Fred James
Chief Regulatory Officer
Phone: 604-623-4046
Fax: 604-623-4407
bchydroregulatorygroup@bchydro.com

December 22, 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 2022 Revenue Requirements Application (the Application)

BC Hydro is hereby filing the attached Fiscal 2022 Revenue Requirements Application. BC Hydro is requesting various approvals from the BCUC which, if approved, would result in a rate increase of 1.16 per cent.

We request that these changes be made effective April 1, 2021, on an interim basis, pending a final BCUC decision on the Application.

BC Hydro is providing the Application as follows:

Exhibit B-2	Application
Exhibit B-2-1	Application – Chapter 6 (Confidential Version)
Exhibit B-2-2	Appendices A to Y
Exhibit B-2-3	Appendices I and N (Confidential Version)
Exhibit B-2-4	Appendix Z (Confidential)

Confidentiality Request

BC Hydro requests the following information to be held confidential in accordance with Part IV of the BCUC's Rules of Practice and Procedure, for the reasons explained below:

1. Certain information in Chapter 6, Appendix I, and Appendix N, which is either customer-specific and/or commercially sensitive; and
2. The entirety of Appendix Z related to Mandatory Reliability Standards.

Chapter 6, Appendix I and Appendix N - Customer-Specific / Commercially Sensitive Information

In Chapter 6 and Appendix I, BC Hydro has redacted the name of a BC Hydro project where the project either:

- Is driven by, or specially for, a customer (disclosure of such information may prejudice a customer's commercial or competitive position); or
- Pertains to a substation acquisition (disclosure of such information may prejudice BC Hydro's position in future negotiations).

In Appendix N, the information redacted pertains to the name or identifiable information of a customer. If disclosed, the information may potentially prejudice the customer's competitive position. BC Hydro has a contractual obligation to keep the information specifically related to the customer and the customer's project confidential.

For the purpose of this proceeding and on appropriate undertakings, as contemplated by the BCUC's Rules of Practice and Procedure, BC Hydro is able to make non-customer specific project information in Chapter 6 and Appendix I available to registered interveners. BC Hydro reserves the right to object to a request for access to confidential information on a case-by-case basis.

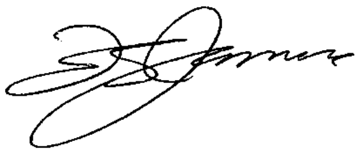
Appendix Z – Confidential Mandatory Reliability Standards Information

In the Application, we have split the discussion on Mandatory Reliability Standards (**MRS**) between public content in Chapter 5 and confidential content in Appendix Z. Appendix Z is confidential and made available to the BCUC only for two related reasons:

- First, information related to the protection of cyber infrastructure is highly security sensitive and could compromise the safety and reliability of the Bulk Electric System by exposing it to physical attacks by malicious actors or cyberattacks; and
- Second, the BCUC's MRS Rules of Procedure, including the Compliance Monitoring Program Rules and Penalty Guidelines, make the framework and processes for reporting, auditing and oversight of MRS compliance confidential. While certain information about an entity's violations, if confirmed, may become public after the fact, there remains a presumption of confidentiality. The presumption of confidentiality is especially important where the subject-matter relates to a cyber-security incident or may otherwise jeopardize the security of the Bulk Electric System.

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

Yours sincerely,



Fred James
Chief Regulatory Officer

cs/rh

Enclosure

Copy to: BCUC Project No. 1598990 (BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application) Registered Intervener Distribution List.

Summary Table of Contents

Chapter 6. Capital Expenditures and Additions

Chapter 8. Other Revenue Requirements Items

Chapter 9. Transmission Revenue Requirement

List of Figures

Chapter 3. Load and Revenue Forecast

List of Tables

Chapter 6. Capital Expenditures and Additions

List of Appendices

BC Hydro
Power smart

BC Hydro Fiscal 2022
Revenue Requirements Application

Chapter 1

Executive Summary

Table of Contents

List of Tables

1.1 Introduction

British Columbia Hydro and Power Authority (**BC Hydro**) is a Crown Corporation established under the *Hydro and Power Authority Act* and regulated by the British Columbia Utilities Commission (**BCUC**) under the *Utilities Commission Act*. Our owner and sole shareholder is the Government of B.C.

BC Hydro's mission is to safely provide reliable, affordable, clean electricity throughout British Columbia. This mission recognizes that we have a responsibility to keep rate increases as low as possible. This is especially important given the economic challenges caused by the COVID-19 pandemic. At the same time, we recognize that ongoing investment is necessary so that we can continue to deliver safe, reliable and cost-effective service into the future.

In the Application, we are seeking various BCUC approvals for fiscal 2022 (**Test Period**). Our requested orders are set out in section 1.4, and a Draft Order is provided as Appendix B. If approved, these requests would result in a rate increase of 1.16 per cent on April 1, 2021 while providing $49.7 million in additional operating funding for reliability investments[1] in Mandatory Reliability Standards (**MRS** or **Standards**), vegetation management and cybersecurity as well as an additional $3.3 million for employee training. BC Hydro foreshadowed the need for this additional funding during the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**Previous Application**) proceeding and the BCUC also directed BC Hydro to address the adequacy of funding in these areas.[2]

We respectfully submit that the requested rate orders are just and reasonable and submit that they should be approved as sought.

[1] This consists of $21.7 million for Mandatory Reliability Standards (refer to Chapter 5, section 5.6), $25 million for vegetation management (refer to Chapter 5, section 5.7) and $3 million for cybersecurity (refer to Chapter 5, section 5.8).

[2] Refer to Directive 21, Directive 22 and page (v) of BCUC Order No. G-246-20.

During BC Hydro's Previous Application proceeding, the BCUC expressed a desire to realign the timing of BC Hydro's future Revenue Requirements Applications. The goal is for applications to be submitted earlier so that there is enough time remaining in the period under review for BC Hydro to implement directives within that period.[3] BC Hydro and a number of interveners supported that objective. In order to achieve that outcome, the BCUC directed BC Hydro to file this one-year "gap year" Revenue Requirements Application for fiscal 2022 by December 2020, to be reviewed through a streamlined process.[4] Streamlining the fiscal 2022 process will facilitate the new regulatory cycle commencing with the fiscal 2023 application[5], which BC Hydro expects to file in August 2021. On December 9, 2020, BC Hydro filed a letter with the BCUC setting out a proposed regulatory process for hearing this one-year Revenue Requirements Application (**Application**) that will achieve the BCUC's objective.[6]

This chapter is organized around the following key points:

- Section 1.2 responds to Directive 65 of the BCUC's Decision on the Previous Application by providing a summary of the impact of the COVID-19 pandemic on BC Hydro's operations with references to other chapters where further detail is provided. The pandemic has had significant implications for BC Hydro;
- Section 1.3 identifies how we have considered and acted upon the directives and recommendations in the BCUC's Decision on the Previous Application;
- Section 1.4 sets out the approvals that we are seeking in the Application;

3 For example, in its Decision on the Previous Application, the Panel agreed with BC Hydro that vegetation management was an area of concern requiring evaluation. However, the Panel did not approve more than what BC Hydro had requested in its budget for vegetation management, in part, because BC Hydro would not have been able to adequately spend the extra funds on vegetation management in the few months remaining in the test period. Refer to Order No. G-246-20, pages 72 to 73.

4 Refer to BCUC Order No. G-246-20, page (iii) and page 185. The BCUC had previously characterized the fiscal 2022 year as a "gap year" when soliciting comments on a proposed approach.

5 BC Hydro expects its Fiscal 2023 Revenue Requirements Application to cover multiple years. In the proceeding to review BC Hydro's Performance Based Regulation Report, BC Hydro proposed a three-year test period, covering fiscal years 2023 to 2025.

6 Refer to Exhibit B-1.

- Section 1.5 summarizes our forecast revenue requirements, which total $5,211.7 million for fiscal 2022; and
- Section 1.6 provides contact information for communications regarding the Application.

1.2 The COVID-19 Pandemic Has Impacted BC Hydro's Revenues, Costs and Operations

In its Decision on the Previous Application, the BCUC directed BC Hydro to report, in all future Revenue Requirements Applications until directed otherwise, on the impact of the COVID-19 pandemic with respect to its operations and how it plans to handle the resulting impact on its revenue requirements, rates and regulatory accounts.[7]

First and foremost, BC Hydro recognizes the impact on our customers from the economic challenges of the pandemic. Many individual customers have lost their jobs or seen reduced hours. Our commercial and industrial customers are facing lower sales and higher costs and, in some cases, have had to close their businesses. In response, BC Hydro has provided financial relief programs for customers, including a COVID-19 Relief Fund and bill payment deferrals.

Further information on the impact of the COVID-19 pandemic is provided throughout the Application, as follows:

- **Load Forecast:** BC Hydro prepared a comprehensive twenty-year load forecast over the winter of 2019 and spring of 2020, prior to the onset of impacts associated with the COVID-19 pandemic. To address those potential impacts, BC Hydro quickly developed two scenarios that were used to inform decisions based on two potential outcomes. The sales projection for fiscal 2022 from one of those scenarios (referred to as "**Scenario A**") is used in the calculation of the Test Period revenue requirements in the Application. As of

[7] Directive 65; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 181.

November 2020, two-thirds of the way through fiscal 2021, actual total domestic sales were 1.2 per cent higher than COVID-19 Scenario A for the three main customer classes. Given this performance, we believe that Scenario A is appropriate for the purpose of forecasting revenue to set rates for the Test Period. That said, significant uncertainty and risk remains with regard to the ongoing impacts of the COVID-19 pandemic on actual domestic sales. Further information is provided throughout Chapter 3;

- **Operating Costs:** The COVID-19 pandemic has resulted in operating cost pressures and savings as well as cost reduction strategies, which largely occurred during the first two quarters of fiscal 2021. The net COVID-19 related cost pressures in fiscal 2021 are forecast at $4.8 million. While future costs and savings associated with the COVID-19 pandemic are uncertain, many of BC Hydro's Key Business Units (**KBUs**) returned to normal work levels in the second and third quarter of fiscal 2021. Accordingly, BC Hydro has not forecast any COVID-19 pandemic-related cost pressures in the Test Period. Further information is provided in Chapter 5, section 5.10;

- **Capital Projects and Programs:** The delivery of BC Hydro's capital investments was impacted by the COVID-19 pandemic; however, these changes are not expected to have a material impact on the forecast capital additions that affect the fiscal 2022 revenue requirements. Projects and programs with active construction or field work this year were required to incorporate new safety protocols, which resulted in slowing or delaying aspects of some projects and programs. Many projects either continued with limited impact or were delayed and have now resumed.

  BC Hydro's ex-plan governance process[8] allows investments that address emerging needs to be added to the capital portfolio, outside of the annual enterprise wide capital planning process. For example, Technology investments

[8] BC Hydro's ex-plan governance process is described in Appendix S, section 6.3.5.

required to facilitate remote working by BC Hydro's employees during the COVID-19 pandemic were added to the portfolio through the ex-plan governance process. We reallocated funding so that the overall portfolio remained aligned with the capital budget.

Further information is provided in Chapter 6, section 6.2.3.1;

- **Regulatory Accounts:** The COVID-19 pandemic has impacted, and is expected to continue to impact, several regulatory accounts. Further information is provided in Chapter 7, section 7.5;
- **Interest Rates and Discount Rates:** The low interest rate environment which, in part, is a result of measures taken in response to the COVID-19 pandemic is impacting BC Hydro's forecast revenue requirements. Finance Charges are decreasing because of lower interest rates (refer to Chapter 8, section 8.4). Current service costs for BC Hydro's pension plan are increasing due to a decrease in the discount rate (refer to Chapter 5, section 5.11.5); and
- **Demand-Side Management (DSM):** In the initial months of the pandemic, there was a reduction in the number of participants in our traditional DSM programs. However, many customers remained engaged and BC Hydro attempted to mitigate impacts. As a result, participation returned to close to planned levels for many programs after the initial months. We continue to see strong interest in advancing study activities for Low Carbon Electrification. Two implementation projects that were planned to complete in fiscal 2021 could be delayed to fiscal 2022, as a result of the pandemic. Further information is provided in Chapter 10, section 10.2.1.3.

1.3 BC Hydro Has Considered and Acted Upon the BCUC's Directives and Recommendations

The Application reflects our consideration and response to the BCUC's Directives and recommendations in its Decision on our Previous Application (**Decision**). Details are provided in the sub-sections below.

1.3.1 We Are Updating Our Service Plan Performance Measure on Affordable Bills

One of BC Hydro's Service Plan performance measures is Affordable Bills. BC Hydro is focused on affordability for all customers classes; however, to simplify reporting, the Service Plan performance measure has been based on residential bills. During the Previous Application proceeding, interveners provided feedback that affordability for commercial and industrial customers should have a higher profile in BC Hydro's Service Plan. In its Decision, the BCUC indicated a preference for the Service Plan performance measures to give greater weight to commercial and industrial competitiveness.[9] BC Hydro recognizes the importance of providing the same profile for commercial and industrial affordability in the Service Plan. We will be adding performance measures for those customer classes in the fiscal 2022 to fiscal 2024 Service Plan, expected to be released early in 2021.

1.3.2 We Use Performance Metrics to Manage Operations and Inform Decisions (Directive 68)

In its Decision, the BCUC directed BC Hydro to include in the Application the metrics it uses to manage its operations.[10] Appendix O provides a list of the performance measures and targets that we use to manage operations at the Business Group level. Appendix Q provides BC Hydro's Service Plan performance measures and targets.

These Business Group metrics and Service Plan performance measures are used by the Executive team to monitor how the business is performing. Business Group metrics and targets are determined annually for the upcoming fiscal year. Work is underway on the development of new operational metrics, including metrics to

[9] BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 195.

[10] Directive 68; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 188.

monitor our effectiveness in areas where operating costs are increasing, such as cybersecurity and vegetation management.

BC Hydro also recognizes that performance metrics are a useful tool to help the BCUC and interveners evaluate BC Hydro's revenue requirements and operations. We are committed to engaging with the BCUC and interveners on this topic and will consider any feedback received as our performance metrics are developed and updated. In addition, in the proceeding to review BC Hydro's Performance Based Regulation Report, we have proposed that the Fiscal 2023 Revenue Requirements Application include a proposal for information-only performance metrics, which would be informed through stakeholder engagement, including a workshop.[11]

1.3.3 Electric Vehicle Costs Are Prescribed Undertakings and Should Be Recovered in Rates

BC Hydro owns and operates electric vehicle charging stations in British Columbia. In its Decision, the BCUC directed that these stations be removed from rate base. It disallowed the forecast operating costs and cost of energy associated with these stations because the stations were not part of BC Hydro's utility service.[12]

Section 5 of the Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**) sets out criteria that qualify an electric vehicle charging station as a prescribed undertaking for the purposes of section 18 of the *Clean Energy Act*. The BCUC must set rates that allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings.

Section 5 of the GGRR came into effect after the evidentiary phase for the Previous Application was closed. Therefore, BC Hydro did not have the opportunity in that proceeding to provide information that its electric vehicle charging stations were prescribed undertakings under section 5 of the GGRR. In its Decision on the

[11] Refer to BC Hydro's Supplementary Evidence in the proceeding to review BC Hydro's PBR Report (Exhibit B-8, pages 18 to 20).

[12] Directive 27; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 93.

Previous Application, the BCUC encouraged BC Hydro to apply for recovery of "any of its prior, current or future electric vehicle capital expenditures considered as possible prescribed undertakings under the GGRR".[13]

As discussed in Chapter 7, section 7.2.5, BC Hydro is seeking to establish an Electric Vehicle Costs Regulatory Account to recover, in the Test Period, its fiscal 2020 and fiscal 2021 costs related to electric vehicle charging stations that are prescribed undertakings.

For fiscal 2022, costs with respect to the prescribed undertakings are included in the revenue requirements in the categories of cost to which they relate. For further information on BC Hydro's electric vehicle charging stations that meet the requirements of a prescribed undertaking under section 5 of the GGRR, refer to Chapter 2, section 2.3.2.3.

1.3.4 Estimated Actual Vacancy Factor Savings Were Close to Forecast in Fiscal 2020 (Directive 20)

BC Hydro included $5.6 million per year of forecast vacancy factor savings in fiscal 2020 and fiscal 2021 to recognize the cost savings that occur because positions do not remain filled 100 per cent of the time. This forecast amount was in addition to labour budget reductions already included in the budgets of some KBUs. In its Decision, the BCUC directed BC Hydro to begin tracking and measuring the annual actual vacancy factor savings and reporting on the results in future Revenue Requirements Applications.[14]

BC Hydro's analysis shows that, for fiscal 2020 (actual results for fiscal 2021 are not yet available), estimated actual vacancy factor savings were within approximately $0.5 million of the forecast amount. This analysis reinforced the reasonableness of the amount included for fiscal 2020 in the Previous Application. As a result of the

[13] Refer to page 94 of Order No. G-246-20.

[14] Directive 20; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), pages 69 to 70.

minimal change in FTEs in fiscal 2022, BC Hydro has used the same amount of vacancy factor savings for fiscal 2022. Further information is provided in Chapter 5, section 5.11.3.

1.3.5 Cybersecurity Threat Landscape is Growing and Changing, and Additional Funding is Required to Improve Capacity and Capability (Directive 21)

The cybersecurity threat landscape is growing in sophistication and the environment is constantly changing. During the proceeding for the Previous Application, BC Hydro indicated that additional investment in cybersecurity management would likely be required starting in fiscal 2022. In its Decision, the BCUC directed BC Hydro to address the adequacy of its cybersecurity programs in the Application.[15]

BC Hydro's fiscal 2021 base operating budget for cybersecurity is $4.6 million. BC Hydro's planned increase for fiscal 2022 is $3.0 million which will be directed to areas identified for improvement in assessments and audits of BC Hydro's cybersecurity capability. This additional funding, along with some reallocated internal resources, will result in a total base operating budget for cybersecurity of $8.0 million to enhance BC Hydro's overall capacity and capability to meet cybersecurity management needs. Further information is provided in Chapter 5, section 5.8.

1.3.6 Vegetation Management Funding Must Increase to Address Growth, Cost Escalation and Climate Change (Directive 22)

During the proceeding for the Previous Application, BC Hydro indicated that additional investment in vegetation management would likely be required. In its Decision, the BCUC directed BC Hydro to address the adequacy of its vegetation management funding in the Application.[16]

---

[15] Directive 21; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 71.

[16] Directive 22; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 73.

BC Hydro has included an additional $25 million, including an additional 18 FTEs, to support the vegetation management program in fiscal 2022, bringing the total vegetation budget to $74.4 million. This additional investment is associated with a variety of factors, notably:

- Vegetation that was cleared during a period of heightened activity over a decade ago has regrown and is now reaching maturity size that poses a risk to the system;
- Cost pressures have increased with electrical system expansion, new regulatory requirements and general cost inflation associated with vegetation maintenance activities, and these costs pressures can no longer be absorbed in existing budgets; and
- Climate change is impacting the growth rate and health of vegetation across the province.

This additional budget will improve BC Hydro's overall vegetation management capacity and capability to meet transmission and distribution system needs in fiscal 2022. It will lay the foundation for our new Vegetation Management Strategy going forward. Further information is provided in Chapter 5, section 5.7.

