BC Hydro
Power smart

**Fred James**
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September 1, 2020

Ms. Marija Tresoglavic
Acting Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Tresoglavic:

**RE: British Columbia Utilities Commission (BCUC or Commission)**
**British Columbia Hydro and Power Authority (BC Hydro)**
**Fiscal 2020 Annual Report to the Commission**

BC Hydro writes pursuant to BCUC Letter Nos. L-36-94 and L-14-95, and subsection 45(6) of the *Utilities Commission Act* to provide BC Hydro's Fiscal 2020 Annual Report to the Commission for the period April 1, 2019 to March 31, 2020.

BC Hydro's Fiscal 2020 Annual Report to the Commission includes some changes relative to the Fiscal 2019 Annual Report[1]. Specifically:

1. Appendix A - Annual Deferral Accounts Report – Changes have been made to streamline and reduce redundancy across sections. The Consolidated Statement of Operations has been moved to Attachment 2 of Section 6, Financial Schedules;
2. Section 6, Attachment 1, Financial Schedules and Variance Explanations:
   (a) Non-Capital sections – Additional information on domestic energy sales, domestic revenues and sources of supply variances has been included so that the scope of this section includes all of the variance explanation sections provided as part of BC Hydro's revenue requirements applications; and
   (b) Capital section – A new section 11 has been added, in compliance with BCUC Order No. G-313-19 (section 3.3.1) on the Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding;
3. A new attachment to Section 7 has been added, entitled Summary of Planned Capital Extension Projects and Anticipated Regulatory Filings, in compliance with

[1] While BC Hydro received and incorporated comments from the BCUC staff on these changes, BC Hydro understands that these comments do not confer BCUC acceptance or approval of the BC Hydro annual report filing or its methodology, nor does it preclude the BCUC from requiring the filing of any information in any future compliance inquiry or proceeding relating to the subject matter of this filing.

Directive 2 of BCUC Order No. G-313-19 (section 3.1.3) on the Review of the Regulatory Oversight of Capital Expenditures and Projects proceeding; and

4. A new Appendix C has been added, entitled Residential Service Customers Charging Zero Emission Vehicles at their Dwelling Annual Report, in compliance with BCUC Order No. G-92-19, Directive 2, on the BC Hydro Electric Tariff Terms and Conditions Amendments (2019) proceeding.

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

Yours sincerely,

Fred James
Chief Regulatory Officer

ls/rh

Enclosure

# BC Hydro Fiscal 2020 Annual Report to the British Columbia Utilities Commission

## April 1, 2019 to March 31, 2020

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## Table of Contents

1 Declaration ........ 1-1
2 Directors and Officers ........ 2-1
3 Control Over Utility ........ 3-1
4 Corporations Controlled by BC Hydro ........ 4-1
5 Important Changes During the Year – Fiscal 2020 ........ 5-1
6 Fiscal 2020 Financial Schedules and Variance Explanations ........ 6-1
7 Planned Capital Extension Projects and Anticipated Regulatory Filings ........ 7-1
8 Internal Audit Reviews and/or Reports Provided in Fiscal 2020 ........ 8-1
9 Management Letter Topics from External Auditor ........ 9-1
10 British Columbia Utilities Commission Status Report of Compliance with Financial Directives or Commitments ........ 10-1
- 10.1 The Waneta Transaction Report as prescribed in British Columbia Utilities Commission Order No. G-130-18 ........ 10-1
- 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 ........ 10-2

## List of Appendices

Appendix A Annual Deferral Accounts Report
Appendix B Debt Management Regulatory Account Annual Status Report
Appendix C Residential Service Customers Charging Zero Emission Vehicles at their Dwelling Annual Report

# 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*.

I also confirm BC Hydro's compliance with the Commission's financial directives with regard to the following attachments:

- Section 6, Attachment 1: Financial Schedules and Variance Explanations in accordance with BCUC Order No. G-313-19 (section 3.3.1);
- Section 7, Attachment: Summary of Planned Capital Extension Projects and Anticipated Regulatory Filings as required by BCUC Order No. G-313-19, Directive 2 (section 3.1.3);
- Section 10.1: Waneta Transaction Annual Report as required by BCUC Order No. G-130-18, Directive 4 (e);
- 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[1] as required by BCUC Order No. G-96-04 Directive 8, items 17 and 19;
- Appendix B: Debt Management Regulatory Account Annual Status Report as required by BCUC Order No. G-42-16 Directive 4; and
- Appendix C – Residential Service Customers Charging Zero Emission Vehicles at their Dwelling Annual Report as required by BCUC Order No. G-92-19, Directive 2.

Per:

David Wong

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

British Columbia Hydro and Power Authority

September 1, 2020

[1] 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.

# 2 Directors and Officers

Report below the name, title and business address of each director and officer, as at March 31, 2020.

| Name | Business Address | Office Held |
|---|---|---|
| Board of Directors | | |
| Ken Peterson | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Chair |
| Lenard F. Boggio | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |
| Daryl Fields | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |
| Bob Gallagher | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |
| James Hatton | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |
| Irene Lanzinger | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |
| Valerie Lambert | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |
| Nalaine Morin[1] | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |
| John Nunn | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |
| Catherine Roome | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |
| Chris Sanderson | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Director |

1 Nalaine Morin was appointed Director on February 10, 2020.

| Name | Business Address | Office Held |
|---|---|---|
| Officer (Executive Team) | | |
| Chris O'Riley[2] | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | President and Chief Executive Officer |
| Janet Fraser | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Executive Vice-President, People, Customer, Corporate Affairs |
| Maureen Daschuk | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Senior Vice-President, Integrated Planning |
| Ken Duke[3] | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Vice-President & General Counsel |
| Al Leonard | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Senior Vice-President, Capital Infrastructure Project Delivery |
| Charlotte Mitha[4] | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Executive Vice-President, Operations |
| Ken McKenzie | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Executive Vice-President, Site C |
| Kirsten Peck[5] | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Senior Vice-President, Safety & Chief Compliance Officer |
| David Wong | 333 Dunsmuir St<br>Vancouver, BC V6B 5R3 | Executive Vice-President, Finance, Technology, Supply Chain & Chief Financial Officer |

[2] Chris O'Riley was appointed as President and Chief Executive Officer (formerly President and Chief Operating Officer) on September 13, 2019.

[3] Ken Duke was appointed as Vice-President & General Counsel on October 1, 2019.

[4] Charlotte Mitha was appointed Executive Vice-President, Operations on September 3, 2019.

[5] Kirsten Peck was appointed Senior Vice-President, Safety & Chief Compliance Officer on February 1, 2020.

# 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.

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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, 2020.

| 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 |
| Columbia Hydro Constructors Ltd | Administers the projects and supplies the labour force for projects primarily on the Columbia River. | 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 |

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 2020

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 2019/20 BC Hydro Annual Service Plan Report as follows:
   - Leasehold information within Note 12: Right-Of-Use Assets, page 65 and *Long-term energy purchase agreements, property leases and other leases* sections within Note 19: *Lease Liabilities*, page 78;
   - *Energy Commitments and Lease and Service Agreements* sections within Note 25: *Commitments and Contingencies,* page 99; and

- Significant accounting policies for important leaseholds are disclosed in the *Leases* section within Note 3: *Significant Accounting Policies,* page 57.

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

5. In fiscal 2020 BC Hydro upgraded Units 5 and 6 at Bridge River 2 Generating Station and replaced the generators at Cheakamus Generating Station.

The Bridge River 2 Units 5 and 6 Upgrade Project was put into service in June 2019. Generators 5 and 6 were replaced with two new 75 MW units along with associated Exciters, Governors and Switch Gear. In addition, Protection and Control systems were replaced. Due to stator winding failures prior to the commencement of the project, generation capacity at Bridge River 2 had been reduced by 54 MW. At that time, there was a substantial risk of further winding failures due to the age and poor condition of the equipment. Lost generation capacity resulted in increased frequency of high flow events in the Lower Bridge River. High flow events impacted Water Use Plan (**WUP**) stakeholder interests agreements as well as St’at’imc Nation core interests and agreements. The restoration of water conveyance capacity has reduced the likelihood and magnitude of high flow events in the Lower Bridge River that were of concern to BC Hydro and St’at’imc Nation.

The Cheakamus Units 1 and 2 Generator Replacement project put generators G1 and G2 into service in August 2018 and June 2019, respectively. Both generators were replaced and upgraded from 70 MW - 13.8 kV to 90 MW - 13.8 kV along with a new grounding grid, compressed air system, Remote Terminal Unit/ Station Integration Panels and associated unit control system. The two generators were at the end of life and replacement was required to mitigate the risk of unplanned outages. Two new higher efficiency turbines installed in 2004 and 2011, respectively, enabled the generating capacity upgrade at each unit.

6. Union wage scales increased 2.0 per cent effective April 1, 2019. Manager and exempt professional (**M&P**) salary scales increased 2.0 per cent effective April 1, 2019.

7. Important legal proceedings pending, in progress, or concluded during the year can be found in BC Hydro's Consolidated Financial Statements of the 2019/20 BC Hydro Annual Service Plan Report as follows:

   - *Contingencies and Guarantees* section within Note 25: *Commitments and Contingencies*, page 99.

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

# 6 Fiscal 2020 Financial Schedules and Variance Explanations

BC Hydro has provided, in Attachment 1 to this section, a detailed comparison between the fiscal 2020 Evidentiary Update in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**F2020-F2021 RRA**) and fiscal 2020 actual financial results, including variance explanations. Included in Attachment 2 to this section are financial schedules which provide additional comparison details to the fiscal 2020 Evidentiary Update and fiscal 2020 actual financial results and which support the fiscal 2020 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 Fiscal 2020 Annual Report to the British Columbia Utilities Commission

## Attachment 1 to Section 6

## Fiscal 2020 Financial Schedules and Variance Explanations

# Table of Contents

1 Domestic Energy Sales Variance Explanations (Schedule 14.0) ........................ 1
2 Domestic Revenue Variance Explanations (Schedule 14.0) .............................. 3
3 Cost of Energy Variance Explanations (Schedule 4.0)....................................... 4
4 Operating Costs and Provisions Variance Explanations (Schedule 5.0) ............ 6
5 Taxes Variance Explanations (Schedule 6.0).................................................... 8
6 Amortization Variance Explanations (Schedule 7.0)........................................... 9
7 Finance Charges Variance Explanations (Schedule 8.0) .................................... 9
8 Miscellaneous Revenue Variance Explanations (Schedule 15.0)..................... 11
9 Summary of Inter-Segment Revenue Variance Explanations (Schedule 3.0)........................................................................................ 12
10 Capital Expenditures and Capital Additions Variance Explanations ................. 13
10.1 Overall Capital Expenditures and Additions Variance Explanations ....... 14
10.2 Generation Capital Expenditures and Additions Variance Explanations ........................................................................... 16
10.3 Transmission Capital Expenditures and Additions Variance Explanations ........................................................................... 22
10.4 Distribution Capital Expenditures and Additions Variance Explanations ........................................................................... 29
10.5 Business Support Capital Expenditures and Additions Variance Explanations ........................................................................... 33
10.6 Site C Project Capital Expenditures and Additions Variance Explanations ........................................................................... 39
11 Capital Projects and Programs: First Full Funding Amount vs Estimate at Completion ........................................................................................ 40

# List of Tables

Table 1 Fiscal 2020 Domestic Energy Sales Variances .................................. 1
Table 2 Fiscal 2020 Domestic Revenues Variances ....................................... 3
Table 3 Fiscal 2020 Sources of Supply ......................................................... 4
Table 4 Fiscal 2020 Cost of Energy Variances .............................................. 5
Table 5 Fiscal 2020 Operating Costs and Provisions Variances..................... 6
Table 6 Fiscal 2020 Taxes Variances ........................................................... 9
Table 7 Fiscal 2020 Amortization Variances .................................................. 9

Table 8 Fiscal 2020 Finance Charges Variances .......... 10
Table 9 Fiscal 2020 Miscellaneous Revenue Variances .......... 11
Table 10 Fiscal 2020 Inter-Segment Revenue Variances .......... 12
Table 11 Fiscal 2020 Capital Expenditures Variances .......... 14
Table 12 Fiscal 2020 Capital Additions Variances .......... 14
Table 13 Fiscal 2020 Generation Capital Expenditures Variances (excluding Site C Project) .......... 16
Table 14 Fiscal 2020 Generation Capital Additions Variances (excluding Site C Project) .......... 17
Table 15 Fiscal 2020 Transmission Capital Expenditures Variances .......... 22
Table 16 Fiscal 2020 Transmission Capital Additions Variances .......... 23
Table 17 Fiscal 2020 Distribution Capital Expenditures Variances .......... 29
Table 18 Fiscal 2020 Distribution Capital Additions Variances .......... 30
Table 19 Fiscal 2020 Business Support Capital Expenditures Variances .......... 33
Table 20 Fiscal 2020 Business Support Capital Additions Variances .......... 34
Table 21 Fiscal 2020 Technology Capital Expenditures Variances .......... 34
Table 22 Fiscal 2020 Technology Capital Additions Variances .......... 34
Table 23 Fiscal 2020 Properties Capital Expenditures Variances .......... 36
Table 24 Fiscal 2020 Properties Capital Additions Variances .......... 36
Table 25 Fiscal 2020 Fleet Capital Expenditures Variances .......... 37
Table 26 Fiscal 2020 Fleet Capital Additions Variances .......... 37
Table 27 Fiscal 2020 Business Support –Other and Other Technology Capital Expenditures Variances .......... 37
Table 28 Fiscal 2020 Business Support –Other and Other Technology Capital Expenditures Variances .......... 38
Table 29 Fiscal 2020 Site C Project Capital Expenditures Variances .......... 39
Table 30 Fiscal 2020 Site C Project Capital Additions Variances .......... 39
Table 31 Projects and Programs with Final In-Service Dates between April 1, 2019 to March 31, 2020 .......... 42

In sections 1 through 9, variance explanations are provided for actual gross amounts in fiscal 2020 compared to the fiscal 2020 Evidentiary Update in the F2020-F2021 RRA. With the exception of domestic energy sales variances, all explanations are provided where variances between actual and planned 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 2020 actual domestic energy sales amounts in GWh with the fiscal 2020 Evidentiary Update.

**Table 1 Fiscal 2020 Domestic Energy Sales Variances**

| | | Schedule | F2020 | | | |
|---|---|---|---|---|---|---|
| | (GWh) | Reference | Update | Actual | Diff | % Diff |
| | | | 1 | 2 | 3=2-1 | 4=3/1 |
| 1 | Residential | 14.0 L1 | 18,151 | 17,993 | (157) | -1% |
| 2 | Light Industrial and Commercial | 14.0 L2 | 18,915 | 18,692 | (224) | -1% |
| 3 | Large Industrial | 14.0 L3 | 14,592 | 13,383 | (1,210) | -8% |
| 4 | Other | 14.0 L4:L10 | 1,638 | 1,863 | 226 | 14% |
| 5 | **Total Domestic Energy Sales** | 14.0 L11 | **53,296** | **51,931** | (1,365) | -3% |

Overall, actual domestic energy sales in fiscal 2020 were 1,365 GWh (or 3 per cent) lower than the fiscal 2020 Evidentiary Update. This was due to:

- Line 1 - Actual residential sales were 157 GWh (or 1 per cent) lower than the fiscal 2020 Evidentiary Update. Variances in residential sales are driven by three main factors: electricity sales per account (use per account), temperature and number of accounts. In fiscal 2020, the residential sales variance was driven primarily by lower than expected use per account, partly offset by colder temperatures. The lower use per account variance can be attributed to many different factors and while the exact drivers are not known, the likely drivers are higher Demand-Side Management savings, denser housing developments (more multiple unit dwellings), fewer people per account, and changes in appliance mix resulting in more efficient appliances (appliance stock turnover). Temperatures were colder than normal, primarily in October and March, which drove higher sales that partially offset the lower use per account variance. The total number of residential accounts was 2,000 (less than 1 per cent) higher than plan and did not contribute significantly to the sales variance;

- Line 2 - Actual light industrial and commercial sales were 224 GWh (or 1 per cent) lower than the fiscal 2020 Evidentiary Update. Most of the variance was due to curtailed operations within the light industrial wood manufacturing sector, which was driven by many factors including high log costs and low lumber prices. The commercial sector also experienced slightly lower sales relative to plan due to lower use per account. The commercial sector is comprised of a diverse group of business classes and lower use per account can be attributed to many different factors with continued energy efficiency improvements being a likely contributor;
- Line 3 - Actual large industrial sales were 1,210 GWh (or 8 per cent) lower than the fiscal 2020 Evidentiary Update. The variance can primarily be attributed to the following sectors: Pulp and Paper (due to curtailed operations driven by fibre shortages and various operational issues); Cryptocurrency (due to customer project delays or cancellations); Oil and Gas (driven by production slowdowns due to weak market conditions); and Wood Manufacturing (due to curtailed operations driven by many factors including high log costs, low lumber prices and labour disputes); and
- Line 4 - Actual energy sales to the Other customer sector were 226 GWh (or 14 per cent) higher than the fiscal 2020 Evidentiary Update, primarily due to transactions under an energy supply contract which were planned under IPPs and Long-Term Commitments as a reduction in Sources of Supply.

# 2 Domestic Revenue Variance Explanations (Schedule 14.0)

This section compares fiscal 2020 actual domestic revenue amounts with the fiscal 2020 Evidentiary Update.

**Table 2 Fiscal 2020 Domestic Revenues Variances**

| | ($ million) | Schedule Reference | F2020 Update | F2020 Actual | Diff | % Diff |
|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3=2-1 | 4=3/1 |
| 1 | Residential | 14.0 L12 | 2,197.8 | 2,168.8 | (29.0) | -1% |
| 2 | Light Industrial and Commercial | 14.0 L13 | 1,958.8 | 1,942.0 | (16.8) | -1% |
| 3 | Large Industrial | 14.0 L14 | 944.7 | 848.4 | (96.2) | -10% |
| 4 | Other | 14.0 L15:L21 | 152.1 | 155.7 | 3.6 | 2% |
| 5 | Subtotal | 14.0 L22 | 5,253.3 | 5,114.9 | (138.4) | -3% |
| 6 | Revenue from Deferral Rider | 14.0 L23 | - | 0.2 | 0.2 | 0% |
| 7 | **Total Domestic Revenues** | 14.0 L24 | **5,253.3** | **5,115.1** | (138.2) | -3% |

Actual domestic revenues in fiscal 2020 were $138.2 million (or 3 per cent) lower than the fiscal 2020 Evidentiary Update. This was primarily due to:

- Line 1 - Residential revenue was $29.0 million (or 1 per cent) lower, driven by lower sales, as described in section 1 above;
- Line 2 - Light industrial and commercial revenue was $16.8 million (or 1 per cent) lower, mainly due to lower sales, as described in section 1 above;
- Line 3 - Large industrial customer revenue was $96.2 million (or 10 per cent) lower due to lower sales, as described in section 1, as well as a lower average rate due to a different mix of customer rates than planned (fewer sales were at the Rate Schedule 1823 A exempt rate ($50.97/MWh) and more sales were at the Tier 1 rate ($45.31/MWh)); and
- Other revenue was $3.6 million (or 2 per cent) higher, mainly due to the transactions described in section 1. These transactions were planned under IPPs and Long-Term Commitments as a reduction in Cost of Energy.

# 3 Cost of Energy Variance Explanations (Schedule 4.0)

This section compares fiscal 2020 actual sources of energy supply and cost of energy amounts with the fiscal 2020 Evidentiary Update.

**Table 3 Fiscal 2020 Sources of Supply**

| | | Schedule | F2020 | | | |
|---|---|---|---|---|---|---|
| | (GWh) | Reference | Update | Actual | Diff | % Diff |
| | | | 1 | 2 | 3=2-1 | 4=3/1 |
| 1 | Water Rentals | 4.0 L1 | 39,368 | 40,383 | 1,015 | 3% |
| 2 | IPPs and Long-Term Commitments | 4.0 L5 | 13,949 | 14,475 | 526 | 4% |
| 3 | Market Electricity Purchases | 4.0 L8 | 5,104 | 3,471 | (1,633) | -32% |
| 4 | Natural Gas for Thermal Generation | 4.0 L2 | 181 | 171 | (10) | -5% |
| 5 | Surplus Sales | 4.0 L9 | (84) | (182) | (98) | 117% |
| 6 | Net Purchases (Sales) from Powerex | 4.0 L10 | 468 | (940) | (1,407) | -301% |
| 7 | Non-Integrated Area | 4.0 L6 | 118 | 106 | (11) | -10% |
| 8 | Exchange Net | 4.0 L3 | (473) | (581) | (108) | 23% |
| 9 | **Total Sources of Supply** | 4.0 L12 | **58,630** | **56,903** | (1,727) | -3% |

Actual fiscal 2020 energy supplied was 1,727 GWh (or 3 per cent) lower than the fiscal 2020 Evidentiary Update. This was primarily due to:

- Line 3 – Lower market electricity purchases due to lower domestic load requirements and higher water inflows starting in late summer; and
- Line 6 – Higher net sales to Powerex due to higher opportunities for trade exports resulting from lower domestic load requirements and higher water inflows starting in late summer.

Partially offset by:

- Line 1 - Higher hydro generation due to higher water inflows starting in late summer.

**Table 4 Fiscal 2020 Cost of Energy Variances**

| | ($ million) | Schedule Reference | F2020 Update | F2020 Actual | F2020 Diff | F2020 % Diff |
|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3=2-1 | 4=3/1 |
| | **Heritage Energy** | | | | | |
| 1 | Water Rentals | 4.0 L13 | 329.3 | 331.6 | 2.3 | 1% |
| 2 | Natural Gas for Thermal Generation | 4.0 L14 | 7.5 | 7.1 | (0.4) | -6% |
| 3 | Domestic Transmission - Other | 4.0 L15 | 24.5 | 24.8 | 0.3 | 1% |
| 4 | Non-Treaty Storage and Libby Coordination Agreements | 4.0 L16 | 15.0 | 37.7 | 22.7 | 152% |
| 5 | Remissions and Other | 4.0 L17 | (25.2) | (42.4) | (17.2) | 68% |
| 6 | **Subtotal** | 4.0 L18 | **351.2** | **358.8** | 7.7 | 2% |
| | **Non-Heritage Energy** | | | | | |
| 7 | IPPs and Long-Term Commitments | 4.0 L19 | 1,294.7 | 1,314.0 | 19.3 | 1% |
| 8 | Non-Integrated Area | 4.0 L20 | 30.5 | 31.3 | 0.7 | 2% |
| 9 | Gas & Other Transportation | 4.0 L21 | 3.7 | 4.5 | 0.8 | 23% |
| 10 | Water Rentals (Waneta 2/3) | 4.0 L22 | 3.5 | 3.3 | (0.2) | N/A |
| 11 | **Subtotal** | 4.0 L23 | **1,332.4** | **1,353.1** | 20.7 | 2% |
| | **Market Energy** | | | | | |
| 12 | Market Electricity Purchases | 4.0 L24 | 211.6 | 133.1 | (78.4) | -37% |
| 13 | Surplus Sales | 4.0 L25 | (0.4) | (1.0) | (0.6) | 138% |
| 14 | Net Purchases (Sales) from Powerex | 4.0 L26 | 33.1 | (35.2) | (68.3) | -206% |
| 15 | Domestic Transmission - Export | 4.0 L27 | 1.1 | 2.0 | 0.9 | 86% |
| 16 | **Subtotal** | 4.0 L28 | 245.3 | 99.0 | (146.4) | -60% |
| 17 | **Total Gross Cost of Energy** | 1.0 L1 | **1,928.9** | **1,810.9** | (118.0) | -6% |

Fiscal 2020 actual gross Cost of Energy was $118.0 million (or 6 per cent) lower than the fiscal 2020 Evidentiary Update. This was primarily due to:

- Line 5 - Higher recoveries from remissions and other of $17.2 million due to higher remission credits for the Bridge River system and John Hart generating station which were eligible for full remission credits in fiscal 2020. Remission credits were not planned for Bridge River, while partial remissions were planned for John Hart;
- Line 12 - Lower market electricity purchases of $78.4 million due to lower domestic load requirements, higher water inflows than planned and higher hydro generation starting in late summer; and
- Line 14 - Higher net sales of $68.3 million to Powerex due to higher than planned net exports as a result of higher inflows and hydro generation, starting in late summer, and lower domestic load requirements.

