Anticipated Regulatory Filings

The attachment to this section summarizes planned capital extension projects and anticipated regulatory filings. The attachment includes the following four tables as well as the criteria used in identifying the projects reported:

- Table 1: Capital Extension Projects;
- Table 2: Projects with Anticipated CPCN or Section 44.2 Filings;
- Table 3: Extension Capital Expenditures Approved at the Group, Program or Aggregated Level; and
- Table 4: Capital Expenditures net of Contributions in Aid.

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Attachment to Section 7

Summary of Planned Capital Extension Projects and Anticipated Regulatory Filings

List of Tables

This attachment includes three tables consistent with the information provided in previous annual reports, and a new table, in compliance with BCUC Letter No. L-65-20. In the tables, BC Hydro has redacted commercially sensitive customer information.

Table 1 lists, by category, the capital extension[1] projects with a total forecast or planned cost of more than $5 million that are included in Appendix I in the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application that will be filed in August 2021.

BC Hydro's current expectation regarding projects that may be subject to a future CPCN or Section 44.2 regulatory filing[2] is provided in Table 2.

In compliance with Directive 2 of BCUC Order No. G-313-19,[3] Table 3 provides a listing and the forecast capital cost, where available, of all capital expenditures with a total forecast or planned capital cost of $50 million or greater that meets the following two criteria:

- Financial approval of the capital expenditure is authorized or expected to be authorized at a group, program or other aggregated level; and
- Any subset of capital expenditures within the group, program or other aggregated level is an extension as defined in BC Hydro's 2018 Capital Filing Guidelines[4] (**2018 Guidelines**).

[1] An extension is a project initiated with the intent to expand the service area or capacity of a utility plant or system, in accordance with paragraph 13 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.

[2] The Capital Project Filing Guideline thresholds for CPCN and Section 44.2 filings are $100 million for Power System projects, $50 million for Buildings projects and $20 million for IT projects in accordance with paragraph 11 of BC Hydro's 2018 Capital Filing Guidelines filed with the BCUC on January 17, 2020.

[3] https://www.bcuc.com/Documents/Proceedings/2019/DOC_56448_2019-12-02-BCH-Review-of-BCH-Capital-Expenditures-Decision.pdf from the Review of the Regulatory Oversight of Capital Expenditures and Projects proceedings

[4] Filed with the BCUC on January 17, 2020.

Table 3 also includes references to the Appendices I and J of BC Hydro's Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, where applicable.

In compliance with BCUC Letter No. L-65-20, Table 4 provides a summary of Capital Expenditures categorized by CPCN, System Extensions which do not meet the threshold for a CPCN filing and Other Capital Expenditures for the current fiscal reporting year and the following two fiscal years.

Table 1 Capital Extension Projects ($ million)

Planning ID	Project Name	Total Forecast Cost[5]	Reference (from F2023 - F2025 RRA)
Generation Growth Capital			
115778	Site C Project	16,000.0[6]	Appendix I, Site C, Line 1 Appendix J, F2023-F2025 RRA
Generation Sustain Capital			
G003207	Mica Replace Units 1 to 4 Generator Transformers	80	Appendix I, Generation, Line 47, Appendix J, F2023-F2025 RRA
G000334	Wahleach Refurbish Generator	51	Appendix I, Generation, Line 57, Appendix J, F2023-F2025 RRA
G001047	Waneta U3 Life Extension	38	Appendix I, Generation, Line 58, Appendix J, F2023-F2025 RRA
G000776	Bridge River 1 Replace Units 1-4 Generators / Governors	333 - 202	Appendix I, Generation, Line 59, Appendix J, F2023-F2025 RRA
G000181	Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	TBD	Appendix I, Generation, Line 68, Appendix J, F2023-F2025 RRA
G003026	Seton - Upgrade Unit	TBD	Appendix I, Generation, Line 71, Appendix J, F2023-F2025 RRA

5 For projects included in Appendix I of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, the Total Forecast Cost shown is:

- The Authorized Amount (Column K) shown in Appendix I of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application for projects in the Implementation phase and projects that are in- service, and
- The Pre-Implementation Cost Estimate (Column J) shown in Appendix I of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application.

6 In February 2021, the Government of B.C. announced that the Site C Project would continue with an updated cost estimate of $16 billion. This included a new expected in-service date of 2025, as a result of the delays and impacts of the pandemic. The Government of B.C. approved the cost estimate of $16 billion in June 2021 as the updated Project budget. The updated Project budget includes the present value of the future operating payments and costs deferred to the Site C Regulatory Account.

Planning ID	Project Name	Total Forecast Cost[5]	Reference (from F2023 - F2025 RRA)
Transmission Growth Capital			
92423	Bridge River Transmission Project	TBD	Appendix I, Transmission, Line 1, Appendix J, F2023-F2025 RRA
901572	North Montney Region - Electrification	TBD	Appendix I, Transmission, Line 2, Appendix J, F2023-F2025 RRA
94034	West Kelowna Transmission and Westbank Upgrade Projects	TBD	Appendix I, Transmission, Line 3, Appendix J, F2023-F2025 RRA
900598	West End - Substation Construction and System Reinforcement	TBD	Appendix I, Transmission, Line 4, Appendix J, F2023-F2025 RRA
900266	East Vancouver - Substation Construction	TBD	Appendix I, Transmission, Line 6, Appendix J, F2023-F2025 RRA
902126	Sunshine Coast - Transmission Reinforcement	TBD	Appendix I, Transmission, Line 7, Appendix J, F2023-F2025 RRA
900992	Lower Mainland - Capacitive and Reactive Power Reinforcement	TBD	Appendix I, Transmission, Line 9, Appendix J, F2023-F2025 RRA
901574	Prince George to Terrace Capacitors Project	TBD	Appendix I, Transmission, Line 10, Appendix J, F2023-F2025 RRA
93788	Capilano Substation Upgrade	87	Appendix I, Transmission, Line 11, Appendix J, F2023-F2025 RRA
92910	Clayburn Substation Upgrade	36	Appendix I, Transmission, Line 12, Appendix J, F2023-F2025 RRA
92907	Mount Lehman Substation Upgrade	59	Appendix I, Transmission, Line 13, Appendix J, F2023-F2025 RRA
900268	Horne Payne - Feeder Section Addition	TBD	Appendix I, Transmission, Line 14, Appendix J, F2023-F2025 RRA
901580	Customer IPID - 901580	18 - 10	Appendix I, Transmission, Line 15,
901573	Customer IPID - 901573	TBD	Appendix I, Transmission, Line 16,
901851	Customer IPID - 901851	TBD	Appendix I, Transmission, Line 17,
901581	Customer IPID - 901581	TBD	Appendix I, Transmission, Line 18,
901940	Customer IPID - 901940	TBD	Appendix I, Transmission, Line 19,
902121	Customer IPID - 902121	TBD	Appendix I, Transmission, Line 20,
901943	Customer IPID - 901943	TBD	Appendix I, Transmission, Line 21,
901938	Customer IPID - 901938	TBD	Appendix I, Transmission, Line 22,

Planning ID	Project Name	Total Forecast Cost[5]	Reference (from F2023 - F2025 RRA)
Transmission Sustain Capital			
900243	SPG Metalclad Switchgear Replacement	54	Appendix I, Transmission, Line 23, Appendix J, F2023-F2025 RRA
901612	Pemberton - Substation Rebuild	TBD	Appendix I, Transmission, Line 25,
901613	Maple Ridge - Feeder Section 60 Series Refurbishment	TBD	Appendix I, Transmission, Line 26, Appendix J, F2023-F2025 RRA
900564	Hundred Mile House T1/T2 EOL Replacement	20	Appendix I, Transmission, Line 29,
900152	Natal Sub - NTL 60-138 kV Rebuild	139 - 47	Appendix I, Transmission, Line 32, Appendix J, F2023-F2025 RRA
94079	Sandspit Substation Replacement	15 - 12	Appendix I, Transmission, Line 33,
94081	Ah-sin-heek - Substation Replacement	TBD	Appendix I, Transmission, Line 34,
92478	Mainwaring Station Upgrade	TBD	Appendix I, Transmission, Line 41, Appendix J, F2023-F2025 RRA
92479	Newell Substation Upgrade	TBD	Appendix I, Transmission, Line 42, Appendix J, F2023-F2025 RRA
901045	Canal Flats - Substation Wood Pole Replacement	TBD	Appendix I, Transmission, Line 55,
901049	Skookumchuck - Substation Wood Pole Replacement	TBD	Appendix I, Transmission, Line 56,
900766	Project IPID - 900766	TBD	Appendix I, Transmission, Line 64,
901002	2L146 - Cable Replacement	TBD	Appendix I, Transmission, Line 72, Appendix J, F2023-F2025 RRA
94057	Gulf Islands - Transmission Reinforcement	TBD	Appendix I, Transmission, Line 74, Appendix J, F2023-F2025 RRA
Distribution Growth Capital			
DY-1545	Customer IPID DY-1545	10	Appendix I, Distribution, Line 1
901955	Customer IPID 901955 -	TBD	Appendix I, Distribution, Line 3
902127	Customer IPID 902127	TBD	Appendix I, Distribution, Line 4
902128	Customer IPID 902128	TBD	Appendix I, Distribution, Line 5
900316	LOH 12F56, 12F62 Voltage Conversion Preparation (LM-BBY-082)	3	Appendix I, Distribution, Line 6

Planning ID	Project Name	Total Forecast Cost[5]	Reference (from F2023 - F2025 RRA)
901518	Mount Lehman New Feeder to Offload Balfour, Mount Lehman and Gloucester Feeders (FV-ABT-042)	4	Appendix I, Distribution, Line 7
93650	Two new CBN Feeders to Offload SMW (LM-FVE-606)	7 - 3	Appendix I, Distribution, Line 8
92802	Glenmore Voltage Conversion (LM-NSC-088)	5 - 3	Appendix I, Distribution, Line 9
901355	Norgate - Offload NOR loads to NVR feeders (LM-NSH-074)	22 - 12	Appendix I, Distribution, Line 10
901356	North Vancouver - Offload NVR loads to LYN new feeders (LM-NSH-075)	14 - 4	Appendix I, Distribution, Line 11
900431	Oldfield (OFD) Voltage Conversion 12 to 25kV (NI-NEW-273)	13 - 4	Appendix I, Distribution, Line 12
901132	Three Fleetwood feeders to offload McLellan (FV-FVW-723)	21 - 12	Appendix I, Distribution, Line 13
93669	Three new MLE Feeders to offload CBN (LM-FVE-607)	13 - 8	Appendix I, Distribution, Line 14
901890	Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-023)	TBD	Appendix I, Distribution, Line 16
901949	Fleetwood - Distribution Feeder Ductbank and Feeder Installation (FV-FVW-805)	TBD	Appendix I, Distribution, Line 17
901950	Langley - MLN 25F32 and MLN 25F33 Offload (FV-FVW-741)	TBD	Appendix I, Distribution, Line 18
901820	Tofino - New LBH 25F54 Feeder Installation to Offload LBH 25F52 (VI-PAL-010)	TBD	Appendix I, Distribution, Line 19
900541	Vancouver Island - Saltspring 25F61 Cable Extension to North Pender Island (VI-GUL-005)	TBD	Appendix I, Distribution, Line 20 Appendix J, F2023-F2025 RRA

Planning ID	Project Name	Total Forecast Cost[5]	Reference (from F2023 - F2025 RRA)
Distribution Sustain Capital			
901822	Mission - Feeder 25F51 Tie (FV-ABT-039)	TBD	Appendix I, Distribution, Line 23

Table 2 Projects with Anticipated CPCN or Section 44.2 Filings

Planning ID	Project	Filing Type	Rationale for Filing Type
Generation Sustain Capital			
G000585	John Hart Dam Seismic Upgrade	Section 44.2	The project is estimated to exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000668	Ladore Spillway Seismic Upgrade	Section 44.2	The project is estimated to exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000525	Strathcona Upgrade Discharge	Section 44.2	The project is estimated to exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000459	La Joie - Dam Improvements	Section 44.2	The project may exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G003365	Mica - Discharge Facilities Seismic and Reliability Upgrades	Section 44.2	The project may exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000052	Cheakamus - Dam Improvements	Section 44.2	The project may exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
G000485	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	Section 44.2	The project may exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.