1.3.7 Additional Funding Is Required to Maintain and Achieve Compliance with Mandatory Reliability Standards

During the Previous Application proceeding, BC Hydro also identified MRS as an area where additional funding would likely be required.[17]

MRS are in place to ensure the reliable operation of the Bulk Electric System[18] throughout North America. Ongoing compliance with these standards is, as the name MRS suggests, mandatory. The scope and complexity of the requirements

[17] BCUC Order No. G-246-20, page 190 to 191.

[18] The Bulk Electric System is defined as the electrical generation resources, transmission lines, interconnections with neighbouring systems and associated equipment, generally operated at voltages of 100 kV or higher.

under these Standards is increasing. The work that we must undertake to achieve and maintain compliance is increasing commensurately.

BC Hydro's fiscal 2022 plan includes an operating cost increase of $21.7 million and an FTE increase of 21.5 to maintain and achieve compliance with MRS.

BC Hydro regards these incremental costs as non-discretionary. They represent a significant step forward in BC Hydro's MRS program and will ensure the successful implementation of the latest and future versions of the CIP standards. This investment leaves a legacy to build upon in the future and make addressing new standards more efficient and effective. BC Hydro anticipates further expansion of our MRS program and investments in future years as our efforts mature and new standards and iterations of existing standards are implemented.

Further information is provided in Chapter 5, section 5.6. Appendix Z contains additional information that is confidential and is being provided to the BCUC only.[19]

1.3.8 BC Hydro is Increasing Resources for Employee Training

In its Decision, the BCUC identified five areas where it was concerned that cost cutting may have been too aggressive or needed increases may have been put on hold: employee training, energy studies, vegetation management, cybersecurity and safety.[20] Vegetation management and cybersecurity are addressed in the subsections above.

With regard to employee training, we have reviewed BC Hydro's current training plan and determined that further investment is required. Specifically, training budgets are no longer sufficient to allow IBEW employees in the Operations Business Group to complete both the mandatory safety and regulatory training, as well as the technical and leadership training to maintain their current skills required to work safely and efficiently and maintain system reliability. BC Hydro has included an increase of

[19] Further information on the confidentiality of Appendix Z is provided in Chapter 5, section 5.6.1.

[20] Refer to page (v) of Order No. G-246-20.

$3.3 million in the Test Period, which will provide an average of an additional three-and-a-half training days per IBEW employee for a total of 13.5 days of training. Further information is provided in Chapter 5, section 5.9.

With regard to the Energy Studies, an additional FTE has been added to the Energy Studies team. In our recent Compliance Filing to the Previous Application, we described work being advanced on additional enhancements to the Energy Studies models.

In accordance with Directive 23, BC Hydro will consider the BCUC's comments with regard to safety in its Fiscal 2023 Revenue Requirements Application.

1.3.9 BC Hydro Has Responded to the BCUC's Directives on Capital Projects (Directives 29 and 31)

BC Hydro has responded to the BCUC's directives related to capital projects.

In its Decision, the BCUC directed BC Hydro to file a joint CPCN application for the Bridge River 1 Units 1-4 Generators / Governors Project and the Bridge River Transmission Project.[21] BC Hydro expects to file this application by mid-2021. The BCUC also removed the requirement for BC Hydro to file a CPCN for the cancelled Northwest Substation project but noted that there may be other successor projects to the Northwest Substation project which do require CPCNs.[22] BC Hydro confirms that there may be successor projects to the Northwest Substation project but the related customers have not made final investment decisions. At present, the projects are not expected to meet the materiality threshold for a CPCN application to the BCUC.

For further information on how BC Hydro has responded to the BCUC's directives and comments on capital projects, refer to Chapter 6, section 6.1.3.

---

21 Directive 29; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 100.

22 Directive 31; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 103.

1.3.10 BC Hydro is Seeking to Recover Actual Project Write-Off Costs (Directives 32 and 33)

In its Decision, the BCUC accepted that some project write-offs are reasonable and to be expected in a utility's normal course of business, However, it disallowed BC Hydro's proposal to include these costs, on a forecast basis, in the revenue requirements. Instead, the BCUC indicated it would consider a mechanism to capture actual project write-off costs for recovery in rates, following BCUC review.[23]

In response, BC Hydro made a separate application for approval to establish a Project Write-off Costs Regulatory Account to capture the portion of actual project write-off costs for which BC Hydro believes future recovery from ratepayers is appropriate.[24] BC Hydro's request to establish the Project Write-off Costs Regulatory Account was approved by BCUC Order No. G-337-20 dated December 17, 2020. In this Application, BC Hydro is requesting approval for a recovery mechanism for the Project Write-off Costs Regulatory Account. In fiscal 2022, BC Hydro proposes to recover $9.3 million in actual project write-off costs related to fiscal 2020, which were deferred to this account, subject to BCUC review and approval of the recovery of these amounts in the Application. Further information on these requests is provided in Chapter 7, section 7.2.4. Appendix L of the Application provides a description the amounts that have been written-off in fiscal 2020 that were deferred for recovery from ratepayers along with the supporting information to demonstrate why cost recovery is appropriate.

1.3.11 BC Hydro Has Complied with the BCUC's Directives on Regulatory Accounts (Directives 15, 38, 39, 41, 48 and 55)

The BCUC issued several directives regarding regulatory accounts, which we have addressed.

---

23 Directives 32 and 33; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 107 to 108.

24 Refer to: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=833

BC Hydro has established the Load Variance Regulatory Account and the Biomass Energy Program Variance Regulatory Account, as directed.[25] Further information is provided in Chapter 7, section 7.3.

The BCUC directed BC Hydro to assess whether its practice of expensing dismantling costs as they occur would result in intergenerational inequity and to provide options to better promote intergenerational inequity.[26] BC Hydro's initial assessment is that expensing costs as they occur could result in some intergenerational inequities. An alternative is to collect net salvage costs over the lives of the assets. This alternative should be assessed once BC Hydro has completed a net salvage study.[27] Further discussion is provided in Chapter 7, section 7.2.3.

The BCUC disallowed BC Hydro's forecast of net gains in fiscal 2020 and fiscal 2021 from the sale of surplus real property.[28] Consistent with that determination, BC Hydro has forecast $0 from the sale of surplus real property in the Test Period. This is shown in Chapter 7, Table 7-4, line 14.

In its Decision, the BCUC also directed BC Hydro to separately track low carbon electrification expenditures in the DSM Regulatory Account.[29] BC Hydro is doing so; these expenditures are shown separately in Appendix A, Schedule 2.2, line 4.

---

[25] Directives 15 and 38; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020).

[26] Directive 39; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020).

[27] BC Hydro will be providing a net salvage study in accordance with Directive 40 of the BCUC's Decision.

[28] Directive 41; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020).

[29] Directive 48; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 150.

Lastly, the BCUC directed BC Hydro to provide, in Revenue Requirements Applications, the Debt Management Regulatory Account Annual Status Report as provided in its Annual Report to the BCUC.[30] This report is provided as Appendix V.

1.3.12 The Benefits of a Comprehensive Review of OATT Rate Design Would Not Outweigh the Costs

In its Decision, the panel recommended that the BCUC initiate a proceeding to conduct a comprehensive review of the Open Access Transmission Tariff (**OATT**) rate design.[31]

BC Hydro does not support the initiation of a proceeding to conduct a comprehensive review of the OATT rate design for the following four reasons:

- The OATT rate design has been comprehensively reviewed by the BCUC twice since its introduction in 1998;
- BC Hydro has relatively few external OATT customers and there is relatively little customer interest in the OATT;
- BC Hydro has limited flexibility to amend the OATT as it must maintain comparability with FERC's *pro forma* OATT to demonstrate that it is complying with FERC's reciprocity requirement.; and
- A comprehensive OATT rate design proceeding would require significant resources, including specialized consultants familiar with OATT rate design, which would increase regulatory costs.

Accordingly, BC Hydro does not consider that the benefits of a comprehensive OATT rate design application would outweigh the costs. We submit that the OATT should be maintained and modernized as needed to respond to specific customer needs and FERC developments. BC Hydro plans to file an OATT application with

30 Directive 55; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 170.

31 Refer to pages 158 to 159 of Order No. G-246-20.

regard to FERC Order No. 845/842 (generator interconnection) in 2021. Any further interest in OATT amendments or review could be explored through that proceeding. For further information, refer to Chapter 9, section 9.4.

1.3.13 BC Hydro is Responding, Or Will Respond, to the BCUC's Directives on Demand-Side Management (Directives 47 and 51)

In its Decision on the Previous Application, the BCUC made several directives on DSM to which BC Hydro has responded or will respond in due course.

Among other things, the BCUC directed BC Hydro to report on the progress of the Non-Integrated Area (**NIA**) program.[32] BC Hydro's Fiscal 2020 Annual Report on DSM Activities, provided as Appendix W, contains a section on Non-Integrated Area Activities, which was enhanced to include information on the progress of the NIA program in that year. We have also provided information on further progress of the NIA program during fiscal 2021 in the NIA program description in Appendix M, page 12. As directed, we will also report on the progress of the NIA program as part of the annual DSM report, and in the Fiscal 2023 Revenue Requirements Application.

The BCUC also established conditions for inter-year and inter-program area transfers of BC Hydro's DSM expenditures.[33] In fiscal 2020 and fiscal 2021, no transfers between program areas were made or are anticipated to be made beyond the allowed levels. BC Hydro is also not anticipating any transfers from the previous test period to the current Test Period. Going forward, should BC Hydro determine that a transfer in excess of the allowed levels is warranted, BC Hydro will seek acceptance from the BCUC of the transfer.

32 Directive 47; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020).

33 Directive 51; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020).

Further information on BC Hydro's response to the BCUC's Directives on Demand-Side Management is provided in Chapter 10, section 10.2.2.

1.3.14 BC Hydro Has Requested a Reconsideration of Directives on Powerex Trade Income (Directive 17)

In its Decision on the Previous Application, the BCUC directed that no actual Powerex net income be captured in the Trade Income Deferral Account absent further review and approval by the BCUC.[34] On December 1, 2020, BC Hydro filed a reconsideration application in response to this directive.[35] In the reconsideration application, BC Hydro requests that the BCUC rescind and vary its directive so that BC Hydro can continue to record variances between forecast and actual Trade Income in the Trade Income Deferral Account and make a proposal for the disposition of any balance in the account from the fiscal 2020 to fiscal 2021 test period in this Application.[36] Further information is provided in Chapter 7, section 7.2.1.1.

1.4 Orders Sought

1.4.1 Permanent Rates

BC Hydro requests approval pursuant to sections 59 to 61 of the *Utilities Commission Act* to amend its rate schedules on a permanent basis as follows:

- A general rate increase of 1.16 per cent, effective April 1, 2021, for fiscal 2022 as set out in Appendix Y, Table 1; and
- Changes to BC Hydro's OATT rates, as set out in Chapter 9, Table 9-4 and Appendix Y, Table 2, effective April 1, 2021.

[34] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 17.

[35] Application to Reconsider and Vary Directives Relating to Powerex Net Income in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Decision (December 1, 2020).

[36] Application to Reconsider and Vary Directives Relating to Powerex Net Income in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Decision (December 1, 2020), page 6.

1.4.2 Interim Rates

As a final order will not be issued in this proceeding in time to implement permanent rates effective April 1, 2021, we request that the general rate increase of 1.16 per cent set out in Appendix Y, Table Y-1 of and the OATT rates set out in Chapter 9, Table 9-4 and Appendix Y, Table Y-2 of, be made effective April 1, 2021, on an interim basis pursuant to section 89 of the *Utilities Commission Act* and section 15 of the *Administrative Tribunals Act*.

1.4.3 Other Rate-Related Requests

BC Hydro also requests the following approvals:

- **Regulatory Accounts:** BC Hydro requests approval pursuant to sections 59 to 61 of the *Utilities Commission Act* to make the following changes to its regulatory accounts as set out in Chapter 7, section 7.2:
  - ► Recover the balances in the Cost of Energy Variance[37] Accounts through the Deferral Account Rate Rider (**DARR**) using the DARR table mechanism as described in Chapter 7, section 7.2.1.2; specifically, starting in fiscal 2022 and on an ongoing basis, set the DARR percentage effective April 1 of a given year based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year. Following this approach, the DARR percentage would be set at 0 per cent as of April 1, 2021 for fiscal 2022;
  - ► Defer the variances arising in fiscal 2022 as a result of any changes determined in the depreciation study to the Amortization of Capital Additions Regulatory Account, with interest charges and recovery of these amounts being on the same basis as previously approved for this account;

[37] For further information on the Cost of Energy Variance Accounts, refer to Chapter 7, section 7.2.1. Chapter 7, Table 7-3 of provides the balances of various accounts within the Cost of Energy Variance Accounts.

- Continue to defer any variances between forecast and actual dismantling costs in fiscal 2022 to the Dismantling Cost Regulatory Account; continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; continue to recover the forecast interest charged to the account each year from the account each year; and, continue to recover the forecast account balance at the end of a test period over the next test period;
- Recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in fiscal 2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and, recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period;
- Establish an Electric Vehicle Costs Regulatory Account to defer any actual operating costs, amortization, and cost of energy amounts related to electric vehicle charging stations that meet the definition of a prescribed undertaking under the GGRR for fiscal 2020 and fiscal 2021; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt and recover the forecast interest charged to the account each year from the account each year; and, starting in fiscal 2022, recover the forecast balance at the end of a test period over the next test period, until such time that the actual amounts deferred to the account for fiscal 2020 and fiscal 2021 are recovered in rates; and
- Close the Rock Bay Remediation Regulatory Account at the end of fiscal 2022;

- **Depreciation Rates at Burrard:** BC Hydro requests BCUC approval, pursuant to Sections 59-61 of the *Utilities Commission Act*, to set depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2022 as set out in Chapter 8, Table 8-2, and as described in Chapter 8, section 8.2.1;

- **Amortization of Infrastructure Rights Asset Class:** BC Hydro requests BCUC approval, pursuant to Sections 59-61 of the *Utilities Commission Act*, to amortize the assets within the infrastructure rights asset class over a 35-year useful life, as described in Chapter 8, section 8.2.2; and
- **DSM Expenditure Schedule:** BC Hydro requests acceptance pursuant to section 44.2 of the *Utilities Commission Act* of the proposed DSM expenditure schedule of $82.2 million, as set out in Chapter 10.

Chapter 2, section 2.4 provides a summary of the legislation and regulations applicable to the orders sought and the role of the BCUC within that framework. Draft interim and final orders are provided in Appendix B.

1.5 Overview of BC Hydro's Revenue Requirements

This section provides an overview of our revenue requirements for fiscal 2022 and shows the revenue shortfall that will result from the existing rates. BC Hydro requires a rate increase to generate the necessary revenues to provide safe and reliable service during the Test Period.

There are two ways to summarize BC Hydro's revenue requirements:

- **Gross View:** The Gross View shows the total costs for each component of the revenue requirements before any forecast transfers to/from regulatory accounts and then shows the regulatory account transfers as a separate total. In other words, "Gross View" shows the total costs *incurred* in fiscal 2022; and
- **Current View:** The Current View shows the total costs for each component of the revenue requirements after any forecast transfers to/from regulatory

accounts. In other words, the "Current View" shows the actual costs *being recovered from* customers in rates in fiscal 2022.

As was the case in previous revenue requirements applications, Appendix A contains the detailed financial schedules of our revenue requirements model and is intended to provide a single location for all costs contained in the Application. The working revenue requirements model that produces these schedules is also provided in electronic form as part of this filing. A reconciliation of the Gross View and the Current View for each component of the revenue requirements is provided in Schedule 3.0 of Appendix A.

Table 1–1 below shows BC Hydro's revenue requirements for fiscal 2022 from a Gross View.

Table 1–1 Gross View of BC Hydro's Revenue Requirements

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	**Cost of Energy**	1.0 L1	1,867.9	1,810.9	1,666.5	1,583.7	1,670.1
2	**Operating Costs**	1.0 L2	1,136.1	1,115.2	1,135.4	1,148.4	1,226.7
3	**Provisions & Other**	1.0 L3	116.4	176.8	95.4	197.9	101.4
4	**Taxes**	1.0 L4	249.8	249.7	262.2	254.8	263.8
5	**Amortization**	1.0 L5	977.8	977.7	998.0	996.6	1,023.7
6	**Finance Charges**	1.0 L6	874.9	1,656.8	743.3	951.5	555.6
7	**Return on Equity**	1.0 L7	712.0	704.9	712.0	690.7	712.0
8	**Miscellaneous Revenue**	1.0 L8	(240.6)	(247.3)	(247.0)	(243.7)	(255.4)
9	**Inter-Segment Revenue**	1.0 L9	(64.9)	(72.0)	(71.9)	(97.4)	(83.5)
10	**Deferral Account Transfers**	1.0 L13	(373.9)	(335.7)	(230.8)	(264.4)	16.2
11	**Other Regulatory Account Transfers**	1.0 L17	69.1	(729.1)	204.4	(137.3)	203.5
12	**Subsidiary Net Income**	1.0 L20	(179.7)	(192.7)	(179.9)	(176.2)	(192.1)
13	**Other Utilities Revenue**	1.0 L21	(36.1)	(29.7)	(35.9)	(30.2)	(30.2)
14	**Liquefied Natural Gas Revenue**	1.0 L22	(0.5)	(1.3)	0.0	0.0	0.0
15	**Deferral Rider Revenue**	1.0 L23	0.0	(0.2)	0.0	(0.0)	0.0
16	**Total Rate Revenue Requirement**	1.0 L24	5,108.1	5,084.0	5,051.6	4,874.3	5,211.7
17	**Less Revenue at F2021 Rates**	1.0 L29	(5,108.1)	(5,084.0)	(5,051.6)	(4,874.3)	(5,152.2)
18	**Revenue Shortfall**	1.0 L30	0.0	0.0	0.0	0.0	59.5
19	**Annualized Rate Increase**	1.0 L31	6.85%	6.85%	-1.62%	-1.62%	1.16%
20	**Deferral Account Rate Rider**	1.0 L32	0.00%	0.00%	0.00%	0.00%	0.00%
21	**Net Bill Increase**	1.0 L33	1.76%	1.76%	-1.62%	-1.62%	1.16%

Table 1–2 below provides an explanation of the difference between the fiscal 2021 RRA and the fiscal 2022 plan amounts, based on the Gross View. This provides a summary of the key differences between the revenue requirements in the Application and the revenue requirements approved by the BCUC in the Previous Application.