Partially offset by:

- Line 4 - Higher water transactions associated with Non-Treaty Storage and Libby Coordination agreements of $22.7 million due to higher storage of water driven by lower market electricity prices and favourable storage opportunities during fiscal 2020.

# 4 Operating Costs and Provisions Variance Explanations (Schedule 5.0)

This section compares fiscal 2020 actual gross operating costs and provisions amounts with the fiscal 2020 Evidentiary Update.

**Table 5 Fiscal 2020 Operating Costs and Provisions Variances**

| | ($ million) | Schedule Reference | F2020 Update | Actual | Diff | % Diff |
|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3=2-1 | 4=3/1 |
| 1 | Integrated Planning | 5.0 L1 | 290.8 | 289.3 | (1.5) | -1% |
| 2 | Capital Infrastructure Project Delivery | 5.0 L2 | 80.1 | 80.1 | 0.1 | 0% |
| 3 | Operations | 5.0 L3 | 237.3 | 246.1 | 8.8 | 4% |
| 4 | Safety | 5.0 L4 | 56.8 | 55.0 | (1.9) | -3% |
| 5 | Finance, Technology, Supply Chain | 5.0 L5 | 262.6 | 265.1 | 2.5 | 1% |
| 6 | People, Customer, Corporate Affairs | 5.0 L6 | 110.6 | 110.0 | (0.6) | 0% |
| 7 | Other | 5.0 L7 | (244.3) | (241.4) | 2.9 | -1% |
| 8 | **Base Operating Costs** | 5.0 L8 | **793.8** | **804.2** | 10.3 | 1% |
| 9 | IFRS Ineligible Capitalized Costs | 5.0 L9 | 170.1 | 170.1 | - | 0% |
| 10 | Waneta 2/3 | 5.0 L10 | 5.7 | 5.4 | (0.3) | N/A |
| 11 | Customer Crisis Fund | 5.0 L11 | 5.3 | 4.4 | (0.9) | N/A |
| 12 | **Subtotal** | 5.0 L12 | **181.1** | **179.8** | (1.2) | -1% |
| 13 | Deferred Account Additions | 5.0 L15 | - | (1.4) | (1.4) | N/A |
| 14 | Regulatory Account Additions | 5.0 L24 | 157.1 | 132.6 | (24.5) | -16% |
| 15 | **Subtotal** | | **157.1** | **131.2** | (25.9) | -16% |
| 16 | **Total Gross Operating Costs** | 5.0 L25 | **1,132.0** | **1,115.2** | (16.8) | -1% |
| 17 | Net Provisions & Other | 5.0 L38 | 116.2 | 128.7 | 12.5 | 11% |
| 18 | Regulatory Account Additions - Provisions & Other | 5.0 L45 | (9.1) | 48.0 | 57.2 | -627% |
| 19 | **Total Gross Provisions & Other** | 5.0 L46 | **107.1** | **176.8** | 69.6 | 65% |
| 20 | **Total Gross Operating Costs and Provisions** | 1.0 L2 | **1,239.1** | **1,292.0** | 52.9 | 4% |

Fiscal 2020 actual gross Operating Costs and Provisions were $52.9 million (or 4 per cent) higher than the fiscal 2020 Evidentiary Update. Of this amount, $57.2 million (line 18 in Table 5 above) was related to higher regulatory account additions for provisions, $12.5 million (line 17 in Table 5 above) was related to higher net provisions and other, and $10.3 million (line 8 in Table 5 above) was related to higher base operating costs. These amounts were partially offset by $24.5 million (line 14 in Table 5 above) related to lower regulatory account additions for operating costs.

Variances of $57.2 million related to higher regulatory account additions for provisions and other and variances of $24.5 million related to lower regulatory account additions for operating costs, netting to $32.7 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 $44.9 million and an increase in the Asbestos Remediation provision of $6.3 million. The provisions increased due to increases in forecast PCB and Asbestos remediation costs, and decreases in discount rates (resulting in an increase in the present value of the forecast remediation expenditures); and
- Higher than planned increase in the Real Property Sales Regulatory Account of $13.5 million due to surplus property sales being delayed to future years.

Partially offset by:

- Lower than planned increase in the Demand-Side Management Regulatory Account of $13.7 million due to fewer project completions and studies than planned, primarily in the industrial sector, and due to cancelations and shifts in timing for some capacity-focused Demand-Side Management activities;
- A decrease in the Dismantling Costs Regulatory Account of $8.5 million primarily due to lower than planned dismantling costs for the John Hart Generating Station Replacement project, and lower end of life plant and equipment removal costs under various projects and programs;

- A decrease in the Storm Restoration Costs Regulatory Account of $7.8 million due to 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 2020, 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; and
- Other variances, totalling $2.0 million.

Variances of $12.5 million related to net provisions and other were primarily due to:

- Higher capital asset retirements and project write-offs of $8.6 million primarily due to partial project costs being written off as a result of scope changes or as a result of revisiting leading alternatives on certain projects due to higher project cost estimates. This included a $6.5 million write-off of the Metro North Transmission project. The write-off occurred because the project was cancelled due to a lower load forecast which showed that the project will not be required until 2029 at the earliest. The costs were written-off in accordance with accounting rules, as there were no probable future economic benefits; and
- Other variances, totaling $3.9 million.

Variances of $10.3 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.

# 5 Taxes Variance Explanations (Schedule 6.0)

This section compares fiscal 2020 actual taxes amounts with the fiscal 2020 Evidentiary Update.

**Table 6 Fiscal 2020 Taxes Variances**

| | | Schedule | F2020 | | | |
|---|---|---|---|---|---|---|
| | ($ million) | Reference | Update | Actual | Diff | % Diff |
| | | | 1 | 2 | 3=2-1 | 4=3/1 |
| 1 | Grants in Lieu | 6.0 L15 | 110.8 | 111.3 | 0.5 | 0% |
| 2 | School Taxes | 6.0 L16 | 138.3 | 137.5 | (0.8) | -1% |
| 3 | Waneta 2/3 Property Taxes | 6.0 L17 | 0.6 | 0.9 | 0.3 | N/A |
| 4 | **Subtotal Before Regulatory Accounts** | 6.0 L17 | **249.8** | **249.7** | (0.1) | 0% |
| 5 | Deferred Account Additions | 6.0 L | - | - | - | N/A |
| 6 | **Total Gross Taxes** | 1.0 L3 | **249.8** | **249.7** | (0.1) | 0% |

Fiscal 2020 actual gross Taxes of $249.7 million were comparable to the fiscal 2020 Evidentiary Update amount of $249.8 million.

# 6 Amortization Variance Explanations (Schedule 7.0)

This section compares fiscal 2020 actual amortization amounts with the fiscal 2020 Evidentiary Update.

**Table 7 Fiscal 2020 Amortization Variances**

| | | Schedule | F2020 | | | |
|---|---|---|---|---|---|---|
| | ($ million) | Reference | Update | Actual | Diff | % Diff |
| | | | 1 | 2 | 3=2-1 | 4=3/1 |
| 1 | Amortization of Capital Assets | 7.0 L5 | 885.4 | 885.8 | 0.4 | 0% |
| 2 | IPP Capital Leases | 7.0 L7 | 88.9 | 88.9 | - | 0% |
| 3 | Other Leases | 7.0 L8 | 3.4 | 2.6 | (0.8) | -23% |
| 4 | **Subtotal Before Regulatory Accounts** | | **977.8** | **977.3** | (0.4) | 0% |
| 5 | Deferred Account Additions | 7.0 L10 | - | 0.4 | 0.4 | N/A |
| 6 | **Total Gross Amortization** | 1.0 L4 | **977.8** | **977.7** | (0.1) | 0% |

Fiscal 2020 actual gross Amortization of $977.7 million was comparable to the fiscal 2020 Evidentiary Update amount of $977.8 million.

# 7 Finance Charges Variance Explanations (Schedule 8.0)

This section compares fiscal 2020 actual finance charges amounts with the fiscal 2020 Evidentiary Update.

**Table 8 Fiscal 2020 Finance Charges Variances**

| | | Schedule | F2020 | | | |
|---|---|---|---|---|---|---|
| | ($ million) | Reference | Update | Actual | Diff | % Diff |
| | | | 1 | 2 | 3=2-1 | 4=3/1 |
| 1 | Sinking Fund Income | 8.0 L9 | (7.8) | (9.1) | (1.2) | 16% |
| 2 | Long-Term Debt Costs | 8.0 L10 | 825.3 | 824.9 | (0.4) | 0% |
| 3 | Short-Term Debt Costs | 8.0 L11 | 63.8 | 47.5 | (16.2) | -25% |
| 4 | Interest Capitalized | 8.0 L12 | (181.5) | (175.5) | 6.0 | -3% |
| 5 | Other (Income) / Loss | 8.0 L13 | 39.2 | 50.5 | 11.3 | 29% |
| 6 | IPP Capital Leases | 8.0 L14 | 48.4 | 48.4 | - | 0% |
| 7 | Accretion - Non-Deferrable | 8.0 L15 | 1.3 | 1.3 | (0.0) | -1% |
| 8 | Non-Current PEB | 8.0 L16 | (36.5) | 62.1 | 98.6 | -270% |
| 9 | Other Leases | 8.0 L17 | 1.0 | 1.3 | 0.2 | N/A |
| 10 | **Subtotal Before Regulatory Accounts** | 8.0 L18 | **753.1** | **851.5** | 98.3 | 13% |
| 11 | Regulatory Account Additions | 8.0 L7 | 121.8 | 805.3 | 683.5 | 561% |
| 12 | **Total Gross Finance Charges** | 1.0 L5 | **874.9** | **1,656.8** | 781.8 | 89% |

Fiscal 2020 actual gross Finance Charges were $781.8 million (or 89 per cent) higher than the fiscal 2020 Evidentiary Update. This was primarily due to:

- Line 5 - Higher other loss of $11.3 million primarily due to lower than planned interest income on US dollar bank balances and higher foreign exchange losses on US payables balances given the decline of the Canadian dollar against the US dollar;
- Line 8 - Higher non-current post-employment benefit costs of $98.6 million as the rate of return on pension plan assets (prescribed under International Financial Reporting Standards) was lower than the planned rate of return; and
- Line 11 - Higher regulatory account additions of $683.5 million primarily due to a decrease in the fair value of future debt hedges as a result of changes in forward interest rates. Losses on future debt hedges are offset by lower interest costs when the future debt is issued.

Partially offset by:

- Line 3 - Lower short-term debt costs of $16.2 million due to lower interest rates and lower outstanding short-term debt balance.

# 8 Miscellaneous Revenue Variance Explanations (Schedule 15.0)

This section compares fiscal 2020 actual miscellaneous revenue amounts with the fiscal 2020 Evidentiary Update.

**Table 9 Fiscal 2020 Miscellaneous Revenue Variances**

| | | Schedule | F2020 | | | |
|---|---|---|---|---|---|---|
| | ($ million) | Reference | Update | Actual | Diff | % Diff |
| | | | 1 | 2 | 3=2-1 | 4=3/1 |
| 1 | Amortization of Contributions | 15.0 L1+L8+L12 | 59.6 | 64.0 | 4.4 | 7% |
| 2 | External OATT | 15.0 L4 | 15.9 | 10.7 | (5.2) | -33% |
| 3 | FortisBC Wheeling Agreement | 15.0 L5 | 5.2 | 5.2 | (0.0) | 0% |
| 4 | Secondary Revenue (MMBU, Secondary Use, Other) | 15.0 L6+L11+L28 | 23.9 | 28.0 | 4.2 | 17% |
| 5 | Interconnections | 15.0 L7 | 2.2 | 6.4 | 4.2 | 190% |
| 6 | Meter/Trans Rents & Power | 15.0 L14 | 14.6 | 16.1 | 1.5 | 11% |
| 7 | Smart Metering & Infrastructure | 15.0 L15 | 2.1 | 2.2 | 0.1 | 6% |
| 8 | Diversion Net Recoveries | 15.0 L16 | 0.1 | 0.2 | 0.1 | 52% |
| 9 | Other Operating Recoveries | 15.0 L17 | 4.5 | 4.1 | (0.3) | -7% |
| 10 | Customer Crisis Fund Rider Revenue | 15.0 L18 | 5.3 | 4.4 | (0.9) | N/A |
| 11 | Waneta 2/3 | 15.0 L24 | 84.9 | 84.7 | (0.2) | N/A |
| 12 | Corporate General Rents | 15.0 L26 | 3.7 | 3.9 | 0.2 | 5% |
| 13 | Late Payment Charges | 15.0 L27 | 7.9 | 7.1 | (0.8) | -10% |
| 14 | NTL Supplemental Charge | 15.0 L9 | 2.3 | 2.3 | 0.0 | 2% |
| 15 | Other (Income) / Loss | 15.0 L2+L19+L29 | 5.4 | 6.6 | 1.3 | 24% |
| 16 | **Subtotal Before Regulatory Accounts** | 15.0 L31 | **237.6** | **246.0** | 8.5 | 4% |
| 17 | Deferral Account Additions | 15.0 L33 | 3.1 | 1.3 | (1.8) | N/A |
| 18 | **Total Gross Miscellaneous Revenue** | 1.0 L7 | **240.7** | **247.3** | 6.6 | 3% |

Fiscal 2020 actual gross Miscellaneous Revenue was $6.6 million (or 3 per cent) higher than the fiscal 2020 Evidentiary Update. This was primarily due to:

- Line 1 - Higher amortization of contributions of $4.4 million, primarily due to a change in the scope of a project, resulting in a partial write-off and higher mass asset retirements than planned which resulted in the write-off at the associated contributions;
- Line 4 - Higher secondary revenue of $4.2 million, primarily due to higher than planned house moves and temporary connections, higher than planned transmission third party projects for shared assets, and higher rental revenues; and

- Line 5 - Higher interconnections of $4.2 million, primarily due to higher than planned project revenues from feasibility, system and facilities studies.

Partially offset by:

- Line 2 - Lower external OATT revenue of $5.2 million, primarily due to the resale of long-term transmission service from an external customer to BC Hydro.

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

This section compares fiscal 2020 actual inter-segment revenue amounts with the fiscal 2020 Evidentiary Update.

**Table 10 Fiscal 2020 Inter-Segment Revenue Variances**

| | ($ million) | Schedule Reference | F2020 Update | 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 | (1.4) | 0.8 | 2.2 | N/A |
| 3 | Powerex PTP Charges | 3.0 L3 | (41.5) | (49.8) | (8.3) | 20% |
| 4 | BC Hydro PTP Charges | 3.0 L4 | (19.1) | (20.1) | (1.0) | 5% |
| 5 | **Total Inter-Segment Revenue** | 1.0 L8 | **(64.9)** | **(72.0)** | (7.1) | 11% |

Fiscal 2020 actual Inter-Segment revenues were $7.1 million (or 11 per cent) higher than the fiscal 2020 Evidentiary Update due to higher point-to-point transmission charges allocated to Powerex (line 3 in Table 10 above), driven by higher than planned transmission rates per unit and higher trade account exports due to favourable trade export opportunities.

# 10 Capital Expenditures and Capital Additions Variance Explanations

The following tables and discussion provide information on the variances between fiscal 2020 actual capital expenditures and capital additions compared to the Fiscal 2020 RRA Plan amounts in the F2020-F2021 RRA, which was based on a Currency Date of April 1, 2018. There were no changes to the capital expenditures and capital additions as part of the Evidentiary Update to the F2020-F2021 RRA.

On an annual basis, BC Hydro manages over 900 projects and programs in various project and program 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 F2020-F2021 RRA.

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 11 and Table 12 below provide BC Hydro's fiscal 2020 capital expenditures and capital additions by main asset category.

**Table 11 Fiscal 2020 Capital Expenditures Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Generation | 345.1 | 305.1 | (40.0) | -12% |
| Site C Project | 1,530.0 | 1,619.1 | 89.1 | 6% |
| Transmission & Distribution | 895.2 | 898.8 | 3.6 | 0% |
| Business Support | | | | |
| Technology | 93.5 | 132.2 | 38.7 | 41% |
| Properties | 58.9 | 56.4 | (2.5) | -4% |
| Fleet | 26.2 | 27.0 | 0.8 | 3% |
| Business Support - Other and Other Technology | 39.5 | 32.8 | (6.7) | -17% |
| **Total Gross** | **2,988.3** | **3,071.4** | **83.1** | **3%** |
| Less: Contribution in Aid | (157.8) | (179.0) | (21.2) | 13% |
| **Total** | **2,830.5** | **2,892.5** | **62.0** | **2%** |

**Table 12 Fiscal 2020 Capital Additions Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Generation | 314.7 | 359.5 | 44.8 | 14% |
| Site C Project | 27.9 | 12.9 | (15.0) | - |
| Transmission & Distribution | 796.0 | 669.3 | (126.7) | -16% |
| Business Support | | | - | |
| Technology | 141.0 | 93.7 | (47.3) | -34% |
| Properties | 40.0 | 44.3 | 4.3 | 11% |
| Fleet | 26.2 | 29.2 | 3.0 | 12% |
| Business Support - Other and Other Technology | 45.3 | 27.2 | (18.1) | -40% |
| **Total Gross** | **1,391.0** | **1,236.1** | **(154.9)** | **-11%** |
| Less: Contribution in Aid | (146.1) | (140.5) | 5.6 | -4% |
| **Total** | **1,244.9** | **1,095.6** | **(149.3)** | **-12%** |

Fiscal 2020 capital expenditures were $83.1 million (or 3 per cent) above the Fiscal 2020 RRA Plan, excluding contribution in aid, primarily because:

- The Site C project was $89.1 million above plan due to advancement of work and claims as discussed in section 10.6; and
- Technology was $38.7 million above plan due to certain software subscription license costs which were determined to be eligible for capitalization but were expected to be operating costs.

The increase in capital expenditures above was partially offset by lower than planned Generation capital expenditures of $40.0 million, primarily due to various projects schedule changes as discussed in section 10.2.

Fiscal 2020 gross capital additions were $154.9 million (or 11 per cent) below the Fiscal 2020 RRA Plan, excluding contribution in aid, primarily because:

- The Supply Chain Applications project (included in the Technology line) was below plan by $57.4 million as the project was delayed 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; and
- Transmission and Distribution capital additions were below plan by $126.7 million, primarily due to lower than planned capital additions of $18.7 million for the Bringing additional capacity from ARN to Tilbury (FV-FVW-057) project, due to a delayed completion date, as well as various projects and programs schedule changes which shifted the timing of placing certain assets in-service, as discussed in section 10.3 and 10.4.

The decrease in capital additions was partially offset by higher than planned Generation capital additions of $44.8 million. This was primarily a result of certain assets being placed in-service in fiscal 2020 rather than in prior year due to the delayed additions of $28.2 million for the John Hart Generating Station Replacement project, and $25.2 million for the Ruskin Dam and Powerhouse Upgrade project as a result of schedule extensions.

## 10.2 Generation Capital Expenditures and Additions Variance Explanations

Generation capital expenditures and capital additions in fiscal 2020 are presented in Table 13 and Table 14 below. Results exclude amounts for the Site C project, which are presented separately in section 10.6 below.

**Table 13 Fiscal 2020 Generation Capital Expenditures Variances (excluding Site C Project)**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | Update | Actual | Diff | % Diff |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Hydroelectric Generation | | | | |
| Growth | 3.2 | 2.6 | (0.6) | -17% |
| Redevelopment / Rehabilitation | 28.6 | 29.5 | 0.9 | 3% |
| Dam Safety | 68.8 | 44.7 | (24.1) | -35% |
| Sustaining - Other | 241.0 | 220.8 | (20.2) | -8% |
| Total Hydroelectric Generation | 341.7 | 297.6 | (44.1) | -13% |
| Total Non-Integrated Areas | 8.7 | 5.8 | (2.9) | -33% |
| Total Thermal Generation | 6.6 | 1.7 | (4.9) | -73% |
| Less: Portfolio Risk Adjustment | (11.9) | - | 11.9 | -100% |
| **Total Gross** | **345.1** | **305.1** | **(40.0)** | **-12%** |
| Less: Contribution in Aid | - | 0.0 | 0.0 | - |
| **Total** | **345.1** | **305.1** | **(40.0)** | **-12%** |

**Table 14 Fiscal 2020 Generation Capital Additions Variances (excluding Site C Project)**

**Generation**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **RRA** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Hydroelectric Generation | | | | |
| Growth | 2.7 | - | (2.7) | -100% |
| Redevelopment / Rehabilitation | 42.8 | 96.2 | 53.4 | 125% |
| Dam Safety | 49.3 | 7.4 | (41.9) | -85% |
| Sustaining - Other | 199.4 | 253.4 | 54.0 | 27% |
| Total Hydroelectric Generation | 294.1 | 357.0 | 62.9 | 21% |
| Total Non-Integrated Areas | 7.9 | 1.2 | (6.7) | -85% |
| Total Thermal Generation | 3.8 | 1.4 | (2.4) | -63% |
| Plus: Portfolio Risk Adjustment | 8.9 | - | (8.9) | -100% |
| **Total Gross** | **314.7** | **359.5** | **44.8** | **14%** |
| Less: Contribution in Aid | - | (0.0) | (0.0) | - |
| **Total** | **314.7** | **359.5** | **44.8** | **14%** |

*Growth Capital*

In general, excluding the Site C Project, planned capital expenditures and additions for Generation Growth Capital are a small component of the annual capital plan. The majority of the capital investments in the Generation portfolio are driven by the need to address issues and risks associated with existing facilities.

Fiscal 2020 capital expenditures and capital additions for Generation Growth Capital were comparable to the Fiscal 2020 RRA Plan.

*Redevelopment/ Rehabilitation*

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were $53.4 million (or 125 per cent) above the Fiscal 2020 RRA Plan. This was primarily because:

- The John Hart Generating Station Replacement project was $28.2 million above the fiscal 2020 planned expenditures due to timing. The project was above the fiscal 2020 planned expenditures because the project schedule was extended into fiscal 2020 in order to complete the trailing and final deficiency work of the plant construction. These remaining trailing costs are a small percentage of the total project costs, which are forecasted to be under the approved authorized project cost; and

- The Ruskin Dam and Powerhouse Upgrade project was $25.2 million above the fiscal 2020 planned expenditures due to timing. The project was above the fiscal 2020 planned expenditures because the project schedule was extended into Fiscal 2020 due to the new Dam Safety Diesel Generation unit commissioning and additional time needed to complete the final deficiency work. These remaining trailing costs are a small percentage of the total project costs, which are forecasted to be under the approved authorized project cost.

*Dam Safety*

Fiscal 2020 capital expenditures were $24.1 million (or 35 per cent) below the Fiscal 2020 RRA Plan. This was primarily because:

- The Bridge River 1 Improve Slope Drainage project was $7.0 million below plan because the re-planning of the project was extended due to delayed conclusion of land negotiations with Indigenous Nations;
- The Peace Canyon Spillway Gate Upgrade project was $5.9 million below plan because the project was cancelled due to the high cost relative to the amount of risk reduction that would be achieved;
- The Bridge River 1 - Mitigate Surge Spill Hazard project was $4.2 million below plan because the design was delayed due to the complexity of site conditions and construction safety risk mitigation considerations; and
- The Strathcona Upgrade Discharge project was $2.9 million below plan because the project schedule was delayed due to additional time required at the Feasibility stage to confirm the Gate configuration and reliability requirements.

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

Fiscal 2020 capital additions were $41.9 million (or 85 per cent) below the Fiscal 2020 RRA Plan. This was primarily because:

- The W.A.C. Bennett Dam Spillway Gate Upgrade project was $25.9 million below plan because the construction start date was delayed due to longer than anticipated time required to finalize the Design Build contract. The project in-service date is now planned for fiscal 2021;
- The Bridge River 1 Improve Slope Drainage project was $8.2 million below plan because the re-planning of the project was extended due to delayed conclusion of land negotiations with Indigenous Nations. The project in-service date is now planned for fiscal 2025;
- The Bridge River 1 - Mitigate Surge Spill Hazard project was $4.9 million below plan because the design was delayed due to the complexity of site conditions and construction safety risk mitigation considerations. The project in-service date is now planned for fiscal 2022; and
- The Wahleach Unit 1 Tailrace Tunnel Improvement was $3.1 million below plan because the required concrete work has been rescheduled to fiscal 2021 mainly due to longer than anticipated steel culvert recoating work. The project in-service date is now planned for fiscal 2022.