Planning ID	Project	Filing Type	Rationale for Filing Type
G000776	Bridge River 1 Replace Units 1-4 Generators / Governors	CPCN	BCUC Order No. G-246-20 directed BC Hydro to file a joint CPCN application for this project and the Bridge River Transmission Project (No. 14 below)
G003026	Seton - Upgrade Unit	Potential CPCN or Section 44.2	The project may exceed the $100 million threshold for Power System projects. Multiple alternatives are under investigation and a determination on whether the project may be considered an extension to the BC Hydro system will depend on the selected alternative.
G003058	Kootenay Canal - U1 - U4 Generators Refurbishment	Potential CPCN or Section 44.2	The project may exceed the $100 million threshold for Power System projects. Multiple alternatives are under investigation and a determination on whether the project may be considered an extension to the BC Hydro system will depend on the selected alternative.
G000252	Revelstoke - U1 - U4 Stator Replacement	Potential CPCN or Section 44.2	The project may exceed the $100 million threshold for Power System projects. Multiple alternatives are under investigation and a determination on whether the project may be considered an extension to the BC Hydro system will depend on the selected alternative.
G000183	Mica - U1 - U2 Turbine Overhaul	Potential CPCN or Section 44.2	The project may exceed $100 million threshold for Power System projects. Multiple alternatives are under investigation and a determination on whether the project may be considered an extension to the BC Hydro system will depend on the selected alternative.

Planning ID	Project	Filing Type	Rationale for Filing Type
G004155	Seven Mile - U1 - U3 Turbine Upgrade	Potential CPCN or Section 44.2	The project may exceed the $100 million threshold for Power System projects. Multiple alternatives are under investigation and a determination on whether the project may be considered an extension to the BC Hydro system will depend on the selected alternative.
Transmission Growth Capital			
92423	Bridge River Transmission Project	CPCN	BCUC Order No. G-246-20 directed BC Hydro to file a joint CPCN application for this project and the Bridge River 1 Replace Units 1-4 Generators / Governors project (No. 8 above).
901572	North Montney Region - Electrification	CPCN	The project may exceed the $100 million threshold for Power System projects and is considered an extension to BC Hydro's system.
94034	West Kelowna Transmission Project and Westbank Upgrade Project	CPCN	BCUC Order No. G-47-18 directed BC Hydro to file CPCN applications for these projects.
900598	West End - Substation Construction and System Reinforcement	CPCN	The project may exceed the $100 million threshold for Power System projects and is considered an extension to BC Hydro's system.
900266	East Vancouver - Substation Construction	CPCN	The project may exceed the $100 million threshold for Power System projects and is considered an extension to BC Hydro's system.
900992	Lower Mainland - Capacitive and Reactive Power Reinforcement	Potential CPCN	The project may exceed the $100 million threshold for Power System projects and is considered an extension to BC Hydro's system. Multiple alternatives are under investigation and a determination on whether the project will exceed the threshold for Power System projects will depend on the selected alternative.

Planning ID	Project	Filing Type	Rationale for Filing Type
901943	Customer IPID - 901943	CPCN	The project may exceed the $100 million threshold for Power System projects and is considered an extension to the BC Hydro system.
Transmission Sustain Capital			
901821	Peace to Kelly Lake - Stations Sustainment	Section 44.2	The project is estimated to exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
92478	Mainwaring Station Upgrade	CPCN	BCUC Order No. G-47-18 directed BC Hydro to file a CPCN application for this project.
900019	System Wide – Bulk Electric System Telecom Equipment Replacement	Potential Section 44.2	The project may exceed the $100 million threshold for Power System projects and is not considered an extension to the BC Hydro system.
Properties Sustain Capital			
P201901	Kamloops Field Building Redevelopment	Section 44.2	The project may exceed the $50 million threshold for Building projects and is not considered an extension to the BC Hydro system.
Technology Sustain Capital			
T001397	Contact Centre Technology Foundation	Potential Section 44.2	The project may exceed the $20 million threshold for IT projects and is not considered an extension to the BC Hydro system.
T002122	Stations Work Management	Potential Section 44.2	The project may exceed the $20 million threshold for IT projects and is not considered an extension to the BC Hydro system.
T002549	Distribution Design Modernization	Potential Section 44.2	The project may exceed the $20 million threshold for IT projects and is not considered an extension to the BC Hydro system.
T001379	SAP S/4HANA Upgrade	Potential Section 44.2	The project may exceed the $20 million threshold for IT projects and is not considered an extension to the BC Hydro system.
T002036	Energy Management System (EMS) 3.x Upgrade	Potential Section 44.2	The project may exceed the $20 million threshold for IT projects and is not considered an extension to the BC Hydro system.

The following projects are expected to exceed the Capital Project Filing Guideline threshold for Power System projects but are not included in Table 2:

- The Revelstoke Unit 6 Installation project is expected to exceed the Capital Project Filing Guideline threshold and is exempt from sections 45 to 47 of the *Utilities Commission Act* pursuant to section 7 of the *Clean Energy Act*.
- The Prince George to Terrace Capacitors is exempt from Part 3 of the *Utilities Commission Act* pursuant to the Transmission Upgrade Exemption Regulation, as amended by B.C. Reg. 160/2018.

Table 3 Extension Capital Expenditures Approved at the Group, Program or Aggregated Level ($ million)

Planning ID	Program Name	Total Forecast Cost[7]	Reference (from F2023 - F2025 RRA)
	Not applicable		

At this time, there are no groups, programs or other aggregated level of capital expenditures that meet the criteria for inclusion in Table 3.

[7] For programs, the Total Forecast Cost is based on the forecast project cost at the earliest phase in the program. For projects that were included in Appendix I of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, the Total Forecast Cost used for the project is:

- The Authorized Amount (Column K) shown in Appendix I of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application for projects in the Implementation phase and projects that are in-service, and
- The Pre-Implementation Cost Estimate (Column J) shown in Appendix I of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application with the upper value of the range shown for projects for which a range was given in Appendix I.

Table 4 Capital Expenditures net of Contributions in Aid ($ million)

	F2021 RRA	F2021 Actual	F2021 Variance	F2022 Forecast	F2023 RRA
	(a)	(b)	(a)-(b)=(c)	(d)	(e)
CPCN	95	3	92	23	37
System Extensions[8]	257	319	(62)	345	369
Other Capital:					
Section 44.2	51	29	23	41	72
Exempt	83	60	23	17	1
Other Capital Investments	934	866	67	986	930
Site C	1,536	1,725	(189)	2,790	2,708
Total	2,956	3,002	(46)	4,201	4,118

[8] System Extensions includes capital expenditures to expand the service area or capacity of a utility plant or system and are not anticipated to exceed the $100 million CPCN filing threshold for Power System projects.

8 Internal Audit Reviews and/or Reports Provided in Fiscal 2021

British Columbia Utilities Commission Letter No. L-36-94, Direction No. 5

A list of topics covered in the internal audit reports together with a brief description of each topic.

The following internal audits were completed in the year ended March 31, 2021.

All audits were conducted in conformance with the International Standards for the Professional Practice of Internal Auditing.

A. Risk Based Audits

Integrated Planning

- Customer Interconnections
  - ▶ Description: Assessed the effectiveness of the Customer Interconnections processes to ensure projects comply with tariffs while maintaining customer relationships.

Capital Infrastructure Project Delivery

- Peace Region Electricity Supply Project
  - ▶ Description: Assessed the implementation and project management practices for the Peace Region Electricity Supply Project to meet the project objectives.
- Properties Capital Projects
  - ▶ Description: Assessed whether Properties capital projects are being appropriately managed and executed to deliver stated objectives.

- Bridge River Generator Units 7&8 Upgrade Project
  - ▶ Description: Assessed the implementation and project management practices for the Bridge River Generator Units 7 and 8 Upgrade Project to meet the stated objectives.
- Capital Infrastructure Project
  - ▶ Description: Assessed whether capital projects under $50 million are managed and executed in accordance with BC Hydro's processes and controls.

Powerex

- Regulatory Reporting
  - ▶ Description: Assessed the effectiveness of processes to ensure Powerex complies with regulatory reporting requirements.

B. Core Financial Process Audits

People, Customer, Corporate Affairs

- Transmission Billing
  - ▶ Description: Evaluated billing processes and controls to ensure transmission bills are complete, accurate, issued on time and in accordance with the Electric Tariff and Tariff Supplements.

Finance, Technology, Supply Chain

- Accounts Payable
  - ▶ Description: Assessed whether controls are operating effectively to ensure validity, accuracy and timeliness of payments.

C. Policy Compliance

Powerex

- Trade Processing Controls
  - Description: Confirmed whether Powerex has effective governance over the trade processing lifecycle and appropriate controls to ensure quality and accuracy of trade records.

D. Audit Follow-ups

Capital Infrastructure Project Delivery

- Polychlorinated Biphenyls (**PCB**) Phase Out Program
  - Description: Follow-up to the fiscal 2020 audit that assessed whether an effective Polychlorinated Biphenyls Phase Out Program is in place to meet regulatory requirements.

Finance, Technology, Supply Chain

- Cybersecurity Audit
  - Description: Follow-up to the fiscal 2019 audit that assessed whether BC Hydro has effective governance and appropriate controls related to threat and vulnerability management, incident response and vendor risk management.
- Fleet Management
  - Description: Follow-up to the fiscal 2020 audit that provided assurance that effective fleet management lifecycle processes exist to support business operations.

Integrated Planning

- Joint Ownership and Use Agreement
  - Description: Follow-up to the fiscal 2020 audit that assessed effectiveness of the management and administration of the Joint Ownership and Use Agreement for distribution poles between BC Hydro and Telus.

People, Customer, Corporate Affairs

- Payroll
  - Description: Follow-up to the fiscal 2020 audit that assessed controls over the payroll and related human resources processes and compliance with BC Hydro policies.
- Customer Billing
  - Description: Follow-up to the fiscal 2019 audit that assessed whether Customer Service billing processes and controls ensure bills are complete, accurate, timely and in accordance with the electric tariff.