Table 1–2 Explanation of Differences Between Fiscal 2021 RRA and Fiscal 2022 Plan (Gross View)

Cost Component and References	Difference ($ million)	Explanation
Cost of Energy Chapter 4 Appendix A, Schedule 4.0	3.6	Cost of Energy is relatively consistent with the Previous Application. Heritage Energy Costs are increasing primarily due to increased Water Rentals costs. Non-Heritage Energy Costs are increasing primarily due to increased costs from existing Electricity Purchase Agreements. These increases are mostly offset by decreased Market Energy Costs as a result of lower forecast System Imports and higher forecast System Exports.
Operating Costs Chapter 5 Appendix A, Schedule 5.0	91.3	BC Hydro's operating costs are increasing primarily due to reliability investments in Mandatory Reliability Standards, vegetation management and cybersecurity, as well as uncontrollable cost pressures that are increasing due to changing market conditions. Other cost pressures have been largely offset by identified cost savings.
Provisions & Other Chapter 8, section 8.10 Appendix A, Schedule 5.01	6.0	Provisions and Other costs are relatively consistent with the Previous Application.
Taxes Chapter 8, section 8.5 Appendix A, Schedule 6.0	1.6	Taxes are relatively consistent with the Previous Application.
Amortization Chapter 8, section 8.2 Appendix A, Schedule 7.0	25.7	Amortization expense is increasing primarily due to capital additions.
Finance Charges Chapter 8, section 8.4 Appendix A, Schedule 8.0	(187.7)	Finance Charges are decreasing primarily due to lower interest rates.
Return on Equity Chapter 8, section 8.3 Appendix A, Schedule 9.0	0.0	BC Hydro continues to forecast its return on equity as a specific dollar amount of $712 million for fiscal 2022.
Miscellaneous Revenue Chapter 8, section 8.6 Appendix A, Schedule 15.0	(8.4)	Miscellaneous revenues are relatively consistent with the Previous Application.

Cost Component and References	Difference ($ million)	Explanation
Inter-Segment Revenue Chapter 8, section 8.7 Appendix A, Schedule 3.0	(11.6)	Inter-Segment revenues are increasing primarily due to an increase in the point-to-point transmission service rate under the OATT and higher transmission reservations.
Deferral Account Transfers Chapter 7 Appendix A, Schedule 2.1	247.0	Credit balances in the Cost of Energy Variance Accounts were refunded to ratepayers in fiscal 2020 and fiscal 2021, which resulted in lower deferral account transfers. In the Application, forecast deferral account transfers are increasing, primarily because this credit balance has now been refunded to ratepayers and is no longer offsetting transfers in the Test Period. The DARR percentage for fiscal 2022 is zero in accordance with the DARR table mechanism described in Chapter 7, section 7.2.1. As a result, there are no recoveries or refunds of the balances in the Cost of Energy Variance Accounts in the Test Period.
Other Regulatory Account Transfers Chapter 7 Appendix A, Schedule 2.2	(0.9)	Other Regulatory Account Transfers are largely unchanged as a result of mostly offsetting movements in a number of regulatory accounts, both increasing the balances (e.g., the Non-Current Pension Costs Regulatory Account due to lower discount rates) and decreasing the balances (e.g., the Total Finance Charges Regulatory Account due to lower interest rates).
Subsidiary Net Income Chapter 8, section 8.8 Appendix A, Schedule 1.0	(12.2)	The inclusion of subsidiary net income in BC Hydro's revenue requirements reduces the overall revenue requirements. Subsidiary net income includes Trade Income from BC Hydro's energy trading subsidiary Powerex as well as our subsidiary Powertech. Subsidiary net income is increasing, primarily due to an increase in the five-year average that is used to forecast Trade Income.
Other Utilities Revenue Appendix A, Schedule 14.0	5.7	Other utilities revenue is decreasing due to lower forecast Seattle City Light revenues in fiscal 2022.
Liquefied Natural Gas Revenue Appendix A, Schedule 14.0	0.0	In October 2018, the Government of B.C. removed a previous provision that prevented LNG customers from receiving service under BC Hydro's transmission rate schedules. This means that revenue from LNG customers is now recorded as general rate revenue and not as a separate line item.
Deferral Rider Revenue Appendix A, Schedule 14.0	0.0	In accordance with the DARR table mechanism described in Chapter 7, section 7.2.1.2, the DARR percentage for fiscal 2022 is 0 per cent which is unchanged from fiscal 2020 and fiscal 2021.

Table 1–3 below shows BC Hydro's revenue requirements for fiscal 2022 from a Current View.

Table 1–3 Current View of BC Hydro's Revenue Requirements

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	**Cost of Energy**	3.0 L19	1,634.8	1,552.5	1,537.7	1,376.0	1,670.1
2	**Operating Costs**	3.0 L25	1,195.8	1,207.6	1,226.7	1,253.2	1,357.2
3	**Provisions & Other**	3.0 L31	162.6	175.0	138.7	138.9	165.3
4	**Taxes**	3.0 L34	249.8	249.7	262.2	254.8	263.8
5	**Amortization**	3.0 L40	1,095.7	1,095.9	1,119.4	1,119.0	1,134.7
6	**Finance Charges**	3.0 L47	735.8	735.8	696.0	695.6	454.2
7	**Return on Equity**	3.0 L51	712.0	704.9	712.0	690.7	712.0
8	**Miscellaneous Revenue**	3.0 L56	(237.5)	(246.0)	(243.6)	(240.2)	(239.9)
9	**Inter-Segment Revenue**	3.0 L61	(64.9)	(72.0)	(71.9)	(97.4)	(83.5)
10	**Subsidiary Net Income**	3.0 L80	(339.2)	(288.2)	(289.7)	(286.0)	(192.1)
11	**Other Utilities Revenue**	3.0 L81	(36.1)	(29.7)	(35.9)	(30.2)	(30.2)
12	**Liquefied Natural Gas Revenue**	3.0 L82	(0.5)	(1.3)	0.0	0.0	0.0
13	**Deferral Rider Revenue**	3.0 L83	0.0	(0.2)	0.0	(0.0)	0.0
14	**Total Rate Revenue Requirement**	3.0 L84	5,108.1	5,084.0	5,051.6	4,874.3	5,211.7
15	**Less Revenue at F2021 Rates**	1.0 L29	(5,108.1)	(5,084.0)	(5,051.6)	(4,874.3)	(5,152.2)
16	**Revenue Shortfall**	1.0 L30	0.0	0.0	0.0	0.0	59.5
17	**Annualized Rate Increase**	1.0 L31	6.85%	6.85%	-1.62%	-1.62%	1.16%
18	**Deferral Account Rate Rider**	1.0 L32	0.00%	0.00%	0.00%	0.00%	0.00%
19	**Net Bill Increase**	1.0 L33	1.76%	1.76%	-1.62%	-1.62%	1.16%

Table 1–4 below provides an explanation of the difference between the fiscal 2021 RRA and the fiscal 2022 plan amounts, based on the Current View. This provides a summary of the key differences between the revenue requirements in this application and the revenue requirements approved by the BCUC in the Previous Application.

Table 1–4 Explanation of Differences Between Fiscal 2021 RRA and Fiscal 2022 Plan (Current View)

Cost Component and References	Difference ($ million)	Explanation
Cost of Energy Chapter 4 Appendix A, Schedule 4.0	132.4	Credit balances in the Cost of Energy Variance Accounts were refunded to ratepayers in fiscal 2020 and fiscal 2021, which resulted in lower cost of energy in fiscal 2021. In the Application, forecast cost of energy is increasing, primarily because this credit balance has now been refunded to ratepayers and is no longer offsetting the gross cost of energy in the Test Period. The DARR percentage for fiscal 2022 is zero in accordance with the DARR table mechanism described in Chapter 7, section 7.2.1.2. As a result, there are no recoveries or refunds of the balances in the Cost of Energy Variance Accounts in the Test Period.
Operating Costs Chapter 5 Appendix A, Schedule 5.0	130.5	BC Hydro’s operating costs are increasing primarily due to reliability investments in Mandatory Reliability Standards, vegetation management and cybersecurity, as well as uncontrollable cost pressures that are increasing due to changing market conditions. Other cost pressures have been largely offset by identified cost savings.
Provisions & Other Chapter 8, section 8.10 Appendix A, Schedule 5.01	26.6	Provisions and Other are increasing primarily due to higher regulatory account recoveries.
Taxes Chapter 8, section 8.5 Appendix A, Schedule 6.0	1.6	Taxes are relatively consistent with the Previous Application.
Amortization Chapter 8, section 8.2 Appendix A, Schedule 7.0	15.3	Amortization expense is increasing primarily due to capital additions.
Finance Charges Chapter 8, section 8.4 Appendix A, Schedule 8.0	(241.8)	Finance Charges are decreasing primarily due lower interest rates and the recovery of the credit balance in the Total Finance Charges Regulatory Account.
Return on Equity Chapter 8, section 8.3 Appendix A, Schedule 9.0	0.0	BC Hydro continues to forecast its return on equity as a specific dollar amount of $712 million for fiscal 2022.
Miscellaneous Revenue Chapter 8, section 8.6 Appendix A, Schedule 15.0	3.7	Miscellaneous revenues are relatively consistent with the Previous Application.

Cost Component and References	Difference ($ million)	Explanation
Inter-Segment Revenue Chapter 8, section 8.7 Appendix A, Schedule 3.0	(11.6)	Inter-Segment revenues are forecast to increase primarily due to an increase an increase in the point-to-point transmission service rate under the OATT and higher transmission reservations.
Subsidiary Net Income Chapter 8, section 8.8 Appendix A, Schedule 1.0	97.6	Credit balances in the Cost of Energy Variance Accounts were refunded to ratepayers in fiscal 2020 and fiscal 2021, which resulted in higher subsidiary net income in fiscal 2021. In the Application, subsidiary net income is decreasing because this credit balance has now been refunded to ratepayers.
Other Utilities Revenue Appendix A, Schedule 14.0	5.7	Other utilities revenue is decreasing due to lower forecast Seattle City Light revenues in fiscal 2022.
Liquefied Natural Gas Revenue Appendix A, Schedule 14.0	0.0	In October 2018, the Government of B.C. removed a previous provision that prevented LNG customers from receiving service under BC Hydro's transmission rate schedules. This means that revenue from LNG customers is now recorded as general rate revenue and not as a separate line item.
Deferral Rider Revenue Appendix A, Schedule 14.0	0.0	In accordance with the DARR table mechanism described in Chapter 7, section 7.2.1.2, the DARR percentage for fiscal 2022 is 0 per cent.

1.6 Communications

Communications regarding the Application should be directed to:

Fred James Chief Regulatory Officer BC Hydro 16th Floor 333 Dunsmuir Street Vancouver, BC V6B 5R3 Telephone: 604-623-4046 Fax: 604-623-4407 Email: bchydroregulatorygroup@bchydro.com	Matthew Ghikas Legal Counsel Fasken Martineau DuMoulin LLP 2900-550 Burrard Street Vancouver, BC V6C 0A3 Telephone: 604-631-3191 Fax: 604-631-3232 Email: mghikas@fasken.com	Christopher Bystrom Legal Counsel Fasken Martineau DuMoulin LLP 2900-550 Burrard Street Vancouver, BC V6C 0A3 Telephone: 604-631-4715 Fax: 604-631-3232 Email: cbystrom@fasken.com

BC Hydro Fiscal 2022

Revenue Requirements Application

Chapter 2

Legal and Regulatory Framework

Table of Contents

List of Tables

2.1 Introduction

This chapter provides an overview of the three statutes and specific regulations that will inform the BCUC's consideration of the approvals that BC Hydro is seeking in the Application. It also describes the prescribed undertakings carried out by BC Hydro under the Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**), including low carbon electrification infrastructure projects, low carbon electrification programs and electric vehicle charging stations.

This chapter is organized around the following key points:

- Section 2.2 explains that most provisions of the *Hydro and Power Authority Act*, the *Clean Energy Act*, and the *Utilities Commission Act* remain unchanged from when the Previous Application was filed. Where changes have occurred, there is either no direct effect on the BCUC's review of the Application or the effect is to continue, through legislation, certain provisions that already existed in Direction No. 8 to the BCUC;
- Section 2.3 summarizes the regulations relevant to BC Hydro's revenue requirements for the Test Period, including regulations that have become effective since the Previous Application was filed. In particular, this section provides a discussion of the impact of the GGRR on certain prescribed undertaking investments and expenditures incurred in fiscal 2020 and fiscal 2021, to be recovered in fiscal 2022 as well as expenditures planned for fiscal 2022; and
- Section 2.4 provides a summary of the BCUC's legal authority with regard to the approvals that BC Hydro is seeking in the Application.

2.2 Most Statutory Provisions Affecting BCUC Jurisdiction for Setting BC Hydro's Rates this Test Period Remain Unchanged

The Previous Application was the first application since changes to regulations that resulted in greater oversight of BC Hydro by the BCUC. In Chapter 2 of the Previous Application, BC Hydro provided a detailed overview of the legislation relevant to the review of BC Hydro’s revenue requirements. Most of those statutory provisions and regulations are still in force and applicable to the Application. As discussed in section 2.2.2 and section 2.2.3 below respectively, while there have been amendments to the *Utilities Commission Act* and the *Clean Energy Act* since the Previous Application was filed, these amendments essentially continue the effect of sections 5, 6, and 8 of Direction No. 8 to the BCUC that were in place when the BCUC reviewed the Previous Application.

2.2.1 The Hydro and Power Authority Act

The *Hydro and Power Authority Act* continues to mandate BC Hydro to generate, manufacture, conserve, supply, acquire and dispose of power and related products, and to supply and acquire related services.

BC Hydro acts as an agent of the Government of B.C. and reports to the Government through the Minister of Energy, Mines, and Low Carbon Innovation. The Minister of Finance is the fiscal agent of BC Hydro. The Lieutenant Governor in Council appoints BC Hydro’s Board of Directors and Chair. The Board is responsible for managing the affairs of BC Hydro or supervising the management of those affairs and may delegate its responsibilities to the President and Chief Executive Officer.

Section 32 (Application of other statues) of the *Hydro and Power Authority Act*, sets out, among other things, certain provisions of the *Utilities Commission Act* that are not applicable to BC Hydro, including section 52 (Restraint on disposition) of that Act. Section 32 was amended since the filing of the Previous Application to make section 44.1 (Long-term resource and conservation planning) of the *Utilities*

Commission Act applicable to BC Hydro. As a result, BC Hydro's demand-side measures now need to meet the adequacy requirements as set out in section 3 of the Demand-Side Measures Regulation. While this is a new requirement for BC Hydro, it does not change BC Hydro's Demand-Side Management (**DSM**) plan as it has been aligned with the adequacy requirements.[38] Chapter 10, section 10.4.1.4 sets out how BC Hydro's traditional demand-side measures for the Test Period align with the adequacy requirements set out in the Demand-Side Measures Regulation.

2.2.2 The Utilities Commission Act

Sections 59 to 61 of the *Utilities Commission Act* continue to provide the fundamental legal framework for the BCUC to review BC Hydro's revenue requirements and to set rates for fiscal 2022. These sections require the BCUC to consider factors prescribed in section 60(1)(b) of the *Utilities Commission Act*, including the setting of a rate that is not unjust or unreasonable within the meaning of section 59(5) of the Act, while still providing the BCUC with discretion in setting rates.

Section 44.2 (Expenditure schedule) and section 45 (Certificate of Public Convenience and Necessity) allow the BCUC to review BC Hydro's capital projects and associated expenditures and additions, unless the project is exempted from BCUC review by legislation or regulation. Whether the project has been or will be subject to a separate CPCN or section 44.2 application and process may influence the scope of BCUC review of the capital expenditures and additions in a revenue requirements application.[39] In Appendix I, BC Hydro identifies the projects exempted from regulation as well as the projects that may be subject to a separate section 44.2 or CPCN application. In the Application, BC Hydro is not seeking any

[38] Refer to page 141 of Order No. G-246-20.

[39] A more detailed description of the BCUC's jurisdiction and role in reviewing capital expenditures and additions is provided in Chapter 2 of the Previous Application.

approval under section 44.2 or section 45 of the *Utilities Commission Act* for any capital projects.

Section 44.2 (Expenditure schedule) also provides the BCUC with the authority to accept BC Hydro's demand-side measures expenditure schedule. In the Application, BC Hydro is seeking BCUC acceptance of its expenditures on demand-side measures that BC Hydro has made or anticipates making in fiscal 2022. Information on the proposed demand-side measures expenditure schedule is provided in Chapter 10.

Section 71 provides the BCUC with authority to review BC Hydro's Electricity Purchase Agreements. In the Application, BC Hydro is not seeking BCUC acceptance of any Electricity Purchase Agreements (**EPAs**). BC Hydro files separate applications pursuant to section 71 of the *Utilities Commission Act* seeking acceptance of any non-exempt EPAs that constitute energy supply contracts pursuant to section 68 of the *Utilities Commission Act*. The cost of energy associated with the EPAs is included in the revenue requirements for the Test Period. Further information on BC Hydro's EPAs is provided in Chapter 4, section 4.5.1.

Since the Previous Application was filed, there have been three additions to the *Utilities Commission Act*:

- Section 1(2), which states that the *Utilities Commission Act* does not apply to Powerex Corp. This change codified section 8 of Direction No. 8 to the BCUC as part of the *Utilities Commission Act*;
- Section 44.1 (2.1), which states that BC Hydro does not need to file a long-term resource plan before February 28, 2021. This addition follows the amendment to section 32 of the *Hydro and Power Authority Act* discussed above, which makes section 44.1 of the *Utilities Commission Act* applicable to BC Hydro; and

- Section 58.1, which states that the BCUC may not set rates for BC Hydro for the purpose of changing the revenue-cost ratio for a class of customers except on application by BC Hydro. This change codified section 5 of Direction No. 8 to the BCUC as part of the *Utilities Commission Act*.

2.2.3 The Clean Energy Act

Section 2 (British Columbia's energy objectives), section 7 (Exempt projects, programs, contracts and expenditures), section 8 (Rates), and section 18 (Greenhouse gas reduction) of the *Clean Energy Act* continue to have direct relevance to BC Hydro's revenue requirements.

- Section 2 lists British Columbia's energy objectives. When considering whether to accept BC Hydro's demand-side measures expenditure schedule, the BCUC is required, under section 44.2 of the *Utilities Commission Act*, to consider the applicable energy objectives. Section 10.4.1.2 of Chapter 10 provides a summary of how BC Hydro's proposed fiscal 2022 DSM expenditures continue to support the applicable energy objectives in the *Clean Energy Act*.
- Section 7 exempts various BC Hydro projects, programs, contracts and expenditures from BCUC review under sections 45 to 47 and 71 of the *Utilities Commission Act*. Section 8 requires the BCUC to ensure that BC Hydro collects sufficient revenue to recover the costs associated with these projects, programs, contracts and expenditures. Appendix I identifies the projects exempted under section 7 of the *Clean Energy Act*.
- Section 18 requires that the BCUC allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings. Prescribed undertakings are projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in British Columbia. A public utility that chooses to engage in prescribed undertakings is entitled to "recover its costs incurred with respect to the prescribed undertaking" in its rates, and the BCUC "must not exercise a power under the *Utilities Commission*

Act in a way that would directly or indirectly prevent [the] public utility … from carrying out a prescribed undertaking”.[40]

The GGRR issued under the *Clean Energy Act* sets out various classes of prescribed undertakings, including low carbon electrification infrastructure projects, low carbon electrification programs and expenditures, and electric vehicle charging stations. In section 2.3.2 below, BC Hydro provides information on how its low carbon electrification infrastructure projects, low carbon electrification programs, and electric vehicle charging stations meet the criteria of a prescribed undertaking.

There have been two changes to the *Clean Energy Act* since the Previous Application was filed:

- The concept of expenditures for export has been removed. This amendment continues the effect of section 6 of Direction No. 8 to the BCUC, which directed the BCUC to refrain from considering expenditures for export when setting BC Hydro’s rates; and
- The Government of B.C.’s authority to order BC Hydro to establish a feed-in tariff program has been removed. BC Hydro does not have a feed-in-tariff program so this removal has no effect.