*Sustaining – Other*

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were $54.0 million (or 27 per cent) above the Fiscal 2020 RRA Plan. This was primarily because:

- The Bridge River 2 Unit 5 and 6 Upgrade project was $40.9 million above plan because the project in-service date was delayed from fiscal 2019 to fiscal 2020 reflecting a delay in the project schedule due to the time required to study two additional feasibility stage alternatives;
- The Cheakamus Unit 1 and 2 Generator Replacement project was $27.7 million above plan because both units were put in-service with expenditures recognized as capital additions in fiscal 2020; however, one of the units had a planned in-service date in fiscal 2019; and
- The Wahleach Fire Risk Reduction project was $8.3 million above plan because the construction completion was delayed from fiscal 2019 to fiscal 2020 due to design change which resulted from the as-found geotechnical conditions and worse than expected winter weather.

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

- The Lake Buntzen 1 - Power House Crane Upgrade project was $6.9 million below plan because the project in-service date was delayed to fiscal 2021 due to scheduling overlaps amongst BC Hydro projects with the same crane contractor; and
- The Waneta – Sustaining projects were $4.7 million below plan because the in-service dates were delayed. This was mainly due to the Unit 3 Life Extension work transitioning into the execution phase in the winter of 2020, primarily due to delays in Teck getting internal funding approvals;
- The Jordan Fire Risk Reduction project was $4.3 million below plan because the project in-service date was delayed to fiscal 2022 due to additional time required to resolve issues encountered while commissioning the fire protection water supply system; and

- $7.0 million of smaller below plan variances on various projects primarily due to projects schedule changes.

*Non-Integrated Areas and Diesel and Thermal Generation*

Fiscal 2020 capital expenditures and additions for Non-Integrated Areas and Diesel and Thermal Generation were comparable to the Fiscal 2020 RRA Plan.

*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 2020 RRA Plan Portfolio Risk Adjustment amount was $(11.9) million for capital expenditures and $8.9 million for capital additions.

## 10.3 Transmission Capital Expenditures and Additions Variance Explanations

Transmission fiscal 2020 capital expenditures and capital additions are provided in Table 15 and Table 16, below.

**Table 15 Fiscal 2020 Transmission Capital Expenditures Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Transmission Growth | | | | |
| Regional System Reinforcement | 107.9 | 79.6 | (28.3) | -26% |
| Bulk System Reinforcement | 12.0 | 5.9 | (6.1) | -51% |
| Station Expansion & Modification | 11.9 | 9.1 | (2.8) | -23% |
| Feeder Positions / Section Additions | 1.6 | 0.6 | (1.0) | -63% |
| Generator Interconnections | 5.1 | 8.3 | 3.2 | 63% |
| Transmission Load Interconnection | 58.7 | 56.1 | (2.6) | -4% |
| Total Growth | 197.2 | 159.6 | (37.6) | -19% |
| Transmission Sustain - Stations | | | | |
| Circuit Breakers | 16.3 | 20.5 | 4.2 | 25% |
| Other Power Equipment | 63.5 | 52.2 | (11.3) | -18% |
| Protection and Control | 18.4 | 7.6 | (10.8) | -58% |
| Stations Auxiliary Equipment | 25.6 | 25.9 | 0.3 | 1% |
| Stations Risk Mitigation | 12.9 | 8.9 | (4.0) | -31% |
| Telecommunications | 25.4 | 20.4 | (5.0) | -20% |
| Total Sustain - Stations | 162.1 | 135.6 | (26.5) | -16% |
| Transmission Sustain - Lines | | | | |
| Cable Sustainment | 5.0 | 7.5 | 2.5 | 51% |
| O/H Lines Life Extension | 45.5 | 51.9 | 6.4 | 14% |
| O/H Lines Performance Improvement | 1.4 | 1.7 | 0.3 | 22% |
| O/H Lines Risk Mitigation | 10.7 | 16.2 | 5.5 | 51% |
| ROW Sustainment | 9.7 | 10.6 | 0.9 | 10% |
| Third Party Requested Transmission Line Relocations | 10.0 | (0.2) | (10.2) | -102% |
| Total Sustain - Lines | 82.3 | 87.7 | 5.4 | 7% |
| Less: Portfolio Risk Adjustment | (34.0) | - | 34.0 | -100% |
| **Total Gross** | **407.7** | **382.9** | **(24.8)** | **-6%** |
| Less: Contribution in Aid | (23.7) | (17.9) | 5.8 | -24% |
| **Total** | **384.0** | **365.0** | **(19.0)** | **-5%** |

**Table 16 Fiscal 2020 Transmission Capital Additions Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Transmission Growth | | | | |
| Regional System Reinforcement | 83.8 | 84.5 | 0.7 | 1% |
| Bulk System Reinforcement | 0.1 | 1.2 | 1.1 | 1053% |
| Station Expansion & Modification | 2.5 | 2.0 | (0.5) | -21% |
| Feeder Positions / Section Additions | 2.5 | 0.5 | (2.0) | -82% |
| Generator Interconnections | 1.2 | - | (1.2) | -100% |
| Transmission Load Interconnection | 7.8 | (0.0) | (7.8) | -100% |
| Total Growth | 97.9 | 88.0 | (9.9) | -10% |
| Transmission Sustain - Stations | | | | |
| Circuit Breakers | 28.0 | 6.9 | (21.1) | -75% |
| Other Power Equipment | 21.9 | 5.7 | (16.2) | -74% |
| Protection and Control | 11.2 | 3.6 | (7.6) | -68% |
| Stations Auxiliary Equipment | 40.1 | 8.0 | (32.1) | -80% |
| Stations Risk Mitigation | 4.0 | 3.7 | (0.3) | -8% |
| Telecommunications | 13.6 | 6.1 | (7.5) | -55% |
| Total Sustain - Stations | 118.8 | 34.0 | (84.8) | -71% |
| Transmission Sustain - Lines | | | | |
| Cable Sustainment | 4.1 | 6.7 | 2.6 | 62% |
| O/H Lines Life Extension | 49.1 | 38.6 | (10.5) | -21% |
| O/H Lines Performance Improvement | 1.4 | 1.1 | (0.3) | -23% |
| O/H Lines Risk Mitigation | 16.2 | 19.4 | 3.2 | 20% |
| ROW Sustainment | 19.3 | 11.6 | (7.7) | -40% |
| Third Party Requested Transmission Line Relocations | 9.0 | 0.3 | (8.7) | -97% |
| Total Sustain - Lines | 99.1 | 77.6 | (21.5) | -22% |
| Less: Portfolio Risk Adjustment | (22.0) | - | 22.0 | -100% |
| **Total Gross** | **293.8** | **199.7** | **(94.1)** | **-32%** |
| Less: Contribution in Aid | (15.2) | (3.0) | 12.2 | -81% |
| **Total** | **278.6** | **196.7** | **(81.9)** | **-29%** |

*Transmission Growth - Regional System Reinforcement*

Fiscal 2020 capital expenditures were $28.3 million (or 26 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The Fort St. John and Taylor Electric Supply project was $8.0 million below plan because part of the substation construction work planned for fiscal 2020 was completed in fiscal 2019 due to higher contractor productivity. In addition, certain construction work was deferred to fiscal 2021 due to colder than expected winter weather conditions at the construction site;

- The Peace Region Electric Supply (**PRES**) project was $6.6 million below plan because the costs of substation and transmission line contracts were lower than estimated due to favourable market pricing from the suppliers;
- The Metro North Transmission (**MNT**) project was $6.5 million below plan because the project was cancelled due to a lower load forecast which showed that the project will not be required until 2029 at the earliest. The expenditures incurred did not meet the capitalization criterion of providing future economic benefits as the design and engineering work cannot be reused when project is re-initiated; and
- The West Kelowna Transmission and Westbank Upgrade Projects were $6.0 million below plan because the project schedule was delayed due to the project returning to the Conceptual Design stage to revisit other alternatives.

Fiscal 2020 capital additions were comparable to the Fiscal 2020 RRA Plan.

All other line items under Transmission Growth in fiscal 2020 for both capital expenditures and capital additions were comparable to the Fiscal 2020 RRA Plan.

*Transmission Sustain-Stations*

*Circuit Breakers*

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were $21.1 million (or 75 per cent) below the Fiscal 2020 RRA Plan primarily due to:

- The BND 60kV CB and Relay Building Replacement project was $11.3 million below plan because it was completed ahead of schedule and put in-service in fiscal 2019 due to the efficiencies gained during the circuit breaker replacement work;

- The Substation 60 KV Circuit Breaker Replacement program was $4.6 million below plan because fewer than planned units were put in-service in fiscal 2020;
- The System Spare Breaker Purchases project was $2.7 million below plan because, as a result of early equipment delivery, the project was completed ahead of schedule and put in-service in fiscal 2019; and
- $2.5 million of smaller below plan variances on various projects.

*Other Power Equipment*

Fiscal 2020 capital expenditures were $11.3 million (or 18 per cent) below the Fiscal 2020 RRA Plan. This was primarily because:

- The JOR T1 & T2 Replacement project was $5.8 million below plan because the project schedule was delayed due to extended construction, and the “must run” operational requirement for Jordan River Generation Station during the winter and spring seasons;
- The Mainwaring Station Upgrade project was $5.1 million below plan because the project schedule was delayed due to additional time required to finalize the project scope, to complete the preliminary design and project estimates, and to prepare an application for regulatory approval; and
- The SC Excitation Systems Upgrade - VIT/KLY project was $4.2 million below plan because the implementation phase of the project was delayed to perform additional investigations and studies to define the project scope and schedule.

The decrease in capital expenditures above was partially offset by $3.8 million of smaller above plan variances on various projects.

Fiscal 2020 capital additions were $16.2 million (or 74 per cent) below the Fiscal 2020 RRA Plan. This was primarily because:

- The Substation Feeder Section Upgrade program was $7.3 million below plan because fewer than planned units within the program were put in-service in fiscal 2020;
- The Peace Region to Kelly Lake - Reactor Replacement (Phase 1) project was $3.6 million below plan because the work was deferred to fiscal 2021 due to the change of project release sequence within the program of projects; and

The remaining variance of $5.3 million was due to smaller below plan variances on various projects.

*Protection and Control*

Fiscal 2020 capital expenditures were $10.8 million (or 58 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The Control PLC984 and RTU Replacement (WSN) project was $2.9 million below plan because the project was delayed due to interface with, and timing of, a decision on a new Williston Substation (WSN) Control Building as part of the Peace to Kelly Lake Sustainment Project;

The remaining variance of $7.9 million was due to smaller below plan variances on various projects.

Fiscal 2020 capital additions were comparable to the Fiscal 2020 RRA Plan.

*Stations Auxiliary Equipment*

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were $32.1 million (or 80 per cent) below with the Fiscal 2020 RRA Plan primarily because:

- The Stn Service Transfer & AC panels - WSN project was $10.5 million below plan because the construction was delayed and in-service date was delayed to fiscal 2021 due to a decision to de-scope the upgrade of the existing 500 kV building from the project;
- The Wood Pole Substation Rep – PSN project was $5.2 million below plan due to construction delays as a result of steel quality issues;
- The Wood Pole Substation Rep – MTE project was $5.3 million below plan due to construction delays as a result of steel quality issues; and
- The Substation Safety and Minor Capital program was $4.7 million below plan because fewer than planned units within the program were put in-service in fiscal 2020.

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

All other line items under Transmission Sustain-Stations in fiscal 2020 for both capital expenditures and capital additions were comparable to the Fiscal 2020 RRA Plan.

*Transmission Sustain-Lines*

*O/H Lines Life Extension*

Fiscal 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were $10.5 million (or 21 per cent) below the Fiscal 2020 RRA Plan, primarily because:

- The Copper Conductor Replace - Phase 2 project was $10.4 million below plan because it was completed in fiscal 2019; as a result, the capital additions planned for fiscal 2020 were recognized in fiscal 2019.

*Third Party Requested Transmission Line Relocations*

Fiscal 2020 capital expenditures were $10.2 million (or 102 per cent) below the Fiscal 2020 RRA Plan primarily due to a customer project cancellation as well as changes on customer requests and timing of the requests.

Fiscal 2020 capital additions were comparable to the Fiscal 2020 RRA Plan.

All other line items under Transmission Sustain-Lines in fiscal 2020 for both capital expenditures and capital additions were comparable to the Fiscal 2020 RRA Plan.

*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 2020 RRA Plan Portfolio Risk Adjustment amount was $(34.0) million in capital expenditures and $(22.0) million in capital additions.

*Contribution in Aid*

Fiscal 2020 Transmission Contribution in Aid expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 Transmission Contributions in Aid additions were $12.2 million (or 81 per cent) below the Fiscal 2020 RRA Plan due to timing differences on the completion of customer work and a lower volume of third-parties requests for relocations than originally forecasted.

## 10.4 Distribution Capital Expenditures and Additions Variance Explanations

Distribution fiscal 2020 actual to Fiscal 2020 RRA Plan capital expenditures and capital additions are provided in Table 17 and Table 18, below.

The distribution system improvement portfolio is primarily comprised of small projects, with the average project size in the $1 million to $2 million ranges 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 17 Fiscal 2020 Distribution Capital Expenditures Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | Update | Actual | Diff | % Diff |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Distribution Growth | | | | |
| Customer Driven | 231.9 | 279.0 | 47.1 | 20% |
| System Expansion and Improvement | 67.5 | 60.3 | (7.2) | -11% |
| Uneconomic Extension Assistance | 0.6 | 0.4 | (0.2) | -41% |
| Total Growth | 300.0 | 339.7 | 39.7 | 13% |
| | | | | |
| Distributon Sustain | | | | |
| System Expansion and Improvement | 56.6 | 55.1 | (1.5) | -3% |
| Asset Replacement | | | | |
| Poles | 76.1 | 36.5 | (39.6) | -52% |
| Overhead Equipment | 14.4 | 27.7 | 13.3 | 92% |
| Underground Equipment | 21.6 | 32.1 | 10.5 | 49% |
| Trouble | 17.7 | 20.1 | 2.4 | 14% |
| Asset Replacement sub-total | 129.8 | 116.4 | (13.4) | -10% |
| Beautification | 1.1 | 4.8 | 3.7 | 333% |
| Total Sustain | 187.5 | 176.2 | (11.3) | -6% |
| **Total Gross** | **487.5** | **515.9** | **28.4** | **6%** |
| Less: Contribution in Aid | (134.0) | (161.1) | (27.1) | 20% |
| **Total** | **353.5** | **354.8** | **1.3** | **0%** |

**Table 18 Fiscal 2020 Distribution Capital Additions Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Distribution Growth | | | | |
| Customer Driven | 226.5 | 254.6 | 28.1 | 12% |
| System Expansion and Improvement | 79.8 | 52.5 | (27.3) | -34% |
| Uneconomic Extension Assistance | 0.6 | 0.5 | (0.1) | -15% |
| Total Growth | 306.9 | 307.6 | 0.7 | 0% |
| Distributon Sustain | | | | |
| System Expansion and Improvement | 64.8 | 36.4 | (28.4) | -44% |
| Asset Replacement | | | | |
| Poles | 75.9 | 56.3 | (19.6) | -26% |
| Overhead Equipment | 13.4 | 19.9 | 6.5 | 48% |
| Underground Equipment | 22.5 | 28.7 | 6.2 | 28% |
| Trouble | 17.6 | 20.1 | 2.5 | 14% |
| Asset Replacement sub-total | 129.4 | 124.9 | (4.5) | -3% |
| Beautification | 1.1 | 0.7 | (0.4) | -33% |
| Total Sustain | 195.3 | 162.0 | (33.3) | -17% |
| **Total Gross** | **502.2** | **469.6** | **(32.6)** | **-6%** |
| Less: Contribution in Aid | (131.0) | (137.5) | (6.5) | 5% |
| **Total** | **371.2** | **332.1** | **(39.1)** | **-11%** |

*Distribution Growth – Customer Driven*

Fiscal 2020 capital expenditures were $47.1 million (or 20 per cent) above the Fiscal 2020 RRA Plan due to an increase in distribution customer driven extension activities, meter purchases for secondary connections, and the required design effort to support this increase. This work is difficult to plan as it is dependent on customer requests and their related timing.

Fiscal 2020 capital additions were $28.1 million (or 12 per cent) above the Fiscal 2020 RRA Plan primarily due to the increase in capital expenditures discussed above.

*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 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were $27.3 million (or 34 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The Bringing additional capacity from ARN to Tilbury (FV-FVW-057) project was $18.8 million below plan because the project completion date was delayed to fiscal 2021 due to additional scope and time required to handle unfavorable site conditions encountered for the crossing under the Hwy 99;
- The WKA New Substation Bring 4 New Feeders (SI-KAM-001) project was $10.7 million below plan due to a delay in the resolution of deficiencies and final contractor claims for the general contractor construction works. As a result of this delay, the project in-service date was deferred to fiscal 2021;
- The CBL New Feeder South Campbell River (VI-NVI-417) project was $6.4 million below plan because the project was cancelled due to reduced load growth and a lower load forecast.

The decrease in capital additions above was partially offset by:

- The New Feeder to Bowen Island (LM-NSC-125) project was $6.5 million above plan because the project in-service date was moved from previous fiscal years to fiscal 2020 due to additional time required for project closeout activities.

*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 2020 capital expenditures were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions were $28.4 million (or 44 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The H-Frame Elimination – Chinatown program of projects was $12.4 million below plan as a result in changes in the project schedule affecting the timing of additions. The entire program of projects will be put in-service in fiscal 2021 instead of partially in fiscal 2020, as originally forecasted.;
- The Takla Landing (NI-NEW-287) project was $8.4 million below plan because the project in-service date was delayed to fiscal 2022 as a result of project re-scoping; and
- The QNL Voltage Conversion (NI-NC-160) project was $8.8 million below plan because the project in-service date was delayed to fiscal 2021 as a result of procurement delays.

*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 2020 capital expenditures were $13.4 million (or 10 per cent) below the Fiscal 2020 RRA Plan primarily due to lower volume of joint-use pole replacements and true-up of the third-party recoveries received.

Fiscal 2020 capital additions were comparable to the Fiscal 2020 RRA Plan.

*Contribution in Aid*

Fiscal 2020 Distribution Contribution In Aid expenditures were $27.1 million (or 20 per cent) above the Fiscal 2020 RRA Plan primarily due to higher than planned distribution customer driven extension activities.

Fiscal 2020 Distribution Contribution In Aid additions were comparable to the Fiscal 2020 RRA Plan.

### 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 2020 capital expenditures and capital additions are presented by category in the tables below.

**Table 19 Fiscal 2020 Business Support Capital Expenditures Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Business Support | | | | |
| Technology | 93.5 | 132.2 | 38.7 | 41% |
| Properties | 58.9 | 56.4 | (2.5) | -4% |
| Fleet | 26.2 | 27.0 | 0.8 | 3% |
| Business Support - Other and Other Technology | 39.5 | 32.8 | (6.7) | -17% |
| **Total** | **218.1** | **248.4** | 30.3 | 14% |

**Table 20 Fiscal 2020 Business Support Capital Additions Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Business Support | | | | |
| Technology | 141.0 | 93.7 | (47.3) | -34% |
| Properties | 40.0 | 44.3 | 4.3 | 11% |
| Fleet | 26.2 | 29.2 | 3.0 | 12% |
| Business Support - Other and Other Technology | 45.3 | 27.2 | (18.1) | -40% |
| **Total** | **252.5** | **194.4** | (58.1) | -23% |

### *Technology*

**Table 21 Fiscal 2020 Technology Capital Expenditures Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Technology | 93.5 | 132.2 | 38.7 | 41% |
| **Total** | **93.5** | **132.2** | 38.7 | 41% |

**Table 22 Fiscal 2020 Technology Capital Additions Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Technology | 141.0 | 93.7 | (47.3) | -34% |
| **Total** | **141.0** | **93.7** | (47.3) | -34% |

Fiscal 2020 capital expenditures were $38.7 million (or 41 per cent) above the Fiscal 2020 RRA Plan. This was primarily because:

- The terms of a software licensing contract changed from a perpetual license contract to a term subscription license. The subscription license costs of $19.5 million were determined to be eligible for capitalization and recognized up-front for the full length of the contract. This resulted in an increase of $17.5 million from the annual license fee of $2.0 million, planned in each of the fiscal 2020 and fiscal 2021 in RRA under the original perpetual license contract.

- The Information Technology Service Management Toolset project was $11.8 million above plan as prepaid and future software subscription license costs, which were expected to be operating costs, were determined to be eligible for capitalization; and
- The Supply Chain Applications project was $7.5 million above plan due to additional project code development build and testing activities to meet the required quality standards.

Fiscal 2020 capital additions were $47.3 million (or 34 per cent) below the Fiscal 2020 RRA Plan. This was primarily because:

- The Supply Chain Applications project was $57.4 million below 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 End of Life Firewall Replacement project was $3.6 million below plan because the in-service date was delayed to fiscal 2021 due to a scope change to include replacing the Calgary Internet Data Center (**CIDC**) edge firewalls in the project, and the corresponding increase in time required for the technical design in Definition phase;
- The Data Center Network Security Improvement project was $2.5 million below plan due to the in-service date being delayed to fiscal 2022 as a result of more time required for technical design of the administrative access gateway solution in the Definition phase; and

  The decrease in capital additions outlined above was partially offset by the increase of $17.5 million in a software licensing agreement because the subscription license costs of $19.5 million were determined to be eligible for capitalization and recognized up-front for the full length of the contract in fiscal 2020.

*Properties*

**Table 23 Fiscal 2020 Properties Capital Expenditures Variances**

**Properties**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **RRA** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Interior Space Renovations | - | - | - | - |
| Building Development | 37.8 | 14.7 | (23.1) | -61% |
| Building Improvements and Others | 21.1 | 40.7 | 19.6 | 93% |
| Other Properties | - | 1.0 | 1.0 | 100% |
| **Total** | **58.9** | **56.4** | **(2.5)** | -4% |

**Table 24 Fiscal 2020 Properties Capital Additions Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Interior Space Renovations | - | - | - | - |
| Building Development | 18.9 | 10.2 | (8.7) | -46% |
| Building Improvements and Others | 21.1 | 34.1 | 13.0 | 62% |
| Other Properties | - | - | - | - |
| **Total** | **40.0** | **44.3** | 4.3 | 11% |

Fiscal 2020 capital expenditures and capital additions for Properties were comparable to the Fiscal 2020 RRA Plan.

There were delays on the building development projects including:

- The Material Classification Facility Building Redevelopment project to allow for the Ministry of Environment approval of the Operations Plan for the new facilities; and
- The Chilliwack Facility Building Redevelopment project due to difficulties in securing suitable land for the new office.

As Properties manages the project portfolios on an overall basis to meet the annual plan, the impact of these delays was offset by the advancement of Building Improvement projects for generator equipment, property resurfacing and base building upgrades from future years.

*Fleet*

**Table 25 Fiscal 2020 Fleet Capital Expenditures Variances**

**Fleet**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **RRA** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Fleet | 26.2 | 27.0 | 0.8 | 3% |
| **Total** | **26.2** | **27.0** | **0.8** | **3%** |

**Table 26 Fiscal 2020 Fleet Capital Additions Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Fleet | 26.2 | 29.2 | 3.0 | 12% |
| **Total** | **26.2** | **29.2** | **3.0** | **12%** |

Fiscal 2020 capital expenditures and capital additions for Fleet were comparable to the Fiscal 2020 RRA Plan.

*Business Support - Other and Other Technology*

**Table 27 Fiscal 2020 Business Support –Other and Other Technology Capital Expenditures Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Business Support - Other | 37.4 | 32.0 | (5.4) | -14% |
| Other Technology | 2.1 | 0.8 | (1.3) | -60% |
| **Total** | **39.5** | **32.8** | **(6.7)** | **-17%** |

**Table 28 Fiscal 2020 Business Support –Other and Other Technology Capital Expenditures Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | **Update** | **Actual** | **Diff** | **% Diff** |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| Business Support - Other | 38.7 | 27.2 | (11.5) | -30% |
| Other Technology | 6.6 | - | (6.6) | -100% |
| **Total** | **45.3** | **27.2** | **(18.1)** | **-40%** |

*Business Support - Other*

Business Support – Other is comprised of capital expenditures such as security equipment, field tools and minor equipment. Fiscal 2020 capital expenditures for Business Support - Other were comparable to the Fiscal 2020 RRA Plan.