Operations

- Columbia River Treaty
  - Description: Follow-up to the fiscal 2020 audit that assessed whether effective controls exist over the financial settlement process relating to the Columbia River Treaty: Non-Treaty Storage and Short-term Libby Agreements

Safety

- Asbestos Management Program
  - Description: Follow-up to the fiscal 2019 audit that assessed whether an effective Asbestos Management Program is in place and being followed.

Powerex

- IT Operational Controls
    - Description: Follow-up to the fiscal 2020 audit that provided assurance on the effectiveness of IT Operational Controls across key applications.

Powertech

- Financial Controls
    - Description: Follow-up to the fiscal 2020 audit that assessed the effectiveness of controls over financial processes at Powertech Labs Inc.

9 Management Letter Topics from External Auditor

British Columbia Utilities Commission Letter No. L-36-94, Direction No. 4

A list of topics covered in the management letter.

The following topic was covered in the management letter issued to British Columbia Hydro and Power Authority by the external auditor for the year ended March 31, 2021:

1. Security Controls in SAP Oracle Database.

10 British Columbia Utilities Commission Status Report of Compliance with Financial Directives or Commitments

10.1 The Waneta Transaction Report as prescribed in British Columbia Utilities Commission Order No. G-130-18

The Waneta Transaction Report shall consist of and shall be provided in a format acceptable to the Commission. The reports will be submitted as part of BC Hydro's Regulatory Annual Report and as an appendix in its Revenue Requirements Applications until 2058.

The Fiscal 2021 Waneta Transaction Annual Report, as required by Directive 4 (e) of BCUC Order No. G-130-18 is attached.

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Attachment to Section 10.1

Fiscal 2021 Waneta Transaction Annual Report

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List of Tables

1 Introduction

The Waneta Transaction Annual Report is prepared in compliance with BCUC Order No. G-130-18, Directive 4(e) of the Commission's Decision on the Waneta 2017 Transaction[1], as follows.

4. Pursuant to section 43 of the Act, the Commission Panel directs BC Hydro to file with the Commission:

   (e) An annual Waneta 2017 Transaction report (**Report**) which must include the following[2]:

      i. The operations, maintenance and capital expenditures including those major sustaining capital expenditures or operating and maintenance expenditures that BC Hydro was entitled to refer to a third-party referee and the related referee determinations as well as any significant non-sustaining capital expenditures that BC Hydro had the right to veto.

      ii. Annual cash flow comparison of actual expenditures versus estimated expenditures and an explanation for any variance greater than ten percent from the estimated expenditures;

      iii. Organization chart showing the Operator and members of the Operating Committee;

      iv. The monthly energy sale volumes and revenues; and the annual average energy selling price (in $/MWh);

      v. Summary of the Resource Physical Major Risks and mitigation measures employed;

1 BCUC Decision and Order No. G130-18, dated July 18, 2018 on British Columbia Hydro and Power Authority's Application for approval of BC Hydro's proposed purchase from Teck Metals Ltd. of its two-third Interest in the Waneta Dam along with Teck's transmission assets (Waneta 2017 Transaction Application).

2 Order No. G-130-18 included a bulleted list of directives under 4(e) which have been replaced with roman numerals for ease of reference against the sections in this report.

vi. Statement of Delivery of Capacity and Energy to BC Hydro under the Waneta 2017 Transaction; and

vii. Statement of Entitlement Adjustments under the Canal Plant Agreement and amendments to the Canal Plant Agreement.

viii. Once BC Hydro has purchased Teck's Transmission Assets, the annual OATT revenues accrued from Line 71.

(f) The Report will be submitted as part of BC Hydro's annual report and as an appendix in its revenue requirements applications until 2058.

2 Third-party Determinations (Response to Directive 4(e)(i))

No operations, maintenance and capital expenditures were referred to a third-party referee in fiscal 2021. Matters which require the unanimous approval of the Operating Committee, and which are subject to resolution by a third-party referee if Teck's and BC Hydro's representatives on the Operating Committee are unable to reach agreement, are set out in section 6.7(a) of the Co-Possessors and Operating Agreement (**COPOA**).

Non-Sustaining Capital Expenditures that are a "Shared Upgrade" require unanimous approval of the Operating Committee, and if there is no agreement, then the upgrade does not proceed (and there is no referral to a third-party referee) as set out in section 6.8(a) of the COPOA. BC Hydro notes that a Non-Sustaining Capital Expenditure can also be undertaken by BC Hydro at its sole discretion and cost (i.e., a BC Hydro Upgrade). There were no Non-Sustaining Capital Expenditures or BC Hydro Upgrades in fiscal 2021.

3 Operations, Maintenance and Capital Expenditures (Response to Directive 4(e)(ii))

Table 1 below provides the comparison of the Fiscal 2021 Decision and actual expenditures for fiscal 2021 for BC Hydro's 1/3 ownership. Table 2 provides the comparison Fiscal 2021 Decision and actual expenditures for fiscal 2021 for BC Hydro's 2/3's ownership, managed by Teck. Explanations are provided for variances greater than 10 per cent.

Table 1 Comparison of Actual and Forecast Expenditures for BC Hydro's 1/3, April 1, 2020 to March 31, 2021

($ thousand)	F2021 Decision	F2021 Actual	Variance	Variance (%)	Variance Explanation (if >10 %)
	1	2	3 = 2 - 1	4 = 3/1 x 100	
Operations and Maintenance[1]	2,634	2,805	171	6.5	
Sustaining Capital	1,726	2,670	944	54.7	Expenditures are higher than Forecast in fiscal 2021 primarily related to the Unit 3 Life Extension project. Project approvals were delayed in fiscal 2020, resulting in higher expenditures in fiscal 2021 than originally anticipated
Water Fees	6,638	6,071	-568	-8.5	

[1] Includes insurance and Teck administration.

Table 2 Comparison of Actual and Forecast Expenditures for Teck's 2/3, April 1, 2020 to March 31, 2021

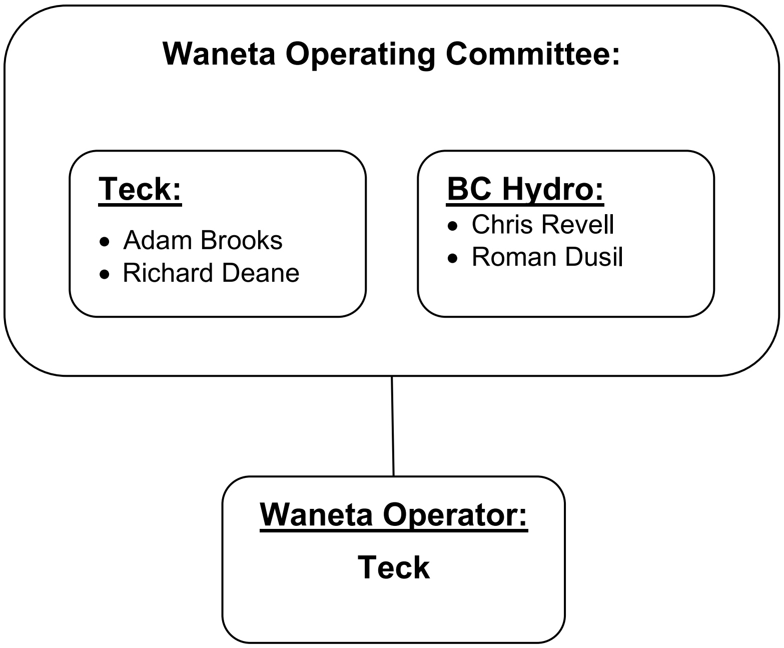
($ thousand)	F2021 Decision	F2021 Actual	Variance	Variance (%)	Variance Explanation (if >10 %)
	1	2	3 = 2 - 1	4 = 3/1 x 100	
Operations and Maintenance[1]	5,877	5,827	-49	-0.8	
Sustaining Capital	3,452	5,023	1,571	45.5	Expenditures are higher than Forecast in fiscal 2021 primarily related to the Unit 3 Life Extension project. Project approvals were delayed in fiscal 2020, resulting in higher expenditures in fiscal 2021 than originally anticipated.
Water Fees	3,868	3,254	-614	-15.9	Water rental fees are determined as a function of generation multiplied by the applicable water rental rates, and generation varies based on inflows. Accordingly, lower than average inflows in the year the calculation is based on, fiscal 2021, resulted in lower generation and corresponding lower Water Rental Fees

[1] Includes insurance and Teck administration.

Based on the criteria defined under the COPOA, unanimous approval of the Operating Committee was required for the calendar 2020 sustaining capital budget. This provision was triggered as a result of increases to planned capital work compared to prior years.

4 Organization Chart (Response to Directive 4(e)(iii))

The following chart shows the members of the Operating Committee and the Operator.



5 Surplus Power Rights Agreement (Response to Directive 4(e)(iv))

Table 3 below provides monthly energy sale volumes and payments pursuant to the Surplus Power Rights Agreement with Teck. BC Hydro purchased a total of 85.6 GWh of surplus energy from Teck during fiscal 2021 under section 5 of the agreement at an average price of C$33.59/MWh.

Table 3 Surplus Power Rights Agreement Purchases

	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	Mar 2021	Total
Invoice Total ($k)	-	-	-	-	291	555	605	202	160	380	289	391	2,874
Volume (MWh)	-	-	-	-	17,056	15,000	15,000	5,000	5,000	11,000	10,500	7,000	85,556

6 Risks and Mitigation Measures (Response to Directive 4(e)(v))

As part of phase two of the dam stability work, the buried channel assessment is an ongoing study to assess potential percolation flows and effectiveness of a drainage filter that was installed during the original construction of the Waneta Dam in the 1950s. Two monitoring wells were installed in 2019 and the data is being monitored and will be analyzed in 2021.

Starting in 2021, a new stability analysis will be undertaken using present day best practices including a damping ratio of 5% and use of foundation with mass. An independent review team, including representation from BC Hydro, has been proposed for this project. If deemed appropriate by the independent review team, field measurements (i.e., ambient vibration testing) will be completed to calibrate the stability model.

7 Delivery of Capacity and Energy to BC Hydro (Response to Directive 4(e)(vi))

The annual capacity and energy benefit to BC Hydro under the Waneta Transaction is the reduction in the amount of entitlement that BC Hydro is obligated to provide Teck under the Canal Plant Agreement (**CPA**), with and without the Waneta 2017 Transaction. The reduction in BC Hydro's obligation to provide capacity and energy entitlement to Teck for fiscal 2021, with and without the Waneta 2017 Transaction, is provided below in Table 4. Additional information on this entitlement adjustment is provided in section 8 of this report.

Table 4 Comparison of BC Hydro's Obligation to Provide CPA Entitlement

F2021 (April 1, 2020 to March 31, 2021)	Without Waneta Transaction	With Waneta Transaction	Reduction
	1	2	3 = 1 - 2
Base Capacity Entitlement (MW)	496 (winter peak)	248 (winter peak)	248
Base Energy Entitlement (GWh)	2,746	1,880	866

8 Statement of Entitlement Adjustments under the Canal Plant Agreement (Response to Directive 4(e)(vii))

The last entitlement adjustment resulted from a redetermination when the Waneta Expansion came online in April 2015.