2.3 Many Regulations Remain Effective and Relevant to this Application

Some regulations enacted under the *Utilities Commission Act*, the *Clean Energy Act* and other Acts that were discussed in the Previous Application continue to have an impact on the Application, while others that were relevant to the Previous Application have no impact on BC Hydro’s revenue requirements in the Test Period.

[40] *Clean Energy Act*, section 18(2) and section 18(3).

2.3.1 Summary of Regulations Impacting the Application

Table 2-1 below provides a summary of the regulations impacting the Application as well as regulations that were relevant to the Previous Application but have no impact on BC Hydro's revenue requirements in the Test Period.

Table 2-1 Summary of Regulations Relevant to this Application

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
New Regulations Since Filing of Fiscal 2020-Fiscal 2021 Revenue Requirements Application		
Direction to the BCUC Respecting COVID-19 Relief (B.C. Reg. 76/2020, amended by B.C. Reg. 137/2020)	This regulation requires the BCUC to approve or consent to various regulatory mechanisms relating to BC Hydro's implementation of COVID-19 customer relief programs, and to allow BC Hydro to recover costs for those programs. The regulation specifies that in setting rates, the BCUC must not disallow, for any reason, the recovery in rates of: • The balance of the Customer Crisis Fund Regulatory Account; and • Despite section 3(3) of the Direction to the BCUC Respecting Mining Customers, the balance of the Mining Customer Payment Plan Regulatory account.	BC Hydro's COVID-19 pandemic relief measures for residential and commercial customers are deferred to the Customer Crisis Fund Regulatory Account and the Mining Customer Payment Plan Regulatory Account, respectively. The total amount deferred related to these programs is set out in Chapter 7, section 7.5.
Direction to the BCUC Respecting the Biomass Energy Program (B.C. Reg. 71/2019)	This regulation prohibits the BCUC from exercising its power under section 71(1)(b) or (3) of the *Utilities Commission Act* with regard to energy supply contracts with seven specified biomass facilities. The regulation specifies that, in setting rates for BC Hydro, the BCUC may not disallow, for any reason, the recovery in rates of BC Hydro's costs with respect to these energy supply contracts.	The Biomass Energy Program Variance Regulatory Account captures all variances between forecast and actual amounts related to these seven energy supply contracts. The balance of the account is provided in Chapter 7, Table 7-3.

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**) (B.C. Reg. 102/2012, amended by Order in Council No. 339 dated June 22, 2020)	This regulation makes certain electrification infrastructure projects (subsection 4(2)) and electrification programs/projects (subsection 4(3)) prescribed undertakings for the purpose of section 18 of the *Clean Energy Act*. The regulation was amended in June 2020 to add eligible electric vehicle charging stations constructed or purchased and operated by a public utility as prescribed undertakings (subsection 5).	In section 2.3.2 below, BC Hydro provides information on how its low carbon electrification infrastructure projects, low carbon electrification programs, and electric vehicle charging stations meet the criteria of a prescribed undertaking under the GGRR. Under section 18 of the *Clean Energy Act*, the BCUC must set rates that allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings.
Direction No. 8 to the BCUC		
Section 3	This section requires the BCUC to ensure that BC Hydro collects sufficient revenue in fiscal 2020 and fiscal 2021 to achieve an annual rate of return on deemed equity that would yield a distributable surplus of $712 million.	BC Hydro's distributable surplus is no longer prescribed by Direction No. 8. BC Hydro plans to file a cost of capital application in fiscal 2022 to recommend an appropriate return on equity. In the interim, BC Hydro continues to forecast its return on equity in the Application to collect sufficient revenue to achieve an annual rate of return on deemed equity to yield a distributable surplus of $712 million for fiscal 2022. For further discussion, refer to Chapter 8, section 8.3.
Section 4	This section states that the BCUC must not disallow recovery in rates, for any reason, of: • The balance of BC Hydro's regulatory accounts as at March 31, 2019; • Costs incurred for the construction of extensions to BC Hydro's plant or system that came into service before fiscal 2017; • Costs incurred for energy supply contracts entered into before fiscal 2017; and • Debt servicing costs related to the Rate Smoothing Regulatory Account approved by Order No. G-48-14.	Information on BC Hydro's regulatory accounts is provided in Chapter 7. Information on BC Hydro's system extensions is provided in Chapter 6 and Appendix I. Information on BC Hydro's EPAs is provided in Chapter 4.

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Section 5	This section prohibits the BCUC from setting rates for the purpose of changing the revenue-cost ratio for a class of customers.	This section is now codified as section 58.1 of the *Utilities Commission Act*.
Section 6	This section states that the BCUC must not comply with section 4(5) of the *Clean Energy Act* (expenditures for export) when setting rates for fiscal 2020 and fiscal 2021.	Section 4(5) of the *Clean Energy Act* has now been rescinded.
Section 7	This section states that, except on application by BC Hydro, the BCUC must not set rates for BC Hydro that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers.	BC Hydro is not making any application relating to retail access in the Application.
Section 8	The section prohibits the BCUC from exercising any power under Part 3 of the *Utilities Commission Act* in regard to Powerex Corp.	This section is now codified as section 1(2) of the *Utilities Commission Act*.
Other Existing Regulations Applicable to the Application		
Demand-Side Measures Regulation (B.C. Reg. 326/2008)	This regulation sets out the requirements for a DSM portfolio to be considered adequate and for the demand side measures within that portfolio to be considered cost-effective.	BC Hydro's proposed DSM expenditure schedule meets the adequacy and cost-effectiveness requirements set out in the regulation. For further information, refer to Chapter 10, section 10.4.1.4 (adequacy) and section 10.4.1.5 (cost-effectiveness).
Direction No. 4 to the BCUC (B.C. Reg. 203/2013)	This regulation concerns the Meter Choices Program. It requires the BCUC to allow BC Hydro to collect sufficient revenue to recover the costs for the Meter Choices Program, which allows customers to retain or install legacy or radio-off meters instead of smart meters under certain conditions specified under BC Hydro's Electric Tariff. Standard charges relating to legacy meters and radio-off meters are also set out in the Electric Tariff.	In the Application, BC Hydro is not seeking to change any of the charges relating to legacy or radio-off meters. The costs of the Meter Choices Program are included in the forecast revenue requirements for the Test Period.

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Direction to the BCUC Respecting Mining Customer (B.C. Reg. 47/2016)	BC Hydro's Mining Customer Payment Plan (approved as Tariff Supplement No. 90) allows eligible mining customers to defer payment of a portion of their account under specified conditions. This regulation requires the BCUC to allow BC Hydro to establish a regulatory account for any impaired balances of participating mining customers. It also requires the BCUC to allow BC Hydro to recover the balance of this regulatory account in rates over a period determined by BC Hydro, after the closing date.	As discussed in Chapter 7, section 7.4, BC Hydro expects to propose a recovery mechanism for Mining Customer Payment Plan Regulatory Account in its next revenue requirements application.
Direction to the BCUC Respecting the Authority's TMP Program (B.C. Reg. 139/2015)	Under this regulation, the BCUC must not disallow, for any reason, the recovery in rates of the costs incurred by BC Hydro in carrying out the Thermo-Mechanical Pulp (**TMP**) program, subject to a $100 million cost recovery limit. The costs incurred as a result of carrying out the TMP program are deferred to the DSM Regulatory Account.	The TMP program is no longer active and no expenditures related to this program are included in BC Hydro's fiscal 2022 DSM expenditure schedule. The balance of the DSM Regulatory Account is amortized into rates over 15 years, on an ongoing basis.
Direction to the BCUC Respecting the Iskut Extension Project (B.C. Reg. 137/2013, amended by B.C. Reg. 24/2019)	This regulation exempts the Iskut Extension Project from the CPCN requirement under the *Utilities Commission Act*. It also requires the BCUC, when setting rates, to allow BC Hydro to collect sufficient revenue to recover its costs incurred in relation to the project, including costs incurred for negotiating, entering into and carrying out agreements with First Nations.	The project was completed in March 2020 with a final cost of $110 million now being amortized into rates.

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Direction to the BCUC Respecting Undertaking Costs (B.C. Reg. 77/2017)	This regulation requires the BCUC to allow BC Hydro to defer to the DSM Regulatory Account its costs for implementing the prescribed undertaking programs under section 4(3)(a), (b), (c) or (d) of the GGRR.	The prescribed undertaking programs meeting the requirements of those subsections of the GGRR are discussed in Chapter 10, section 10.4.2 of and Appendix N. In accordance with Directive 48 of the BCUC's Decision on the Previous Application,[41] the balance of low-carbon electrification expenditures in the DSM Regulatory Account, for the Test Period, is provided in Appendix A, Schedule 2.2.
Electricity Self-Sufficiency Regulation (B.C. Reg. 315/2010)	For the purpose of the definition of "electricity supply obligations" and "heritage energy capability" in section 6(1) of the *Clean Energy Act*, this regulation specifies that they are to be determined based on the mid-level load forecasts and the maximum amount of annual energy generated under average water conditions.	Information on the load forecast is provided in Chapter 3. Information on the cost of energy, including cost of Heritage Energy, is provided in Chapter 4.
Remote Communities Regulation (B.C. Reg. 240/2007)	This regulation requires BC Hydro to provide services to specified remote communities.	Under Special Direction No. 10 to the BCUC, BC Hydro is allowed to recover costs for providing service to those remote communities. The costs of providing this service are included in the Test Period revenue requirements.
Shore Power Regulation (B.C. Reg. 291/2008)	This regulation encourages operators of cruise ships docked at Canada Place wharf in Vancouver to use port electricity instead of on-board, diesel-generated electricity. In setting the rate for shore power service, the BCUC must ensure that the rate allows BC Hydro to collect sufficient revenue to recover the costs incurred as a result of providing that service.	BC Hydro's shore power rates for fiscal 2022 are set out in Appendix Y.

[41] Directive 48 of the BCUC's Decision on the Previous Application approved BC Hydro's request to defer low-carbon electrification expenditures up to the undertaking costs to the DSM Regulatory Account and directed BC Hydro to separately track these expenditures in the DSM Regulatory Account.

Name of the Regulation	Purpose/Description of the Regulation	Impact on the Application
Special Direction – B.C. Hydro No. 2 Regulation (B.C. Reg. 390/85)	This regulation concerns the Skagit Agreement between the Government of B.C. and the City of Seattle and subsequently assigned by the Government of B.C. to BC Hydro. It requires the BCUC to consider all payments related to the assignment as revenue to BC Hydro.	Volumes delivered to, and the related revenues received from, Seattle City Light, which is the electricity provider for the City of Seattle, are recorded as domestic revenue as Other Sector revenue as shown in Appendix A, Schedule 14, line 19.
Special Direction No. 10 to the BCUC (B.C. Reg. 245/2007)	This regulation, among other things, requires that the BCUC ensure that BC Hydro collects sufficient revenue in each fiscal year to recover costs related to providing service under the Remote Communities Regulation.	The costs related to serving the 11 remote communities specified in the Remote Communities Regulation are included in the revenue requirements for the Test Period.
Transmission Upgrade Exemption Regulation (B.C. Reg. 140/2013)	The regulation exempts the following projects from Part 3 of the *Utilities Commission Act*: • A series capacitor station and related facilities and equipment in the vicinity of the District of Vanderhoof, the Village of Burns Lake and the Village of Telkwa; • Various upgrades and additions at the Skeena and Minette substations; and • Construction, operation, upgrades or extensions, reasonably expected to come into service before October 1, 2025, to provide service to an LNG facility in the vicinity of the District of Kitimat and to provide service to facilities necessary for the construction of that LNG facility.	In its Decision on the Previous Application, the BCUC confirmed that the Minette to LNG Canada Interconnection Project is an exempted project under this regulation. The forecast capital expenditures for this project for the Test Period is shown in Appendix I.

2.3.2 BC Hydro’s Prescribed Undertakings under the GGRR

The GGRR was issued in 2012 and has been amended twice: once in 2017 to add new classes of prescribed undertakings for electrification infrastructure projects and electrification programs (section 4 of the GGRR), and again in 2020 to add a new class of prescribed undertakings for electric vehicle charging stations (section 5 of the GGRR). Under section 18 of the *Clean Energy Act*, the BCUC must set rates that allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings.

The prescribed undertakings carried out by BC Hydro fall into three classes, each of which is discussed further below:

- Low carbon electrification infrastructure projects under sections 4(2) and 4(3)(e) of the GGRR;
- Low carbon electrification programs under sections 4(3)(a)(i); 4(3)(a)(ii); 4(3)(b)(i); 4(3)(b)(ii); 4(3)(c) and 4(3)(d) of the GGRR; and
- Electric vehicle charging stations under section 5 of the GGRR.

2.3.2.1 Low Carbon Electrification Infrastructure Projects

Currently, the Peace Region Electric Supply project is the only low carbon electrification infrastructure project that BC Hydro is implementing as a prescribed undertaking under section 4(2) of the GGRR. In its Decision on the Previous Application, the BCUC found that the project meets the definition of a prescribed undertaking under section 4(2) of the GGRR. The nature of the project has not changed since the Previous Application, and the planned in-service date for the project continues to be before December 31, 2022.

In the Previous Application, BC Hydro identified the Bear Mountain Terminal to Dawson Creek Transmission Voltage Conversion project and the North Montney – Transmission Development Project as potential prescribed undertaking projects. Based on current project information and the criteria set out in the GGRR, BC Hydro does not currently expect these projects to qualify as prescribed undertakings because, at this time, neither project would reasonably be expected to be in service by December 31, 2022. Further information on these two projects is provided in Chapter 6, section 6.4.2.1.

2.3.2.2 Low Carbon Electrification Programs

BC Hydro’s low carbon electrification programs fall into two categories: (i) initial projects introduced in fiscal 2018 to enable and support low carbon electrification opportunities among BC Hydro’s customers, and (ii) a multi-year BC Hydro funded low carbon electrification program developed in fiscal 2019. BC Hydro continues to carry out programs in those two categories and our planned low-carbon electrification activities for fiscal 2022 are similar to those described in the Previous Application. In its Decision on the Previous Application, the BCUC accepted that expenditures for low carbon electrification projects/programs are prescribed undertakings under section 4(2)(a) to (d) of the GGRR.[42] Further information on low carbon electrification projects/programs for fiscal 2022 is provided in Chapter 10, section 10.3.2.4 and section 10.4.2 and Appendix N.

2.3.2.3 Electric Vehicle Charging Stations

Section 5(2) of the GGRR sets out criteria that qualify an electric vehicle charging station as a prescribed undertaking for the purposes of section 18 of the *Clean Energy Act*:

> (2) A public utility's undertaking that is in a class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:
>
> (a) the public utility constructs and operates, or purchases and operates, an eligible charging station;
>
> (b) the public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that
>
> (i) the station will come into operation by December 31, 2025, and
>
> (ii) if the station will be located in a limited municipality, the number of eligible charging sites in the municipality on the date the station will come into operation will not exceed the site limit for the municipality on that date;
>
> (c) if an eligible charging station comes into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.

Section 5(1) further defines a few terms used in section 5(2). An “eligible charging station” is a fast charging station (i.e., a fixed device capable of charging an electric vehicle using a direct current) that:

(a) Is available for use 24-hours a day by any member of the public;

[42] Refer to page 150 of Order No. G-246-20.

(b) Does not require users to be members of a charging network; and

(c) Is capable of charging electric vehicles of more than one make.

A "limited municipality" is defined as a municipality with a population of 9,000 or more, and "site limit", in relation to a limited municipality, is the number calculated by dividing the population of the municipality by 9,000, and if applicable, rounding the quotient up to the nearest whole number.

Section 5 of the GGRR came into effect after the evidentiary phase for the Previous Application was closed. Therefore, BC Hydro did not have the opportunity in that proceeding to provide information that its electric vehicle charging stations were prescribed undertakings under section 5 of the GGRR. In its Decision on the Previous Application, the BCUC encouraged BC Hydro to apply for recovery of "any of its prior, current or future electric vehicle capital expenditures considered as possible prescribed undertakings under the GGRR".[43]

As discussed in Chapter 7, section 7.2.5, BC Hydro is seeking to establish an Electric Vehicle Costs Regulatory Account to recover, in the Test Period, its fiscal 2020 and fiscal 2021 costs related to electric vehicle charging stations that are prescribed undertakings. For fiscal 2022, costs with respect to the prescribed undertakings are included in the revenue requirements in the categories of cost to which they relate. The discussion below, together with Appendix C, provides information on BC Hydro's electric vehicle charging stations that meet the requirements of a prescribed undertaking under section 5 of the GGRR.

[43] Refer to page 94 of Order No. G-246-20.

Eligible Electric Vehicle Charging Stations for Fiscal 2020 and Fiscal 2021

At the beginning of fiscal 2020, BC Hydro had 59 fast charging stations[44] in operation across the province. During fiscal 2020 and fiscal 2021, BC Hydro put into operation, or reasonably expects to put into operation, an additional 43 fast charging stations, while decommissioning four stations,[45] resulting in a total of 98 fast charging stations in operation at the end of fiscal 2021.

Two of BC Hydro's fast charging stations do not meet the definition of an "eligible charging stations": one station at the Langley Event Centre and one station at Powertech Labs in Surrey (which is also one of the four decommissioned stations identified above and will be decommissioned in March 2021). These two stations are not eligible charging stations because they are not available for use by the public 24-hours a day. For fiscal 2020 and fiscal 2021, BC Hydro is not seeking recovery of the costs related to these two fast charging stations.

During fiscal 2020 and fiscal 2021, there are 100 fast charging stations, including three that have been decommissioned (Uptown Saanich Mall, Surrey Central City Hall, and Penticton), that meet the definition of an "eligible charging station" under the GGRR, because they:

(a) Are available for use 24-hours a day by any member of the public;

(b) Do not require users to be members of a charging network; and

(c) Are capable of charging electric vehicles of more than one make.

[44] BC Hydro has four Level 2 charging stations at Britton Creek, Ucluelet, Rogers Pass, and Field. BC Hydro is not seeking cost recovery for those four Level 2 charging stations because they are not capable of charging an electric vehicle using a direct current and thus are not "fast charging stations" as defined in section 5 of the GGRR.

[45] The four stations decommissioned are at the following locations: Uptown Saanich Mall (March 20, 2020), Surrey Central City Hall (September 30, 2020), Penticton (October 1, 2020), and Powertech Labs (March 31, 2021).

BC Hydro constructs and operates, or purchases and operates, the eligible charging stations.[46] While BC Hydro currently leases certain charging equipment at nine eligible charging stations to a private entity or municipality that provides the site for the equipment as noted in Appendix C-1, Column Q, BC Hydro continues to be the public utility that operates the charging stations and provides service to the public under these equipment leases, because:

- The charging stations are labeled or identified as BC Hydro's stations;
- The service number on the charging stations is directed to BC Hydro's contact centre;
- The stations are at locations determined and approved by BC Hydro;
- The station consumption is separately metered, and BC Hydro is entitled to collect and analyze meter data; and
- BC Hydro has the ability to remotely control the equipment load by working with the equipment lessee.