Fiscal 2020 capital additions for Business Support - Other were $11.5 million (or 30 per cent) below the Fiscal 2020 RRA Plan primarily because:

- The completion and in-service date of the Security Command Center at South Interior Command Center project was delayed primarily due to vendors not meeting all the compliance requirements related to the North American Electric Reliability Corporation (**NERC**) Information Protection. In addition, there were schedule changes on smaller security projects which resulted in projects completion delays; and
- The completion and in-service dates for the Site Engineering and Acceptance projects were delayed to fiscal 2021 due to order delivery delays by the vendors.

*Other Technology*

Other Technology is comprised of the Mobile Radio Optimization project which was not classified as part of the main asset Technology category as the project was for Field Operations tools and equipment. Fiscal 2020 capital expenditures and capital additions were comparable to the Fiscal 2020 RRA Plan.

## 10.6 Site C Project Capital Expenditures and Additions Variance Explanations

Site C Project fiscal 2020 capital expenditures and capital additions are presented in the tables below.

**Table 29 Fiscal 2020 Site C Project Capital Expenditures Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | Update | Actual | Diff | % Diff |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| **Total Site C** | **1,530.0** | **1,619.1** | **89.1** | **6%** |

**Table 30 Fiscal 2020 Site C Project Capital Additions Variances**

| ($ million) | F2020 | | | |
|---|---|---|---|---|
| | Update | Actual | Diff | % Diff |
| | 1 | 2 | 3=2-1 | 4=3/1 |
| **Total Site C** | **27.9** | **12.9** | **(15.0)** | -54% |

Fiscal 2020 capital expenditures were $89.1 million (or 6 per cent) above the Fiscal 2020 RRA Plan. Variances were primarily due to:

- Spillway buttress construction activities were completed in fiscal 2020, ahead of plan;
- Higher than planned diversion tunnel work, and claims for main civil works;
- Work planned to be completed in prior years was completed in fiscal 2020;
- Additional change orders and claims for generating station and spillway; and
- Schedule advancement of highway early works and higher than planned worker accommodation and transmission expenditures.

The increase in capital expenditures above was partially offset by timing differences for turbines and generators, property acquisitions and reservoir clearing expenditures.

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

Fiscal 2020 capital additions were $15.0 million (or 54 per cent) below the Fiscal 2020 RRA Plan primarily due to the in-service date for the outdoor portion of the Peace Canyon Gas-Insulated Switchgear (part of the Transmission-related assets) being delayed to fiscal 2021.

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

In compliance with BCUC Order No. G-313-19,[1] Table 31 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, 2019 and March 31, 2020; or final in-service date achieved prior to this fiscal year and where the remaining capital expenditures has increased 25 per cent or more and a minimum amount of $0.5 million compared to the estimated remaining capital expenditures when previously reported;[2] 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

1 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."

2 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.

- 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.

Table 31 includes the variance between the EAC[3] and the FFF[4] amount and provides a brief explanation for any variance greater than or equal to 10 per cent.

[3] 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.

[4] 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.

## Table 31 Projects and Programs with Final In-Service Dates between April 1, 2019 to March 31, 2020

($ 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) |
| G000492 | Bridge River 2 Upgrade Units 5 and 6 | N/A | Page 27 | F2020 | N | 79.4 | 86.2 | N/A | 70.7 | 78.0 | (1.4) | -2% | | N/A |
| G000614 | Cheakamus Units 1 and 2 Generator Replacement | N/A | Page 30 | F2020 | N | 64.8 | 74.2 | N/A | 61.3 | 62.3 | (2.4) | -4% | | N/A |
| G003362 | Mica Townsite Augment Accommodations Capacity | N/A | Page 36 | F2020 | N | 22.1 | 23.3 | N/A | 21.6 | 22.0 | (0.2) | -1% | | N/A |
| G003542 | Mica Upgrade Powerhouse Cranes | N/A | Page 37 | F2020 | N | 32.4 | 36.1 | N/A | 27.4 | 28.6 | (3.8) | -12% | **Note A** | N/A |
| YT-01082 | Microsoft Enterprise Agreement 2019 | N/A | N/A | F2020 | Y | 19.5 | 19.5 | N/A | 19.5 | 19.5 | 0.0 | 0% | **Note B** | 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, 2020
**Note 7** Estimate at Completion refers to the forecasted capital cost when the project is expected to be financially closed

Note A The Mica Upgrade Powerhouse Cranes was $3.8 million (or 12 per cent) below plan because the anticipated cost of major scaffolding requirements during the runway steel upgrade was not utilized due to the contractor being able to use a series of man lifts and cranes for the installation which resulted in cost savings.

Note B An update on this project was included in Exhibit B-29, which was filed on January 15, 2020 as part of the F2020–F2021 RRA proceedings.

# BC Hydro Fiscal 2020 Annual Report to the British Columbia Utilities Commission

## Attachment 2 to Section 6

## Financial Schedules

# 1 Financial Schedules[1]


| Schedule | | Page |
|---|---|---|
| | **Consolidated Statement of Operations** | 1 |
| 1.0 | **Revenue Requirements Summary** | 2 |
| | **Deferral and Other Regulatory Accounts** | |
| 2.1 | Deferral Accounts | 3 |
| 2.2 | Other Regulatory Accounts | 4 |
| 3.0 | **Reconciliation of Current and Gross Views** | 8 |
| 4.0 | **Cost of Energy** | 9 |
| 5.0 | **Operating Costs and Provisions – Total Company** | 11 |
| 6.0 | **Taxes** | 12 |
| 7.0 | **Depreciation and Amortization** | 13 |
| 8.0 | **Finance Charges** | 14 |
| 9.0 | **Return on Equity** | 15 |
| 10.0 | **Rate Base** | 16 |
| 11.0 | **Contributions** | 17 |
| 12.0 | **Assets – Total (Excluding DSM and IPP Capital Leases)** | 18 |
| 13.0 | **Capital Expenditures and Additions** | 19 |
| 14.0 | **Domestic Energy Sales and Revenue** | 20 |
| 15.0 | **Miscellaneous Revenue** | 21 |


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 | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 |
| | **REVENUES** | | | | |
| | Domestic | | | | |
| 1 | Residential | 14.0 L12 | 2,197.8 | 2,168.8 | (29.0) |
| 2 | Light industrial and commercial | 14.0 L13 | 1,958.8 | 1,942.0 | (16.8) |
| 3 | Large industrial (includes LNG revenues) | 14.0 L14+L20 | 945.3 | 849.7 | (95.6) |
| 4 | Other energy sales | 14.0 L15:L18+L21 | 122.7 | 124.7 | 2.0 |
| 5 | Seattle City Light | 14.0 L19 | 28.8 | 29.7 | 0.9 |
| 6 | Revenue from Deferral Rider | 14.0 L23 | 0.0 | 0.2 | 0.2 |
| 7 | Miscellaneous | 15.0 L34 | 240.7 | 247.3 | 6.6 |
| 8 | Subtotal | | 5,494.0 | 5,362.5 | (131.6) |
| 9 | Intersegment revenues | 3.0 L5 | 64.9 | 72.0 | 7.1 |
| 10 | **TOTAL REVENUES** | Line 8+9 | **5,558.9** | **5,434.4** | **(124.5)** |
| | **EXPENSES** | | | | |
| 11 | Domestic energy costs | 1.0 L1 | 1,928.9 | 1,810.9 | (118.0) |
| 12 | Operating costs | 1.0 L2 | 1,239.1 | 1,292.0 | 52.9 |
| 13 | Depreciation and amortization | 1.0 L4 | 977.8 | 977.7 | (0.1) |
| 14 | Taxes | 1.0 L3 | 249.8 | 249.7 | (0.1) |
| 15 | Finance charges | 1.0 L5 | 874.9 | 1,656.8 | 781.8 |
| 16 | Subtotal | Line 13:17 | 5,270.4 | 5,987.1 | 716.6 |
| 17 | **DOMESTIC INCOME (LOSS) BEFORE TRANSFER (TO)/FROM DEFERRAL ACCOUNTS** | Line 10-18 | **288.5** | **(552.6)** | **(841.1)** |
| 18 | **POWEREX NET INCOME** | 1.0 L17 | **120.6** | **189.2** | **68.7** |
| 19 | **POWERTECH NET INCOME** | 1.0 L18 | **3.4** | **3.4** | **(0.0)** |
| 20 | **TOTAL INCOME (LOSS) BEFORE TRANSFER TO/(FROM) DEFERRAL ACCOUNTS** | Line 17:19 | **412.5** | **(360.0)** | **(772.5)** |
| 21 | Heritage Deferral Account | 2.1 L3:L5 | 267.5 | 185.0 | (82.5) |
| 22 | Non-Heritage Deferral Account | 2.1 L9:L12 | (39.4) | 63.8 | 103.2 |
| 23 | Trade Income Deferral Account | 2.1 L16:L18 | 157.4 | 86.9 | (70.5) |
| 24 | Demand-Side Management Reg. Account | 2.2 L3:L5 | 5.8 | (7.9) | (13.7) |
| 25 | First Nation Costs Regulatory Account | 2.2 L9:L12 | (13.7) | (15.6) | (1.9) |
| 26 | First Nation Settlement Provisions Reg. Acct. | 2.2 L16:L18 | 2.6 | 5.7 | 3.0 |
| 27 | Site C Regulatory Account | 2.2 L22:L24 | 17.0 | 17.0 | 0.0 |
| 28 | Foreign Exchange Gains/Losses Reg. Account | 2.2 L28:L29 | (2.8) | 4.7 | 7.5 |
| 29 | Pre-1996 Customer Contributions Reg. Acct. | 2.2 L32:L33 | (5.1) | (5.1) | - |
| 30 | Storm Restoration Regulatory Account | 2.2 L37:L39 | (29.0) | (37.3) | (8.3) |
| 31 | Capital Project Investigation Costs Reg. Acct. | 2.2 L43 | (5.2) | (5.2) | (0.0) |
| 32 | Amortization of Capital Additions Reg. Acct. | 2.2 L47:L49 | (9.2) | (9.6) | (0.4) |
| 33 | Total Finance Charges Regulatory Account | 2.2 L53:L54 | (10.1) | (9.2) | 0.9 |
| 34 | Smart Metering and Infrastructure Reg. Acct. | 2.2 L58:L62 | (21.7) | (21.8) | (0.1) |
| 35 | Non-Current Pension Costs Reg. Account | 2.2 L67:L71 | (56.8) | 41.8 | 98.6 |
| 36 | Environmental Provisions Regulatory Account | 2.2 L75:L80 | (42.3) | 26.6 | 68.8 |
| 37 | Rock Bay Remediation Regulatory Account | 2.2 L84:L86 | 10.3 | 10.2 | (0.1) |
| 38 | IFRS Property Plant & Equipment Reg. Account | 2.2 L90:L91 | 14.9 | 14.9 | (0.0) |
| 39 | IFRS Pension Regulatory Account | 2.2 L95 | (38.2) | (38.2) | 0.0 |
| 40 | Remediation Regulatory Account | 2.2 L99:L102 | 15.4 | (3.5) | (18.8) |
| 41 | Real Property Sales Regulatory Account | 2.2 L106:L108 | (7.4) | 7.0 | 14.5 |
| 42 | Debt Management Regulatory Account | 2.2 L112:L113 | 113.3 | 789.7 | 676.4 |
| 43 | Dismantling Costs Regulatory Account | 2.2 L117:L119 | (24.1) | (32.3) | (8.2) |
| 44 | PEB Current Pension Regulatory Account | 2.2 L123:L127 | 0.9 | (0.0) | (0.9) |
| 45 | Customer Crisis Fund Regulatory Account | 2.2 L130:L131 | (0.3) | (2.7) | (2.4) |
| 46 | **TOTAL TRANSFER TO/(FROM) DEFERRAL ACCOUNTS** | 1.0 L12+L16 | **299.5** | **1,064.8** | **765.4** |
| 47 | **TOTAL NET INCOME** | Line 20+46 | **712.0** | **704.9** | **(7.1)** |

**Revenue Requirements Summary**
**($ million)**

| Line | | Column | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|---|
| | | | | 1 | 2 | 3 = 2 - 1 |
| 1 | **Cost of Energy** | | 4.0 L29 | 1,928.9 | 1,810.9 | (118.0) |
| 2 | **Operating Costs** | | 5.0 L47 | 1,239.1 | 1,292.0 | 52.9 |
| 3 | **Taxes** | | 6.0 L19 | 249.8 | 249.7 | (0.1) |
| 4 | **Amortization** | | 7.0 L11 | 977.8 | 977.7 | (0.1) |
| 5 | **Finance Charges** | | 8.0 L1 | 874.9 | 1,656.8 | 781.8 |
| 6 | **Return on Equity** | | 9.0 L12 | 712.0 | 704.9 | (7.1) |
| 7 | **Miscellaneous Revenue** | | 15.0 L34 | (240.7) | (247.3) | (6.6) |
| 8 | **Inter-Segment Revenue** | | 3.0 L5 | (64.9) | (72.0) | (7.1) |
| | **Deferral Accounts** | | | | | |
| 9 | Deferral Account Additions | | 2.1 L24 | 3.1 | 52.2 | 49.1 |
| 10 | Interest on Deferral Accounts | | 2.1 L25 | 15.4 | 15.9 | 0.5 |
| 11 | Deferral Account Recoveries | | 2.1 L26 | (403.9) | (403.9) | 0.1 |
| 12 | Total | | | (385.4) | (335.7) | 49.7 |
| | **Other Regulatory Accounts** | | | | | |
| 13 | Regulatory Account Additions | | 2.2 L156 | (267.7) | (984.2) | (716.5) |
| 14 | Interest on Regulatory Accounts | | 2.2 L157 | (33.1) | (32.6) | 0.5 |
| 15 | Regulatory Account Recoveries | | 2.2 L158 | 386.7 | 287.7 | (99.1) |
| 16 | Total | | | 85.9 | (729.1) | (815.1) |
| | **Subsidiary Net Income** | | | | | |
| 17 | Powerex Net Income | | | **(120.6)** | **(189.2)** | (68.7) |
| 18 | Powertech Net Income | | | **(3.4)** | **(3.4)** | 0.0 |
| 19 | Total | | | (124.0) | (192.7) | (68.6) |
| 20 | **Less Other Utilities Revenue** | | 14.0 L19 | (28.8) | (29.7) | (0.9) |
| 21 | **Less Liquefied Natural Gas Revenue** | | 14.0 L20 | (0.6) | (1.3) | (0.7) |
| 22 | **Less Deferral Account Rate Rider** | | 14.0 L23 | 0.0 | (0.2) | (0.2) |
| 23 | **Total Rate Revenue Requirement** | | | 5,223.9 | 5,084.0 | (140.0) |

**Deferral Accounts**
**($ million)**

| Line | | Reference Column | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 |
| | **Heritage Deferral Account** | | | | |
| 1 | Beginning of Year | | (485.1) | (485.1) | 0.0 |
| 2 | Adjustment to Opening Balance | | 0.0 | 0.0 | 0.0 |
| 3 | Additions | Line 30 | 0.0 | (82.4) | (82.4) |
| 4 | Interest | | (13.1) | (13.2) | (0.1) |
| 5 | Recovery | | 280.6 | 280.6 | (0.0) |
| 6 | End of Year | | (217.6) | (300.1) | (82.5) |
| | **Non-Heritage Deferral Account** | | | | |
| 7 | Beginning of Year | | 76.1 | 76.1 | 0.0 |
| 8 | Adjustment to Opening Balance | | 64.8 | 64.8 | 0.0 |
| 9 | Additions | Line 31 | 0.0 | 100.1 | 100.1 |
| 10 | Additions - Waneta 2/3 | 15.0 L33 | (3.1) | (1.3) | 1.8 |
| 11 | Interest | | 4.5 | 5.9 | 1.3 |
| 12 | Recovery | | (40.8) | (40.9) | (0.0) |
| 13 | End of Year | | 101.5 | 204.7 | 103.2 |
| | **Trade Income Deferral Account** | | | | |
| 14 | Beginning of Year | | (258.8) | (258.8) | 0.0 |
| 15 | Adjustment to Opening Balance | | (1.9) | (1.9) | 0.0 |
| 16 | Additions | Line 32 | 0.0 | (68.7) | (68.7) |
| 17 | Interest | | (6.8) | (8.6) | (1.8) |
| 18 | Recovery | | 164.2 | 164.2 | 0.0 |
| 19 | End of Year | | (103.3) | (173.7) | (70.5) |
| | **End of Year Balances** | | | | |
| 20 | Heritage | Line 6 | (217.6) | (300.1) | (82.5) |
| 21 | Non-Heritage | Line 13 | 101.5 | 204.7 | 103.2 |
| 22 | Trade Income | Line 19 | (103.3) | (173.7) | (70.5) |
| 23 | Total | | (219.4) | (269.1) | (49.7) |
| | **Summary** | | | | |
| 24 | Deferral Account Additions | | (3.1) | (52.2) | (49.1) |
| 25 | Interest on Deferral Accounts | | (15.4) | (15.9) | (0.5) |
| 26 | Deferral Account Recoveries | | 403.9 | 403.9 | (0.1) |
| 27 | Adjustment to Opening Balance | L2+L8+L15 | 62.9 | 62.9 | 0.0 |
| 28 | Deferral Account Net Transfers | | 448.4 | 398.6 | (49.7) |
| 29 | **Interest Rate** | 8.0 L24 | 3.81% | 3.74% | (0.07%) |
| | **Summary of Items Subject to Deferral** | | | | |
| 30 | Cost of Heritage Energy | 4.0 L39 | 581.7 | 499.3 | (82.4) |
| 31 | Cost of Non-Heritage Energy | 4.0 L48 | 1,357.5 | 1,457.6 | 100.1 |
| 32 | Trade Income | 1.0 L17 | (120.6) | (189.2) | (68.7) |

**Other Regulatory Accounts**
**($ million)**

| Line | | Reference Column | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 |
| | **Demand-Side Management** | | | | |
| 1 | Beginning of Year | | 914.5 | 914.5 | 0.0 |
| 2 | Adjustment to Opening Balance | | 0.0 | 0.0 | 0.0 |
| 3 | Additions | 5.0 L16 | 109.1 | 95.4 | (13.7) |
| 4 | Amortization on Existing | | (103.3) | (103.3) | 0.0 |
| 5 | Amortization on Additions | | 0.0 | 0.0 | 0.0 |
| 6 | End of Year | | 920.3 | 906.6 | (13.7) |
| | **First Nations Costs** | | | | |
| 7 | Beginning of Year | | 85.0 | 85.0 | 0.0 |
| 8 | Adjustment to Opening Balance | | 0.0 | 0.0 | 0.0 |
| 9 | Additions | 5.0 L17 | 3.2 | 2.5 | (0.6) |
| 10 | Transfer from Provision | Line 18 | 15.0 | 12.8 | (2.1) |
| 11 | Interest | | 2.9 | 3.1 | 0.2 |
| 12 | Recovery | | (34.7) | (34.1) | 0.6 |
| 13 | End of Year | | 71.4 | 69.5 | (1.9) |
| | **First Nations Settlement Provisions** | | | | |
| 14 | Beginning of Year | | 420.3 | 420.3 | 0.0 |
| 15 | Adjustment to Opening Balance | | 0.0 | 0.0 | 0.0 |
| 16 | Additions - Operating | 5.0 L41 | 0.0 | 0.9 | 0.9 |
| 17 | Additions - Accretion | 8.0 L4 | 17.6 | 17.6 | 0.0 |
| 18 | Transfer to Negotiation Costs | | (15.0) | (12.8) | 2.1 |
| 19 | End of Year | | 423.0 | 426.0 | 3.0 |
| | **Site C Project** | | | | |
| 20 | Beginning of Year | | 491.3 | 491.3 | 0.0 |
| 21 | Adjustment to Opening Balance | | 0.0 | 0.0 | 0.0 |
| 22 | Additions | 5.0 L18+8.0 L20 | (1.7) | (1.5) | 0.1 |
| 23 | Interest | | 18.7 | 18.6 | (0.1) |
| 24 | Recovery | | 0.0 | 0.0 | 0.0 |
| 25 | End of Year | | 508.4 | 508.4 | 0.0 |
| | **Foreign Exchange Gains/Losses** | | | | |
| 26 | Beginning of Year | | 11.9 | 11.9 | 0.0 |
| 27 | Adjustment to Opening Balance | | 0.0 | 0.0 | 0.0 |
| 28 | Additions | 8.0 L2 | (2.3) | 5.3 | 7.5 |
| 29 | Recovery | | (0.5) | (0.5) | (0.0) |
| 30 | End of Year | | 9.0 | 16.6 | 7.5 |
| | **Pre-1996 Customer Contributions** | | | | |
| 31 | Beginning of Year | | 83.3 | 83.3 | 0.0 |
| 32 | Adjustment to Opening Balance | | 0.0 | 0.0 | 0.0 |
| 33 | Recovery | | (5.1) | (5.1) | 0.0 |
| 34 | End of Year | | 78.2 | 78.2 | 0.0 |
| | **Storm Restoration Costs** | | | | |
| 35 | Beginning of Year | | 58.0 | 58.0 | 0.0 |
| 36 | Adjustment to Opening Balance | | 0.0 | 0.0 | 0.0 |
| 37 | Additions | 5.0 L19 | 0.0 | (7.8) | (7.8) |
| 38 | Interest | | 1.6 | 1.1 | (0.5) |
| 39 | Recovery | | (30.6) | (30.6) | (0.0) |
| 40 | End of Year | | 29.0 | 20.8 | (8.3) |
| | **Capital Project Investigation** | | | | |
| 41 | Beginning of Year | | 10.5 | 10.5 | 0.0 |
| 42 | Adjustment to Opening Balance | | 0.0 | 0.0 | 0.0 |
| 43 | Recovery | | (5.2) | (5.2) | (0.0) |
| 44 | End of Year | | 5.2 | 5.2 | (0.0) |

**BC Hydro**
**F20 actual RRA**



**Other Regulatory Accounts**
**($ million)**

| Line | | Column | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|---|
| | | | | 1 | 2 | 3 = 2 - 1 |
| | **Amortization of Capital Additions** | | | | | |
| 45 | Beginning of Year | | | 18.4 | 18.4 | 0.0 |
| 46 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 47 | Additions | | | 0.0 | (0.4) | (0.4) |
| 48 | Interest | | | 0.5 | 0.6 | 0.1 |
| 49 | Recovery | | | (9.7) | (9.7) | 0.0 |
| 50 | End of Year | | | 9.2 | 8.9 | (0.4) |
| | **Total Finance Charges** | | | | | |
| 51 | Beginning of Year | | | 20.2 | 20.2 | 0.0 |
| 52 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 53 | Additions | | 8.0 L19 | 0.0 | 0.9 | 0.9 |
| 54 | Recovery | | | (10.1) | (10.1) | 0.0 |
| 55 | End of Year | | | 10.1 | 11.1 | 0.9 |
| | **Smart Metering & Infrastructure** | | | | | |
| 56 | Beginning of Year | | | 217.2 | 217.2 | 0.0 |
| 57 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 58 | Additions - Deferred Operating | | 5.0 L20 | 0.0 | 0.0 | 0.0 |
| 59 | Additions - DSMD Write-Off | | 5.0 L | 0.0 | 0.0 | 0.0 |
| 60 | Additions - Miscellaneous Revenue | | | 0.0 | 0.0 | 0.0 |
| 61 | Interest | | | 7.7 | 7.8 | 0.0 |
| 62 | Recovery | | | (29.4) | (29.6) | (0.2) |
| 63 | End of Year | | | 195.5 | 195.4 | (0.1) |
| | **Non-Current Pension Cost** | | | | | |
| 64 | Beginning of Year | | | 485.5 | 485.5 | 0.0 |
| 65 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 66 | OCI Deferral | | | (70.0) | (317.2) | (247.2) |
| 67 | Additions | | | 0.0 | 0.0 | 0.0 |
| 68 | Recovery - Operating | | | (56.8) | (56.8) | 0.0 |
| 69 | Recovery - Finance Charges | | | 0.0 | 98.6 | 98.6 |
| 70 | Transfer to PEB Current Pension-Addition | | | 0.0 | 0.0 | 0.0 |
| 71 | Transfer to PEB Current Pension-Recovery | | | 0.0 | 0.0 | 0.0 |
| 72 | End of Year | | | 358.7 | 210.1 | (148.6) |
| | **Environmental Provisions** | | | | | |
| 73 | Beginning of Year | | | 278.5 | 278.5 | 0.0 |
| 74 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 75 | Additions - Deferred Operating | | 5.0 L42 | 0.0 | 51.2 | 51.2 |
| 76 | Additions - Accretion | | 8.0 L5 | 5.5 | 4.8 | (0.7) |
| 77 | Transfer to Rock Bay | | | 0.0 | 0.0 | 0.0 |
| 78 | Transfer to Remediation (Asbestos) | | | (21.7) | (8.2) | 13.5 |
| 79 | Transfer to Remediation (PCB) | | | (26.1) | (21.2) | 4.9 |
| 80 | Recovery | | | | | 0.0 |
| 81 | End of Year | | | 236.2 | 305.1 | 68.8 |
| | **Rock Bay Remediation** | | | | | |
| 82 | Beginning of Year | | | (20.5) | (20.5) | 0.0 |
| 83 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 84 | Transfer from Environmental | | Line 77 | 0.0 | 0.0 | 0.0 |
| 85 | Interest | | | (0.6) | (0.6) | (0.1) |
| 86 | Recovery | | | 10.8 | 10.8 | 0.0 |
| 87 | End of Year | | | (10.3) | (10.4) | (0.1) |