9 Annual OATT Revenues Accrued from Line 71 (Response to Directive 4(e)(viii))

Teck continues to own Line 71 until the end of the Waneta Lease in 2038 (or 2048 if Teck elects to extend the lease). As such, there were no OATT revenues in fiscal 2021.

10.2 Summary Report on Volumes and Pricing of Transmission Capacity Reassignment and Simultaneous Submission Window as Required by British Columbia Utilities Commission Order No. G-102-09

The Commission Panel directs BCTC to prepare a summary report on the volumes and pricing of any reassigned transmission capacities on its system. This report is to be included in BCTC's annual report to the Commission.

The fiscal 2021 summary report on volumes and pricing of transmission capacity reassignments, and simultaneous submission window, as required by BCUC Order No. G-102-09, is provided below.

10.2.1 Introduction

On November 21, 2008, British Columbia Transmission Corporation (**BCTC**) applied to the Commission to amend its Open Access Transmission Tariff (**OATT**) (**the Application**). The Application consisted of four parts:

- Amendments requested to maintain consistency with the revised pro forma tariff of U.S. Federal Energy Regulatory Commission (**FERC**);
- Miscellaneous "housekeeping amendments" required to address minor issues which had arisen under BCTC's current OATT;
- Amendments to the rate design for Short-Term Point-to-Point transmission service; and
- Amendments to address issues which had arisen on the British Columbia to Alberta path, including a complaint filed by TransCanada Energy Ltd., one of BCTC's customers, on October 9, 2008.

On September 10, 2009, the Commission issued its Decision on all parts of the Application (The TransCanada Energy Ltd. complaint was addressed in a separate decision issued on the same day). In its Decision and Order No. G-102-09, section 3.3.3 and 3.6.3.1, among other things, the Commission directed BCTC to include two new reports in its Annual Financial Report to the Commission. The following two reports are provided below:

- Transmission capacity reassignment; and
- Assessment of simultaneous submission window.

Unless otherwise defined, capitalized terms in sections 10.2.2 and 10.2.3 are defined in the North American Energy Standards Board's (**NAESB**) Business Practice Standards (**BPS**) Abbreviations, Acronyms and Definition of Terms document.

10.2.2 Transmission capacity reassignment

As part of the Application, BCTC proposed to amend the OATT to accord with FERC Order 890 provisions that lifted the price cap on reassignment of transmission capacity for a trial period ending in October 2010, subject to FERC assessment of the impact of the measure. BCTC proposed to review FERC's assessment and file any necessary changes to the OATT with the Commission.

The Commission approved the Capacity Reassignment provisions as proposed in the Application and observed that the creation of a secondary market may provide increased access to the transmission system, thereby promoting more efficient utilization of the grid. The Decision noted that the implementation plan described in FERC Order 890 included a requirement for quarterly reporting and directed BCTC to include a summary report in BCTC's annual report to the Commission on the volumes and pricing of any reassigned transmission capacity on its system.[1]

On December 1, 2010, BC Hydro implemented the Market Operations Development System (**MODS**). MODS provides BC Hydro the ability to facilitate the capacity reassignment provisions contemplated in the Application.

During the fiscal year ended March 31, 2021, BC Hydro observed that 711 Confirmed Resale transactions occurred on three paths:

- 14 occurred on the BCHA-AESO path;
- 670 occurred on the BCHA-BPAT path; and
- 27 occurred on the BPAT-AESO wheel through path.

Of the total Resale transactions:

[1] In The Matter Of British Columbia Transmission Corporation and Amendments to The Open Access Transmission Tariff Decision, September 10, 2009, page 7.

- 647 were from Hourly Firm Point-to-Point (**PTP**) Transmission Service to Hourly Firm PTP Transmission Service;
- 25 were from Daily Firm PTP Transmission Service to Daily Firm PTP Transmission Service;
- 11 were from Monthly Firm PTP Transmission Service to Monthly Firm PTP Transmission Service; and
- 28 were from Yearly Firm PTP Transmission Service to Yearly Firm PTP Transmission Service.

On two of the three paths (BCHA-AESO and BCHA-BPAT), the same customer resold transmission service to itself. On the third path (BPAT-AESO), transmission service was sold from one customer to a second customer, and the second customer resold the transmission service to a third customer. Each path's Resales were scheduled on the same path, Point of Receipt (**POR**), and Point of Delivery (**POD**) as the Original transmission reservation, but for terms varying from one hour up to 11 months.

On the BCHA-AESO path, 14 Resale transactions ranging from 25 MW to 380 MW were resold. A total of 380 MW was resold in one month, 710 MW was resold in 10 months, and 810 MW was resold in one month of the fiscal year. All of these Resale transmission reservations were the aggregation of two to six transmission reservations from one customer to itself on the same path. The duration of Resale transmission reservations ranged from two days to 11 months.

On the BCHA-BPAT path, there were a total of 670 hourly Resale transmission reservations. All Resale transmission reservations were the aggregation of two to seven transmission reservations from one customer to itself on the same path and varied between 1 MW and 1,980 MW. The duration of the Resale transmission reservations ranged from one hour to three days.

On the BPAT-AESO path, 27 Resale transactions ranging from 25 MW to 50 MW were resold on the same path in one-month terms. In nine months of the fiscal year, one to two transmission reservations were resold from one customer to a second customer. The second customer aggregated the two Resale transmission reservations and resold the capacity to a third customer.

Prices of the Confirmed Resale transmission reservations varied between originating and resold transmission reservations. Prices ranged from $1.00 to $10.11 with $0.00 being the smallest difference in price and $8.31 being the greatest difference in price.

On the BCHA-AESO path, 14 Resale transmission reservation prices ranged from $8.95 to $9.31 while originating transmission reservation prices ranged from $7.42 to $10.11. Five Resale transmission reservations had a lower price, seven Resale transmission reservations had a higher price, and two Resale transmission reservations had a price equal to their originating transmission reservations.

On the BCHA-BPAT path, 670 Resale transmission reservation prices ranged from $8.95 to $9.31 while originating transmission reservation prices ranged from $1.00 to $9.31. One Resale transmission reservation had a lower price, 535 Resale transmission reservations had a higher price, and 134 Resale transmission reservations had a price equal to their originating transmission reservations.

On the BPAT-AESO path, 27 Resale transmission reservation prices ranged from $8.95 to $9.44 while originating transmission reservation prices ranged from $5.40 to $9.44. Four Resale transmission reservations had a lower price, and 23 Resale transmission reservations had a higher price than their originating transmission reservations.

10.2.3 Assessment of Simultaneous Submission Window (SSW)

During the fiscal year ended March 31, 2021, BC Hydro experienced 9 instances of SSW, which involved a total of 16 Transmission Service Requests (**TSRs**). In each instance, the SSW opened during the first five minutes of the earliest request time for Hourly Firm and Non-Firm Transmission Service, which ranged from one to five working days prior to the start of service (subject to extended windows, if applicable).

There were no instances of SSW during the months of April, May, June and July 2020.

During the month of August 2020, there were five instances of SSW. Ten Original TSRs for Hourly Firm and one Original TSR for Hourly Non-Firm Transmission Service ranging from 1 to 400 MW were submitted on OASIS within the five-minute SSW between 00:00:00 to 00:05:00 PPT. In two instances, there were two customers competing for transmission service. In the other three instances, only one customer requested transmission service. Seven TSRs were Confirmed and granted the requested capacity shortly after the SSW closed. Four TSRs were Refused for insufficient Available Transfer Capability (**ATC**).

There were no instances of SSW during the month of September 2020.

During the month of October 2020, there were three instances of SSW. Four Original TSRs for Hourly Firm Transmission Service ranging from 25 to 1,420 MW were submitted on OASIS within the five-minute SSW between 00:00:00 PPT to 00:05:00 PPT. In all three instances, only one customer requested transmission service. Three TSRs were Confirmed and granted the requested capacity shortly after the SSW closed, and one TSR was Withdrawn by the customer.

There were no instances of SSW during the months of November and December 2020, and January 2021.

During the month of February 2021, there was one instance of SSW. One Original TSR for Hourly Firm Transmission Service of 1,720 MW was submitted on OASIS within the five-minute SSW between 00:00:00 PPT to 00:05:00 PPT. The one TSR was Confirmed and granted the requested capacity shortly after the SSW closed.

There were no instances of SSW during the month of March 2021.

Given the limited number of SSW instances, the absence of multiple parties competing for the same capacity, and the fact that most Confirmed TSRs were granted their requested capacity, BC Hydro is of the view that all instances of competition are fair since the implementation of SSW.

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Appendix A

Annual Deferral Accounts Report

April 1, 2020 to March 31, 2021

List of Schedules

Appendices

Schedule A BC Hydro Summary of Deferral Accounts For the Year Ended March 31, 2021 ($ million)

Line No.	Particulars (Note 1)	Opening Balance at April 1, 2020	Opening Balance Adjustment (Note 2)	Changes (Note 3)	Amortization (Note 4)	Interest (Note 5)	Net Change	Ending Balance at March 31, 2021
	(1)	(2)	(3)	(4)	(5)	(6)	(7) = (3)+(4)+(5)+(6)	(8)=(2)+(7)
1	Heritage Deferral Account (HDA)	(300.1)	60.6	77.8	229.5	(3.0)	364.9	64.8
2	Non-Heritage Deferral Account (NHDA)	204.7	(351.6)	(117.7)	116.8	(5.7)	(358.2)	(153.4)
3	Trade Income Deferral Account (TIDA)	(173.8)	55.7	(210.2)	105.1	(3.5)	(52.9)	(226.7)
4	Load Variance	-	20.3	85.8	-	3.5	109.6	109.6
5	Biomass Energy Program Variance	-	(1.1)	(13.0)	-	(0.3)	(14.3)	(14.3)
6	Total	(269.1)	(216.2)	(177.1)	451.4	(9.0)	49.1	(220.0)

Due to minor rounding some totals may not add.

Note 1: In the October 29, 2004 Commission Decision (Order No. G-96-04) on the Fiscal 2005 to Fiscal 2006 Revenue Requirements Application (**Fiscal 2005 to Fiscal 2006 RRA**), the Commission approved the creation of four deferral accounts (Heritage Deferral Account, Non-Heritage Deferral Account, Trade Income Deferral Account and BCTC Deferral Account) to capture the differences between forecasts used in setting rates and actual costs. By Order No. G-16-11, the Commission approved the termination of the BCTC Deferral Account.

In the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**Fiscal 2020 to Fiscal 2021 RRA**) dated October 2, 2020 (Order No. G-246-20), the Commission approved the creation of two additional cost of energy variance accounts. The Load Forecast Variance account captures the variance between planned and actual domestic customer load. The Biomass Energy Program account captures the variance between forecast and actual amounts related to the Biomass Energy Program.

Note 2: The opening balance adjustment relates to the BCUC's Decision on the Previous Application (Order No. G 246 20) issued in October 2020. In its Decision BCUC directed adjustments to BC Hydro's revenue requirements for fiscal 2020 and fiscal 2021. As BC Hydro's fiscal 2020 financial statements were already finalized, the impacts to the deferral accounts related to fiscal 2020 were reflected as opening balance adjustments.

Note 3: Please refer to Schedule B for details of the changes.