Site Limit in Limited Municipalities

Section 5(2)(b) of the GGRR focuses on "eligible charging sites", which is defined as a site "where one or more eligible charging stations are located", in a "limited municipality". BC Hydro has eligible charging sites in limited municipalities, and for these municipalities, the site limit calculated in accordance with the GGRR is applicable. For the purposes of this calculation:

- The site limit is "in relation to a limited municipality". Therefore, there is a limitation on sites only if a municipality meets the definition of a "limited municipality" (i.e., having a population of 9,000 or more);

[46] There are eight stations, noted in Appendix C-1, Column Q, that were constructed by the Community Energy Association. The ownership of those stations was turned over to BC Hydro to operate once construction was completed.

- While the number of eligible charging sites must not exceed the site limit, the number of charging stations on an eligible charging site is not limited. An eligible charging site may have multiple charging stations;
- All eligible charging sites located in a limited municipality and operated by any public utility (i.e., not just by BC Hydro) are counted against the site limit in a limited municipality. If BC Hydro decides to add a charging station on a pre-existing site operated by any public utility, this would not increase the total eligible charging site number in the limited municipality; and
- The time to determine whether the applicable site limit is exceeded is "on the date the public utility decides to construct or purchase an eligible charging station." That is, in deciding whether to construct or purchase an eligible charging station, the public utility needs to consider at that time whether "the number of eligible charging sites in the municipality on the date the station will come into operation [exceeds] the site limit for the municipality on that date." If, at the time when the charging station actually comes into operation (i.e., when it is available for the public to use for charging electric vehicles) on a new site, the number of the sites in the limited municipality exceeds the limit, the charging station can still be a prescribed understating as long as the other criteria were met.

Table 2-2 below lists the limited municipalities, their respective population, the site limits for a limited municipality, the number of BC Hydro sites in those municipalities, and the number of sites operated by other public utilities. None of the applicable site limits is exceeded.

Table 2-2 Electric Vehicle Charging Sites in Limited Municipalities[47]

Limited Municipality	Population	Site Limit (Population / 9,000)	Number of BC Hydro Sites*	Other Charging Sites Operated by the Public Utilities in Limited Municipality	
				As of ISD (of BC Hydro Sites)	As of Oct 31, 2020
Abbotsford	158,457	18	1	0	2
Campbell River	35,849	4	1	0	0
Chilliwack	94,534	11	1	0	0
Colwood	18,867	2	1	0	0
Coquitlam	149,894	17	2	0	0
Courtenay	28,216	3	1	0	0
Cranbrook	21,247	2	1	0	0
Dawson Creek	12,981	1	1	0	0
Delta	109,490	12	1	0	0
Fort St. John	21,976	2	1	0	0
Kamloops	100,046	11	1	0	2
Langley, District Municipality	130,924	15	1	0	3
Mission	43,202	5	1	0	0
Nanaimo	99,856	11	2	0	1
North Vancouver, City of	57,325	6	1	0	2
Penticton	36,425	4	0	0	1
Port Alberni	18,751	2	1	0	0
Powell River	13,829	2	1	0	0
Prince George	81,345	9	1	0	0
Qualicum Beach	9,166	1	1	0	0
Quesnel	10,392	1	1	0	0
Richmond	212,276	24	1	1	1
Saanich	122,173	14	1	0	1
Salmon Arm	19,115	2	1	0	0
Sechelt District Municipality	10,809	1	1	0	0

47 The population estimates for 2019 are provided by BC Stats. In some instances, data from Statistics Canada for the census year 2016 was used as data from BC Stats was unavailable. The information on other utilities' charging sites is sourced from Plughshare.com or from Natural Resources Canada (**NRCan**), combined with information sourced internally regarding in-service dates, and may be subject to change.

Limited Municipality	Population	Site Limit (Population / 9,000)	Number of BC Hydro Sites*	Other Charging Sites Operated by the Public Utilities in Limited Municipality	
Sidney	12,235	1	1	0	0
Squamish	20,404	2	1	0	1
Surrey	584,526	65	3	3	3
Vancouver	685,885	76	5	2	7
Vernon	43,315	5	1	0	0
Victoria	94,005	10	1	0	1
West Kelowna	35,818	4	1	0	0
West Vancouver	43,945	5	1	0	0
Whistler	13,763	2	1	0	0
Williams Lake	11,359	1	1	0	0

* This does not include sites where the stations are decommissioned or to be decommissioned by the end of fiscal 2021. Including the sites where the decommissioned stations were located (Surrey, Saanich, and Penticton) does not exceed the site limit for those limited municipalities.

Appendix C-2 (Eligible Charging Stations for Cost Recovery Fiscal 2020 and Fiscal 2021) provides a summary of how BC Hydro's fast charging stations in operation during fiscal 2020 and fiscal 2021 (including decommissioned stations which were operating during part of this period) meet each applicable criterion of a prescribed undertaking under section 5 of the GGRR. Under section 18 of the *Clean Energy Act*, BC Hydro is allowed to recover in rates its costs incurred with respect to the prescribed undertaking. BC Hydro is seeking to establish an Electric Vehicle Costs Regulatory Account to facilitate the recovery in fiscal 2022 of its fiscal 2020 and fiscal 2021 costs related to electric vehicle charging stations that are prescribed undertakings. Further information on this request is provided in Chapter 7, section 7.2.5.

Eligible Electric Vehicle Charging Stations for Fiscal 2022

In fiscal 2022, BC Hydro continues to operate the 98 fast charging stations discussed above. All those stations are, or continue to be, "eligible charging stations" as defined in the GGRR because they:

(a) Are available for use 24-hours a day by any member of the public;

(b) Do not require users to be members of a charging network; and

(c) Are capable of charging electric vehicles of more than one make.

While it was not an eligible charging station in fiscal 2020 and fiscal 2021, the site at Langley Events Center will be modified[48] so that the public can use the fast charging station at that site 24-hours a day in fiscal 2022 and onward. This will make the station an eligible charging station in fiscal 2022 and onward.

During fiscal 2022, BC Hydro reasonably expects to construct and operate 57 new fast charging stations, 26 of which will be at existing sites and 31 of which will be at 16 new sites. All of these new stations will be eligible charging stations because they will be available for use 24-hours a day by any member of the public, will not require users to be members of a charging network, and will be capable of charging electric vehicles of more than one make.

Five new sites will be in limited municipalities: Burnaby, Maple Ridge, Prince Rupert, Surrey, and Terrace. As shown in Table 2-3 below, the number of charging sites in those municipalities will not exceed the site limit for the limited municipality on the date that BC Hydro reasonably expects the eligible charging stations on these sites to come into operation.

[48] This is scheduled to be done before the end of fiscal 2021.

Table 2-3 Electric Vehicle Charging Sites in Limited Municipalities (new sites for fiscal 2022)

Limited Municipality	Population	Site Limit (Population / 9,000)	Number of BC Hydro Sites	Other Charging Sites Operated by the Public Utilities in Limited Municipality	
				As of ISD (of BC Hydro Sites)	As of Oct 31, 2020
Burnaby	253,007	28	1	0	0
Maple Ridge	91,222	10	1	0	0
Prince Rupert	13,054	1	1	0	0
Surrey*	584,526	65	4	6	3
Terrace	12,594	1	1	0	0

* A new station will be constructed at a new site of Powertech Labs, which will be accessible to the public 24-hours a day.

Appendix C-3 provides a summary of how BC Hydro's 57 new fast charging stations planned for fiscal 2022 meet the definition of a prescribed undertaking under section 5 of the GGRR. As discussed above, Appendix C-2 provides a summary of how BC Hydro's existing 98 fast charging stations, which BC Hydro will continue to operate in fiscal 2022 meet the definition of a prescribed undertaking under section 5 of the GGRR.

Under section 18 of the *Clean Energy Act*, the BCUC must set rates that allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings. Accordingly, for the Test Period, costs with respect these 155 eligible charging stations are included in the revenue requirements in the categories of cost to which they relate.

2.4 Summary of Legal Authority for Orders Sought

The approvals that BC Hydro is seeking in the Application are set out in Chapter 1, section 1.4. Table 2-4 below provides a summary of these requests as well as the applicable legislation and regulations and the role of the BCUC within that framework.

Table 2-4 Summary Approvals Sought and Legal/Regulatory Framework

Approvals Sought	Applicable Legislation and Regulations	BCUC's Role
Approving a general rate increase of 1.16 per cent, effective April 1, 2021. Tariff rates reflecting this general rate increase are set out in Appendix Y, Table Y-1.	Sections 59-61 of the *Utilities Commission Act*	The BCUC must approve rates that are just and reasonable, with reference to BC Hydro's forecast revenue requirements. BC Hydro's forecast revenue requirements reflect a variety of other legislative and regulatory requirements as discussed in this chapter.
With regard to regulatory accounts, seeking BCUC approval to: • Recover the balances in the Cost of Energy Variance Accounts[49] through the Deferral Account Rate Rider (**DARR**) using the DARR table mechanism as described in Chapter 7, section 7.2.1.2; specifically, starting in fiscal 2022 and on an ongoing basis, set the DARR percentage effective April 1 of a given year based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year. Following this approach, the DARR percentage would be set at 0 per cent as of April 1, 2021 and for fiscal 2022. • Defer the variances arising in fiscal 2022 as a result of any changes determined in the depreciation study to the Amortization of Capital Additions Regulatory Account, with interest charges and recovery of these amounts being on the same basis as previously approved for this account; • Continue to defer any variances between forecast and actual dismantling costs in fiscal 2022 to the Dismantling Cost Regulatory Account; continue to apply interest to the balance of the account	Sections 59-61 of the *Utilities Commission Act*	The BCUC has the power to direct that certain components of the forecast revenue requirements be deferred by recording the amount in a regulatory account for future recovery. The approved rates/revenue requirements must reflect reasonable amortization expense from previously deferred amounts.

49 For further information on the Cost of Energy Variance Accounts, refer to Chapter 7, section 7.2.1. Chapter 7, Table 7-3 of provides the balances of various accounts within the Cost of Energy Variance Accounts.

Approvals Sought	Applicable Legislation and Regulations	BCUC's Role
each year based on BC Hydro's current weighted average cost of debt; continue to recover the forecast interest charged to the account each year from the account each year; and, continue to recover the forecast account balance at the end of a test period over the next test period; • Recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in fiscal 2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and, recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period; • Establish an Electric Vehicle Costs Regulatory Account to defer any actual operating costs, amortization, and cost of energy amounts related to electric vehicle charging stations that meet the definition of a prescribed undertaking under the GGRR for fiscal 2020 and fiscal 2021; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt and recover the forecast interest charged to the account each year from the account each year; and, starting in fiscal 2022, recover the forecast balance at the end of a test period over the next test period, until such time that the actual amounts deferred to the account for fiscal 2020 and fiscal 2021 are recovered in rates; and • Close the Rock Bay Remediation Regulatory Account at the end of fiscal 2022. For more information on these requests, refer to Chapter 7, section 7.2.		

Approvals Sought	Applicable Legislation and Regulations	BCUC's Role
Setting depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2022 as set out in Chapter 8, Table 8-2. For more information on this request, refer to Chapter 8, section 8.2.1.	Sections 59-61 of the *Utilities Commission Act*	The BCUC must set proper and adequate rates of depreciation.
Amortizing the assets within the infrastructure rights asset class over a 35-year useful life. For more information on this request, refer to Chapter 8, section 8.2.2.	Sections 59-61 of the *Utilities Commission Act*	The BCUC must set proper and adequate rates of depreciation.
Setting Open Access Transmission Tariff rates, as set out in Chapter 9, Table 9-4, effective April 1, 2021. For further information on this request, refer to Chapter 9.	Sections 59-61 of the *Utilities Commission Act*	The BCUC must approve rates that are just and reasonable, with reference to BC Hydro's forecast revenue requirements. BC Hydro's forecast revenue requirements reflect a variety of other legislative and regulatory requirements as discussed in this chapter.
Accepting the requested DSM expenditure schedule of $82.2 million for fiscal 2022. For further information on this request, refer to Chapter 10.	Section 44.2 of the *Utilities Commission Act* Section 2 of the *Clean Energy Act* Demand-Side Measures Regulation	The BCUC must accept the schedule if it considers that making the expenditures would be in the public interest. The public interest inquiry includes consideration of "British Columbia's energy objectives" under section 2 of the *Clean Energy Act*. Alternatively, the BCUC may reject the schedule or reject a part of the schedule. However, section 44.2 does not provide the BCUC with the authority to direct BC Hydro to file a DSM expenditure schedule, make additions to a DSM expenditure schedule, or change the design of a particular DSM program.

BC Hydro Fiscal 2022
Revenue Requirements Application

Chapter 3

Load and Revenue Forecast

Table of Contents

List of Figures

List of Tables

3.1 Introduction

This chapter provides our Load Forecast[50] and associated Revenue Forecast.

BC Hydro prepared a comprehensive 20-year load forecast (the March 2020 Load Forecast) over the winter of 2019 and spring of 2020. The March 2020 Load Forecast was completed prior to the onset of impacts associated with the COVID-19 pandemic. To address those potential impacts, BC Hydro quickly developed two scenarios in April 2020 that were used to inform decisions based on two potential outcomes. The sales projection for fiscal 2022 from one of those scenarios (referred to as "**Scenario A**") is used in the calculation of the Test Period revenue requirements in the Application. As of November 2020, two-thirds of the way through fiscal 2021, actual total domestic sales were 1.2 per cent higher than COVID-19 Scenario A for the three main customer classes on an accrued sales basis. Given this performance, we believe that Scenario A is appropriate for the purpose of forecasting revenue to set rates for the Test Period. That said, significant uncertainty and risk remains regarding the ongoing impacts of the COVID-19 pandemic on actual domestic sales.

Overall, BC Hydro is projecting lower electricity sales in the Test Period relative to the forecasted sales included in the Fiscal 2020 - Fiscal 2021 Revenue Requirements Application (**Previous Application**).

This Chapter is organized around the following key points:

- Section 3.2 explains how we improved the methodology used to create a 20-year load forecast in March 2020 and have accounted for the impacts of the COVID-19 pandemic through the development of scenarios;

[50] For the purposes of the Application, the terms "load forecast" and "electricity sales" are used interchangeably. COVID-19 Scenario A was approved for the purpose of establishing the electricity sales forecast for use in the Application.

- Section 3.3 presents the results of the load forecast and COVID-19 scenarios by customer sector. COVID-19 Scenario A, which is the basis for the Application, has closely tracked actual total domestic sales in fiscal 2021; and
- Section 3.4 presents the results of the Test Period Revenue Forecast by customer sector. The Revenue Forecast is a straightforward calculation, relative to the preparation of the Load Forecast, and the methodology is unchanged from the Previous Application.

3.2 BC Hydro Load Forecast Methodology

This section describes the improvements to the methodology used to develop the March 2020 Load Forecast, and how we accounted for impacts of the COVID-19 pandemic through the development of scenarios. A more detailed summary of our load forecast methodology is provided in Appendix D of the Application.

3.2.1 We Continue to Improve Our Load Forecasting Methodology

BC Hydro is committed to continuous improvement and we frequently review and update our load forecast methodology. The following sub-sections outline the methodological changes made since BC Hydro's October 2018 Load Forecast which was the basis for the Previous Application.

3.2.1.1 Codes and Standards

As discussed in Appendix D, section 5, our methodology includes adjustments to account for the overlap between savings included in BC Hydro's Statistically Adjusted End Use (**SAE**) model results and savings derived from BC Hydro's Demand-Side Management (**DSM**) Plan. This overlap results because of energy savings from codes and standards that are reflected in both our DSM plan and in the U.S. Energy Information Administration (**EIA**) assumptions embedded in the SAE model.

In 2019, Navigant Inc. completed an independent review of the overlap in codes and standards in the EIA projections with those within BC Hydro's DSM plan. The review distinguished codes and standards set out by legislation in British Columbia provincially and Canada federally (which are reflected in BC Hydro's DSM plan) with U.S. federal codes and standards that form the basis of the EIA projections, which are reflected in the SAE model. The review determined that there were some end use technologies that appeared in both the SAE model and the DSM plan. Accordingly, the March 2020 Load Forecast has been adjusted to improve alignment between the two approaches.

3.2.1.2 Electric Vehicles

The March 2020 Load Forecast uses a new methodology for Electric Vehicles (**EVs**), relative to the October 2018 methodology. This change was implemented to reflect the CleanBC Plan's approach to light-duty EVs; specifically, to incorporate the *Zero-Emission Vehicles Act* (**ZEV Act**), which was enacted on May 30, 2019. The ZEV Act stipulates percentage targets for new light-duty vehicle sales in B.C. that must have zero emissions, as follows: 10 per cent of sales by 2025; 30 per cent of sales by 2030; and 100 per cent of sales by 2040. Accordingly, the low-EV scenario in the March 2020 Load Forecast uses these requirements as a floor for EV adoption. In contrast, the high-EV scenario assumes the natural uptake of EVs will be higher than the minimum requirements set out in the ZEV Act, as the purchase costs decline, and consumers' preferences change over time. Due to the significant level of uncertainty when developing a long-term EV forecast, BC Hydro developed its reference EV forecast by taking the average of the high and low EV forecasts.

3.2.1.3 Uncertainty Bands

The large industrial sector presents a significant source of uncertainty because the start up or closure of even a single industrial transmission customer can influence load by as much as 1,000 GWh per year. In the October 2018 Load Forecast and prior, BC Hydro used a Monte Carlo model to develop uncertainty bands around the combined distribution and transmission forecasts, and then added the discrete EV high, reference, and low forecasts. An improvement in the March 2020 Load

Forecast was to use the Monte Carlo model to develop the uncertainty bands around the distribution load only and use discrete high and low cases for transmission load, to fully capture the load variability within the large industrial sector. Figure 3-1 and Figure 3-2 illustrate the two methodologies.