**BC Hydro**
**F20 actual RRA**



**Other Regulatory Accounts**
**($ million)**

| Line | | Column | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|---|
| | | | | 1 | 2 | 3 = 2 - 1 |
| | **IFRS PP&E** | | | | | |
| 88 | Beginning of Year | | | 1,064.4 | 1,064.4 | 0.0 |
| 89 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 90 | Additions - Deferred Operating | | 5.0 L20 | 44.8 | 44.8 | 0.0 |
| 91 | Recovery | | | (29.9) | (29.9) | (0.0) |
| 92 | End of Year | | | 1,079.2 | 1,079.2 | (0.0) |
| | **IFRS Pension** | | | | | |
| 93 | Beginning of Year | | | 497.1 | 497.1 | 0.0 |
| 94 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 95 | Recovery | | | (38.2) | (38.2) | 0.0 |
| 96 | End of Year | | | 458.9 | 458.9 | 0.0 |
| | **Remediation** | | | | | |
| 97 | Beginning of Year | | | (30.8) | (30.8) | 0.0 |
| 98 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 99 | Transfer from Env. Prov. (Asbestos) | | Line 78 | 21.7 | 8.2 | (13.5) |
| 100 | Transfer from Env. Prov. (PCB) | | Line 79 | 26.1 | 21.2 | (4.9) |
| 101 | Interest | | | (0.9) | (1.3) | (0.4) |
| 102 | Recovery | | | (31.6) | (31.6) | 0.0 |
| 103 | End of Year | | | (15.4) | (34.3) | (18.8) |
| | **Real Property Sales** | | | | | |
| 104 | Beginning of Year | | | 49.2 | 49.2 | 0.0 |
| 105 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 106 | Additions | | 5.0 L22+L43 | (9.1) | 5.3 | 14.4 |
| 107 | Interest | | | 1.7 | 1.7 | 0.0 |
| 108 | Recovery | | | 0.0 | 0.0 | 0.0 |
| 109 | End of Year | | | 41.7 | 56.2 | 14.5 |
| | **Debt Management** | | | | | |
| 110 | Beginning of Year | | | 163.2 | 163.2 | 0.0 |
| 111 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 112 | Additions | | 8.0 L6 | 100.9 | 777.3 | 676.4 |
| 113 | Recovery | | | 12.4 | 12.4 | 0.0 |
| 114 | End of Year | | | 276.5 | 952.9 | 676.4 |
| | **Dismantling Cost** | | | | | |
| 115 | Beginning of Year | | | 48.3 | 48.3 | 0.0 |
| 116 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 117 | Additions | | 5.0 L44 | 0.0 | (8.5) | (8.5) |
| 118 | Interest | | | 1.4 | 1.6 | 0.3 |
| 119 | Recovery | | | (25.5) | (25.5) | 0.0 |
| 120 | End of Year | | | 24.1 | 16.0 | (8.2) |
| | **PEB Current Pension Costs** | | | | | |
| 121 | Beginning of Year | | | (1.7) | (1.7) | 0.0 |
| 122 | Adjustment to Opening Balance | | | 0.0 | 0.0 | 0.0 |
| 123 | OCI Deferral | | | 0.0 | 0.0 | 0.0 |
| 124 | Additions | | 5.0 L21+L | 0.0 | (0.9) | (0.9) |
| 125 | Recovery - Operating | | | 0.9 | 0.9 | (0.0) |
| 126 | Transfer from NC Current Pension-Addition | | Line 70 | 0.0 | 0.0 | 0.0 |
| 127 | Transfer from NC Current Pension-Recovery | | Line 71 | 0.0 | 0.0 | 0.0 |
| 128 | End of Year | | | (0.9) | (1.8) | (0.9) |
| | **Customer Crisis Fund** | | | | | |
| 129 | Beginning of Year | | | (2.6) | (2.6) | 0.0 |
| 130 | Additions | | 5.0 L23 | (0.3) | (2.7) | (2.4) |
| 131 | Recovery | | | 0.0 | 0.0 | 0.0 |
| 132 | End of Year | | | (2.9) | (5.3) | (2.4) |

**Other Regulatory Accounts**
**($ million)**

| Line | | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | Column | | 1 | 2 | 3 = 2 - 1 |
| | **End of Year Balances** | | | | |
| 133 | Demand-Side Management | Line 6 | 920.3 | 906.6 | (13.7) |
| 134 | First Nations Costs | Line 13 | 71.4 | 69.5 | (1.9) |
| 135 | First Nations Settlement Provisions | Line 19 | 423.0 | 426.0 | 3.0 |
| 136 | Site C Project | Line 25 | 508.4 | 508.4 | 0.0 |
| 137 | Foreign Exchange Gains/Losses | Line 30 | 9.0 | 16.6 | 7.5 |
| 138 | Pre-1996 Customer Contributions | Line 34 | 78.2 | 78.2 | 0.0 |
| 139 | Storm Restoration Costs | Line 40 | 29.0 | 20.8 | (8.3) |
| 140 | Capital Project Investigation | Line 44 | 5.2 | 5.2 | (0.0) |
| 141 | Amortization of Capital Additions | Line 50 | 9.2 | 8.9 | (0.4) |
| 142 | Total Finance Charges | Line 55 | 10.1 | 11.1 | 0.9 |
| 143 | Smart Metering & Infrastructure | Line 63 | 195.5 | 195.4 | (0.1) |
| 144 | Non-Current Pension Cost | Line 72 | 358.7 | 210.1 | (148.6) |
| 145 | Environmental Provisions | Line 81 | 236.2 | 305.1 | 68.8 |
| 146 | Rock Bay Remediation | Line 87 | (10.3) | (10.4) | (0.1) |
| 147 | IFRS PP&E | Line 92 | 1,079.2 | 1,079.2 | (0.0) |
| 148 | IFRS Pension | Line 96 | 458.9 | 458.9 | 0.0 |
| 149 | Remediation | Line 103 | (15.4) | (34.3) | (18.8) |
| 150 | Real Property Sales | Line 109 | 41.7 | 56.2 | 14.5 |
| 151 | Debt Management | Line 114 | 276.5 | 952.9 | 676.4 |
| 152 | Dismantling Cost | Line 120 | 24.1 | 16.0 | (8.2) |
| 153 | PEB Current Pension Costs | Line 128 | (0.9) | (1.8) | (0.9) |
| 154 | Customer Crisis Fund | Line 132 | (2.9) | (5.3) | (2.4) |
| 155 | Total | | 4,705.2 | 5,273.1 | 567.8 |
| | **Summary** | | | | |
| 156 | Regulatory Account Additions | | 267.7 | 984.2 | 716.5 |
| 157 | Interest on Regulatory Accounts | | 33.1 | 32.6 | (0.5) |
| 158 | Regulatory Account Recoveries | | (386.7) | (287.7) | 99.1 |
| 159 | Adjustments to Opening Balances | | 0.1 | 0.1 | 0.0 |
| 160 | OCI Deferral (Pension) | | (70.0) | (317.2) | (247.2) |
| 161 | Regulatory Account Net Transfers | | (155.9) | 412.0 | 567.8 |
| 162 | **Interest Rate** | 8.0 L24 | 3.81% | 3.74% | (0.07%) |

**Reconciliation of Current and Gross Views**
**($ million)**

| | | | F2020 | | | |
|---|---|---|---|---|---|---|
| | | **Reference** | **Update** | **Actual** | **Diff** | |
| **Line** | | **Column** | 1 | 2 | 3 = 2 - 1 | |
| | **Inter-Segment Revenue** | | | | | |
| 1 | Powerex - Business Support Allocation | | (2.9) | (2.9) | 0.0 | Note 1 |
| 2 | Mark to Market Losses (Gains) | | (1.4) | 0.8 | 2.2 | Note 2 |
| 3 | Powerex PTP Charges | | (41.5) | (49.8) | (8.3) | Note 3 |
| 4 | BC Hydro PTP Charges | | (19.1) | (20.1) | (1.0) | Note 4 |
| 5 | Total | | (64.9) | (72.0) | (7.1) | |

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

Note 2: Commodity Risk of $2.2 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 | F2020 Update | F2020 Actual | F2020 Diff | |
|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 | |
| | **Sources of Supply (GWh)** | | | | | |
| | **Heritage Energy** | | | | | |
| 1 | Water Rentals | | 39,368 | 40,383 | 1,015 | |
| 2 | Natural Gas for Thermal Generation | | 181 | 171 | (10) | |
| 3 | Exchange Net | | (473) | (581) | (108) | |
| 4 | Total | | 39,075 | 39,972 | 897 | |
| | **Non-Heritage Energy** | | | | | |
| 5 | IPPs and Long-Term Commitments | | 13,949 | 14,475 | 526 | |
| 6 | Non-Integrated Area | | 118 | 106 | (11) | |
| 7 | Total | | 14,067 | 14,581 | 514 | |
| | **Market Energy** | | | | | |
| 8 | Market Electricity Purchases | | 5,104 | 3,471 | (1,633) | |
| 9 | Surplus Sales | | (84) | (182) | (98) | |
| 10 | Net Purchases (Sales) from Powerex | | 468 | (940) | (1,407) | |
| 11 | Total | | 5,488 | 2,349 | (3,139) | |
| 12 | **Total Sources of Supply** | L4+L7+L11 | 58,630 | 56,903 | (1,727) | |
| | **Cost of Energy ($ million)** | | | | | |
| | **Heritage Energy** | | | | | |
| 13 | Water Rentals | | 329.3 | 331.6 | 2.3 | |
| 14 | Natural Gas for Thermal Generation | | 7.5 | 7.1 | (0.4) | |
| 15 | Domestic Transmission - Other | | 24.5 | 24.8 | 0.3 | |
| 16 | Non-Treaty Storage and Libby Coordination Agreements | | 15.0 | 37.7 | 22.7 | |
| 17 | Remissions and Other | | (25.2) | (42.4) | (17.2) | |
| 18 | Total | | 351.2 | 358.8 | 7.7 | |
| | **Non-Heritage Energy** | | | | | |
| 19 | IPPs and Long-Term Commitments | | 1,294.7 | 1,314.0 | 19.3 | |
| 20 | Non-Integrated Area | | 30.5 | 31.3 | 0.7 | |
| 21 | Gas & Other Transportation | | 3.7 | 4.5 | 0.8 | |
| 22 | Water Rentals (Waneta 2/3) | 15.0 L22 | 3.5 | 3.3 | (0.2) | |
| 23 | Total | | 1,332.4 | 1,353.1 | 20.7 | |
| | **Market Energy** | | | | | |
| 24 | Market Electricity Purchases | | 211.6 | 133.1 | (78.4) | |
| 25 | Surplus Sales | | (0.4) | (1.0) | (0.6) | |
| 26 | Net Purchases (Sales) from Powerex | | 33.1 | (35.2) | (68.3) | Note 1 |
| 27 | Domestic Transmission - Export | | 1.1 | 2.0 | 0.9 | |
| 28 | Total | | 245.3 | 99.0 | (146.4) | |
| 29 | **Total Gross COE** | L18+L23+L28 | 1,928.9 | 1,810.9 | (118.0) | |
| | **Items Subject to HDA** | | | | | |
| 30 | Heritage Energy | Line 18 | 351.2 | 358.8 | 7.7 | |
| 31 | Market Electricity Purchases | Line 24 | 211.6 | 133.1 | (78.4) | |
| 32 | Surplus Sales | Line 25 | (0.4) | (1.0) | (0.6) | |
| 33 | Domestic Transmission - Export | Line 27 | 1.1 | 2.0 | 0.9 | |
| 34 | Costs in Operating/Amortization | | 12.5 | 12.5 | 0.0 | |
| 35 | Notional Water Rentals | | 3.1 | (6.1) | (9.2) | |
| 36 | Skagit and Ancillary Revenue | 14.0 L19 | (28.8) | (29.7) | (0.9) | |
| 37 | Deferred Operating HDA | 5.0 L14 | 0.0 | (1.4) | (1.4) | |
| 38 | Other | | 31.5 | 31.0 | (0.5) | |
| 39 | Total | | 581.7 | 499.3 | (82.4) | |

**BC Hydro**
**F20 actual RRA**



**Cost of Energy**

| Line | | Column | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|---|
| | | | | 1 | 2 | 3 = 2 - 1 |
| | **Items Subject to NHDA** | | | | | |
| 40 | Non-Heritage Cost of Energy | | Line 23 | 1,332.4 | 1,353.1 | 20.7 |
| 41 | Less: Water Rentals (Waneta 2/3) | | Line 22 | (3.5) | (3.3) | 0.2 |
| 42 | Net Purchases (Sales) from Powerex | | Line 26 | 33.1 | (35.2) | (68.3) |
| 43 | Commodity Risk | | | **(1.4)** | **0.8** | 2.2 |
| 44 | Notional Water Rental | | Line 35 | (3.1) | 6.1 | 9.2 |
| 45 | Revenue Variance | | | **0.0** | **139.3** | 139.3 |
| 46 | Deferred Amortization NHDA | | 7.0 L9 | 0.0 | 0.4 | 0.4 |
| 47 | Other | | | **0.0** | **(3.6)** | (3.6) |
| 48 | Total | | | 1,357.5 | 1,457.6 | 100.1 |

Note 1: These sales / purchases relate to allocations of energy between BC Hydro and Powerex. These sales / purchases are eliminated against trade cost of energy on consolidation. Intercompany transactions between BC Hydro and Powerex have no net impact on the combined NHDA and the TIDA balances.

**Operating Costs and Provisions - Total Company**
**($ million)**

| Line | Column | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 |
| | **Operating Costs by Business Group** | | | | |
| 1 | Integrated Planning | | 290.8 | 289.3 | (1.5) |
| 2 | Capital Infrastructure Project Delivery | | 80.1 | 80.1 | 0.1 |
| 3 | Operations | | 237.3 | 246.1 | 8.8 |
| 4 | Safety | | 56.8 | 55.0 | (1.9) |
| 5 | Finance, Technology, Supply Chain | | 262.6 | 265.1 | 2.5 |
| 6 | People, Customer, Corporate Affairs | | 110.6 | 110.0 | (0.6) |
| 7 | Other | | (244.3) | (241.4) | 2.9 |
| 8 | **Base Operating Costs** | | 793.8 | 804.2 | 10.3 |
| 9 | IFRS Ineligible Capitalized Costs | | 170.1 | 170.1 | 0.0 |
| 10 | Waneta 2/3 | | 5.7 | 5.4 | (0.3) |
| 11 | Customer Crisis Fund | | 5.3 | 4.4 | (0.9) |
| 12 | **Subtotal** | | 181.1 | 179.8 | (1.2) |
| 13 | **Net Operating Costs** | L8+L12 | 974.9 | 984.0 | 9.1 |
| | **Deferral Account Additions** | | | | |
| 14 | Transfers to HDA | | 0.0 | (1.4) | (1.4) |
| 15 | Total | | 0.0 | (1.4) | (1.4) |
| | **Regulatory Account Additions** | | | | |
| 16 | Demand-Side Management | | 109.1 | 95.4 | (13.7) |
| 17 | First Nations Costs | | 3.2 | 2.5 | (0.6) |
| 18 | Site C Project | | 0.3 | 0.3 | 0.0 |
| 19 | Storm Restoration | | 0.0 | (7.8) | (7.8) |
| 20 | IFRS Capitalized Overhead | | 44.8 | 44.8 | 0.0 |
| 21 | PEB Current Pension Costs | | 0.0 | (0.9) | (0.9) |
| 22 | Real Property Sales | | 0.0 | 0.9 | 0.9 |
| 23 | Customer Crisis Fund | | (0.3) | (2.7) | (2.4) |
| 24 | Total | | 157.1 | 132.6 | (24.5) |
| 25 | **Total Gross Operating Costs** | L13+L15+L24 | 1,132.0 | 1,115.2 | (16.8) |
| | **Net Provisions & Other** | | | | |
| 26 | Integrated Planning | | 40.5 | 56.5 | 16.0 |
| 27 | Capital Infrastructure Project Delivery | | 0.0 | 0.7 | 0.7 |
| 28 | Operations | | 6.5 | 0.7 | (5.8) |
| 29 | Safety | | 0.0 | 0.1 | 0.1 |
| 30 | Finance, Technology, Supply Chain | | 0.0 | 4.0 | 4.0 |
| 31 | People, Customer, Corporate Affairs | | 0.0 | 6.2 | 6.2 |
| 32 | Other | | 12.2 | 3.5 | (8.8) |
| | Dismantling Expense | | | | |
| 33 | Integrated Planning | | 33.0 | 33.0 | 0.0 |
| 34 | Capital Infrastructure Project Delivery | | 1.5 | 1.5 | 0.0 |
| 35 | Operations | | 32.4 | 32.4 | 0.0 |
| 36 | Finance, Technology, Supply Chain | | 0.2 | 0.2 | 0.0 |
| 37 | Real Property Sales | | (10.0) | (10.0) | 0.0 |
| 38 | Total | | 116.2 | 128.7 | 12.5 |
| | **Deferral Account Additions - Provisions & Other** | | | | |
| 39 | Transfers to NHDA | | 0.0 | 0.0 | 0.0 |
| 40 | Total | | 0.0 | 0.0 | 0.0 |
| | **Regulatory Account Additions - Provisions & Other** | | | | |
| 41 | First Nations Provisions | | 0.0 | 0.9 | 0.9 |
| 42 | Environmental Provisions | | 0.0 | 51.2 | 51.2 |
| 43 | Real Property Sales | | (9.1) | 4.4 | 13.5 |
| 44 | Dismantling Expense | | 0.0 | (8.5) | (8.5) |
| 45 | Total | | (9.1) | 48.0 | 57.2 |
| 46 | **Total Gross Provisions & Other** | L38 + L40 + L45 | 107.1 | 176.8 | 69.6 |
| 47 | **Total Gross Operating and Provisions & Other** | L25 + L46 | 1,239.1 | 1,292.0 | 52.9 |

**Taxes**
**($ million)**

| Line | | Reference Column | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 |
| | **Generation** | | | | |
| 1 | Grants in Lieu | | 26.9 | 26.6 | (0.3) |
| 2 | School Taxes | | 17.4 | 17.7 | 0.3 |
| 3 | Total | | 44.3 | 44.2 | (0.0) |
| | **Transmission** | | | | |
| 4 | Grants in Lieu | | 63.6 | 64.9 | 1.3 |
| 5 | School Taxes | | 94.0 | 93.5 | (0.5) |
| 6 | Total | | 157.6 | 158.4 | 0.8 |
| | **Distribution** | | | | |
| 7 | Grants in Lieu | | 8.5 | 8.6 | 0.0 |
| 8 | School Taxes | | 20.6 | 20.0 | (0.6) |
| 9 | Total | | 29.1 | 28.6 | (0.6) |
| | **Customer Care** | | | | |
| | Waneta 2/3 | | | | |
| 10 | Teck portion of property taxes | 15.0 L23 | 0.6 | 0.9 | 0.3 |
| 11 | Total | | 0.6 | 0.9 | 0.3 |
| | **Business Support** | | | | |
| 12 | Grants in Lieu | | 11.8 | 11.3 | (0.6) |
| 13 | School Taxes | | 6.3 | 6.4 | 0.1 |
| 14 | Total | | 18.2 | 17.7 | (0.5) |
| | **Total Before Regulatory Accounts** | | | | |
| 15 | Grants in Lieu | L1+L4+L7+L12 | 110.8 | 111.3 | 0.5 |
| 16 | School Taxes | L2+L5+L8+L13 | 138.3 | 137.5 | (0.8) |
| 17 | Waneta 2/3 Property Taxes | L10 | 0.6 | 0.9 | 0.3 |
| 18 | Total | | 249.8 | 249.7 | (0.1) |
| 19 | **Total Gross Taxes** | L18 + L | 249.8 | 249.7 | (0.1) |

**Depreciation and Amortization**
**($ million)**

| Line | | Reference Column | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 |
| | **Amortization of Capital Assets** | | | | |
| 1 | Generation | | 260.9 | 262.7 | 1.8 |
| 2 | Transmission | | 228.4 | 229.2 | 0.8 |
| 3 | Distribution | | 206.3 | 207.3 | 1.1 |
| 4 | Business Support | | 189.9 | 186.6 | (3.3) |
| 5 | Total | | 885.4 | 885.8 | 0.4 |
| | **IPP Capital Leases** | | | | |
| 6 | IPP Capital Leases | | 88.9 | 88.9 | 0.0 |
| 7 | Total | | 88.9 | 88.9 | 0.0 |
| | **Other Leases** | | | | |
| 8 | Amortization | | 3.4 | 2.6 | (0.8) |
| | **Deferral Account Additions** | | | | |
| 9 | Transfers to NHDA | | 0.0 | 0.4 | 0.4 |
| 10 | Total | | 0.0 | 0.4 | 0.4 |
| 11 | **Total Gross Amortization** | | 977.8 | 977.7 | (0.1) |

**Finance Charges**
**($ million)**

| Line | | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | Column | | 1 | 2 | 3 = 2 - 1 |
| 1 | **Total Gross Finance Charges** | L7 + L18 | 874.9 | 1,656.8 | 781.8 |
| | **Regulatory Account Additions** | | | | |
| 2 | FX Gains/Losses | | (2.3) | 5.3 | 7.5 |
| 3 | Deferred IPP Capital Leases (Total Finance Charge Reg. Account Additions) | | 0.0 | 0.3 | 0.3 |
| 4 | Accretion - First Nations | | 17.6 | 17.6 | 0.0 |
| 5 | Accretion - Environmental | | 5.5 | 4.8 | (0.7) |
| 6 | Debt Management | | 100.9 | 777.3 | 676.4 |
| 7 | Total | | 121.8 | 805.3 | 683.5 |
| 8 | **Adj. for Regulatory Account Additions** | | 753.1 | 851.5 | 98.3 |
| | **Total Before Regulatory Accounts** | | | | |
| 9 | Sinking Fund Income | | (7.8) | (9.1) | (1.2) |
| 10 | Long-Term Debt Costs | | 825.3 | 824.9 | (0.4) |
| 11 | Short-Term Debt Costs | | 63.8 | 47.5 | (16.2) |
| 12 | Interest Capitalized | | (181.5) | (175.5) | 6.0 |
| 13 | Other (Income) / Loss | | 39.2 | 50.5 | 11.3 |
| 14 | IPP Capital Leases | | 48.4 | 48.4 | 0.0 |
| 15 | Accretion - Non-Deferrable | | 1.3 | 1.3 | (0.0) |
| 16 | Non-Current PEB | | (36.5) | 62.1 | 98.6 |
| 17 | Other Leases | | 1.0 | 1.3 | 0.2 |
| 18 | Total | | 753.1 | 851.5 | 98.3 |
| 19 | Total Finance Charge Regulatory Acct. Additions | | 0.0 | (0.9) | (0.9) |
| 20 | Site C Project (IFRS 14 IDC impact) | | 2.0 | 1.9 | (0.1) |
| | **Weighted Average Cost of Debt (WACD) Rate** | | | | |
| 21 | Total Gross Finance Charges | Line 1 | 874.9 | 1,656.8 | 781.8 |
| 22 | WACD Adjustment | | 1.8 | (796.1) | (797.9) |
| 23 | Finance Charges for WACD | | 876.7 | 860.6 | (16.1) |
| 24 | Weighted Average Cost of Debt (WACD) Rate | | 3.81% | 3.74% | (0.07%) |