Note 4: Revenues collected via the Deferral Account Rate Rider (**DARR**) are used to amortize the deferral account balances in accordance with Section 10(3) in Direction No. 7 of the Fiscal 2015 to Fiscal 2016 Revenue Requirements Application (**Fiscal 2015 to Fiscal 2016 RRA**). The DARR revenue is allocated to each deferral account based on the proportion of the deferral account balances at the end of the prior fiscal year. In Phase One of the Comprehensive Review, the Government of B.C. repealed Direction No. 7. In the Decision to the Fiscal 2020 to Fiscal 2021 RRA, the BCUC approved BC Hydro's request to reduce the DARR from 5 per cent to 0 per cent on April 1, 2019 and to refund the fiscal 2019 net closing balance and the forecast fiscal 2020 and fiscal 2021 net additions and net interest applied to the Cost of Energy Variance Accounts, over the fiscal 2020 to fiscal 2021 test period.

Note 5: Interest is calculated on the monthly balance in each deferral account. The interest rate used is BC Hydro's actual weighted average cost of debt for its current fiscal year per Directive 1 (xxv) of the Fiscal 2012 to Fiscal 2014 Revenue Requirements Application (**Fiscal 2012 to Fiscal 2014 RRA**).

Schedule B BC Hydro Summary of Deferral Accounts Changes For the Year Ended March 31, 2021 ($ million)

Line No.	Particulars	Plan	Actual	Variance	Ref.
	(1)	(2)	(3)	(4) = (3) - (2)	(5)
1	**Summary of Deferral Accounts Changes**				
2					
3	**Items Subject to Heritage Deferral Account:**				
4	Heritage Deferral Account Transactions	213.0	284.6	71.6	Note 1
5	Notional Water Rental (Displaced Hydro)	(1.8)	0.0	1.8	
6	Skagit Valley Treaty & Ancillary Revenue	(35.9)	(30.0)	5.9	Note 2
7	Costs in Operating / Amortization	12.5	11.0	(1.5)	
8	Other	31.2	31.2	0.0	
9	Total	219.0	296.9	77.8	Schedule A Line 1
10					
11	**Items Subject to Non-Heritage Deferral Account:**				
12	Non-Heritage Deferral Account Transactions	1,449.6	1,234.3	(215.3)	Note 3
13	Commodity Risk	-	90.0	90.0	Note 4
14	Notional Water Rental (Displaced Hydro)	1.8	-	(1.8)	
15	Deferred Operating in NHDA	-	1.5	1.5	
16	Waneta - 2/3 - Teck Portion of Capital Expenditures	-	(5.0)	(5.0)	Note 5
17	Less: IPP subject to Biomass Energy Program Variance	(80.7)	(66.0)	14.7	Note 6
18	Other	-	(1.9)	(1.9)	
19	Total	1,370.7	1,253.0	(117.7)	Schedule A Line 2
20					
21	**Trade Income Deferral Account**				
22	Trade Income	(176.3)	(386.4)	(210.2)	Note 7, Schedule A Line 3
23					
24	**Load Variance Deferral Account**				
25	Load Variance	(5,036.3)	(4,950.5)	85.8	Note 8, Schedule A Line 4
26					
27	**Biomass Energy Program Variance Deferral Account**				
28	Cost of Energy	80.7	66.0	(14.7)	Note 6
29	Revenues	(15.2)	(13.5)	1.7	
30	Biomass Enegy Program Variance	65.5	52.5	(13.0)	Schedule A Line 5
31					
32	Due to minor rounding some totals may not add.				

The following Schedule B explanations are provided for variances over +/- $2 million.

Note 1: Actual Heritage Deferral Account Transactions were $71.6 million higher than fiscal 2021 RRA Plan, mainly driven by changes in the classification of market energy transactions upon the implementation of the 2020 Transfer Pricing Agreement. For additional details, please refer to the BC Hydro Annual Report to the Commission, Attachment 2 to Section 6 Financial Schedules, Schedule 4.0 Cost of Energy, Lines 20+26+27+31+37.

Note 2: As per BCUC Order No. G-96-04, the HDA captures variances between forecast and actual costs and revenues related to the Skagit Valley Treaty. In fiscal 2021, actual revenues under the Skagit Valley Treaty were $5.9 million lower than the fiscal 2021 RRA Plan, which was increased based on Directive 4 of the F20 to F21 RRA Decision to reflect the percentage variance experienced between April 2019 to December 2019 in each of BC Hydro's customer class.

Note 3: Actual Non-Heritage Deferral Account Transactions were ($215.3) million lower than the fiscal 2021 RRA Plan, mainly driven by higher net System Exports of ($201.0) million due to the change in classification of market energy transactions as described in Note 1, as well as due to lower domestic load requirements and higher water inflows. For additional details, please refer to the BC Hydro Annual Report to the Commission, Attachment 2 to Section 6 Financial Schedules, Schedule 4.0 Cost of Energy, Lines 25+28+29+30+46.

Note 4: Commodity Risk of $90.0 million consists of mark-to-market gains/losses on intercompany transactions under the 2020 Transfer Pricing Agreement with Powerex. Powerex recognizes an offsetting gain/loss and therefore there is no impact to ratepayers.

Note 5: Revenues of $5.0 million deferred in the NHDA are associated with capital expenditures made by Teck Resources with respect to BC Hydro's purchase of Teck's two-third interest in Waneta. During the lease term these revenues may be deferred to the NHDA, per BCUC Order No. G-130-18.

Note 6: Variances between approved and actual IPP costs incurred under the Biomass Energy Program were excluded from the NHDA and deferred into the Biomass Energy Program account, as approved per BCUC Order No. G-246-20 (Directive 38). Actual IPP costs incurred under the Biomass Energy Program were $14.7 million lower than the fiscal 2021 RRA due to outages, maintenance, and other factors.

Note 7: The transfer of ($210.2) million is due to higher than plan Powerex Net Income. Powerex Net Income reported for regulatory purposes is net of $2.9 million corporate overhead allocation from BC Hydro to Powerex in accordance with Directive 9 of the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application (Fiscal 2009 to Fiscal 2010 RRA) Decision (BCUC Order No. G-16-09).

Note 8: The load variance of $85.8 million is primarily due to lower sales to Large Industrial customers, related to poor market conditions, that are largely attributable to the COVID-19 pandemic, and to Light Industrial and Commercial customers, which were impacted by closures and curtailments due to public health orders relating to the COVID-19 pandemic. This was partially offset by higher consumption by Residential customers, where the likely primary driver is the COVID-19 pandemic, which saw residential customers stay home more and work from home, resulting in higher consumption. For more information, refer to section 1 of Attachment 1 to Section 6 of the BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission.

BC Hydro
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BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Appendix A

Appendix 1

Deferral Accounts Rules

The following "rules" are used by BC Hydro to determine transfers to the Deferral Accounts. These rules are derived from BC Hydro's interpretation of the evidence and testimony provided during the Fiscal 2005 to Fiscal 2006 Revenue Requirement Application (**RRA**) proceeding and from Directive No. 19 of the BCUC's October 29, 2004 Decision on the Fiscal 2005 to Fiscal 2006 RRA (BCUC Order No. G-96-04). These rules have been updated for the following orders and directives:

- Fiscal 2007 to Fiscal 2008 RRA Negotiated Settlement Agreement (**NSA**) (BCUC Order No. G-143-06);
- Directives included in the BCUC's Decision on the Fiscal 2009 to Fiscal 2010 RRA (BCUC Order No. G-16-09);
- Fiscal 2011 RRA NSA (BCUC Order No. G-180-10);
- Directives included in the BCUC's Decision on the Fiscal 2012 to Fiscal 2014 RRA (BCUC Order No. G-77-12A);
- Directives included in the BCUC's Decision on the Fiscal 2015 to Fiscal 2016 RRA (BCUC Order No. G-48-14);
- Directives included in the BCUC's Decision on the Fiscal 2017 to Fiscal 2019 RRA (BCUC Order No. G-47-18).
- Directives included in the BCUC's Decision on the Fiscal 2020 to Fiscal 2021 RRA (BCUC Order No. G-246-20); and
- Directives included in the BCUC's Decision on the 2020 Transfer Pricing Agreement (BCUC Order No. G-127-21).

In Phase One of the Comprehensive Review, the Government of B.C. repealed Directions 3, 6 and 7 to the BCUC. Direction No. 7 to the BCUC included the

Heritage Contract. The repeal of the Heritage Contract has no impact on BC Hydro or ratepayers; however, it provides BC Hydro with the flexibility to re-categorize its Cost of Energy into Heritage Energy, Non-Heritage Energy and Market Energy as shown in the BC Hydro Annual Report to the Commission, Attachment 2 to Section 6 Financial Schedules, Schedule 4.0 Cost of Energy. Some of the Orders referred to above reference terms that were included in the Heritage Contract, such as the Heritage Payment Obligation. BC Hydro has revised the Deferral Account Rules to update these references. These Deferral Account Rules are also updated for the BCUC's Decision on the F2020-F2021 RRA, which directed BC Hydro to create two new cost of energy variance accounts, the Load Forecast deferral account and the Biomass Energy Program account. Also updated in these Rules are terminologies and references based on the 2020 Transfer Pricing Agreement, which the BCUC accepted as filed pursuant to section 71 of the *Utilities Commissions Act*.

Where a component of the Deferral Account Rules below is followed by a footnote, the language is from the noted BCUC decision or ongoing regulatory proceeding. Where a footnote is not shown, the language represents BC Hydro's interpretation of the evidence and testimony noted above.

Heritage Deferral Account (HDA)

Items Subject to Heritage Deferral Account (HDA)

Commission Decision, October 29, 2004, Page 41:

Commission Findings

The Commission Panel approves the HDA as proposed by BC Hydro.

Variances between the forecast and the actual cost for the following will flow through the HDA:

1. Cost of energy[1]

   This includes the cost of Heritage Energy[2], Domestic Transmission – Export costs as well as all Market Electricity Purchases and Surplus Sales[1] up to March 31, 2020 under the 2003 Transfer Pricing Agreement. The 2003 Transfer Pricing Agreement has been replaced by the 2020 Transfer Pricing Agreement[3] (**2020 TPA**) effective April 1, 2020. In accordance with Direction No.8 to the BCUC, BCUC Order No. G-127-21 approved the 2020 TPA as filed by BC Hydro. The adoption of the 2020 TPA resulted in a change in the presentation of transactions relative to the terms used in BCUC Order G-96-04. The terms from Order G-96-04, “Market Electricity Purchases”, “Surplus Sales” and “Net Purchases (Sales) From Powerex” were replaced by “System Exports” and “System Imports” under the 2020 TPA and variances in these items are deferred to the Non-Heritage Deferral Account.

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[1] Per Fiscal 2005 to Fiscal 2006 RRA Decision, Directive 11 (BCUC Order No. G-96-04), amended by the Fiscal 2009 to Fiscal 2010 RRA Decision, Directive 31 (BCUC Order No. G-16-09), as continued by the Fiscal 2015 to Fiscal 2016 RRA Decision, Directive 5 (BCUC Order No. G-48-14).

[2] As shown in the BC Hydro Annual Report to the Commission, Attachment 2 to Section 6 Financial Schedules, Schedule 4.0 Cost of Energy.