Figure 3-1 October 2018 Uncertainty Band Methodology

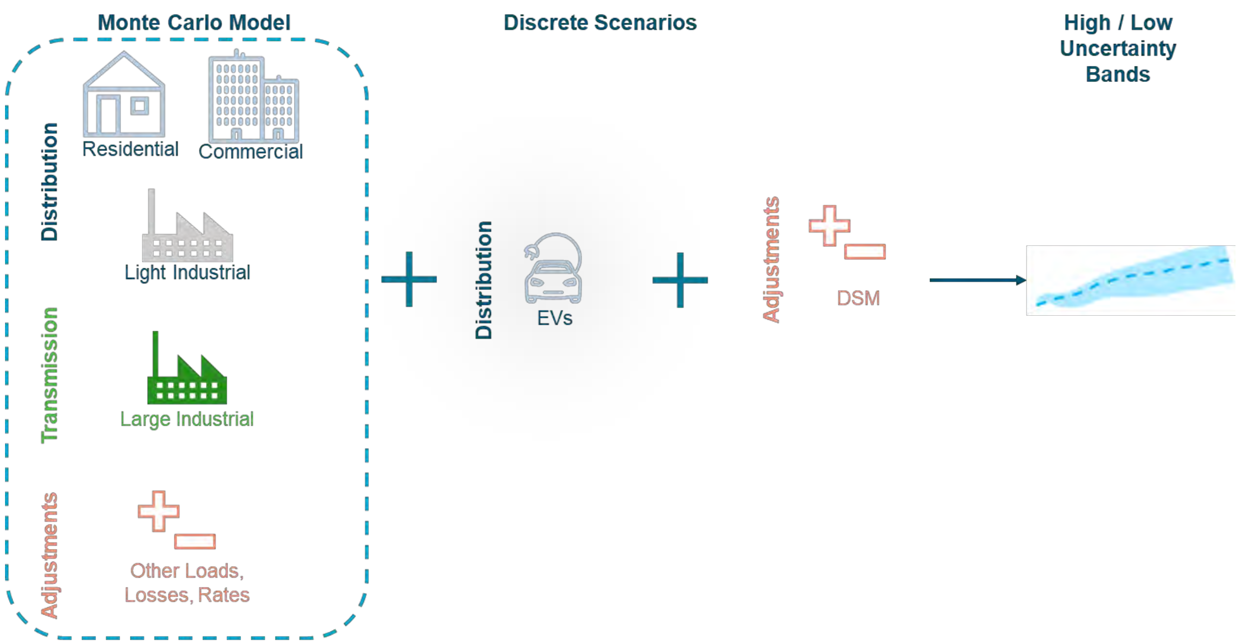
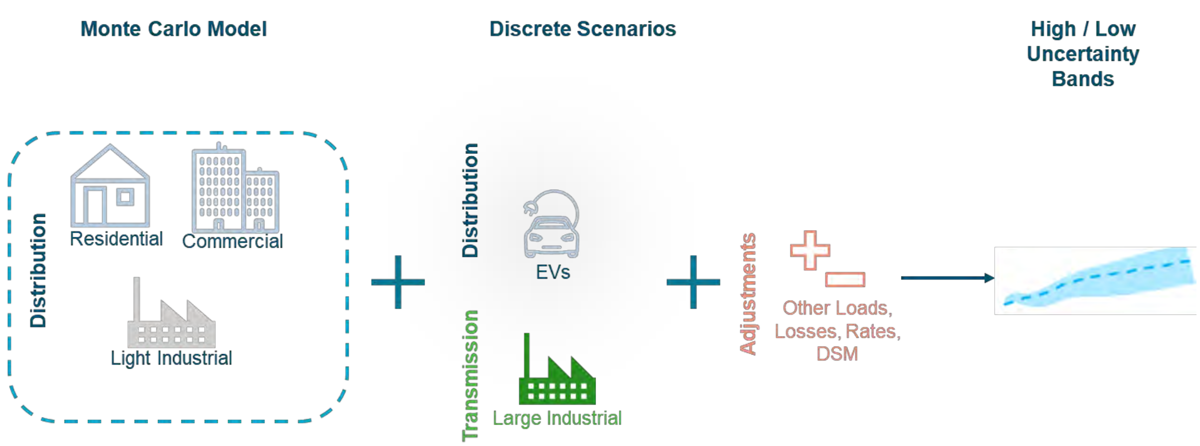


Figure 3-2 March 2020 Uncertainty Band Methodology



The new approach creates asymmetrical uncertainty bands around the energy and peak reference forecasts and also widens the bands. For more information on the uncertainty bands, refer to Appendix D, section 12.

3.2.2 Planned Improvements to Load Forecast Methodology

As stated in BC Hydro's Compliance Filing to the Previous Application, BC Hydro continues to evaluate and improve its methods and processes, with a focus on load forecast performance. Some of the improvements planned for fiscal 2022 include:

- Conducting a review of processes and models for the large industrial forestry sub-sector;
- Developing and implementing a new EV model, which expands the forecasting capability to include medium and heavy-duty vehicles;
- Implementing a residential stock and flow model of B.C. specific end-use efficiency projections, to be used in conjunction with our current SAE models;
- Improving our understanding of DSM code & standards overlap and DSM persistence versus what may already be accounted for in our SAE models;
- Expanding research using smart meter infrastructure data to potentially develop more granular forecast methods within the diverse commercial sector; and
- Reviewing our Monte Carlo model and uncertainty band performance and improvements.

3.2.3 The March 2020 Load Forecast was a Comprehensive Load Forecast

The March 2020 Load Forecast was a comprehensive forecast with revised inputs relative to the October 2018 Load Forecast. Key inputs and drivers to the process were updated for the March 2020 Load Forecast, as outlined below.

BC Hydro uses SAE models to forecast load in the residential and commercial sectors. For the March 2020 Load Forecast, BC Hydro updated the following inputs:

- The calibration period (to include actual billed sales from fiscal 2010 through fiscal 2019);
- The economic forecast (to reflect the July 2019 forecast from the Conference Board of Canada); and
- Average efficiency projections for end uses (to reflect 2019 U.S. EIA data).

For the light industrial sector, BC Hydro uses a combination of customer by customer forecasts and a regression model using GDP. For the March 2020 Load Forecast updates were made to the individual customer and sub-sector forecasts, and revised GDP projections were used in the regression model, as described below:

- Fiscal 2020 to fiscal 2024 - BC Ministry of Finance November 2019 Q1 Report; and
- Fiscal 2025 to fiscal 2040 - Conference Board of Canada July 2019 forecast.

The large industrial forecast included a comprehensive customer by customer update including updated market assessments from third-party industry experts, market research, and information from our customers.

The forecast adjustments for DSM and price elasticity were updated using the DSM plan and rates forecast available at the time of forecast compilation.

3.2.4 BC Hydro's Load Forecasting Responded to the COVID-19 Pandemic

BC Hydro's Executive Team approved the March 2020 Load Forecast on March 17, 2020. In the days surrounding that approval, the World Health Organization declared a global pandemic for COVID-19, and the province of British Columbia entered into various public health restrictions. The energy consumption patterns for all customer sectors shifted as a result of the pandemic, thus immediately calling into question the early years of the forecast and raising questions about the characterization of uncertainty in load over a longer term.

In response, BC Hydro created two scenarios to inform decision-making during this time. The pandemic was in its early stages during the development of these scenarios, so BC Hydro used a wide range of information to assess the potential impacts. This included online research of news articles and third-party reports, attending webinars, consulting with load forecast departments of utilities in other Canadian provinces, using smart meter infrastructure (**SMI**) and billing data to observe actual trends, and communicating directly with our large industrial customers to understand potential impacts. The resulting scenarios fell within the broader bookends of predictions by third-party experts at the time.

The timeline of assumptions regarding public health measures and recovery for the scenarios is shown in Figure 3-3 below.

Figure 3-3 Timeline and Key Assumptions for COVID-19 Scenarios A and B

	Fiscal 2021												Fiscal 2022												Fiscal 2023											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
	20	20	20	20	20	20	20	20	20	21	21	21	21	21	21	21	21	21	21	21	21	22	22	22	22	22	22	22	22	22	22	22	22	23	23	23
A	Measures		Slow Recovery							Revised Long Term Projection																										
B	Measures					Targeted Measures												Slower Recovery							Revised Long Term Projection											

Key assumptions under Scenario A included:

- Three months of closure of non-essential businesses (March to May);
- Gradual return within fiscal 2021 to pre-pandemic conditions for the residential and commercial sectors;
- BC GDP projections based on the BC Business Council's March 27 Scenario 1 (2020/fiscal 2021 minus 7.3 per cent, 2021/fiscal 2022 plus 2 per cent, 2022/fiscal 23 plus 2 per cent) for the light industrial sector;

- Permanent closure of one forestry mill and some delays for other customer start-ups or expansions in the large industrial sector; and
- A global recession either imminent or already underway.

As shown in Table 3-2, this resulted in Scenario A being 3 per cent below the March 2020 Load Forecast for fiscal 2022.

Key Assumptions under Scenario B included:

- Six months of closure of non-essential businesses (March to August);
- Twelve months of targeted closures in response to a potential second wave;
- Following the targeted measures phase, the residential use per account was assumed to return to the March 2020 Load Forecast levels while the number of residential accounts remained at 90 per cent of the accounts in the March 2020 Load Forecast;
- Following the targeted measures phase, the commercial load was assumed to return to 95 per cent of the March 2020 Load Forecast;
- BC GDP projections based on the BC Business Council's March 27 Scenario 2 (2020/fiscal 21 minus 11.4 per cent, 2021/fiscal 2022 plus 1 per cent, 2022/fiscal 23 plus 1 per cent) for the light industrial sector;
- Curtailments and closures due health measures and poor market conditions with the same permanent closure of one forestry mill and some delays for other customer start-ups or expansions in the large industrial sector; and
- Deeper North American and global recessions with impacts beyond anything BC has seen in 70 years.

Taken together, this resulted in Scenario B being 13 per cent below the March 2020 Load Forecast for fiscal 2022.

These scenarios were meant to represent two of the many possible outcomes of the pandemic based on the best information available when they were developed in April 2020. The pandemic remains fluid. As of November 2020, while the widespread closures of non-essential businesses have been relaxed, many businesses have not reopened or returned to their pre-pandemic capacity. Many people continue to work or study from home, and travel and tourism remains depressed. In addition, the forestry and oil and gas sub-sectors face ongoing market challenges which impact their electricity consumption.

For a detailed description of the methodology used to develop the COVID-19 scenarios, refer to Appendix D, section 14.

3.3 Load Forecast and Scenario Results

The load forecast is an important input to BC Hydro's revenue requirements during the Test Period because it provides the basis for estimating future electricity sales revenues from our existing and future customers.

This section provides specific details about our March 2020 Load Forecast and the COVID-19 scenarios. The Test Period revenue requirements are based on COVID-19 Scenario A, which has closely tracked actual total domestic sales in fiscal 2021:

- Section 3.3.1 explains the use of billed and accrued sales in this chapter;
- Section 3.3.2 discusses the shifts in load observed from the onset of the COVID-19 pandemic;
- Section 3.3.3 discusses actual load from April 1, 2020 to November 30, 2020;
- Section 3.3.4 discusses the scenario results for the Test Period by customer sector; and
- Section 3.3.5 discusses the uncertainty that exists around the reference forecast.

3.3.1 Billed Sales and Accrued Sales

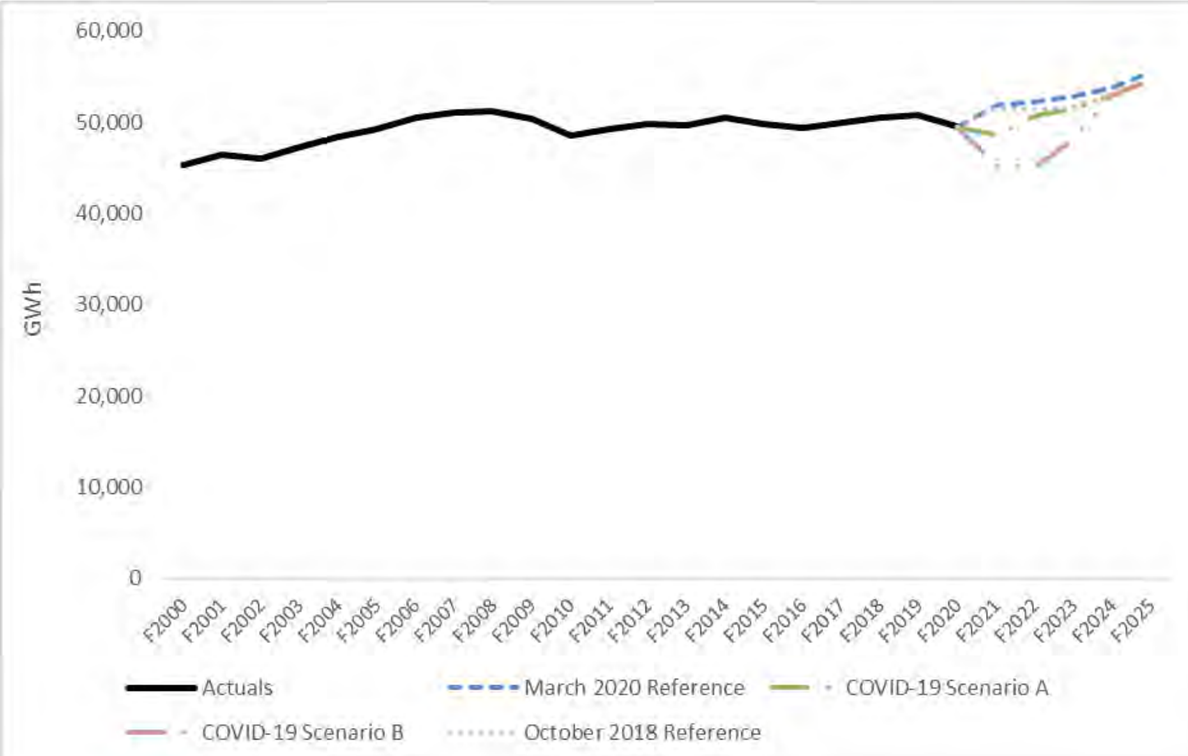
Throughout the chapter, there are tables and figures which specify billed or accrued sales. In general terms, billed sales represent what was billed to our customers in a month or over a fiscal year in line with our billing cycle, while accrued sales are estimates of electricity consumption in a month or over a fiscal year.

Our load forecasts are based on relationships between load drivers and billed sales. As such, the forecast of future customer loads shown in the chapter are usually in the form of billed sales projections. However, revenue projections from these future loads are based on accrued sales as BC Hydro's rates are set on an accrual basis in accordance with accounting principles.

3.3.2 The COVID-19 Pandemic Decreased Electricity Consumption

The March 2020 Load Forecast projected 1.7 per cent higher electricity sales in fiscal 2022 relative to the October 2018 Load Forecast for fiscal 2022 contained in the Previous Application. This projected increase was primarily due to a higher residential forecast (due to higher account growth, a higher EV forecast, and a change in the start year for the DSM plan), and a higher light industrial forecast. The COVID-19 pandemic resulted in an unprecedented drop in electricity demand worldwide. As a result, BC Hydro developed COVID-19 Scenarios A and B to quantify the potential magnitude of this impact and two potential paths to recovery for British Columbia in the short term. Figure 3-4 shows projected electricity sales for the forecasts and scenarios, discussed in this Chapter, compared to the October 2018 Load Forecast used in the Previous Application.

Figure 3-4 Actual Billed Sales and Forecasted Sales After Adjustments for Residential, General, and Transmission Combined



As show in Figure 3-4 above, COVID-19 Scenario A shows a moderate dip in the short-term while COVID-19 Scenario B shows a significant short-term decline in sales and a longer recovery period. At the time of development of the COVID-19 scenarios, the consensus among economic experts was that the pandemic would have effects in calendar year 2020 (fiscal 2021) followed by a recovery to pre-pandemic levels in a year or two. As a result, both scenarios assumed a return to 1.4 per cent below the March 2020 Load Forecast by fiscal 2024. Now that we are many more months into the pandemic, we expect this recovery to be more gradual than what is shown for both the COVID-19 scenarios in Figure 3-4 above. This more gradual recovery will be reflected in future load forecasts.

A detailed breakdown of these forecasts and scenarios is provided in Table 3-1 below.

Table 3-1 Billed Sales After Rate Impacts and After Demand-Side Management[1]

		Temperature Normalized Actuals					October 2018 Load Forecast				March 2020 Load Forecast					COVID-19 Scenario A					COVID-19 Scenario B				
	Fiscal Year	**F2016**	**F2017**	**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**
Main Customer Sectors	Residential	18,019	17,952	17,997	17,876	18,349	18,324	18,411	18,551	18,709	18,623	18,836	19,123	19,380	19,683	19,078	18,836	19,123	19,380	19,683	19,230	19,024	18,828	19,380	19,683
	Commercial	14,257	14,582	14,513	14,557	14,336	14,352	14,244	14,113	14,034	14,438	14,366	14,313	14,239	14,159	13,300	14,366	14,313	14,239	14,159	11,179	12,740	13,578	14,239	14,159
	Light Industrial	4,148	4,275	4,364	4,422	4,311	4,683	4,688	4,697	4,697	4,708	5,002	5,012	4,955	4,978	4,203	4,546	4,554	4,955	4,978	4,028	4,235	4,204	4,955	4,978
	Commercial & Light Industrial[2] (General)	18,405	18,856	18,877	18,979	18,648	19,036	18,931	18,810	18,731	19,146	19,368	19,325	19,193	19,136	17,503	18,911	18,867	19,193	19,136	15,207	16,974	17,782	19,193	19,136
	Large Industrial	13,698	13,106	13,513	13,398	13,103	14,243	14,066	14,371	15,414	14,122	14,108	14,398	15,225	16,666	12,107	12,982	13,511	14,435	15,877	10,828	9,190	11,435	14,435	15,877
Other Loads	Irrigation and Street Lighting	322	312	308	304	285	312	313	314	314	301	291	279	273	272	301	291	279	273	272	301	291	279	273	272
	Inter Utility Sales[3]	971	1,053	1,017	897	1049	1,027	1,056	1,076	1,071	1,105	1,098	1,135	1,163	1,201	1,105	1,098	1,135	1,163	1,201	1,105	1,098	1,135	1,163	1,201
	Total Firm Exports[4]	309	326	319	316	313	312	314	312	312	313	311	311	311	313	313	311	311	311	313	313	311	311	311	313
	Total Domestic Sales[5]	51,724	51,606	52,031	51,770	51,746	53,253	53,093	53,434	54,551	53,610	54,013	54,571	55,546	57,272	50,406	52,430	53,225	54,756	56,482	46,984	46,889	49,770	54,756	56,482

Table notes:

1. All forecast values are on a billed sales basis and include all adjustments for rate impacts, DSM savings, and savings from loss reductions.
2. Light Industrial/Commercial is the sum of the loads in the light industrial sector and commercial sector.
3. BC Hydro sales to City of New Westminster and FortisBC Inc.
4. BC Hydro sales to Seattle City Light and Hyder, Alaska.
5. Total Domestic Sales is the sum of the loads from the Main Customer Sectors and Other Loads.

The COVID-19 pandemic caused shifts in load across all major customer sectors. The differences in load relative to the March 2020 Load Forecast for COVID-19 Scenarios A and B are provided in Table 3-2 below.

Table 3-2 COVID-19 Scenarios Difference from March 2020 Reference Case

Billed Sales Projections - After Rate Impacts and after Demand-Side Management[1]						
Fiscal Year	Main Customer Sectors[1]					
	Residential Sales (GWh)	Commercial Sales (GWh)	Light Industrial Sales (GWh)	Large Industrial Sales (GWh)	Change In Domestic Sales (GWh)	Change In Domestic Sales (%)
COVID-19 Scenario A Relative to March 2020 Forecast						
F2021	454	-1,138	-505	-2,015	-3,204	-6
F2022	0	0	-457	-1,126	-1,582	-3
F2023	0	0	-458	-887	-1,346	-2
F2024	0	0	0	-790	-790	-1
F2025	0	0	0	-790	-790	-1
COVID-19 Scenario B Relative to March 2020 Forecast						
F2021	607	-3,259	-680	-3,294	-6,626	-12
F2022	187	-1,626	-768	-4,918	-7,124	-13
F2023	-295	-734	-809	-2,963	-4,801	-9
F2024	0	0	0	-790	-790	-1
F2025	0	0	0	-790	-790	-1

Table notes:

1. Changes were made to reflect impacts to major customer sectors. No changes were made to other loads (Street Lighting, Irrigation, sales to the City of New Westminster, FortisBC Inc., Seattle City Light, Hyder Alaska, etc.)

As shown, there is a significant load reduction in the short-term followed by a persistent one percent reduction relative to the March 2020 Load Forecast in both scenarios. For fiscal 2022, Scenario A assumes a reduction of 3 per cent relative to the March 2020 Load Forecast and Scenario B assumes a relative reduction of 13 per cent.