**Return on Equity**
**($ million)**

| Line | | Column | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|---|
| | | | | 1 | 2 | 3 = 2 - 1 |
| | **Deemed Equity** | | | | | |
| 1 | Rate Base | | 10.0 L4 | 22,929.3 | 22,750.5 | (178.8) |
| 2 | Pre-1996 Customer Contns | | 2.2 L34 | (78.2) | (78.2) | 0.0 |
| 3 | Powerex & Powertech Assets | | | 65.5 | 90.4 | 24.9 |
| 4 | Allowance for Working Capital | | | 250.0 | 250.0 | 0.0 |
| 5 | Total | | | 23,166.5 | 23,012.7 | (153.9) |
| 6 | Deemed Equity Percentage | | | 30.0% | 30.0% | 0.0% |
| 7 | Year-End Deemed Equity | | | 6,950.0 | 6,903.8 | (46.2) |
| 8 | Mid-Year Deemed Equity | | | 6,894.3 | 6,871.2 | (23.1) |
| 9 | Achieved ROE | | | | 10.26% | |
| 10 | Allowed ROE / Derived ROE (F18-F21) | | | 10.33% | | |
| 11 | Return on Equity | | | 712.0 | 704.9 | (7.1) |
| 12 | Gross Return on Equity | | | 712.0 | 704.9 | (7.1) |

**Rate Base**
**($ million)**

| Line | | Reference Column | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 |
| | **Total** | | | | |
| 1 | Net Assets in Service | 12.0 L10 | 23,773.9 | 23,629.1 | (144.8) |
| 2 | Net Contributions | 11.0 L12 | (1,764.9) | (1,785.3) | (20.3) |
| 3 | Net DSM | 2.2 L6 | 920.3 | 906.6 | (13.7) |
| 4 | Total | | 22,929.3 | 22,750.5 | (178.8) |
| 5 | Mid-Year | | 22,747.1 | 22,657.7 | (89.4) |

**Contributions**
**($ million)**

| Line | | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | Column | | 1 | 2 | 3 = 2 - 1 |
| | **Contributions in Aid - Total** | | | | |
| 1 | Gross Contns - Beginning of Year | | 2,539.0 | 2,539.0 | 0.0 |
| 2 | IFRS Opening Balance Adjustment | | 0.0 | (0.7) | (0.7) |
| 3 | Additions | | 157.8 | 178.8 | 21.0 |
| 4 | Retirements & Transfers | | (4.3) | (16.4) | (12.0) |
| 5 | Gross Contns - End of Year | | 2,692.5 | 2,700.8 | 8.3 |
| 6 | Accum Amort - Beginning of Year | | 877.3 | 877.3 | 0.0 |
| 7 | Amortization | | 55.3 | 55.5 | 0.1 |
| 8 | Amortization of Pre-96 CIAC | | (5.1) | (5.1) | 0.0 |
| 9 | Retirements & Transfers | | 0.0 | (7.8) | (7.8) |
| 10 | IFRS amortization reclassification | | 0.0 | (4.3) | (4.3) |
| 11 | Accum Amort - End of Year | | 927.5 | 915.5 | (12.0) |
| 12 | Net Contributions - End of Year | | 1,764.9 | 1,785.3 | 20.3 |

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

| Line | | Reference Column | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 |
| | **Gross Assets in Service** | | | | |
| 1 | Opening Balance | | 24,956.3 | 24,956.3 | 0.0 |
| 2 | Capital Additions | 13.0 L19 | 1,391.0 | 1,236.1 | (154.9) |
| 3 | Retirements & Transfers | | (43.9) | (68.8) | (24.9) |
| 4 | Closing Balance | | 26,303.4 | 26,123.6 | (179.8) |
| | **Accumulated Amortization** | | | | |
| 5 | Opening Balance | | 1,644.1 | 1,644.1 | 0.0 |
| 6 | Amortization on Existing Assets | | 856.8 | 857.6 | 0.8 |
| 7 | Amortization on Additions | 13.0 L32 | 28.6 | 28.2 | (0.4) |
| 8 | Retirements & Transfers | | 0.0 | (35.4) | (35.4) |
| 9 | Closing Balance | | 2,529.5 | 2,494.5 | (35.0) |
| 10 | **Net Assets in Service (Year-End)** | | 23,773.9 | 23,629.1 | (144.8) |

**Capital Expenditures and Additions**
**($ million)**

| Line | | Reference Column | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | | | 1 | 2 | 3 = 2 - 1 |
| | **Capital Expenditures** | | | | |
| 1 | Generation Growth | | 3.2 | 2.6 | (0.6) |
| 2 | Generation Sustaining | | 341.8 | 302.5 | (39.3) |
| 3 | Transmission Growth | | 185.0 | 159.6 | (25.4) |
| 4 | Transmission Sustaining | | 222.6 | 223.3 | 0.7 |
| 5 | Distribution Growth | | 299.9 | 339.7 | 39.8 |
| 6 | Distribution Sustaining | | 187.6 | 176.2 | (11.4) |
| 7 | Site C Project | | 1,530.0 | 1,619.1 | 89.1 |
| 8 | Technology | | 95.6 | 133.0 | 37.4 |
| 9 | Properties | | 58.9 | 56.4 | (2.5) |
| 10 | Fleet & Other | | 63.6 | 59.0 | (4.6) |
| 11 | Total | | 2,988.3 | 3,071.4 | 83.1 |
| | **Total Capital Additions** | | | | |
| 12 | Generation | | 314.7 | 359.5 | 44.8 |
| 13 | Transmission | | 293.8 | 199.7 | (94.1) |
| 14 | Distribution | | 502.2 | 469.6 | (32.6) |
| 15 | Site C Project | | 27.9 | 12.9 | (15.0) |
| 16 | Technology | | 147.6 | 93.7 | (53.9) |
| 17 | Properties | | 39.9 | 44.3 | 4.4 |
| 18 | Fleet & Other | | 65.0 | 56.4 | (8.6) |
| 19 | Total | | 1,391.0 | 1,236.1 | (154.9) |
| | **Unfinished Construction** | | | | |
| 20 | Beginning of Year | | 4,553.3 | 4,553.3 | 0.0 |
| 21 | Adjustments | | (9.9) | (15.2) | (5.3) |
| 22 | Change in Unfinished | | 1,597.4 | 1,835.3 | 237.9 |
| 23 | End of Year | | 6,140.8 | 6,373.4 | 232.7 |
| 24 | Mid-Year Balance | | 5,347.0 | 5,463.4 | 116.3 |
| | **Amortization on Additions** | | | | |
| 25 | Generation | | 3.9 | 5.3 | 1.5 |
| 26 | Transmission | | 2.5 | 2.2 | (0.3) |
| 27 | Distribution | | 6.0 | 7.4 | 1.3 |
| 28 | Site C Project | | 0.3 | 0.1 | (0.2) |
| 29 | Technology | | 13.6 | 9.9 | (3.7) |
| 30 | Properties | | 0.7 | 0.7 | (0.0) |
| 31 | Fleet & Other | | 1.7 | 2.6 | 1.0 |
| 32 | Total | | 28.6 | 28.2 | (0.4) |

**Domestic Energy Sales and Revenue**

| Line | | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|
| | Column | 1 | 2 | 3 = 2 - 1 |
| | **Domestic Energy Sales (GWh)** | | | |
| 1 | Residential | 18,151 | 17,993 | (157) |
| 2 | Light Industrial and Commercial | 18,915 | 18,692 | (224) |
| 3 | Large Industrial | 14,592 | 13,383 | (1,210) |
| 4 | Irrigation | 77 | 72 | (5) |
| 5 | Street Lighting | 230 | 212 | (18) |
| 6 | New Westminster & Tongass | 467 | 465 | (2) |
| 7 | Fortis | 545 | 586 | 40 |
| 8 | Seattle City Light | 311 | 307 | (3) |
| 9 | Liquefied Natural Gas | 7 | 15.8 | 9 |
| 10 | Other | | 205 | 205 |
| 11 | Total | 53,296 | 51,931 | (1,365) |
| | **Domestic Revenues ($ million)** | | | |
| 12 | Residential | 2,197.8 | 2,168.8 | (29.0) |
| 13 | Light Industrial and Commercial | 1,958.8 | 1,942.0 | (16.8) |
| 14 | Large Industrial | 944.7 | 848.4 | (96.2) |
| 15 | Irrigation | 6.3 | 6.4 | 0.1 |
| 16 | Street Lighting | 44.7 | 40.2 | (4.5) |
| 17 | New Westminster & Tongass | 32.1 | 31.8 | (0.3) |
| 18 | Fortis | 39.5 | 41.0 | 1.5 |
| 19 | Seattle City Light | 28.8 | 29.7 | 0.9 |
| 20 | Liquefied Natural Gas | 0.6 | 1.26 | 0.7 |
| 21 | Other | | 5.4 | 5.4 |
| 22 | Subtotal | 5,253.3 | 5,114.9 | (138.4) |
| 23 | Revenue from Deferral Account Rate Rider | 0.0 | 0.2 | 0.2 |
| 24 | Total | 5,253.3 | 5,115.1 | (138.2) |
| 25 | **Deferral Account Rate Rider** | 0.0% | 0.0% | |

**Miscellaneous Revenue**
**($ million)**

| Line | | Reference | F2020 Update | F2020 Actual | F2020 Diff |
|---|---|---|---|---|---|
| | Column | | 1 | 2 | 3 = 2 - 1 |
| | **Generation** | | | | |
| 1 | Amortization of Contributions | | 0.3 | 0.3 | 0.0 |
| 2 | Other | | 1.6 | 2.2 | 0.6 |
| 3 | Total | | 1.9 | 2.5 | 0.6 |
| | **Transmission** | | | | |
| 4 | External OATT | | 15.9 | 10.7 | (5.2) |
| 5 | FortisBC Wheeling Agreement | | 5.2 | 5.2 | (0.0) |
| 6 | Secondary Revenue | | 6.0 | 7.1 | 1.2 |
| 7 | Interconnections | | 2.2 | 6.4 | 4.2 |
| 8 | Amortization of Contributions | | 14.6 | 14.6 | 0.1 |
| 9 | NTL Supplemental Charge | | 2.3 | 2.3 | 0.0 |
| 10 | Total | | 46.1 | 46.4 | 0.3 |
| | **Distribution** | | | | |
| 11 | Secondary Use Revenue & Other | | 14.1 | 17.0 | 2.8 |
| 12 | Amortization of Contributions | | 44.8 | 49.1 | 4.3 |
| 13 | Total | | 58.9 | 66.0 | 7.1 |
| | **Customer Care** | | | | |
| 14 | Meter/Trans Rents & Power Factor Surcharges | | 14.6 | 16.1 | 1.5 |
| 15 | Smart Metering & Infrastructure Impact | | 2.1 | 2.2 | 0.1 |
| 16 | Diversion Net Recoveries | | 0.1 | 0.2 | 0.1 |
| 17 | Other Operating Recoveries | | 4.5 | 4.1 | (0.3) |
| 18 | Customer Crisis Fund Rider Revenue | | 5.3 | 4.4 | (0.9) |
| 19 | Other | | 3.0 | 3.1 | 0.1 |
| | Waneta 2/3 | | | | |
| 20 | Lease revenue from Teck | | 75.2 | 75.2 | 0.0 |
| 21 | Teck portion of operating costs | | 5.7 | 5.4 | (0.3) |
| 22 | Teck portion of water rentals | | 3.5 | 3.3 | (0.2) |
| 23 | Teck portion of property taxes | | 0.6 | 0.9 | 0.3 |
| 24 | Subtotal | | 84.9 | 84.7 | (0.2) |
| 25 | Total | | 114.5 | 114.8 | 0.3 |
| | **Business Support** | | | | |
| 26 | Corporate General Rents | | 3.7 | 3.9 | 0.2 |
| 27 | Late Payment Charges | | 7.9 | 7.1 | (0.8) |
| 28 | MMBU Secondary Revenue | | 3.8 | 3.9 | 0.1 |
| 29 | Other | | 0.7 | 1.4 | 0.7 |
| 30 | Total | | 16.2 | 16.4 | 0.2 |
| 31 | **Total Before Regulatory Accounts** | | 237.6 | 246.0 | 8.5 |
| | **Deferral Account Additions** | | | | |
| 32 | Waneta 2/3 | | | | |
| 32 | Teck portion of capital expenditures | | 3.1 | 1.3 | (1.8) |
| 33 | Subtotal | | 3.1 | 1.3 | (1.8) |
| 34 | **Total Gross Miscellaneous Revenue** | | 240.7 | 247.3 | 6.6 |

# 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 three 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; and
- Table 3: Extension Capital Expenditures Approved at the Group, Program or Aggregated Level.

# BC Hydro Fiscal 2020 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

Table 1 Capital Extension Projects ($ million) ... 2
Table 2 Projects with Anticipated CPCN or Section 44.2 Filings ... 6
Table 3 Extension Capital Expenditures Approved at the Group, Program or Aggregated Level ($ million) ... 9

This attachment includes three tables.[1] BC Hydro has redacted certain customer, project and extension names in this filing that are deemed to be commercially sensitive.

Table 1 lists, by category, (i) the capital extension[2] projects with a total forecast or planned costs of more than $5 million that are included in Appendix I in the F2020 - F2021 RRA and (ii) new capital extension projects that were identified from the currency date noted in Appendix I up until March 31, 2020.

BC Hydro's current expectation regarding projects that may be subject to a future CPCN or Section 44.2 regulatory filing[3] are identified in Table 2.

In compliance with Directive 2 of BCUC Order No. G-313-19,[4] Table 3 includes 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 were identified up to and including March 31, 2020 and 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

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1 The COVID-19 pandemic may have a material impact on projects. As the evolution of the COVID-19 pandemic is uncertain, and the date of resolution is unknown, cost and schedule impact scenarios continue to be assessed and refined. As a result, the potential impacts of the COVID-19 pandemic are not included in the information presented in these three tables.

2 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.

3 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.

4 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

- 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[5] (**2018 Guidelines**).

Table 3 will also include the F2020-F2021 RRA Appendices I, J, and K references where applicable.

**Table 1 Capital Extension Projects ($ million)**

| Planning ID | Project Name | Total Forecast Cost[6] | Reference (from F2020-F2021 RRA) |
|---|---|---|---|
| **Generation Sustaining Capital** | | | |
| G000597 | John Hart Generating Station Replacement | 1,092.9 | Appendix I, Page 1, Line 2, Appendix J, Page 3 |
| **Generation Growth Capital** | | | |
| G000594 | Revelstoke Unit 6 Installation | 569 | Appendix I, Page 1, Line 1, Appendix J, Page 1 |
| 115778 | Site C Project | 10,005.0[7] | Appendix I, Page 10, Line 15, Appendix J, Page 129 |
| **Transmission Sustaining Capital** | | | |
| 900564 | Hundred Mile House T1/T2 EOL Replacement | TBD | Appendix I, Page 4, Line 30 |
| 92478 | Mainwaring Station Upgrade | TBD | Appendix I, Page 4, Line 33, Appendix J, Page 103 |

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

[6] For projects that were included in Appendix I of the F2020-F2021 RRA, the Total Forecast Cost shown is:
- The Authorized Amount (Column K) shown in Appendix I of the F2020-F2021 RRA 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 F2020-F2021 RRA with the upper value of the range shown for projects for which a range was given in Appendix I.

For projects that were identified from the currency date noted in Appendix I of the F2020-F2021 RRA up until March 31, 2020, the Total Forecast Cost shown is:
- The authorized capital amount for projects in the Implementation phase, and
- The upper value of the pre-Implementation cost estimate range for projects in the Definition phase where this estimate range is available.

[7] Site C forecast amount includes both capital costs and a reserve of $708 million, excluding the present value of the future operating payments and regulatory deferral. BC Hydro is working through the impacts of cost and schedule pressures as identified in its quarterly reporting to the BCUC, which includes, amongst others, the implementation of foundation enhancements and the COVID-19 pandemic.

| Planning ID | Project Name | Total Forecast Cost[6] | Reference (from F2020-F2021 RRA) |
|---|---|---|---|
| 900766 | Project C | TBD | Appendix I, Page 5, Line 55, |
| **Transmission Growth Capital** | | | |
| 92525 | Fort St. John and Taylor Electric Supply | 53.1 | Appendix I, Page 4, Line 1, Appendix J, Page 67 |
| 92216 | Peace Region Electric Supply (**PRES**) | 348.0 | Appendix I, Page 4, Line 3, Appendix J, Page 71 |
| 92423 | Bridge River Transmission Project | TBD | Appendix I, Page 4, Line 5, Appendix J, Page 75 |
| 94034 | West Kelowna Transmission and Westbank Substation Upgrade projects[8] | TBD | Appendix I, Page 4, Line 6, Appendix J, Page 77 |
| 900266 | East Vancouver - Substation Construction[9] | TBD | Appendix I, Page 4, Line 7, Appendix J, Page 79 |
| 900598 | West End - Substation Construction and System Reinforcement[10] | TBD | Appendix I, Page 4, Line 8, Appendix J, Page 80 |
| 900992 | Lower Mainland - Capacitive and Reactive Power Reinforcement | TBD | Appendix I, Page 4, Line 10, Appendix J, Page 84 |
| 93788 | Capilano Substation Upgrade | 88.0 | Appendix I, Page 4, Line 12, Appendix J, Page 87 |
| 92907 | Mount Lehman Substation Upgrade | TBD | Appendix I, Page 4, Line 13, Appendix J, Page 89 |
| 92910 | Clayburn Substation Upgrade | TBD | Appendix I, Page 4, Line 14, Appendix J, Page 91 |
| 93632 | Project B (Substation) | TBD | Appendix I, Page 4, Line 15, Appendix J, Page 93 |
| 900816 | Pemberton - Substation Upgrade | TBD | Appendix I, Page 4, Line 16, Appendix J, Page 95 |
| 900626 | Bremner-Trio Hydro Project | 7.9 | Appendix I, Page 4, Line 17 |
| 94003 | UBC Load Increase Stage 2 | 55.2 | Appendix I, Page 4, Line 18 |

8 Please refer to Note 6 in Table 2.
9 Please refer to Note 7 in Table 2.
10 Please refer to Note 8 in Table 2.

| Planning ID | Project Name | Total Forecast Cost[6] | Reference (from F2020-F2021 RRA) |
|---|---|---|---|
| 93786 | Customer B | 102.0 | Appendix I, Page 4, Line 20 |
| 900836 | Customer C | TBD | Appendix I, Page 4, Line 21 |
| 901580 | Customer I | 22.1 | N/A |
| 901581 | Customer J | TBD | N/A |
| 901232 | Customer K | TBD | N/A |
| 901574 | Prince George Terrace Capacitors (**PGTC**) | TBD | N/A |
| 901573 | Bear Mountain Terminal T4 Transformer Addition | TBD | N/A |
| 901572 | North Montney Transmission Development[11] | TBD | N/A |
| **Distribution Growth Capital** | | | |
| 901557 | Customer D and Customer E[12] | 16 | Customer D Appendix I, Page 7, Line 1; Customer E Appendix I, Page 7, Line 2 |
| DY-0981 | Customer F | 9 | Appendix I, Page 7, Line 3 |
| 901241 | Customer G | TBD | Appendix I, Page 7, Line 4 |
| DY-1545 | Customer H | TBD | Appendix I, Page 7, Line 5 |
| 93639 | 12F51 & 53 HPN Voltage Conversion (LM-BBY-048) | 12.1 | Appendix I, Page 7, Line 6 |
| 93640 | HPN 12F54, 72Q, 73Q, and 324 Voltage Conversion (LM-BBY-051) | 14.1 | Appendix I, Page 7, Line 7 |
| 900749 | Bringing additional capacity from ARN to Tilbury (FV-FVW-057) | 23.7 | Appendix I, Page 7, Line 8 |
| 93669 | Three new MLE Feeders to offload CBN (LM-FVE-607) | 13 | Appendix I, Page 7, Line 9 |
| 900306 | HPN 77Q, 323, 326 and 327 Voltage Conversion Preparation (LM-BBY-062) | 18 | Appendix I, Page 7, Line 10 |
| 900307 | LOH 12F68 Voltage Conversion and Transfer to HPN (LM-BBY-064) | 15 | Appendix I, Page 7, Line 11 |

[11] Please refer to Note 10 in Table 2.