[3] Per Decision on BC Hydro’s 2020 Transfer Pricing Agreement with Powerex, as approved via BCUC Order No. G-127-21.

The following is a list of other variances that also flow through the HDA:

- Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs;
- Variances resulting from changes to compensation and mitigation costs, water rental remissions, or Skagit energy transportation contracts are eligible for deferral. These are price variances as they do not vary with volume; and
- Variances between forecast and actual load curtailment costs are to be included in the HDA.[4]

2. Variable costs related to thermal generation.[1]
3. Significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events.[1]
4. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events.[1]
5. Amortization of unplanned deferred capital costs pursuant to BCUC Order No. G-53-02.[1,5]
6. Skagit Valley Treaty revenues and ancillary services revenues.[1]
7. An interest charge/credit[6] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[7]

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4 Per Fiscal 2009 to Fiscal 2010 RRA Decision, Directive 30 (BCUC Order No. G-16-09).

5 Per Fiscal 2017 to Fiscal 2019 RRA Decision, Directive 7, annual negotiation costs related to First Nations are excluded from amounts deferred to the Heritage Deferral Account, effective March 31, 2017 (BCUC Order No. G-47-18).

Non-Heritage Deferral Account (NHDA)

Items Subject to Non Heritage Deferral Account (NHDA)

Commission Decision, October 29, 2004, Page 41:

Commission Findings

The Commission Panel approves all elements of the NHDA, except the distribution emergency restoration costs elements, item 4, because it can be forecast with some confidence, unlike unplanned major capital expenditures and unplanned major maintenance expenditures, and because of risk/reward considerations. Given the denial of item 4 of the NHDA, item 3 of the NHDA is to be as set forth in Final Argument.

Variances between the forecast and the actual cost for the following components will flow through the NHDA:

1. Cost of energy[8] - all energy costs variances not deferred to the HDA and the Biomass Energy Program Variance Regulatory account, including all System Imports and System Exports variances under the 2020 TPA with Powerex[3] effective April 1, 2020. These items are explained in greater detail below to provide clarification on the methodology used to determine variances:
   - Any variances relating to fixed price gas and other transportation contracts would flow through the deferral accounts as they do not vary with volume;

[6] Per Fiscal 2005 to Fiscal 2006 RRA Decision, Directive 18 (BCUC Order No. G-96-04), amended by the Fiscal 2007 to Fiscal 2008 RRA Negotiated Settlement Agreement (BCUC Order No. G-143-06).

[7] Per Fiscal 2012 to Fiscal 2014 RRA Decision, Directive 1 (xxv) (BCUC Order No. G-77-12A).

[8] Per Fiscal 2005 to Fiscal 2006 RRA Decision, Directive 12 (BCUC Order No. G-96-04), amended by Fiscal 2009 to Fiscal 2010 RRA Decision, Directive 31 (BCUC Order No. G-16-09), as continued by the Fiscal 2015 to Fiscal 2016 RRA Decision, Directive 5 (BCUC Order No. G-48-14).

- Future Trade: For transactions applicable under the 2003 Transfer Pricing Agreement up to March 31, 2020 (replaced with the 2020 TPA[3] with Powerex as of April 1, 2020), when Powerex purchases energy for future trade the cost of the purchase from the external party and the sale to BC Hydro of this energy is recorded in Powerex and is included as part of Trade Income. The BC Hydro side of the entry is shown as part of domestic energy costs (on consolidation, the Powerex revenue from BC Hydro and the BC Hydro energy costs from Powerex are eliminated). The difference between Actual and Plan on the BC Hydro side relating to energy for future trade flows through the NHDA. The Powerex side of the transaction, which is part of Trade Income, flows through the TIDA. Similar treatment is applied when the energy is returned to Powerex;
- Future Trade: For transactions under the 2003 TPA prior to March 31, 2020 (and replaced by the 2020 TPA[3] with Powerex as of April 1, 2020), when Powerex purchased energy for future trade, Heritage Energy was charged with a notional water rental charge for the use of this energy. The other side of this entry was shown as part of Non-Heritage energy. These entries were eliminated on consolidation. The difference between the Actual and Plan notional water rentals that was part of Heritage Energy flowed through the HDA. The opposite variance relating to the Non-Heritage side of the notional water rental transaction flowed through the NHDA. Notional water rentals are no longer applicable under the 2020 TPA[3] as exports and imports of energy are no longer classified as trade and domestic;
- System Imports: represents purchases of electricity by BC Hydro from Powerex and thermal generation run for Powerex under the 2020 TPA;[3]
- System Exports: represents sales of electricity to Powerex by BC Hydro under the 2020 TPA;[3] and

- Gains/losses on energy derivatives and financial instruments used to minimize energy costs are included as part of total energy costs.

2. Significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure.[8]
3. Significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events.[8]
4. Founding Partner Benefits and CIS Credits under the ABS Contract.[8,9]
5. Costs incurred by BC Hydro in fiscal 2014 or a later fiscal year arising from the decommissioning of the Burrard Thermal Plant that are not required for transmission support services, including employee retention costs, penalties or damages that arise as a result of the decommissioning, and the net increase in amortization expense in fiscal 2015 and fiscal 2016.[10]
6. Variances related to the Northwest Transmission Line (**NTL**) Supplemental Charge revenues in conjunction with Tariff Supplement No. 37 amendments.[11]
7. Variances related to Electricity Purchase Agreements (**EPAs**) classified as finance leases in the Fiscal 2017 to Fiscal 2019 RRA. BC Hydro has deferred cost variances attributable to EPAs classified as finance leases that would not be transferred to existing regulatory accounts pursuant to existing orders in fiscal 2017 and fiscal 2018, which benefitted ratepayers.
8. Variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to

[9] The ABS Contract expired on April 30, 2018 and all services previously performed by Accenture have been repatriated by BC Hydro.
[10] Per Fiscal 2015 to Fiscal 2016 RRA Decision, Directive 6 (BCUC Order No. G-48-14).
[11] Per Tariff Supplement No. 37 Amendments Application Decision, Directive 3 (BCUC Order No. G-68-17).

the NHDA, as approved in BCUC's Decision on BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application.

9. Fiscal 2019 incremental lease revenues arising from the Waneta 2017 Transaction and the revenue BC Hydro is required to recognize from time to time in consequence of Teck's capital expenditures at Waneta until the end of the Lease Period.[12]

10. Variances between forecast and actual transmission service revenue[13] including External Open Access Transmission Tariff (**OATT**) revenues and point-to-point charges to Powerex.

11. An interest charge/credit is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[7]

[12] Per Waneta 2017 Transaction Application Decision, Directive 3 (BCUC Order No. G-130-18).

[13] Per Disposition and Termination of BCTC Regulatory Accounts and BC Hydro's BCTC Deferral Account Application Decision, Directive 4 (BCUC Order No. G-16-11).

Trade Income Deferral Account (TIDA)

Commission Decision, October 29, 2004, Page 42, Section 4.6:

Commission Findings

The Commission Panel approves the TIDA as proposed by BC Hydro.

- Any variance between the forecast Trade Income and the actual Trade Income will flow through the TIDA, except where Annual Trade Income is below zero;[14]
- Actual Trade Income is determined as the greater of
  - BC Hydro's consolidated net income adjusted as follows:
    - Subtracting BC Hydro's non-consolidated net income;
    - Subtracting the net income of subsidiaries excluding Powerex;
    - Subtracting any foreign currency translation gains in the fiscal year on intercompany balances between BC Hydro and Powerex;
    - Adding any foreign currency translation losses in the fiscal year on intercompany balances between BC Hydro and Powerex.
  - Zero
- An interest charge/credit[6] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[7]

[14] Per OIC 172 Direction No. 8 amendment, dated March 22, 2021, BC Hydro includes the net income of Powerex and Powertech in its revenue requirements and defers to the trade income deferral account the variances between actual and forecast trade income. The OIC provides the definition of Trade Income.

Biomass Energy Program Variance Regulatory Account

Commission Decision, October 2, 2020, Page 121, Section 4.5.1:

Commission Findings

The Commission Panel directs that this account be categorized as one of BC Hydro's cost of energy variance accounts and to apply the same mechanisms for interest charges and recovery that are applicable to the Non-Heritage Deferral Account[15].

- All variances between forecast and actual amounts related to the Biomass Energy Program are deferred, including variances in:
    - Independent Power Producer costs incurred under the Biomass Energy Program;
    - Domestic Revenues earned under the Biomass Energy Program; and
    - Any other costs not classified as cost of energy for accounting purposes and incurred under the Biomass Energy Program.
- The same mechanism for recovery that is applicable to the Non-Heritage Deferral Account is applied to the Biomass Energy Program Variance Regulatory Account.
- An interest charge/credit[6] is applied to the monthly balance at BC Hydro's weighted average cost of debt for its current fiscal year.[7]

[15] Per Fiscal 2020 to Fiscal 2021 RRA Decision, Directive 38 (BCUC Order No. G-246-20).

Load Variance Regulatory Account (LVRA)

Commission Decision, October 2, 2020, Page 43, Section 4.2.4:

Commission Findings

The Commission Panel directs the establishment of a load forecast variance account and directs BC Hydro to move all balances related to load forecast variance from the Non Heritage Deferral Account to the load forecast variance account. BC Hydro is directed to use the load forecast variance account to capture the variances between planned and actual domestic customer load. The Panel directs that the load forecast variance account be categorized as one of BC Hydro's cost of energy variance accounts and that BC Hydro apply the same mechanisms for interest charges and recovery that are applicable to the Non-Heritage Deferral Account. [16]

- All revenue variances resulting from variances between planned and actual domestic customer load (excluding variances attributable to the Biomass Energy Program) are deferred to LVRA.
- The same mechanisms for recovery that are applicable to the NHDA are applied to the LVRA.
- An interest charge/credit[6] is applied to the monthly balance at BC Hydro's weighted average cost of debt for its current fiscal year.[7]

[16] Per Fiscal 2020 to Fiscal 2021 RRA Decision, Directive 15 (BCUC Order No. G-246-20).

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Appendix B

Debt Management Regulatory Account Annual Status Report

April 1, 2020 to March 31, 2021

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Appendices

Background

On March 30, 2016, the BCUC issued Order No. G-42-16 which authorized BC Hydro to establish a Debt Management Regulatory Account (**DMRA**) to capture mark-to-market gains and losses on financial contracts that hedge future long-term debt to mitigate interest rate risk related to future long-term debt that BC Hydro intends to issue. In compliance with Directive 4 of that Order, BC Hydro provides below its annual report on the DMRA.

Report as at March 31, 2021

During fiscal 2021, BC Hydro did not enter into any future debt hedges (**FDHs**) to mitigate interest rate risk on future long-term debt that BC Hydro intends to issue as we reached our hedging target as per our Liability Risk Management policy. The existing outstanding hedges consist of 10-year and 30-year interest rate swaps, with remaining contract maturity dates ranging from approximately three months to 3.25 years and forecast borrowing yields ranging from 3.15 per cent to 3.67 per cent.