3.3.3 Test Period is Based on COVID-19 Scenario A Which Has Closely Tracked Actual Total Domestic Sales in Fiscal 2021

As of November 2020, two-thirds of the way through fiscal 2021, actual total domestic sales were 1.2 per cent higher than COVID-19 Scenario A for the three main customer classes. This is shown in Table 3-3 below.

Table 3-3 Fiscal 2021 Actuals from April 1, 2020 through November 30, 2020 Compared to COVID-19 Scenario A (Unofficial Accrued Sales)

	April 2020	May 2020	June 2020	July 2020	August 2020	Sept. 2020	October 2020	Nov. 2020	F2021 8-month YTD
COVID-19 Scenario A	**3,871**	**3,621**	**3,508**	**3,634**	**3,638**	**3,493**	**3,892**	**4,394**	**30,050**
Residential	1,588	1,333	1,215	1,208	1,178	1,136	1,395	1,811	10,863
Commercial & Light Industrial	1,288	1,259	1,298	1,398	1,433	1,362	1,469	1,588	11,094
Large Industrial	995	1,028	995	1,028	1,028	995	1,028	995	8,094
Actuals	**3,773**	**3,568**	**3,586**	**3,697**	**3,679**	**3,576**	**4,056**	**4,476**	**30,411**
Residential	1,457	1,264	1,219	1,229	1,234	1,193	1,513	1,837	10,945
Commercial & Light Industrial	1,336	1,294	1,382	1,471	1,428	1,461	1,523	1,581	11,477
Large Industrial	979	1,011	986	996	1,016	922	1,020	1,059	7,989
Actuals vs COVID-19 Scenario A (GWh)	**(98)**	**(52)**	**79**	**63**	**40**	**83**	**164**	**82**	**361**
Residential	(131)	(69)	4	21	57	57	118	26	82
Commercial & Light Industrial	49	35	84	74	(4)	99	54	(7)	383
Large Industrial	(16)	(17)	(9)	(32)	(12)	(74)	(8)	64	(104)
Actuals vs COVID-19 Scenario A (%)	**-2.5%**	**-1.4%**	**2.2%**	**1.7%**	**1.1%**	**2.4%**	**4.2%**	**1.9%**	**1.2%**
Residential	-8.2%	-5.2%	0.3%	1.7%	4.8%	5.0%	8.4%	1.4%	0.8%
Commercial & Light Industrial	3.8%	2.8%	6.5%	5.3%	-0.3%	7.3%	3.7%	-0.5%	3.5%
Large Industrial	-1.6%	-1.7%	-0.9%	-3.1%	-1.2%	-7.4%	-0.8%	6.4%	-1.3%

Table notes:

The allocation of an annual load forecast to a monthly forecast is an approximation based on a rolling five-year average shape of monthly billed sales at the BC Hydro system level. The allocation for the COVID-19 scenarios was adjusted to account for the months where health measures were expected to influence load. The monthly shape could influence the total annual variance.

BC Hydro finalized the inputs into the Application in the summer of 2020. Given that COVID-19 Scenario A was tracking well against actual domestic sales at this time, BC Hydro determined that it was reasonable for use in the Application. Accordingly, the remainder of this chapter will focus on the results of COVID-19 Scenario A for the Test Period.

3.3.4 Fiscal 2022 Test Period Results and Discussion

The results for COVID-19 Scenario A are shown in Table 3-1. A detailed discussion of the individual sector results for the test period follows.

3.3.4.1 Residential Sector

The residential sector consists of approximately 1.9 million accounts and represents about one-third of total sales. The detailed build-up of analysis to the billed sales residential forecast for fiscal 2022 is presented in Table 3-4 below.

Table 3-4 Fiscal 2022 Residential Billed Sales Build-up for COVID-19 Scenario A

Number of Accounts	Use per Account (kWh/account)	Model projection (GWh)[1]	Codes overlap adjustments (GWh)	EV Load Additions (GWh)	Fuel Switching Additions (GWh)	Rate Impacts2 (GWh)	DSM (GWh)	Loss Reduction (GWh)	Residential Load Forecast[3] (GWh)
1,921,842	9,865	18,959	127	271	36	76	(621)	(12)	18,836

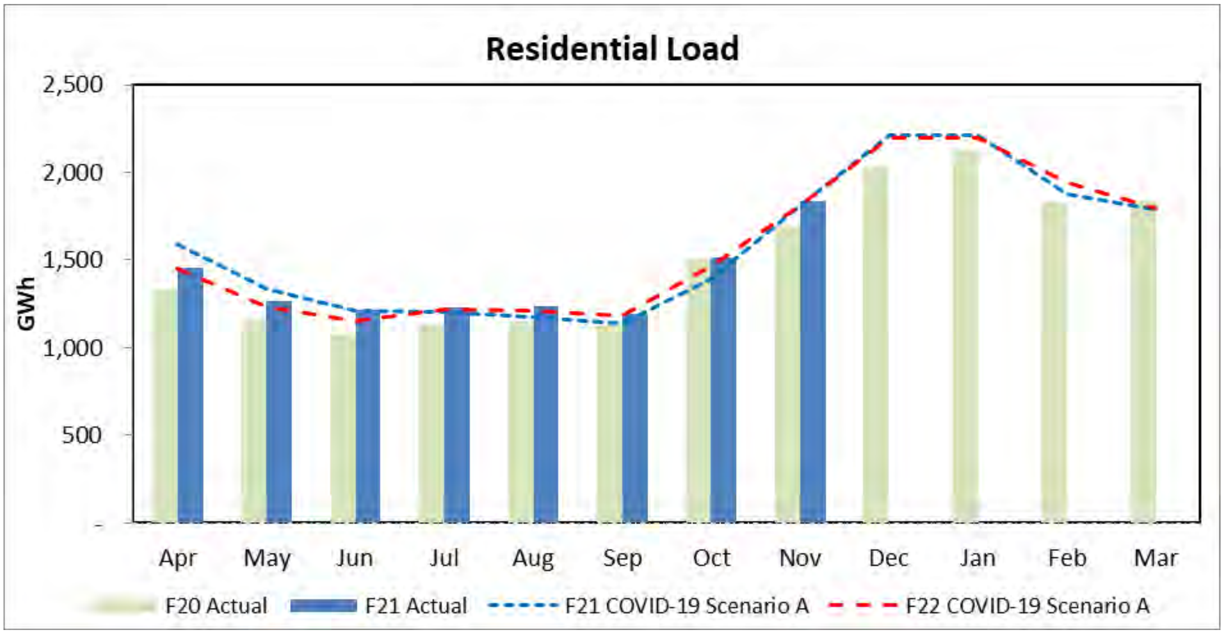
Table notes:

1. A model projection is average use per account times the number of residential accounts which equals model sales. The model projection above is the sum model projections from all four regions on a billed sales basis.
2. Rate Impacts is an estimation of load reduction based on formula that include our forecast of real electricity rate increases, a price elasticity assumption of -0.1 and the residential model projections, load adjustments, and load additions.
3. The Residential Load Forecast is an aggregation of model projections, adjustments for codes and standards, load additions less rate impacts, less DSM savings, and loss reductions.

The residential accrued sales are derived from the billed sales forecast, to develop the revenue forecast. The residential forecast after adjustments of 18,836 GWh in Table 3-4 is 425 GWh (2.3 per cent) higher than the fiscal 2022 residential forecast from the October 2018 Load Forecast provided in the Previous Application. This is primarily due to a higher account growth, higher demand from the EV forecast, and DSM adjustments.

As shown in Figure 3-5 below, residential consumption has been higher in fiscal 2021 than fiscal 2020, and COVID-19 Scenario A assumes this continues for the remainder of fiscal 2021 and fiscal 2022.

Figure 3-5 Actual Accrued Sales and Forecasted Sales for Residential Sector



As shown above, residential consumption is higher in winter months due to electric heating. Actual consumption varies depending on temperature so monthly forecasts are an approximation. BC Hydro is monitoring the impact of residential customers spending more time at home this winter to inform future forecasts. Scenario A did not include the assumption of people working and studying from home in fiscal 2022. To the extent that occurs, there is a potential upside to this forecast.

3.3.4.2 Commercial Sector

The commercial sector consists of approximately 180,000 accounts and represents approximately one-third of total sales. The commercial sector is diverse, including everything from small corner stores to large warehouses, schools, office buildings, restaurants, and health care facilities. For the past 10 years the commercial sector load has been relatively flat as growth in some sub-sectors is offset by declining activity or improved electrical efficiency in others. The detailed build-up of the billed sales commercial forecast for fiscal 2022 is presented Table 3-5 below.

Table 3-5 Fiscal 2022 Commercial Billed Sales Build up for COVID-19 Scenario A

Model projection (GWh)[1]	Codes overlap adjustment (GWh)	EV load addition (GWh)	Fuel switching load addition (GWh)	Rate impacts[2] (GWh)	DSM (GWh)	Loss reductions (GWh)	Commercial Load Forecast[3] (GWh)
14,584	92	48	48	58	(455)	(9)	14,366

Table notes:

1. The model projections are the sum total of all commercial SAE model projections on a billed sales basis.
2. Rate Impacts is an estimation of load reduction based on formula that includes our real rate increase projection, a price elasticity assumption of -0.1, the commercial model projection, codes overlap adjustment and all commercial load additions.
3. Commercial Load Forecast is an aggregation of commercial model projection, adjustments for codes and standards, commercial load additions (i.e., EVs and fuel switching), less rate impacts less loss reductions and DSM savings.

Similar to the residential sector, the commercial accrued sales are derived from the billed sales forecast, to develop the revenue forecast.

The commercial forecast of 14,366 GWh in Table 3-5 is 122 GWh (0.8 per cent) higher than the fiscal 2022 commercial forecast from the October 2018 Load Forecast provided in the Previous Application.

3.3.4.3 Light Industrial Sector

The light industrial sector represents a relatively small component of the overall load forecast (approximately 8 per cent of total sales in fiscal 2020). The sector consists of approximately 29,000 accounts in a diverse range of industries. Examples include accounts in coal mining, forestry, small oil and gas facilities, cannabis facilities, and construction power for Liquified Natural Gas (**LNG**) facilities. By definition, light industrial customers are connected at distribution voltage. The build-up of the fiscal 2022 light industrial forecast is shown in Table 3-6 below.

Table 3-6 Fiscal 2022 Light Industrial Billed Sales Build-up for COVID-19 Scenario A

Light industrial model projections (GWh[1])	Cannabis-crypto currency load addition (GWh)	Construction load addition (GWh[2])	Fuel switching load addition (GWh)	Rate impacts[3] (GWh)	DSM (GWh)	Loss reductions (GWh)	Light Industrial Load Forecast (GWh)
4,280	221	106	0	18	79	-158	4,546

Table notes:

1. The light industrial model projection is the sum of the projections from all four main sub-sectors (forestry, oil and gas, coal mining, and other) on a billed sales basis.
2. Construction loads included are for future LNG terminals and other facilities such as gas pipelines.
3. Rate Impacts is an estimation of load reduction based on formula that include our real rate increase projection, a price elasticity assumption of -0.1 and the model projections and all load additions including in the light industrial sector.

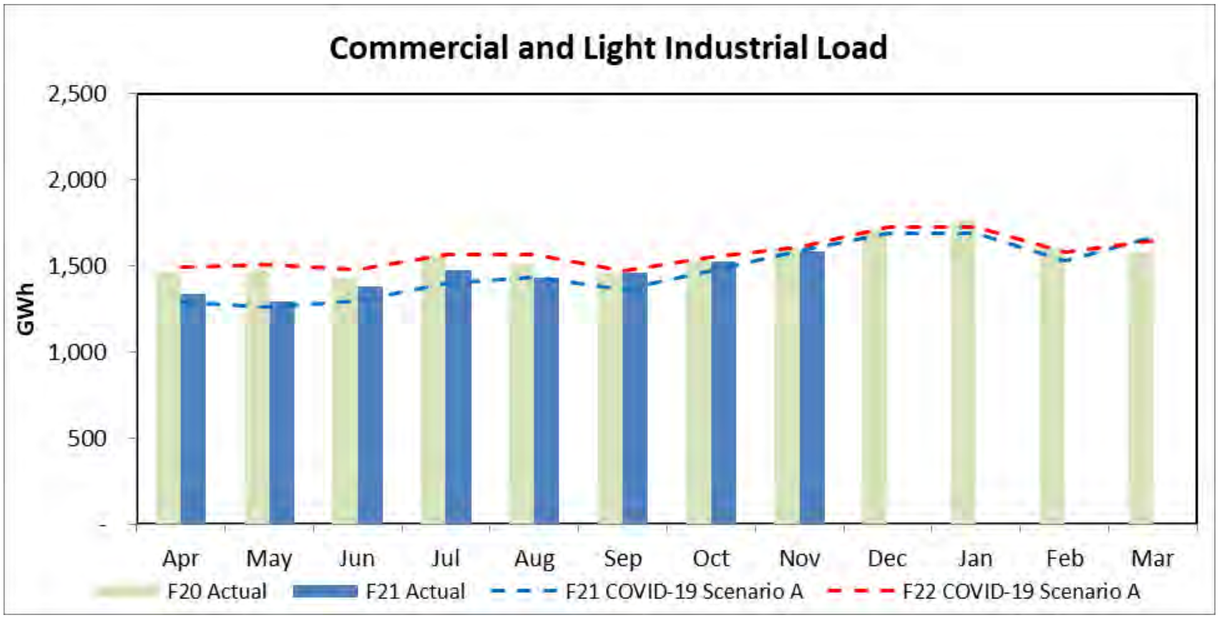
Similarly, the light industrial accrued sales are derived from the billed sales forecast, to develop the revenue forecast.

The light industrial forecast is an aggregation of the light industrial model's projection, adjustments for codes and standards, light industrial load additions (cannabis and cryptocurrency loads, construction loads, and fuel switching loads), less rate impacts, loss reductions, and DSM savings.

The light industrial forecast of 4,546 GWh shown above is 142 GWh (3 per cent) lower than the fiscal 2022 light industrial forecast from the October 2018 Load Forecast provided in the Previous Application. The lower projection reflects lower GDP assumptions resulting from the pandemic, under COVID-19 Scenario A. The lower sales projection also reflects lower expected loads from data centres and cannabis.

As shown in Figure 3-6 below, actual sales to the commercial and light industrial sectors were slightly higher than Scenario A projections during the spring, when COVID-19 heath measures were in place.

Figure 3-6 Actual Accrued Sales and Forecasted Sales for Commercial and Light Industrial Sectors Combined



As the restrictions were eased and businesses re-opened, electricity consumption has returned to close to fiscal 2020 levels. COVID-19 Scenario A assumes consumption will remain at these levels throughout the rest of fiscal 2021 and fiscal 2022. There remains considerable uncertainty around the number of businesses that may permanently close or any impacts caused by renewed public health measures or restrictions imposed to control the second wave. To the extent such developments occur, there is a downside potential to this forecast.

3.3.4.4 Large Industrial Sector Results

BC Hydro has approximately 190 large industrial accounts connected at transmission voltages, which in fiscal 2020 represented approximately 26 per cent of total sales. Table 3-7 below shows historical loads and the build-up of COVID-19 Scenario A used for the Test Period in the Application.

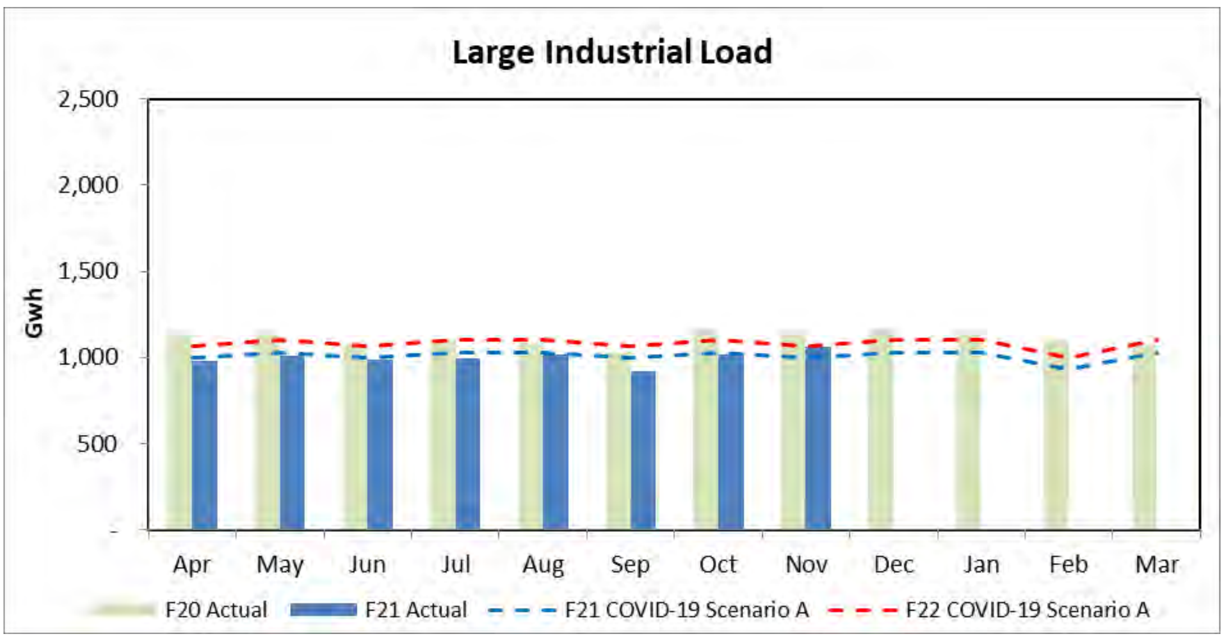
Table 3-7 Fiscal 2022 Large Industrial Billed Sales Build-up for COVID-19 Scenario A[1]

Fiscal Year	Mining		Forestry			Oil and Gas and LNG	Other[2] Large Industrial	Total Large Industrial (GWh)
	Metal Mines (GWh)	Coal Mines (GWh)	Pulp and Paper (GWh)	Wood Products (GWh)	Chemical (GWh)	(GWh)	(GWh)	
F2022	3,356	632	2,543	1,097	1,359	2,806	1,189	12,982

Table notes:
1. Forecast is on a billed sales basis and includes all adjustments for rate impacts, DSM savings, and savings from loss reductions.
2. Other large industrial includes transmission connected cannabis and cryptocurrency loads.

As shown in Figure 3-7 below, large industrial sector load has been lower than fiscal 2020 levels due to market conditions and impacts from the COVID-19 pandemic.

Figure 3-7 Actual Accrued Sales and Forecasted Sales for Large Industrial Sector



COVID-19 Scenario A assumes only a partial recovery in fiscal 2022, with loads not returning to fiscal 2020 levels during the Test Period. In addition to the potential impacts of the COVID-19 pandemic, there is always considerable uncertainty in the large industrial sector due to global economic influences on commodity-based industries.

A discussion of the fiscal 2022 forecast for the major large industrial sub-sectors is provided below.

Mining

The fiscal 2022 forecast for the mining sector is 3,988 GWh after adjustments. This is 88 GWh (2 per cent) higher than the October 2018 forecast of 3,900 GWh. The net forecast is relatively unchanged due to offsetting updates from actuals and revised customer expectations.