[12] Since the F2020-F2021 RRA Appendix I was prepared, the Customer D (Planning ID DY-1543) and Customer E (Planning ID DY-1563) projects listed in that Appendix have been consolidated into a single project due to their common scope.

| Planning ID | Project Name | Total Forecast Cost[6] | Reference (from F2020-F2021 RRA) |
|---|---|---|---|
| 900342 | Voltage Conversion Prep for RIM Substation (LM-FVW-718) | 8 | Appendix I, Page 7, Line 12 |
| 900386 | New MUR Circuit to Offload MUR 12F66 and MUR 12F84 (LM-VAN-020) | 13 | Appendix I, Page 7, Line 13 |
| 900446 | WKA New Substation Bring 4 New Feeders (SI-KAM-001) | 18 | Appendix I, Page 7, Line 14 |
| 900452 | DUG Extension Along Highway 1 East (SI-KAM-008) | 8 | Appendix I, Page 7, Line 15 |
| 94137 | CBL New Feeder South Campbell River (VI-NVI-417) | TBD | Appendix I, Page 7, Line 16 |
| 901132 | Two Fleetwood feeders to offload McLellan (FV-FVW-723) | TBD | Appendix I, Page 7, Line 17 |
| 901141 | Lower Mainland - George Dickie Feeder Voltage Conversion (LM-VAN-066) | TBD | Appendix I, Page 7, Line 18 |
| 901253 | George Dickie - Voltage Conversion preparation of 4F54, 4F61, 4F64 and 4F65 and cutover to Sperling 12F64 (LM-VAN-094) | TBD | Appendix I, Page 7, Line 19 |
| 900541 | Vancouver Island - Saltspring 25F61 Submarine Cable Extension to North Pender Island (VI-GUL-005) | TBD | N/A |
| DY-0347 | Customer L | 13.5 | N/A |
| 92802 | GLR Voltage Conversion (LM-NSC-088) | 11.6 | N/A |
| 93650 | Four new CBN Feeders to Offload SMW (LM-FVE-606) | 13.6 | N/A |
| 900347 | CAP distribution voltage conversion for 51,52,58 (LM-NSC-124) | 11.8 | N/A |
| 900364 | CAP distribution voltage conversion for 57, and 59 (LM-NSH-040) | 9.2 | N/A |
| 92739 | Phase KI14F65 and 4F66 Conversion (LM-MV-158) | 15.0 | N/A |
| 93641 | LOH 12F51, 52, and 53 Voltage Conversion (LM-BBY-063) | 7.3 | N/A |

| Planning ID | Project Name | Total Forecast Cost[6] | Reference (from F2020-F2021 RRA) |
|---|---|---|---|
| 93646 | COK Distribution Egress Reinforcement (LM-COQ-694) | 15.0 | N/A |
| 93670 | VNT 25F66 Rebuild & relocate undersized (SI-OKA-210) | 6.5 | N/A |
| 93902 | Voltage Conversion of ESQ1258 (VI-SVI-259) | 6.0 | N/A |
| 900283 | 1 new MLE feeder to offload BAL and existing MLE feeders (FV-ABT-018) | 5.4 | N/A |
| 900316 | LOH 12F56, 12F62 Voltage Conversion Preparation (LM-BBY-082) | 2.8 | N/A |
| 900841 | New KI2 Ductbank Egress and 1 New Feeder (LM-FVW-701) | 11.0 | N/A |
| 900431 | Oldfield - Voltage Conversion 12 to 25kV (NI-NEW-273) | TBD | N/A |
| 901355 | Norgate - Offload NOR loads to NVR feeders (LM-NSH-074) | TBD | N/A |
| 901356 | North Vancouver - Offload NVR loads to LYN new feeders (LM-NSH-075) | TBD | N/A |

**Table 2 Projects with Anticipated CPCN or Section 44.2 Filings**

| Note | Planning ID | Project | Filing Type | Rationale for Filing Type |
|---|---|---|---|---|
| 1 | G000585 | John Hart Dam Seismic Upgrade | Section 44.2 | Anticipated to exceed $100 million threshold for Power System projects but is not considered an extension to the BC Hydro system. |
| 2 | G000668 | Ladore Spillway Seismic Upgrade | Section 44.2 | Anticipated to exceed $100 million threshold for Power System projects but is not considered an extension to the BC Hydro system. |
| 3 | G000525 | Strathcona Discharge Upgrade | Section 44.2 | Anticipated to exceed $100 million threshold for Power System projects but is not considered an extension to the BC Hydro system. |

| Note | Planning ID | Project | Filing Type | Rationale for Filing Type |
|---|---|---|---|---|
| 4 | G000776 | Bridge River 1 Units 1-4 Generator Replacement | Section 44.2 | Anticipated to exceed $100 million threshold for Power System projects but is not considered an extension to the BC Hydro system. This project will restore the lost capability of the units, within the limit of the existing water licence. |
| 5 | G000252 | Revelstoke - U1 - U4 Stator Replacement | Section 44.2 | Anticipated to exceed $100 million threshold for Power System projects but is not considered an extension to the BC Hydro system. |
| 6 | 94034 | West Kelowna Transmission and Westbank Substation Upgrade projects | CPCN | BCUC Order No. G-47-18 directed BC Hydro to file a CPCN application for these projects. |
| 7 | 900266 | East Vancouver - Substation Construction | CPCN | Anticipated to exceed $100 million threshold for Power System projects and considered an extension to BC Hydro’s system. |
| 8 | 900598 | West End - Substation Project | CPCN | Anticipated to exceed $100 million threshold for Power System projects and considered an extension to BC Hydro’s system. |
| 9 | 901821 | Peace to Kelly Lake - Stations Sustainment | Section 44.2 | Anticipated to exceed $100 million threshold for Power System projects and not considered an extension to BC Hydro’s system. |
| 10 | 901572 | North Montney Transmission Development | CPCN | Anticipated to exceed $100 million threshold for Power System projects and considered an extension to BC Hydro’s system. |
| 11 | G000459 | La Joie - Dam Improvements | Section 44.2 | Anticipated to exceed $100 million threshold for Power System projects but is not considered an extension to the BC Hydro system. |

| Note | Planning ID | Project | Filing Type | Rationale for Filing Type |
|---|---|---|---|---|
| 12 | G003365 | Mica - Discharge Facilities Seismic and Reliability Upgrades | Section 44.2 | Anticipated to exceed $100 million threshold for Power System projects but is not considered an extension to the BC Hydro system. |
| 13 | P201901 | Kamloops Field Building Redevelopment | Section 44.2 | Anticipated to exceed $50 million threshold for Buildings projects but is not considered an extension to the BC Hydro system. |
| 14 | 92478 | Mainwaring Station Upgrade | CPCN | BCUC Order G-47-18 directed BC Hydro to file a CPCN application for this project. |

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 PRES project is expected to exceed the Capital Project Filing Guideline threshold but is a prescribed undertaking pursuant to section 18 of the *Clean Energy Act* (and the related Greenhouse Gas Reduction Regulation section 4(2));
- The Revelstoke Unit 6 Installation project is expected to exceed the Capital Project Filing Guideline threshold but is exempt from the CPCN requirement pursuant to section 7 of the *Clean Energy Act*.
- The PGTC project is expected to exceed the Capital Project Filing Guideline threshold but is exempt from Part 3 of the *Utilities Commission Act* per Ministerial Order M73/2013, deposited March 25, 2013.
- The Customer B project shown in Table 1 is exempt from Part 3 of the *Utilities Commission Act* due 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[13] | Reference (from F2020-F2021 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.

[13] For programs, the Total Forecast Cost is based on project costs and the earliest project phase in the program. For projects that were included in Appendix I of the F2020-F2021 RRA, the Total Forecast Cost used for the project is:

- The Authorized Amount (Column K) shown in Appendix I of the F2020-F2021 RRA 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 F2020-F2021 RRA with the upper value of the range shown for projects for which a range was given in Appendix I.

For projects that were identified from the currency date noted in Appendix I of the F2020-F2021 RRA up until March 31, 2020, the Total Forecast Cost used for the project is:

- The authorized capital amount for projects in the Implementation phase, and the upper value of the pre-Implementation cost estimate range for projects in the Definition phase where this estimate range is available.

# 8 Internal Audit Reviews and/or Reports Provided in Fiscal 2020

*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.

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The following internal audits were completed in the year ended March 31, 2020.

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

## A. Risk Based Audits

*Integrated Planning*

- Joint Ownership and Use Agreement
  - Description: Assessed effectiveness of the management and administration of the Joint Ownership and Use Agreement for distribution poles between BC Hydro and Telus.

*Capital Infrastructure Project Delivery*

- Polychlorinated Biphenyls (**PCB**) Phase Out Program
  - Description: Assessed whether an effective Polychlorinated Biphenyls Phase Out Program is in place to meet regulatory requirements.

*Finance, Technology, Supply Chain*

- Fleet Management
  - Description: Provided assurance that effective fleet management lifecycle processes exist to support business operations.

*Operations*

- Columbia River Treaty
  - Description: 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*

- Contractor Safety
  - Description: Assessed whether an effective Contractor Safety Program is in place and being followed.

*Powerex*

- IT Operational Controls
  - Description: Provided assurance on the effectiveness of IT Operational Controls across key applications.

**B. Core Financial Process Audits**

*People, Customer, Corporate Affairs*

- Payroll
  - Description: Assessed controls over the payroll and related human resources processes and compliance with BC Hydro policies.

*Powertech*

- Financial Controls
  - Description: Assessed the effectiveness of controls over financial processes at Powertech Labs Inc.

## 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. Project Completion and Evaluation Reviews

*Capital Infrastructure Project Delivery*

- Ruskin Dam Upgrade
  - Description: Reviewed the Project Completion and Evaluation Report (**PCER**) and Board of Directors Summary Report of the Ruskin Dam Upgrade. The review provides independent confirmation of Management's submission to the Capital Projects Committee, and the Audit and Finance Committee of the Board.

## E. Audit Follow-ups

*Capital Infrastructure Project Delivery*

- Cheakamus Units 1 & 2 Generator Replacement Project
  - Description: Follow-up to the fiscal 2019 audit that provided assurance that the Cheakamus Units 1 & 2 Generator Replacement Project is appropriately managed and executed to deliver stated objectives.

*Integrated Planning*

- Dam Safety
  - Description: Follow-up to the fiscal 2019 audit that evaluated whether risks are identified, prioritized, and managed to ensure objectives of BC Hydro's Dam Safety Program are achieved.

*Finance, Technology, Supply Chain*

- Smart Meter Operations
  - Description: Follow-up to the fiscal 2019 audit that assessed whether the Smart Meter system is fully operationalized, managed and functioning effectively.

*Operations*

- Energy Studies Process
  - Description: Follow-up to the fiscal 2019 audit that evaluated whether the monthly Energy Studies process reliably supports operations, financial and strategic planning at BC Hydro.

*Safety*

- Confined Space Program
  - Description: Follow-up to the fiscal 2019 audit that assessed whether an effective Confined Space Program is in place and being followed.
- Learning and Development
  - Description: Follow-up to the fiscal 2019 audit that assessed the effectiveness of learning and development to ensure employees have the right skills at the right time.

*Powerex*

- Non-energy Procurement and Disbursements
    - Description: Follow-up to the fiscal 2019 audit that assessed internal controls within the purchases, payables and disbursements cycle to ensure transactions are valid, authorized, accurate, complete and timely.

# 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, 2020:

1. Security Controls in SAP.

# 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.

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The fiscal 2019 Waneta Transaction Report as prescribed in British Columbia Utilities Commission Order No. G-130-18, Directive 4 (e) is attached.

BC Hydro
Power smart

# BC Hydro Fiscal 2020 Annual Report to the British Columbia Utilities Commission

## Attachment to Section 10.1

## Fiscal 2020 Waneta Transaction Annual Report

# Table of Contents

1 Introduction ..... 1
2 Third-party Determinations (Response to Directive 4(e)(i)) ..... 2
3 Operations, Maintenance and Capital Expenditures (Response to Directive 4(e)(ii)) ..... 3
4 Organization Chart (Response to Directive 4(e)(iii)) ..... 5
5 Surplus Power Rights Agreement (Response to Directive 4(e)(iv)) ..... 5
6 Risks and Mitigation Measures (Response to Directive 4(e)(v)) ..... 6
7 Delivery of Capacity and Energy to BC Hydro (Response to Directive 4(e)(vi)) ..... 6
8 Statement of Entitlement Adjustments under the Canal Plant Agreement (Response to Directive 4(e)(vii)) ..... 7
9 Annual OATT Revenues Accrued from Line 71 (Response to Directive 4(e)(viii)) ..... 7

# List of Tables

Table 1 Comparison of Actual[1] and Forecast Expenditures for BC Hydro's 1/3, April 1, 2019 to March 31, 2020 ..... 3
Table 2 Comparison of Actual[1] and Forecast Expenditures for Teck's 2/3, April 1, 2019 to March 31, 2020 ..... 4
Table 3 Surplus Power Rights Agreement Purchases ..... 6
Table 4 Comparison of BC Hydro's Obligation to Provide CPA Entitlement ..... 7

# 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 2020. 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 2020.

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

Table 1 below provides the comparison of the actual (accrued) and forecast expenditures for fiscal 2020, with an explanation for variances greater than 10 per cent.

**Table 1 Comparison of Actual[1] and Forecast Expenditures for BC Hydro's 1/3, April 1, 2019 to March 31, 2020**

| ($ thousand) | F2020 Forecast | F2020 Actual | Variance | Variance (%) | Variance Explanation (if >10 %) |
|---|---|---|---|---|---|
| | 1 | 2 | 3 = 2 - 1 | 4 = 3/1 x 100 | |
| Operations and Maintenance[2] | 2,634 | 2,714 | 80 | 3 | |
| Sustaining Capital | 1,560 | 667 | (893) | (57) | The lower expenditure than Forecast in fiscal 2020 was the result of delaying sustaining capital projects into subsequent years due to delays in Teck getting internal funding approvals. The bulk of the delayed costs relate to the Unit 3 Life Extension project which transitions into the execution phase in the winter of 2020. |
| Water Fees | 6,790 | 6,556 | (234) | (3) | |

[1] BC Hydro is reporting actual expenditures on an accrual basis.
[2] Includes insurance and Teck administration.

**Table 2 Comparison of Actual[1] and Forecast Expenditures for Teck's 2/3, April 1, 2019 to March 31, 2020**

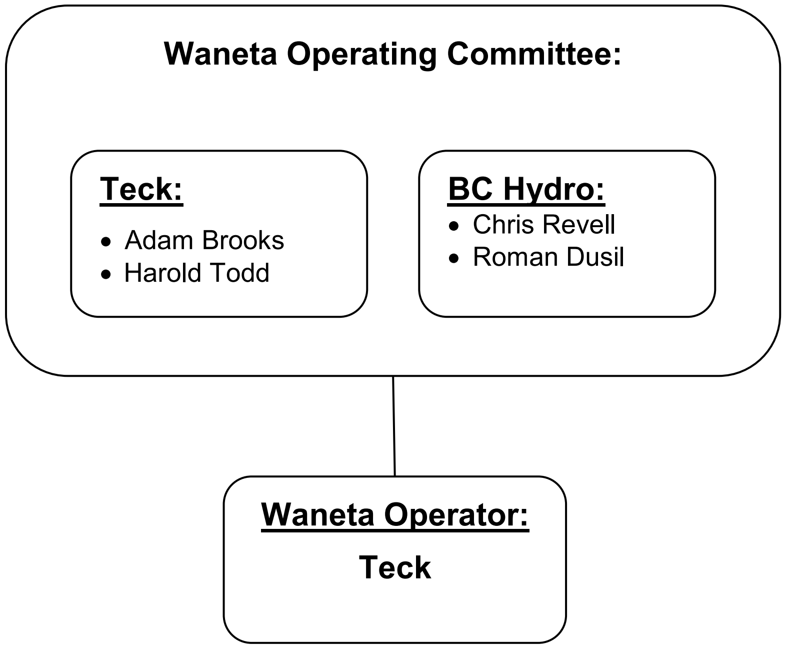
| ($ thousand) | F2020 Forecast | F2020 Actual | Variance | Variance (%) | Variance Explanation (if >10 %) |
|---|---|---|---|---|---|
| | 1 | 2 | 3 = 2 - 1 | 4 = 3/1 x 100 | |
| Operations and Maintenance[2] | 5,705 | 5,389 | (317) | (6) | |
| Sustaining Capital | 3,119 | 1,403 | (1,716) | (55) | The lower expenditure than Forecast in fiscal 2020 was the result of delaying sustaining capital projects into subsequent years due to delays in Teck getting internal funding approvals. The bulk of the delayed costs relate to the Unit 3 Life Extension project which transitions into the execution phase in the winter of 2020 |
| Water Fees | 3,459 | 3,280 | (179) | (5) | |

1. BC Hydro is reporting actual expenditures on an accrual basis.
2 Includes insurance and Teck administration.

Based on the criteria defined under the COPOA, unanimous approval of the Operating Committee was required for the calendar 2019 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 130.5 GWh of surplus energy from Teck during fiscal 2020 under section 5 of the agreement at an average price of C$46.50/MWh.

**Table 3 Surplus Power Rights Agreement Purchases**

| | Apr 2019 | May 2019 | Jun 2019 | Jul 2019 | Aug 2019 | Sep 2019 | Oct 2019 | Nov 2019 | Dec 2019 | Jan 2020 | Feb 2020 | Mar 2020 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Invoice Total ($k) | 2,093 | - | - | 71 | 706 | 531 | 525 | 690 | 537 | 475 | 442 | - | 6,071 |
| Volume (MWh) | 18,000 | - | - | 3,219 | 22,574 | 15,000 | 15,000 | 17,700 | 13,053 | 11,000 | 15,000 | - | 130,546 |

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

Three dam stability projects are planned as part of phase two of the dam stability work which has been reported on previously, including: 1) installation of piezometers, 2) borehole and concrete testing and 3) a buried channel assessment. The piezometer installation was completed in 2019 to provide additional data collection sites to assess water pressure on the dam. Some minor deficiency work remains to be addressed in 2020.

The borehole and concrete testing was also completed in 2019 and confirmed that the concrete strength is within expected values. 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.

# 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 2020, 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**

| F2020 (April 1, 2019 to March 31, 2020) | 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 2020.

## 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.

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The fiscal 2020 summary report on volumes and pricing of transmission capacity reassignments, and simultaneous submission window, as required by Commission Order No. G-102-09 is provided.

### 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, 2020, BC Hydro observed that 982 Confirmed Resale transactions occurred on five paths:

- 17 occurred on the BCHA-AESO path;
- 920 occurred on the BCHA-BPAT path;
- 36 occurred on the BPAT-AESO wheel through path;
- Two occurred on the AESO-BPAT wheel through path; and
- Seven occurred on the BPAT-BCHA path.

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

Of the total Resale transactions:

- 933 were from Hourly Firm Point-to-Point (**PTP**) Transmission Service to Hourly Firm PTP Transmission Service;
- 12 were from Monthly Firm PTP Transmission Service to Monthly Firm PTP Transmission Service; and
- 37 were from Yearly Firm PTP Transmission Service to Yearly Firm PTP Transmission Service.

On three of the five paths (BCHA-AESO, BCHA-BPAT, and BPAT-BCHA), the same customer resold transmission service to itself. On the fourth path (AESO-BPAT) transmission service was sold from once customer to another customer. On the fifth 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 one year.

On the BCHA-AESO path, 17 Resale transactions ranging from 25 MW to 380 MW were resold. There was one yearly resale transaction for 330 MW. It was the aggregate of six transmission reservations from customer to itself on the same path. A total of 380 MW was resold every month in the fiscal year. All of these Resale transmission reservations were the aggregation of two transmission reservations from one customer to itself on the same path. In four of these months, an additional 50 MW of hourly transmission was resold, the aggregation of two transmission reservations from one customer to itself on the same path, in durations ranging form nine hours to two days.

On the BCHA-BPAT path, there were a total of 920 hourly Resale transmission reservations. All Resale transmission reservations were the aggregation up to nine transmission reservations from one customer to itself on the same path and ranged from 1 MW and 2,039 MW. The duration of the Resale transmission reservations ranged from one hour to three days.

On the BPAT-AESO path, 36 Resale transactions ranging from 25 MW to 50 MW were resold on the same path. In each month of the fiscal year, 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.

On the AESO-BPAT path, two Resale transactions ranging from 20 MW to 100 MW were resold. Both of these Resale transmission reservations were resold as one reservation from one customer to another customer on the same path. The duration of the Resale transmission reservations ranged from one to two hours.

On the BPAT-BCHA path, seven Resale transactions ranging from 2 MW to 390 MW were resold. All of these Resale transmission reservations were the aggregation of two to six reservations from one customer to itself on the same path. The duration of the Resale transmission reservations ranged from one to 16 hours.

Prices of the Confirmed Resale transmission reservations varied between originating and resold transmission reservations. Prices ranged from $1.00 to $9.39 with $0.00 being the smallest difference in price and $7.95 being the greatest difference in price.

On the BCHA-AESO path, 17 Resale transmission reservation prices were at $8.95 while originating transmission reservation prices ranged from $5.97 to $9.39. Nine Resale transmission reservations had a higher price, four Resale transmission reservations had a lower price, and four Resale transmission reservations had a price equal to their originating transmission reservations.

On the BCHA-BPAT path, 920 Resale and originating transmission reservation prices ranged from $1.00 to $8.95. There were 223 Resale transmission reservations that had the same price and 697 Resale transmission reservations had a higher price than their originating transmission reservations.

On the BPAT-AESO path, 36 Resale transmission reservation prices ranged from $8.17 to $9.39 while originating transmission reservation prices ranged from $5.40 to $9.39. There were 31 Resale transmission reservations that had a higher price, four Resale transmission reservations had a lower price and one Resale transmission reservation had the same price as their originating transmission reservations.

On the AESO-BPAT path, two Resale transmission reservation prices ranged from $1.00 to $3.00 while originating transmission reservation prices ranged from $3.00 to $8.95. One Resale transmission reservation had a lower price and one Resale transmission reservation had the same price as its originating transmission reservation.

On the BPAT-BCHA path, all seven Resale transmission reservations had the same price as their originating transmission reservations of $8.95.

A total of five Resale transmission reservations were Annulled. Four of these transmission reservations were for Hourly Firm PTP Transmission Service, and one was for Yearly Firm PTP Transmission Service.

### 10.2.3 Assessment of Simultaneous Submission Window (SSW)

During the fiscal year ended March 31, 2020, BC Hydro experienced 12 instances of SSW, which involved a total of 27 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).

During the month of April 2019, there was one instance of SSW. One Original TSR for Hourly Non-Firm Transmission Service for 400 MW was submitted on OASIS within the five-minute SSW between 00:00:00 to 00:05:00 PPT. The TSR was Confirmed and granted the requested capacity shortly after the SSW closed.

There were no instances of SSW during the months of May, June and July 2019.

During the month of August 2019, there were two instances of SSW. Two Original TSRs for Hourly Firm Transmission Service for 1,750 MW each were submitted on OASIS within the five-minute SSW between 00:00:00 PPT to 00:05:00 PPT. Both TSRs were Confirmed and granted the requested capacity shortly after the SSW closed.

During the month of September 2019, there were three instances of SSW. Three Original and two Redirect TSRs for Hourly Firm Transmission Service and three Original TSRs for Hourly Non-Firm Transmission Service, ranging from 148 MW to 1,602 MW were submitted on OASIS within the five-minute SSW between 00:00:00 PPT to 00:05:00 PPT. The eight TSRs were Confirmed and granted the requested capacity shortly after the SSW closed.

There were no instances of SSW during the months of October and November 2019.

During the month of December 2019, there were five instances of SSW. Seven Redirect and seven Original TSRs for Hourly Firm Transmission Service ranging from 148 MW to 1,750 MW were submitted on OASIS within the five-minute SSW between 00:00:00 PPT to 00:05:00 PPT. Eleven TSRs were Confirmed and granted the requested capacity shortly after the SSW closed. Three TSRs were Refused for insufficient Available Transfer Capability (**ATC**).

During the month of January 2020, there was one instance of SSW. One Original and one Redirect TSR for Hourly Firm Transmission Service ranging from 148 MW to 1,601 MW were submitted on OASIS within the five-minute SSW between 00:00:00 PPT to 00:05:00 PPT. Both TSRs were Confirmed and granted the requested capacity shortly after the SSW closed.

There were no instances of SSW during the months of February and March 2020.

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 no gaming has transpired since the implementation of SSW.

# BC Hydro Fiscal 2020 Annual Report to the British Columbia Utilities Commission

# Appendix A

## Annual Deferral Accounts Report

## April 1, 2019 to March 31, 2020

## List of Schedules

Schedule A BC Hydro Summary of Deferral Accounts For the Year Ended March 31, 2020 ($ million) .................................................. 1
Schedule B BC Hydro Summary of Deferral Accounts Changes For the Year Ended March 31, 2020 ($ million) .................................................. 3

## Appendices

Appendix 1 Deferral Accounts Rules

## Schedule A BC Hydro Summary of Deferral Accounts For the Year Ended March 31, 2020 ($ million)

| Line No. | Particulars (Note 1) | Opening Balance at April 1, 2019 (Note 2) | Changes (Schedule B) | | Amortization (Note 6) | Interest (Note 7) | Net Change | Ending Balance at March 31, 2020 |
|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | | (4) | (5) | (6) = (3)+(4)+(5) | (7)=(2)+(6) |
| 1 | Heritage Deferral Account (HDA) | (485.1) | (82.4) | Note 3 | 280.6 | (13.2) | 185.0 | (300.1) |
| 2 | Non-Heritage Deferral Account (NHDA) | 140.9 | 98.8 | Note 4 | (40.9) | 5.9 | 63.8 | 204.7 |
| 3 | Trade Income Deferral Account (TIDA) | (260.6) | (68.7) | Note 5 | 164.2 | (8.6) | 86.9 | (173.7) |
| 4 | Total | (604.8) | (52.2) | | 403.9 | (15.9) | 335.7 | (269.1) |

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.

**Note 2:** On April 1, 2019, BC Hydro adopted IFRS 16, Leases, which resulted in an opening balance adjustment of $64.8 million and ($1.9) million to the NHDA and TIDA, respectively. Under IFRS 16, three long-term electricity purchase agreements (**EPAs**) were newly recognized and three long-term EPAs previously recognized under IAS 17 as finance leases were removed as they no longer met the definition of a lease under IFRS 16.

**Note 3:** The transfer of ($82.4) million, which increased the credit balance in the HDA, is primarily due to lower than plan market electricity purchases and higher than plan remissions credits to water rentals. This is partially offset by higher than plan Non-Treaty Storage and Coordination Agreement costs. Market electricity purchases were lower than plan due to higher water inflows and hydro generation and lower domestic load requirements. Water use planning remissions (recoveries) were higher than plan for the Bridge River System and John Hart Generating Station. Non-treaty Storage and Coordination Agreements costs are higher than plan as a result of higher storage of water in September 2019, October 2019 and January 2020 driven by lower market electricity prices and favorable storage opportunities during these months. Please refer to Schedule B for details.