Since the establishment of the DMRA and as at March 31, 2021, a total of $10.0 billion of FDHs have been placed, of which $3.2 billion remain outstanding. Based on BC Hydro's 2021/22 to 2023/24 Service Plan, at March 31, 2021, BC Hydro had hedged approximately 40 per cent of forecast long-term debt issuances for fiscal 2022 to fiscal 2025. The details of all FDHs are included in Appendix 1.

Lower (higher) long-term interest rates result in lower (higher) interest costs on the associated future long-term debt issues when issued. These lower (higher) interest costs on the associated debt issues provide an offset to the impact of the FDH losses (gains). This results in the net effect of locking in the interest rate and mitigating interest rate risk related to future long-term debt that BC Hydro intends to issue.

Any realized gains and losses will be amortized over the remaining term of the issued debt starting at the beginning of the test period following the test period during which the long-term debt associated with a particular hedge is issued. As a result, the effective interest rate on hedged debt is a combination of the gain or loss on the settled FDH and the yield of the underlying debt issuance.

At March 31, 2021, the DRMA had a balance of $449 million (after amortization). This balance included:

- $126 million of net unrealized losses on the $3.2 billion of outstanding FDHs;
- $298 million of net realized losses on the $6.8 billion of settled FDHs; and
- $25 million of amortization related to net realized gains on the $4.0 billion of FDHs settled during fiscal 2017 to fiscal 2019.

This was a net decrease of $504 million from the balance at March 31, 2020 of $953 million to the balance at March 31, 2021 of $449 million. The $504 million decrease was due to:

- $571 million related to increases in the unrealized mark-to-market value of the $3.2 billion of outstanding FDHs; partially offset by:
- $55 million related to decreases in the value of the $1.8 billion of FDHs that were settled during fiscal 2021; and
- $12 million related to the amortization of net realized gains on the $4.0 billion of FDHs settled during fiscal 2017 to fiscal 2019.

The increase in the value of the outstanding FDHs was due to a significant increase in long-term interest rates during fiscal 2021. The decrease in the value of the FDHs settled during fiscal 2021 was a result of a decrease in long-term interest rates at the time the FDHs were settled relative to the beginning of the fiscal year.

The net unrealized loss of $126 million relating to the $3.2 billion in outstanding FDHs remains sensitive to changes in long-term yields and will continue to change until the hedges are settled. A 100-basis point change in long-term yields would result in a change of approximately $400 million to $550 million in the value of the $3.2 billion in outstanding FDHs.

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Appendix B

Appendix 1

Future Debt Hedges Report

Future Debt Hedges Report

As of March 31, 2021
(in millions of Canadian dollars)

Name	Execution Date	Transaction Type	Forecast Debt Issuance & Contract Maturity Year	Contract Settlement Date	Hedge Term	Notional Amount	Forecast Borrowing Yield	Actual Yield	Fair Market Value[2]	Settlement Value[2]	Total DMRA Balance Before Amortization[2]	Amortization	DMRA Balance[2]
Hedges Placed F2017													
FDH1 [1]	2016-05-16	Bond Lock	F2017	16-Nov	10 years	200	2.24%	3.01%		2.7	2.7	(0.2)	2.5
FDH2A	2016-05-11	Bond Lock	F2017	16-Sep	30 years	200	2.97%	3.00%		(11.3)	(11.3)	0.8	(10.5)
FDH2B	2016-05-12	Bond Lock	F2017	16-Sep	30 years	100	3.01%	3.00%		(6.7)	(6.7)	0.5	(6.2)
FDH3	2016-05-18	Bond Lock	F2018	17-Mar	10 years	300	2.36%	2.35%		8.0	8.0	(1.9)	6.1
FDH4	2016-05-24	Bond Lock	F2018	17-Oct	10 years	200	2.38%	2.37%		7.4	7.4	(1.8)	5.6
FDH5	2016-05-31	Bond Lock	F2018	17-Jun	30 years	200	3.04%	2.87%		0.1	0.1	(0.0)	0.1
FDH6	2016-09-23	Swap	F2018	17-Oct	10 years	200	2.09%	1.83%		17.0	17.0	(4.1)	12.9
FDH7	2016-09-23	Swap	F2018	17-Oct	10 years	200	2.08%	1.82%		17.2	17.2	(4.2)	13.0
FDH8	2016-09-26	Swap	F2018	17-Sep	30 years	200	2.64%	2.27%		40.9	40.9	(2.8)	38.1
FDH9	2016-09-29	Swap	F2019	18-May	10 years	200	2.09%	1.84%		22.7	22.7	(4.7)	18.0
FDH10	2016-10-06	Swap	F2019	18-Apr	30 years	200	2.76%	2.14%		38.7	38.7	(2.6)	36.1
FDH11	2016-06-08	Swap	F2019	18-Sep	10 years	300	2.53%	2.16%		22.4	22.4	(4.6)	17.8
FDH12	2016-06-08	Swap	F2019	18-Sep	10 years	200	2.54%	2.17%		14.7	14.7	(3.0)	11.7
FDH13	2016-06-14	Swap	F2020	19-Jun	10 years	300	2.54%	2.18%		(0.4)	(0.4)	0.0	(0.4)
FDH14	2016-06-22	Swap	F2020	19-Oct	10 years	200	2.74%	2.44%		(3.1)	(3.1)	0.0	(3.1)
FDH15	2016-10-12	Swap	F2020	19-Oct	10 years	200	2.57%	2.24%		0.7	0.7	0.0	0.7
FDH16	2016-10-13	Swap	F2021	20-May	10 years	300	2.60%	2.44%		(28.2)	(28.2)	0.0	(28.2)
FDH17	2016-10-13	Swap	F2021	20-Jun	10 years	200	2.60%	2.31%		(16.5)	(16.5)	0.0	(16.5)
FDH18	2016-10-20	Swap	F2021	20-Sep	10 years	300	2.69%	2.25%		(27.9)	(27.9)	0.0	(27.9)
FDH19	2016-10-20	Swap	F2021	20-Sep	10 years	200	2.69%	2.27%		(18.3)	(18.3)	0.0	(18.3)
Subtotal						**$4,400**			**$0.0**	**$80.1**	**$80.1**	**($28.8)**	**$51.3**
Hedges Placed F2018													
FDH20	2017-09-29	Bond Lock	F2019	18-Jul	10 years	200	2.96%	2.88%		(1.6)	(1.6)	0.3	(1.3)
FDH21	2017-10-03	Bond Lock	F2019	18-Jul	10 years	200	3.00%	2.92%		(2.2)	(2.2)	0.4	(1.7)
FDH22	2017-09-29	Bond Lock	F2019	18-Jul	30 years	200	3.35%	3.36%		(17.3)	(17.3)	1.2	(16.1)
FDH23A	2017-10-04	Bond Lock	F2019	18-Jun	10 years	100	3.01%	2.84%		(0.4)	(0.4)	0.1	(0.3)
FDH23B	2017-10-04	Bond Lock	F2019	18-Jun	10 years	100	3.01%	2.87%		(0.4)	(0.4)	0.1	(0.3)
FDH24A	2017-10-02	Bond Lock	F2019	18-Aug	30 years	100	3.36%	3.35%		(6.4)	(6.4)	0.4	(6.0)
FDH24B	2017-10-03	Bond Lock	F2019	18-Aug	30 years	100	3.38%	3.37%		(6.8)	(6.8)	0.4	(6.4)
FDH25	2017-09-28	Bond Lock	F2019	18-Aug	30 years	250	3.37%	3.36%		(16.7)	(16.7)	1.1	(15.6)
FDH26/27	2018-01-29	Swap	F2020	19-Jun	30 years	50	3.44%	3.16%		(6.7)	(6.7)	0.0	(6.7)
FDH28	2018-02-05	Swap	F2021	20-Jun	30 years	75	3.64%	4.01%		(30.9)	(30.9)	0.0	(30.9)
FDH29	2018-02-05	Swap	F2021	20-Sep	30 years	75	3.64%	3.82%		(29.7)	(29.7)	0.0	(29.7)
FDH30/31	2018-02-08	Swap	F2022		30 years	175	3.67%		(16.4)		(16.4)		(16.4)
FDH32	2018-02-06	Swap	F2022		30 years	100	3.60%		(7.6)		(7.6)		(7.6)
FDH33	2018-02-07	Swap	F2022		30 years	100	3.58%		(7.2)		(7.2)		(7.2)
FDH34/35	2018-02-01	Swap	F2023		30 years	250	3.52%		(11.0)		(11.0)		(11.0)
FDH36/37	2018-01-24	Swap	F2023		30 years	200	3.40%		(3.5)		(3.5)		(3.5)
Subtotal						**$2,275**			**($45.7)**	**($118.9)**	**($164.6)**	**$4.0**	**($160.6)**
Hedges Placed F2019													
FDH38	2018-12-07	Swap	F2022		10 years	125	3.33%		(7.5)		(7.5)		(7.5)
FDH39	2018-12-06	Swap	F2023		10 years	100	3.40%		(4.3)		(4.3)		(4.3)
FDH40	2018-12-07	Swap	F2023		10 years	125	3.41%		(4.6)		(4.6)		(4.6)
FDH41	2018-12-07	Swap	F2024		10 years	175	3.46%		(4.4)		(4.4)		(4.4)
FDH42	2018-12-06	Swap	F2024		30 years	175	3.62%		(7.3)		(7.3)		(7.3)
FDH43	2019-01-15	Bond Lock	F2020	19-Jun	30 years	150	3.13%	3.07%		(18.8)	(18.8)	0.0	(18.8)
FDH44	2019-01-16	Bond Lock	F2020	19-Sep	30 years	125	3.17%	3.24%		(23.1)	(23.1)	0.0	(23.1)
FDH45A	2019-01-17	Bond Lock	F2021	20-Jun	30 years	200	3.20%	3.54%		(60.4)	(60.4)	0.0	(60.4)
FDH45B	2019-01-17	Bond Lock	F2021	20-Jun	30 years	125	3.20%	3.47%		(40.4)	(40.4)	0.0	(40.4)
FDH46A	2019-01-15	Swap	F2021	20-Sep	30 years	100	3.43%	3.51%		(34.6)	(34.6)	0.0	(34.6)
FDH46B	2019-01-16	Swap	F2021	20-Aug	30 years	225	3.49%	3.69%		(82.2)	(82.2)	0.0	(82.2)
FDH47	2019-01-08	Swap	F2022		10 years	275	3.15%		(12.3)		(12.3)		(12.3)
FDH48	2019-01-09	Swap	F2022		30 years	100	3.41%		(3.9)		(3.9)		(3.9)
FDH49	2019-01-09	Swap	F2022		10 years	300	3.22%		(13.5)		(13.5)		(13.5)
FDH50	2019-01-10	Swap	F2022		30 years	175	3.41%		(5.8)		(5.8)		(5.8)
FDH51	2019-01-14	Swap	F2023		10 years	250	3.26%		(7.6)		(7.6)		(7.6)
FDH52	2019-01-10	Swap	F2023		10 years	125	3.27%		(3.2)		(3.2)		(3.2)
FDH53	2019-01-11	Swap	F2023		30 years	100	3.42%		(1.8)		(1.8)		(1.8)
FDH54	2019-01-09	Swap	F2024		10 years	175	3.33%		(2.5)		(2.5)		(2.5)
FDH55	2019-01-08	Swap	F2024		30 years	125	3.44%		(0.9)		(0.9)		(0.9)
FDH56	2019-01-15	Swap	F2025		10 years	75	3.39%		(0.4)		(0.4)		(0.4)
Subtotal						**$3,325**			**($79.9)**	**($259.5)**	**($339.4)**	**$0.0**	**($339.4)**
Total						**$10,000**			**($125.6)**	**($298.2)**	**($423.9)**	**($24.7)**	**($448.6)**

[1] Actual debt was a 30 year issue.
[2] Gain / (loss) deferred to the Debt Management Regulatory Account

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Appendix B

Appendix 2

Glossary for Appendix 1

Name	BC Hydro reference for each individual FDH.
Execution Date	Date the FDH was entered into.
Transaction Type	Type of Future Debt Hedge **Bond Locks** – contracts with financial institutions that are based on the performance of Government of Canada Treasury Bonds. Under a Bond Lock, BC Hydro will effectively sell a particular Government of Canada Bond at the current interest rate and effectively repurchase it at a pre-defined future date at the then-prevailing market interest rate **Forward Swaps** – contracts with financial institutions whereby BC Hydro will pay the current interest rate on the Interest Rate Swap[1] and agree to receive the prevailing interest rate on the Interest Rate Swap at a pre-defined future date.
Forecast Debt Issuance and Contract Maturity Year	Fiscal year the FDH derivative contract is forecast to be unwound and cash settled (set at the inception of the hedge) and the related future debt is expected to be issued.
Contract Settlement Date	Date the FDH derivative was actually unwound and cash settled.
Hedge Term	The term of the future debt issue that is being hedged (i.e., either a 10-year debt issue or a 30-year debt issue).
Notional Amount	The dollar value of the FDH derivative. The notional amount of the derivative will be equal to the principal amount of the related future debt issue.
Forecast Borrowing Yield	The anticipated yield on a particular future debt issue on the day the FDH was executed. The forecast borrowing yield is subject to change based on the difference between the change in the yield on Government of B.C. Bonds vs. the change in the yield on the underlying FDHs (Bond lock or Forward Swap) since the inception of the hedges. The actual yield will only be known upon the cash settlement of the FDH and the issuance of the related future debt.
Actual Yield	The effective yield on the future debt issuance taking into account the gain or loss on the related FDH.
Fair Market Value	The mark to market value of the FDHs that are not yet cash settled.
Settlement Value	The amount of cash paid out by BC Hydro or received by BC Hydro upon the unwinding and cash settlement of the FDH. A loss on the FDH would involve a cash payment by BC Hydro and a gain on the FDH would involve a receipt of cash by BC Hydro.
Total DMRA Balance Before Amortization	The amount of gain or loss on FDHs recorded in the DMRA since inception. Comprised of mark to market gains and losses and settlement gains and losses.

[1] A Canadian Interest Rate Swap is an agreement between two counterparties that agree to exchange an interest payment based on the CDOR Canadian Dollar Offer Rate index.

Amortization	The amount removed from the DMRA and included in Net Income. The gains or losses in the DMRA will be amortized over the remaining term of the associated long-term debt issuances, commencing at the beginning of the test period subsequent to the test period in which the long-term debt to which the FDH is associated is issued. The combination of the amortization of the DMRA and the interest charges on the underlying debt result in the effective yield on the debt at its hedged rate.
DMRA Balance	The balance in the DMRA at the report date.

BC Hydro
Power smart

BC Hydro Fiscal 2021 Annual Report to the British Columbia Utilities Commission

Appendix C

Residential Service Customers Charging Zero Emission Vehicles at their Dwelling Annual Report

Fiscal 2021

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Appendices

1 Summary / Background

On January 15, 2019, BC Hydro filed an Electric Tariff Terms and Conditions Amendments Application (**Amendments**) to facilitate charging of Zero Emissions Vehicles (**ZEV**) by Residential Service Customers at their Dwelling. The Amendments were to:

1. Clarify that a Dwelling may include spaces such as parking stalls, storage areas, garage areas and similar spaces or areas used for the benefit of the customer;
2. Allow more than one meter to be installed at a Dwelling; and
3. Implement aggregate billing for consumption from multiple meters under one account so that customers would pay one Basic Charge and so that the Step 1 Energy Charge threshold of 675 kWh per month would apply to all consumption in aggregate.

BC Hydro proposed these Amendments in consideration of the growing number of Residential Service Customers residing in multi-unit residential buildings (**MURB**) and the increasing number of ZEVs being brought to the market.

On April 29, 2019, the BCUC approved the Amendments by Order No. G-92-19[1] and directed BC Hydro to file information regarding its experience resulting from the amended terms and conditions starting in the Fiscal 2020 Annual Report to the Commission.

The BCUC directed that the reporting should include, but not be limited to, the following:

[1] BC Hydro Electric Tariff Terms and Conditions Amendments Application, BCUC Order No. G-92-19, Directive No. 2

a. Number of accounts that have installed additional meters and whether BC Hydro is meeting the needs of customers;

b. Analysis of having one Basic Charge per account with additional meters and any plans to review the Basic Charge in a future process; and

c. Analysis as to whether additional amendments to the Electric Tariff are appropriate for other rate classes that may have similar multi-unit characteristics such as commercial strata developments.

In August 2020, BC Hydro filed the first annual report regarding its experience from the amended terms and conditions. At that time, the small number of participating customers did not yield a sufficiently large dataset to conduct a meaningful assessment of points (b) and (c). As summarized below, BC Hydro has now had additional time to gather more information.

2 BCUC Order No. G-92-19 Compliance Information

BC Hydro has completed its year-two assessment and analysis of the amended Terms and Conditions and provides the following information in compliance with BCUC Order No. G-92-19:

a. Number of accounts that have installed additional meters and whether BC Hydro is meeting the needs of customers

Since BCUC Order No. G-92-19 came into effect on April 29, 2019, 641 customers moved to aggregate billing for consumption from multiple meters under one account.[2] On March 12, 2021, BC Hydro launched its second survey to capture feedback from customers to determine if BC Hydro was meeting their needs in terms of a second meter being installed (see Attachment 1). The survey was sent to 492

[2] On October 2019, BC Hydro implemented a tracking mechanism to identify secondary meter installations for the purpose of ZEV charging. This metric will be used to report future counts of residential ZEV charging meters.

customers, an increase of 282 customers from the previous year, who installed an additional meter since April 29, 2019, regardless of the reason for the additional meter, in order to obtain broader customer feedback.

BC Hydro received 72 survey responses for a response rate of about 15 per cent. Overall, 43 respondents agreed strongly that the additional meter meets their needs, nine somewhat agreed, seven were neutral, three disagreed somewhat or strongly, and 10 respondents declined to answer.

Of the 72 responses, seven indicated that they installed the additional meter specifically for ZEV charging, and felt that the additional meter met their needs, with five strongly agreeing and two somewhat agreeing. The remaining 65 respondents indicated that they installed the additional meter for purposes unrelated to ZEV charging.

In addition, through general comments received, respondents noted concerns associated with the costs to install the additional meter. A number of respondents who installed additional meters for purposes other than ZEV charging expressed some dissatisfaction with aggregate billing, indicating that they would prefer to keep the bills separate.

b. Analysis of having one Basic Charge per account with additional meters and any plans to review the Basic Charge in a future process

The demand for aggregate billing based on consumption from multiple meters remains low compared to the total number of approximately 1.8 million residential accounts. Given that customer service costs constitute only a portion of the Basic Charge, and the comparatively low number of participating customers, BC Hydro maintains that the current sample size is insufficient to conduct a meaningful analysis of the impact of costs associated with multiple meters on this charge.

Additionally, as discussed in the Rate Design Progress Report filed with the BCUC on March 26, 2021, BC Hydro has initiated a review and examination of alternatives to the current default rate design which is the Residential Inclining Block Rate Schedules 1101 and 1121 (**RIB Rate**). Given that one of the principles behind aggregate billing from multiple meters is based on the structure of the RIB rate, BC Hydro will include the assessment of the corresponding Basic Charge in the current residential rate review efforts.

c. Additional Amendments to the Electric Tariff

BC Hydro's Rate Design Progress Report filed on March 26, 2021 sets out our rate design objectives which include, decarbonization and flexibility. For example, BC Hydro's Street Lighting Rate Application filed this past November, proposed amendments to BC Hydro's Electric Tariff for mixed used loads. BC Hydro expects these amendments to have a favourable economic impact on all ratepayers because the amendment removes barriers to electrification and load growth[3]. Specifically, for EV growth, the amendment facilitates metering and billing for multiple end uses, including EV charging which would help customers mitigate costly impractical modifications to install separate service for a given use. BC Hydro believes a change is needed for a variety of reasons including supporting future load configurations for curbside electricity use.

[3] BC Hydro's Street Lighting Application, pages 63 to 66.

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Appendix C

Attachment 1

Dual Meter Customer Feedback

Dual Meter 2021

Survey Flow

Intro BC Hydro is collecting this survey information under the authority of Section 26(c) of the Freedom of Information and Protection of Privacy Act.

The information will help us to better understand customer's needs and satisfaction relating to second meter installation. All responses are submitted in confidence and treated accordingly.

If you have questions about why your information is being collected, please contact Denise Foxall at 604.623.4570.

Q1 Our records indicate that you have a second meter installed at your location. Please tell us the main reason for requiring a second meter:

- O Charging of an Electric Vehicle
- O Secondary residence, suite, mobile home etc.
- O Other (For privacy reasons, please don't identify yourself or others).

  ____

Q2 Does the installation of the second meter meet your needs?

- O Strongly agree
- O Somewhat agree
- O Neither agree nor disagree
- O Somewhat disagree
- O Strongly disagree

Display This Question:

If Does the installation of the second meter meet your needs? = Somewhat disagree

Or Does the installation of the second meter meet your needs? = Strongly disagree

Q4 Can you please tell us why the second meter does not meet your needs? (For privacy reasons, please don't identify yourself or others).

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Q7 Is there anything else we could do to improve your satisfaction regarding your second meter? (For privacy reasons, please don't identify yourself or others).

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Appendix D

Performance of Rate Schedules 1894 and 1895

Fiscal 2021

Table of Contents

1 Summary / Background

On January 29, 2021, BC Hydro filed an application with the BCUC seeking approval of:

- Rate Schedule (RS) 1894 – Transmission Service – Clean B.C. Industrial Electrification Rate – Clean Industry and Innovation;
- RS 1895 – Transmission Service – Clean B.C. Industrial Electrification Rate – Fuel Switching; and to
- Rescind TS No. 97 - Northwest Transmission Line Supplemental Charge.

On February 5, 2021, the BCUC approved the application by Order No. G-38-21 and directed BC Hydro to provide an annual report to the BCUC on the performance of the new RS 1894 and RS 1895, including the number of new customers on each new rate schedule, the incremental load obtained under each new rate schedule, the incremental revenues associated with each new rate schedule and the quantification of greenhouse gas reduction related to each new rate schedule.

1.1 Progress Report

As at March 31, 2021, BC Hydro has not yet received any applications for service under RS 1894 or RS 1895.