**Note 4:** The transfer of $98.8 million, which increased the debit balance in the NHDA, is primarily due to lower than plan domestic revenues and higher than plan Independent Power Producers (**IPPs**) and long-term commitments costs. This is partially offset by lower than plan Trade Account[1] costs. Domestic revenues were lower than plan across the three main sectors (please refer to Schedule B, Note 9 for details) with most of difference due to lower large industrial revenues as a result of operational issues and market curtailment in the pulp and paper sector and poor market conditions in the oil and gas sector. IPPs and long-term commitments costs were higher than plan due to higher wind generation and higher water inflows; partially offset by outages, maintenance turndowns and other operational factors. Trade Account costs were lower than plan due to higher than plan net exports as a result of higher water inflows, higher hydro generation and lower domestic load requirements. The Trade Account is eliminated upon consolidation and does not impact net income. Please refer to Schedule B for details.

[1] Trade Account represents Powerex purchases/sales from/to BC Hydro for the purpose of trade related activities, provided that the BC Hydro system has the ability to accommodate those transactions. These purchases/sales are eliminated against trade cost of energy on consolidation and have no net impact on the combined NHDA and the TIDA.

**Note 5:** The transfer of ($68.7) million, which increased the credit balance in the TIDA, is primarily due to higher than plan Powerex Net Income. Please refer to Schedule B, line 23.

**Note 6:** 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 Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**Fiscal 2020 to Fiscal 2021 RRA**), BC Hydro is requesting BCUC approval 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 7:** 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, 2020 ($ 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 | 563.4 | 493.0 | (70.4) | Note 1 |
| 5 | Notional Water Rental (Displaced Hydro) | 3.1 | (6.1) | (9.2) | Note 2 |
| 6 | Skagit Valley Treaty & Ancillary Revenue | (28.8) | (29.7) | (0.9) | Note 3 |
| 7 | Costs in Operating / Amortization | 12.5 | 12.5 | (0.0) | Note 4 |
| 8 | Deferred Operating Costs in HDA | 0.0 | (1.4) | (1.4) | Note 5 |
| 9 | Other | 31.5 | 31.0 | (0.5) | Note 6 |
| 10 | Total | 581.7 | 499.3 | (82.4) | Schedule A Line 1 |
| 11 | | | | | |
| 12 | **Items Subject to Non-Heritage Deferral Account:** | | | | |
| 13 | Non-Heritage Deferral Account Transactions | 1,362.0 | 1,314.7 | (47.4) | Note 7 |
| 14 | Commodity Risk | (1.4) | 0.8 | 2.2 | Note 8 |
| 15 | Notional Water Rental (Displaced Hydro) | (3.1) | 6.1 | 9.2 | Note 2 |
| 16 | Domestic Revenue Variance | - | 139.3 | 139.3 | Note 9 |
| 17 | Deferred Amortization in NHDA | - | 0.4 | 0.4 | Note 10 |
| 18 | Lease Revenues (Waneta - 2/3) | - | (1.3) | (1.3) | Note 11 |
| 19 | Other | - | (3.6) | (3.6) | Note 12 |
| 20 | Total | 1,357.5 | 1,456.3 | 98.8 | Schedule A Line 2 |
| 21 | | | | | |
| 22 | **Trade Income Deferral Account** | | | | |
| 23 | Trade Income | (120.6) | (189.2) | (68.7) | Note 13, Schedule A Line 3 |

Due to minor rounding some totals may not add.

**Note 1:** 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, Line 18+24+25+27.

**Note 2:** Notional Water Rentals (Displaced Hydro) relates to water rentals associated with trade income. The Notional Water Rental mechanism is described in BC Hydro's response to BCUC IR 1.2.36 dated January 23, 2004 from the Fiscal 2005 to Fiscal 2006 RRA. The transactions relating to the Notional Water Rental are eliminated on consolidation and there is no net impact on the combined HDA and NHDA as the transactions are mirrored within each account.

**Note 3:** As per BCUC Order No. G-96-04, the HDA captures variances between forecast and actual costs and revenues, which includes Skagit Valley Treaty and Ancillary Services Revenues.

**Note 4:** Costs in Operating / Amortization includes costs associated with compensation and mitigation efforts to fund fish and wildlife programs, Water Use Plan amortization costs, and costs associated with maintaining water use plan licenses.

**Note 5:** Deferred Operating Costs in the HDA relates to the variances between forecast and actual costs described in Note 4 above.

**Note 6:** Other amounts deferred in the HDA mainly include amortization of First Nations settlement and prior negotiation costs of $31.5 million and variable costs relating to thermal generation, which was nil in fiscal 2020.

**Note 7:** 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, Line 23+26+41.

**Note 8:** Commodity Risk of $2.2 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 9:**

| **Domestic Revenue Variance ($ million)** | Plan | Actual | Variance |
|---|---|---|---|
| Residential | 2,197.8 | 2,168.8 | 29.0 |
| Light industrial and commercial | 1,958.8 | 1,942.0 | 16.8 |
| Large industrial (includes LNG revenues) | 945.3 | 849.7 | 95.6 |
| Other energy sales | 122.7 | 124.7 | (2.0) |
| Domestic Revenue Variance deferred in NHDA (Line 16) | 5,224.5 | 5,085.2 | 139.3 |

Load Variance: as per Directive 5 of the Fiscal 2015 to Fiscal 2016 RRA Decision (BCUC Order No. G-48-14), BC Hydro is allowed to continue to defer to the NHDA the variances between the actual and forecast cost of energy arising from differences between forecast and actual domestic customer load. The net cost of energy variance due to domestic customer load is calculated by adding the domestic revenue variance (Line 16) to the gross cost of energy variance (Line 4 + Line 13) as shown below.

| | |
|---|---|
| Gross Cost of Energy Variance ((70.4) + (47.4)) | (117.8) |
| Domestic Revenue Variance | 139.3 |
| **Net Cost of Energy deferred** | 21.5 |

**Note 10:** Deferred Amortization in the NHDA of $0.4 million relates to higher than planned costs for EPAs determined to be leases under IFRS 16.

**Note 11:** Revenues of ($1.3) million deferred in the NHDA relate to revenues 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 12:** Other amounts deferred to the NHDA mainly include a variance of ($9.3) million on point-to-point wheeling charges to Powerex (via Intersegment Revenues) offset by $5.2 million variance in External Open Access Transmission Tariff (**OATT**) revenues (via Miscellaneous Revenues).

**Note 13:** Trade Income 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).

# BC Hydro Fiscal 2020 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:

- 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); and
- Directives included in the BCUC's Decision on the Fiscal 2017 to Fiscal 2019 RRA (BCUC Order No. G-47-18).

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.

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] all Market Electricity Purchases, Surplus Sales[1] and Domestic Transmission – Export costs. This item is explained in greater detail below to provide clarification on the methodology used to determine variances:

   - 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.[3]

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

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.[1,4]
6. Skagit Valley Treaty revenues and ancillary services revenues.[1]
7. An interest charge/credit[5] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[6]

[4] 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).

[5] 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).

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

# 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[7] - all energy cost variances not deferred to the HDA. This item is 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;
   - Future Trade: 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

[7] 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).

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 made when the energy is returned to Powerex;

- Future Trade: when Powerex purchases energy for future trade, Heritage Energy is charged with a notional water rental charge for the use of this energy. The other side of this entry is shown as part of Non-Heritage energy. These entries are eliminated on consolidation. The difference between the Actual and Plan notional water rentals that is part of Heritage Energy flows through the HDA. The opposite variance relating to the Non-Heritage side of the notional water rental transaction flows through the NHDA; 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.[7]
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.[7]
4. Founding Partner Benefits and CIS Credits under the ABS Contract.[7,8]
5. Impact of load variance:[9]
   - The Net Cost of Energy deferral amount is calculated by subtracting the Gross Load Variance and adding the Net Load Variance to the Gross Cost

8 The ABS Contract expired on April 30, 2018 and all services previously performed by Accenture have been repatriated by BC Hydro.

9 Per Fiscal 2009 to Fiscal 2010 RRA Decision, Directive 31 (BCUC Order No. G-16-09) and Fiscal 2012 to Fiscal 2014 RRA Decision, Directive 1 (ix) (BCUC Order No. G-77-12A), as continued by the Fiscal 2015 to Fiscal 2016 RRA Decision, Directive 5 (BCUC Order G-48-14).

of Energy deferral amount. In practice, because Net Load Variance equals Gross Load Variance less Domestic Revenue Variance, the Net Cost of Energy Deferral simplifies to the Gross Cost of Energy Deferral minus the Domestic Revenue Variance.

6. 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]

7. Variances related to the Northwest Transmission Line (**NTL**) Supplemental Charge revenues in conjunction with Tariff Supplement No. 37 amendments.[11]

8. 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.

   In the Fiscal 2020 to Fiscal 2021 RRA, BC Hydro is seeking BCUC approval to:

   - Defer any variances between forecast and actual amounts related to the Biomass Energy Program which are not eligible for deferral treatment under existing orders, to the NHDA; and
   - Defer any variances related to the accounting for EPAs determined to be leases under IFRS 16, which are not eligible for deferral treatment under existing orders, to the NHDA.

9. Fiscal 2019 incremental lease revenues arising from the Waneta 2017 Transaction and the revenue BC Hydro will be required to recognize from time

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).

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[14] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[15]

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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).

14 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).

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

# 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,[16]
- Actual Trade Income is determined by excluding the impact on BC Hydro's consolidated net income due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex Corp; and
- An interest charge/credit[17] is applied to the monthly balance in each deferral account at BC Hydro's weighted average cost of debt for its current fiscal year.[18]

[16] Per Fiscal 2020 to Fiscal 2021 RRA, although Direction No. 7 has been repealed, BC Hydro continues to include the net income of its subsidiaries in its revenue requirements and continues to define Trade Income on the same basis as previously defined in Direction No. 7. The effect of this approach is that Trade Income will not be less than zero.

[17] 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).

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

# BC Hydro Fiscal 2020 Annual Report to the British Columbia Utilities Commission

## Appendix B

## Debt Management Regulatory Account Annual Status Report

## April 1, 2019 to March 31, 2020

## Table of Contents

Background .......... 1
Report as at March 31, 2020 .......... 1

## Appendices

Appendix 1 Future Debt Hedges Report
Appendix 2 Glossary for Appendix 1

# 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 on 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, 2020

During fiscal 2020, BC Hydro did not enter into any further future debt hedges (**FDHs**) to mitigate interest rate risk on future long-term debt that BC Hydro intends to issue. The existing outstanding hedges consist of 10-year and 30-year interest rate swaps and 30-year Government of Canada bond locks, with remaining contract maturity dates ranging from approximately three months to 4.2 years and forecast borrowing yields ranging from 2.60 per cent to 3.67 per cent.

Since the establishment of the DMRA, a total of $10.0 billion of FDHs have been placed, of which $5.0 billion remain outstanding. Based on BC Hydro's 2020/21 – 2022/23 Service Plan, at March 31, 2020, BC Hydro had hedged approximately 75 per cent of forecast total borrowing requirements from fiscal 2021 to fiscal 2025. The details of all FDHs are included in Appendix 1.

At March 31, 2020, the DRMA had a balance of $953 million (after amortization), which included net unrealized losses of $1,011 million on the $5.0 billion of outstanding FDHs and net realized gains of $71 million on the $5.0 billion of settled FDHs. This was a net change of $790 million from the balance at March 31, 2019 of $163 million to the balance at March 31, 2020 of $953 million. The $790 million change was due to:

- $12 million related to the amortization of net realized gains on the $4.0 billion of FDHs settled during fiscal 2017 to fiscal 2019;
- $35 million related to decreases in the value of the $1.0 billion of FDHs that were settled during fiscal 2020; and
- $743 million related to decreases in the unrealized mark-to-market value of the $5.0 billion of outstanding FDHs.

The decrease in the value of both the fiscal 2020 settled and outstanding FDHs is due to a significant decrease in long-term interest rates during fiscal 2020.

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

The net unrealized loss of $1,011 million relating to the $5.0 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 $0.8 billion to $1.0 billion in the value of the $5.0 billion in outstanding FDHs.

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.

# BC Hydro Fiscal 2020 Annual Report to the British Columbia Utilities Commission

## Appendix B

## Appendix 1

## Future Debt Hedges Report

# Future Debt Hedges Report

## As of March 31, 2020

(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 | (0.1) | 2.6 |
| FDH2A | 2016-05-11 | Bond Lock | F2017 | 16-Sep | 30 years | 200 | 2.97% | 3.00% | | (11.3) | (11.3) | 0.4 | (10.9) |
| FDH2B | 2016-05-12 | Bond Lock | F2017 | 16-Sep | 30 years | 100 | 3.01% | 3.00% | | (6.7) | (6.7) | 0.2 | (6.5) |
| FDH3 | 2016-05-18 | Bond Lock | F2018 | 17-Mar | 10 years | 300 | 2.36% | 2.35% | | 8.0 | 8.0 | (1.0) | 7.0 |
| FDH4 | 2016-05-24 | Bond Lock | F2018 | 17-Oct | 10 years | 200 | 2.38% | 2.37% | | 7.4 | 7.4 | (0.9) | 6.5 |
| 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 | (2.1) | 15.0 |
| FDH7 | 2016-09-23 | Swap | F2018 | 17-Oct | 10 years | 200 | 2.08% | 1.82% | | 17.2 | 17.2 | (2.1) | 15.1 |
| FDH8 | 2016-09-26 | Swap | F2018 | 17-Sep | 30 years | 200 | 2.64% | 2.27% | | 40.9 | 40.9 | (1.4) | 39.5 |
| FDH9 | 2016-09-29 | Swap | F2019 | 18-May | 10 years | 200 | 2.09% | 1.84% | | 22.7 | 22.7 | (2.3) | 20.3 |
| FDH10 | 2016-10-06 | Swap | F2019 | 18-Apr | 30 years | 200 | 2.76% | 2.14% | | 38.7 | 38.7 | (1.3) | 37.4 |
| FDH11 | 2016-06-08 | Swap | F2019 | 18-Sep | 10 years | 300 | 2.53% | 2.16% | | 22.4 | 22.4 | (2.3) | 20.1 |
| FDH12 | 2016-06-08 | Swap | F2019 | 18-Sep | 10 years | 200 | 2.54% | 2.17% | | 14.7 | 14.7 | (1.5) | 13.2 |
| 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 | | 10 years | 300 | 2.60% | | (23.0) | | (23.0) | | (23.0) |
| FDH17 | 2016-10-13 | Swap | F2021 | | 10 years | 200 | 2.60% | | (15.3) | | (15.3) | | (15.3) |
| FDH18 | 2016-10-20 | Swap | F2021 | | 10 years | 300 | 2.69% | | (25.1) | | (25.1) | | (25.1) |
| FDH19 | 2016-10-20 | Swap | F2021 | | 10 years | 200 | 2.69% | | (16.8) | | (16.8) | | (16.8) |
| **Subtotal** | | | | | | **$4,400** | | | **($80.2)** | **$171.0** | **$90.8** | **($14.4)** | **$76.4** |
| **Hedges Placed F2018** | | | | | | | | | | | | | |
| FDH20 | 2017-09-29 | Bond Lock | F2019 | 18-Jul | 10 years | 200 | 2.96% | 2.88% | | (1.6) | (1.6) | 0.2 | (1.4) |
| FDH21 | 2017-10-03 | Bond Lock | F2019 | 18-Jul | 10 years | 200 | 3.00% | 2.92% | | (2.2) | (2.2) | 0.2 | (2.0) |
| FDH22 | 2017-09-29 | Bond Lock | F2019 | 18-Jul | 30 years | 200 | 3.35% | 3.36% | | (17.3) | (17.3) | 0.6 | (16.7) |
| FDH23A | 2017-10-04 | Bond Lock | F2019 | 18-Jun | 10 years | 100 | 3.01% | 2.84% | | (0.4) | (0.4) | 0.0 | (0.3) |
| FDH23B | 2017-10-04 | Bond Lock | F2019 | 18-Jun | 10 years | 100 | 3.01% | 2.87% | | (0.4) | (0.4) | 0.0 | (0.3) |
| FDH24A | 2017-10-02 | Bond Lock | F2019 | 18-Aug | 30 years | 100 | 3.36% | 3.35% | | (6.4) | (6.4) | 0.2 | (6.2) |
| FDH24B | 2017-10-03 | Bond Lock | F2019 | 18-Aug | 30 years | 100 | 3.38% | 3.37% | | (6.8) | (6.8) | 0.2 | (6.6) |
| FDH25 | 2017-09-28 | Bond Lock | F2019 | 18-Aug | 30 years | 250 | 3.37% | 3.36% | | (16.7) | (16.7) | 0.5 | (16.1) |
| 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 | | 30 years | 75 | 3.64% | | (27.0) | | (27.0) | | (27.0) |
| FDH29 | 2018-02-05 | Swap | F2021 | | 30 years | 75 | 3.64% | | (27.0) | | (27.0) | | (27.0) |
| FDH30/31 | 2018-02-08 | Swap | F2022 | | 30 years | 175 | 3.67% | | (62.9) | | (62.9) | | (62.9) |
| FDH32 | 2018-02-06 | Swap | F2022 | | 30 years | 100 | 3.60% | | (33.9) | | (33.9) | | (33.9) |
| FDH33 | 2018-02-07 | Swap | F2022 | | 30 years | 100 | 3.58% | | (33.5) | | (33.5) | | (33.5) |
| FDH34/35 | 2018-02-01 | Swap | F2023 | | 30 years | 250 | 3.52% | | (76.6) | | (76.6) | | (76.6) |
| FDH36/37 | 2018-01-24 | Swap | F2023 | | 30 years | 200 | 3.40% | | (55.8) | | (55.8) | | (55.8) |
| **Subtotal** | | | | | | **$2,275** | | | **($316.6)** | **($58.4)** | **($375.0)** | **$2.0** | **($373.0)** |
| **Hedges Placed F2019** | | | | | | | | | | | | | |
| FDH38 | 2018-12-07 | Swap | F2022 | | 10 years | 125 | 3.33% | | (19.1) | | (19.1) | | (19.1) |
| FDH39 | 2018-12-06 | Swap | F2023 | | 10 years | 100 | 3.40% | | (14.3) | | (14.3) | | (14.3) |
| FDH40 | 2018-12-07 | Swap | F2023 | | 10 years | 125 | 3.41% | | (17.7) | | (17.7) | | (17.7) |
| FDH41 | 2018-12-07 | Swap | F2024 | | 10 years | 175 | 3.46% | | (24.6) | | (24.6) | | (24.6) |
| FDH42 | 2018-12-06 | Swap | F2024 | | 30 years | 175 | 3.62% | | (55.1) | | (55.1) | | (55.1) |
| 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 | | 30 years | 200 | 3.20% | | (47.6) | | (47.6) | | (47.6) |
| FDH45B | 2019-01-17 | Bond Lock | F2021 | | 30 years | 125 | 3.20% | | (29.8) | | (29.8) | | (29.8) |
| FDH46A | 2019-01-15 | Swap | F2021 | | 30 years | 100 | 3.43% | | (30.6) | | (30.6) | | (30.6) |
| FDH46B | 2019-01-16 | Swap | F2021 | | 30 years | 225 | 3.49% | | (72.1) | | (72.1) | | (72.1) |
| FDH47 | 2019-01-08 | Swap | F2022 | | 10 years | 275 | 3.15% | | (37.7) | | (37.7) | | (37.7) |
| FDH48 | 2019-01-09 | Swap | F2022 | | 30 years | 100 | 3.41% | | (29.6) | | (29.6) | | (29.6) |
| FDH49 | 2019-01-09 | Swap | F2022 | | 10 years | 300 | 3.22% | | (41.7) | | (41.7) | | (41.7) |
| FDH50 | 2019-01-10 | Swap | F2022 | | 30 years | 175 | 3.41% | | (50.9) | | (50.9) | | (50.9) |
| FDH51 | 2019-01-14 | Swap | F2023 | | 10 years | 250 | 3.26% | | (32.8) | | (32.8) | | (32.8) |
| FDH52 | 2019-01-10 | Swap | F2023 | | 10 years | 125 | 3.27% | | (16.2) | | (16.2) | | (16.2) |
| FDH53 | 2019-01-11 | Swap | F2023 | | 30 years | 100 | 3.42% | | (28.0) | | (28.0) | | (28.0) |
| FDH54 | 2019-01-09 | Swap | F2024 | | 10 years | 175 | 3.33% | | (22.6) | | (22.6) | | (22.6) |
| FDH55 | 2019-01-08 | Swap | F2024 | | 30 years | 125 | 3.44% | | (34.4) | | (34.4) | | (34.4) |
| FDH56 | 2019-01-15 | Swap | F2025 | | 10 years | 75 | 3.39% | | (9.5) | | (9.5) | | (9.5) |
| **Subtotal** | | | | | | **$3,325** | | | **($614.4)** | **($41.9)** | **($656.3)** | **$0.0** | **($656.3)** |
| **Total** | | | | | | **$10,000** | | | **($1,011.2)** | **$70.7** | **($940.5)** | **($12.4)** | **($952.9)** |

[1] Actual debt was a 30 year issue.

[2] Gain / (loss) deferred to the Debt Management Regulatory Account

# BC Hydro Fiscal 2020 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<br>**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<br>**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 Province of BC 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 Future Debt Hedge 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 Fiscal 2020 Annual Report to the British Columbia Utilities Commission

## Appendix C

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

## Fiscal 2020

# Table of Contents

1 Summary / Background ... 1
2 BCUC Order No. G-92-19 Compliance Information ... 2

# Appendices

Attachment 1 Dual Meter Customer Feedback

# 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.

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

BC Hydro has completed its 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 Order No. G-92-19 came into effect on April 29, 2019, 287 customers have requested a second meter[2].

On March 13, 2020, BC Hydro launched a 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 210 customers who had a second meter installed since April 29, 2019, regardless of the reason for the additional meter, in order to obtain broader customer feedback.

BC Hydro received 28 survey responses for a response rate of about 13 per cent. Three respondents or about 11 per cent indicated that they installed the second meter specifically for ZEV charging and felt that the installation of the second meter

[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.

met their needs. Two respondents indicated that they were extremely satisfied with the service. The remaining responses indicated that they installed the second meter for purposes unrelated to ZEV charging.

BC Hydro plans to follow-up with another survey towards the end of November 2020 and report the results in the Fiscal 2021 Annual Report to the Commission.

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

BC Hydro acknowledges that there are additional costs in administering accounts with multiple meters. However, the number of customers with multiple meters remains low, with only 13 accounts confirmed for ZEV charging purposes, and two with no consumption history. Given the small number of accounts involved, BC Hydro is unable to perform meaningful analysis comparing one Basic Charge plus increased consumption billed on one Residential Inclining Block (**RIB**) rate account versus two Basic Charges with consumption billed on two separate RIB accounts. BC Hydro will continue to monitor metering and billing treatments.

Review of the RIB basic charge, including for ZEV charging purposes, could be included a future BC Hydro residential service rate design application when meaningful analysis data is available.

### c. Additional Amendments to the Electric Tariff

The existing amendments apply to Rate Schedule 1107 and 1101.

At this time, BC Hydro does not see the need for additional amendments to the Electric Tariff for other rate classes that may have similar multi-unit characteristics such as commercial strata developments.

BC Hydro will continue to review the outcome of these amendments, in particular for customers living in MURBs, and consider whether similar proposals (rate treatments) are appropriate for other rate classes.

BC Hydro
Power smart

# BC Hydro Fiscal 2020 Annual Report to the British Columbia Utilities Commission

## Appendix C

## Attachment 1

## Dual Meter Customer Feedback

BC Hydro is collecting this information in accordance with our mandate under the Hydro and Power Authority 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 Recently you had a second BC Hydro smart meter installed under your account at your location. Please tell us the main reason for requesting 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 Has the installation of the second meter met your needs?

O Yes

O No

*Display This Question:*

*If Has the installation of the second meter met your needs? = No*

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

________________________________________________________________

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________________________________________________________________

Q5 Please tell us how satisfied you are with BC Hydro's additional meter installation experience?

- O Extremely dissatisfied
- O .
- O Neutral
- O .
- O Extremely satisfied
- O

*Display This Question:*

*If Please tell us how satisfied you are with BC Hydro's additional meter installation experience? = Extremely dissatisfied*

*Or Please tell us how satisfied you are with BC Hydro's additional meter installation experience? = .*

Q6 Can you tell us why you were dissatisfied? (For privacy reasons, please don't identify yourself or others).

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Q7 Is there anything we could do to improve the experience? (For privacy reasons, please don't identify yourself or others).

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