Forestry

The fiscal 2022 forecast for the forestry sector is 4,999 GWh after adjustments. This is 318 GWh (6 per cent) lower than the fiscal 2022 projection in the October 2018 forecast of 5,317 GWh. The lower forecast is a result of fibre supply challenges, operating inefficiencies, and weak demand impacting pulp and paper mills. Curtailments of one mill and of lines at another are expected to continue in the face of industry challenges and the economic impacts on customer demand associated with the COVID-19 pandemic.

Oil and Gas

The fiscal 2022 forecast for oil and gas including LNG is 2,806 GWh after adjustments. This is 449 GWh (14 per cent) lower than the October 2018 forecast of 3,255 GWh. The lower forecast is primarily a result of current low natural gas and liquids prices causing companies to curtail operations and defer or cancel expansions. These weaker market conditions are due to various factors including the global oil price war between Saudi Arabia and Russia as well as the economic impacts on consumer demand associated with the COVID-19 pandemic.

Other Large Industrial

The fiscal 2022 forecast for the other sub-sector is 833 GWh after adjustments. This is 392 GWh (37 per cent) lower than the October 2018 forecast of 1,225 GWh. The lower forecast is a result of curtailments by existing customers, and delays in ramp ups for new cannabis customers. The impacts of the COVID-19 pandemic also resulted in deferred expansion plans for several customers (including airports, ports, terminals, universities, and colleges) as well as reduced production at several industrial facilities (e.g., cement and auto parts manufacturing facilities).

3.3.4.5 Other Sales

The Other sub-sector currently represents approximately 3 per cent of the total sales demand in the load forecast. Demand in this sub-sector comes from irrigation and street light customers, sales to other inter utility sales (City of New Westminster and FortisBC Inc.), and firm exports (Seattle City Light and Hyder, Alaska). The fiscal 2022 forecast is 1,701 GWh. This is comparable to the October 2018 forecast of 1,683 GWh. Due to the short timeframe of scenario development and lack of information that would change previous assumptions, no updates were made to this projection in the COVID-19 scenarios. The March 2020 Load Forecast was used. The Other sales forecast will be updated during the next comprehensive load forecast.

3.3.5 Uncertainty Exists When Forecasting Load

Load forecasts are sensitive to many input variables, which have varying degrees of uncertainty associated with them. These uncertainties influence the risk that future loads will be lower or higher than forecast. They can exist at a customer-specific level up through to sector-wide or economy-wide levels. To account for this, BC Hydro develops low and high uncertainty bands around each reference forecast to capture a range of potential outcomes. In keeping with this practice, high and low bands were developed for the March 2020 Load Forecast. The range of uncertainty for the Test Period is reflected in the Integrated Planning Dashboard, which is included in Appendix O of the Application.

3.4 Fiscal 2022 Revenue Forecast

The Revenue Forecast is used to determine the revenue shortfall and the proposed rate increase to meet BC Hydro's forecast revenue requirements. The forecast methodology uses accrued customer projections of load and applies approved fiscal 2021 tariff rates submitted in the Compliance Filing to the Previous Application to calculate revenue. The Revenue Forecast is a straightforward calculation, relative to the preparation of the Load Forecast, and the methodology is unchanged from the Previous Application.

Table 3-8 below summarizes the Domestic Revenue Forecast for the Test Period. This calculation, including accrued forecast sales volumes, the applicable rates and the resulting revenue forecast are shown on Appendix A, Schedule 14.0. The Domestic Revenue Forecast for fiscal 2022 excludes the proposed rate increase sought in this application or the impact of any future rate structure changes.

In fiscal 2022, total Domestic Revenue is forecast to increase by $95.0 million (1.9 per cent) compared to the Fiscal 2021 RRA (as recalculated to reflect the load reduction from Directive 4 of the BCUC's Decision on the Previous Application).[51]

[51] For further information, refer to Order No. G-246-20, page 21.

Table 3-8 Fiscal 2020 to Fiscal 2022 Domestic Revenues

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	Residential	14.0 L12	2,149.5	2,168.8	2,140.4	2,182.5	2,234.0
2	Light Industrial and Commercial	14.0 L13	1,929.4	1,942.0	1,905.9	1,835.0	1,954.1
3	Large Industrial	14.0 L14+L20	876.2	849.7	852.2	731.1	842.3
4	Other	14.0 L15:L19+L21	189.7	154.4	188.9	156.0	152.0
5	Subtotal	14.0 L22	5,144.8	5,114.9	5,087.4	4,904.6	5,182.4
6	Revenue from Deferral Rider	14.0 L23	0.0	0.2	0.0	0.0	0.0
7	Total	14.0 L24	5,144.8	5,115.1	5,087.4	4,904.6	5,182.4

BC Hydro
Power smart

BC Hydro Fiscal 2022
Revenue Requirements Application

Chapter 4

Cost of Energy

Table of Contents

List of Tables

4.1 Introduction

This chapter discusses BC Hydro's Cost of Energy and provides the necessary information to demonstrate that the fiscal 2022 Plan Cost of Energy is reasonable for the purpose of setting rates for the Test Period. Overall, BC Hydro's total Cost of Energy is planned to be $1,669.4 million in fiscal 2022, which is effectively unchanged compared to fiscal 2021 Plan. The fiscal 2022 Plan Cost of Energy, which is discussed further in section 4.3 below, is used to determine our total revenue requirements for the Application; however, regulatory accounts capture variances between actual and planned costs so that customers only pay the actual Cost of Energy.[52]

In the Application, BC Hydro is not seeking acceptance of any Electricity Purchase Agreements (**EPAs**). A new Transfer Pricing Agreement between BC Hydro and Powerex came into effect on April 1, 2020 (**2020 TPA**). BC Hydro has submitted the 2020 TPA to the BCUC under section 71 of the *Utilities Commission Act* and it is being reviewed through a separate proceeding.[53]

This Chapter is organized around the following key points:

- Section 4.2 describes how BC Hydro is proactively managing energy costs associated with Independent Power Producers (**IPPs**);
- Section 4.3 provides BC Hydro's forecast Cost of Energy for the Test Period, which is effectively unchanged compared to fiscal 2021;
- Section 4.4 provides a discussion of the components of BC Hydro's Cost of Heritage Energy, which is increasing from the fiscal 2021 Plan to the fiscal 2022 Plan, primarily due to water rental fees associated with higher hydro generation volumes in calendar year 2020 as a result of high inflows in the Peace and Columbia regions;

[52] A discussion of the regulatory accounts related to Cost of Energy is provided in Chapter 7, section 7.2.1.
[53] The 2020 TPA changes how Market Energy is categorized, as described in section 4.6.

- Section 4.5 provides a discussion of the components of BC Hydro's Cost of Non-Heritage Energy, which is increasing from the fiscal 2021 Plan to the fiscal 2022 Plan, primarily due to predetermined factors, such as terms included in existing EPAs, increased forecast energy deliveries as permitted under existing agreements, and new IPP projects under existing EPAs reaching commercial operation; and
- Section 4.6 provides a discussion of the components of BC Hydro's Cost of Market Energy, which is decreasing from the fiscal 2021 Plan to the fiscal 2022 Plan, primarily due to lower system imports and higher system exports driven by higher inflows.

4.2 BC Hydro is Proactively Managing IPP Energy Costs

BC Hydro is proactively managing its energy costs from IPPs. Among other things, we are reducing the volume of IPP energy in accordance with the terms of our agreements and where there are cost savings to BC Hydro. For example, BC Hydro actively enforces its rights and obligations in EPAs by exercising turn down rights when it is cost effective to do so.

As discussed further in section 4.5 below, Non-Heritage Cost of Energy is increasing from the fiscal 2021 Plan to the fiscal 2022 Plan, primarily due to increasing IPP energy costs under existing agreements. BC Hydro does not have any active programs for the procurement of new energy resources from IPPs. Other than EPA renewals[54], including the EPA renewals under the Biomass Energy Program[55], the only expected new EPAs are a small number of potential new First Nations energy

[54] EPA renewals are new contracts that replace existing EPAs and are not extensions of existing agreements. Other than the Biomass Energy Program renewal EPAs, the only other EPA renewals to be filed with the BCUC as of the date of the Application and the end of the Test Period are the Hluely Lake EPA renewal (for the Dease Lake Non-Integrated Area) and potentially an EPA renewal for a small run-of-river hydro project.

[55] As part of the Comprehensive Review, the Government of B.C. announced the Biomass Energy Program. Under the Biomass Energy Program, BC Hydro procures energy through a combination of load offset and/or energy purchases with a priority given first to load offset. A load offset is energy generated by a BC Hydro customer at its customer site to offset the energy purchased from BC Hydro to serve the load at this same site. The total estimated impact of the cost and energy volumes for the load offset and energy purchase contracts are included in the Application under Cost of Energy.

projects, including two potential EPAs remaining from the Standing Offer Program (**SOP**).[56]

4.2.1 Opportunities to Reduce Supply Cost Commitments in Non-Integrated Areas are More Limited

BC Hydro serves 14 Non-Integrated Areas,[57] which are communities that are not connected to BC Hydro's integrated system and are served by local generating facilities which are primarily diesel-based. In support of the Government of B.C.'s CleanBC plan, we actively look for opportunities to displace diesel generation with clean or renewable resources in Non-Integrated Area communities when it is cost effective to do so.

There are two types of energy costs related to serving these communities: costs from BC Hydro diesel generating facilities and IPP costs.[58] Given the remoteness of these communities and the lack of connection to the integrated system, there are limited opportunities to reduce supply costs. In any given year, diesel fuel costs may change based on market conditions.

There are currently five Non-Integrated Area IPPs in operation.[59] BC Hydro has EPAs with each of these IPPs, with the exception of the Ocean Falls IPP (which

[56] In February 2019, as part of the Comprehensive Review, the Government of B.C. issued a regulation which allowed BC Hydro to indefinitely suspend the SOP. BC Hydro will not be executing any other SOP EPAs, except for five First Nations' clean energy projects that are part of Impact Benefit Agreements with BC Hydro and/or are mature projects that have significant First Nations involvement. To date, BC Hydro has executed three of these five agreements.

[57] Non-Integrated Areas: Zone IB is Bella Bella and Zone II is Anahim Lake, Atlin, Bella Coola, Dease Lake, Elhlateese, Fort Ware, Good Hope Lake, Haida Gwaii, Hartley Bay, Jade City, Telegraph Creek, District of Toad River and Tsay Keh Dene.

[58] There are no forecast energy costs for BC Hydro's Clayton Falls Generating Station in the Bella Coola Non-Integrated Area, as the annual costs are quite small. Actual costs are captured in Water Rentals, as noted in footnote 72 below.

[59] Non-integrated Area IPPs: Hluey Lake (Dease Lake), Moresby Lake (Haida Gwaii), Ocean Falls (Bella Bella), Pine Creek (Atlin) and Kwadacha Bioenergy Project (Fort Ware) are operational facilities. The Gabion River EPA (Hartley Bay), which was referenced in the Previous Application, was terminated by mutual agreement in September 2019 and had not reached commercial operation.

serves Bella Bella) as BC Hydro now receives services from the Ocean Falls IPP under a rate that has been approved by the BCUC.[60]

4.3 Cost of Energy Forecast

BC Hydro categorizes its Cost of Energy into the following components for financial reporting, which align with the source of the energy supply:

- Heritage Energy;
- Non-Heritage Energy; and
- Market Energy.

Monthly Energy Studies are one tool used by BC Hydro to optimize the operational management of all sources of energy supply on BC Hydro's integrated system. BC Hydro uses the Energy Studies to inform dispatch decisions and cost of energy forecasts for financial reporting purposes.

BC Hydro's Energy Studies methodology has not changed from the methodology used in the Previous Application other than updates to reflect the 2020 TPA. BC Hydro's objective function in the Energy Studies is to maximize expected Consolidated Net Revenue from Operations (**CNRO**). In the Compliance Filing to the Previous Application, we responded to Directives from the BCUC related to the Energy Studies and provided further information on this objective.

BC Hydro's Cost of Energy for the fiscal 2022 Plan[61] is provided in Table 4-1 below, classified by the three categories. Additional discussion on each of the three categories is provided in sections 4.4, 4.5, and 4.6 below, to explain the drivers of cost increases or decreases in each category and to provide comparisons of the costs in the fiscal 2022 Plan to the Previous Application test period.

60 Refer to BCUC Order No. G-270-20.
61 Fiscal 2022 Plan values are based on August 2020 forecast costs.

Table 4-1 Cost of Energy Forecast (Integrated System and Non-Integrated Areas)

Cost of Energy ($million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
Heritage Energy	4.0 L32	351.2	358.8	317.7	288.6	350.6
Non-Heritage Energy[1]	4.0 L37	1,332.4	1,353.1	1,447.2	1,423.1	1,511.5
Market Energy	4.0 L44	184.4	99.0	(98.4)	(128.1)	(191.9)
Total	4.0 L45	1,867.9	1,810.9	1,666.5	1,583.7	1,670.1

1 These values are after Accounting Adjustments.

Overall, BC Hydro's total fiscal 2022 Plan Cost of Energy is effectively unchanged compared to the fiscal 2021 Plan. Forecast increases to Heritage Energy costs of $32.9 million, primarily related to Water Rentals (described further in section 4.4), and forecast increases to Non-Heritage Energy costs of $64.3 million, primarily related to IPPs and Long Term Commitments (described further in section 4.5), are mostly offset by lower Market Energy costs which have decreased by $93.5 million compared to the fiscal 2021 Plan, primarily due to increased system exports (described further in section 4.6).

4.3.1 Regardless of Forecast Cost of Energy, Customers Only Pay the Actual Cost

It is expected that BC Hydro's costs of energy will vary from planned amounts for a number of reasons including weather, water inflows, and market conditions.

BC Hydro's revenue requirements are based on planned Cost of Energy for fiscal 2022; however, customers will only pay the actual costs of energy and not the planned costs. This is because the BCUC has approved the Cost of Energy Variance Accounts to capture any variances so that customers only pay for the actual energy costs. Variances between planned and actual costs of energy are deferred to one of the Heritage Deferral Account, the Non-Heritage Deferral Account, the Load Variance Regulatory Account,[62] or the Biomass Energy Program Variance

[62] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 15.

Regulatory Account.[63] The balances in these accounts are amortized into rates in subsequent years. These accounts are discussed further in Chapter 7, section 7.2.1 and in Appendix U, section 7.7.1.

4.4 Cost of Heritage Energy

Heritage Energy costs are generally related to the operation of heritage assets listed in Schedule 1 of the *Clean Energy Act*. Table 4-2 below provides a detailed breakdown of the components of the Cost of Heritage Energy.

Table 4-2 Cost of Heritage Energy

Cost of Heritage Energy ($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
Water Rentals	4.0 L27	329.3	331.6	323.2	331.0	375.4
Natural Gas for Thermal Generation	4.0 L28	7.5	7.1	8.5	8.2	11.8
Domestic Transmission - Other	4.0 L29	24.5	24.8	24.4	25.7	25.5
Columbia River Treaty Related Agreements	4.0 L30	15.0	37.7	(11.7)	(34.2)	(19.0)
Remissions and Other	4.0 L31	(25.2)	(42.4)	(26.7)	(42.1)	(43.2)
Total	4.0 L32	351.2	358.8	317.7	288.6	350.6

Each component identified in Table 4-2 is discussed in more detail below.

4.4.1 Water Rentals

Water rental fees include fees paid to the Government of B.C. on the generation output and capacity of the heritage assets, including BC Hydro's one third interest in the Waneta generation facility.[64] They also include water rental fees paid on water storage as well as miscellaneous water licences for the use of water for purposes other than power generation, including, for example, permits to use Crown Land, and irrigation. Further, water rentals also include the financial impact of

[63] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 38.

[64] Consistent with BCUC Order No. G-130-18, water rental fees paid on the generation output and capacity of BC Hydro's other two-thirds interest in the Waneta Generation Facility, purchased in 2017 and now leased to Teck, are classified as Non-Heritage Energy. For further information, refer to section 4.5.

reimbursements or payments of water rental fees related to BC Hydro's entitlement obligations under the Canal Plant Agreement and the Keenleyside Agreement.[65] These are energy transfers, not financial transactions; however, they may result in reimbursement or the payment of water rental fees.[66]

Total water rental fees are forecast to increase by $52.2 million in the fiscal 2022 Plan compared to the fiscal 2021 Plan, mainly due to higher hydro generation volumes in calendar year 2020 as a result of high inflows in the Peace and Columbia regions.

Water rental fees on the generation of energy are calculated as the actual energy output of the license holder from the prior calendar year multiplied by the current year water rental rates. Water rental fees on operating capacity are calculated as the maximum sustained capacity observed for the current year times the current year rate.

Table 4-3 provides a detailed breakdown of actual and forecast water rental rates.

Table 4-3 Water Rental Rates

Water Rental: General Power Use	Calendar Year			
	Actual		Forecast	
	2019	2020	2021	2022
Output (Tier 1) ($/MWh) < 160,000 MWh	1.404	1.436	1.449	1.475
Output (Tier 1) ($/MWh) > 160,000 MWh	6.546	6.697	6.757	6.879
Operating Capacity ($/kW)	4.678	4.786	4.829	4.916
Construction Capacity ($/kW)	0.467	0.478	0.482	0.491
B.C. CPI (%)	2.3	0.9	1.8	1.8

65 The Canal Plant Agreement is a coordination agreement where BC Hydro plans the dispatch of generating plants on the Kootenay and Pend-d'Oreille rivers that are owned by parties to the agreement (FortisBC Inc., Teck, Brilliant Power Corp, Brilliant Expansion Power Corp and Waneta Expansion Limited Partnership) and BC Hydro to optimize the generation of the system. The plant owners make the actual generation available to BC Hydro in exchange for a fixed monthly energy and capacity entitlement. Similarly, the Keenleyside Entitlement Agreement provides the project owner (Arrow Lakes Power Corporation) with an energy and capacity entitlement associated with the Arrow Lakes Hydro project on the Columbia River.

66 These energy transfers are reported as Exchange Net on line 3 of Schedule 4.0, Appendix A. For reporting of actuals, Exchange Net also includes energy that is used to reconcile the total sources of supply to the total recorded load, for financial statement purposes.

4.4.2 Natural Gas for Thermal Generation

Natural Gas for Thermal Generation includes the natural gas purchases, gas transportation, carbon tax, motor fuel tax and other related costs associated with BC Hydro's Prince Rupert and Fort Nelson generation facilities. The breakdown for each facility is provided in Table 4-4 below.

Table 4-4 Natural Gas for Thermal Generation

($ million)	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
	1	2	3	4	5
Fort Nelson	7.2	6.1	8.5	8.1	11.8
Prince Rupert	0.3	1.0	0.0	0.1	0.0
Total	7.5	7.1	8.5	8.2	11.8

The planned increase in the costs of natural gas for thermal generation for the fiscal 2022 Plan compared to the fiscal 2021 Plan is driven by the forecast higher volume of thermal generation at the Fort Nelson generating station.

Total natural gas costs for the Prince Rupert facility are planned to be zero in the fiscal 2022 Plan. This is because the Prince Rupert facility only runs for testing or to supply area load when the transmission line to Prince Rupert is out of service. Therefore, the facility is not modelled in the Energy Study.

4.4.3 Domestic Transmission - Other

This category includes transmission costs associated with BC Hydro's obligations under the Skagit River Valley Treaty.[67] These costs are generally stable from year to year. Approximately 75 per cent of costs are for wholesale transmission in British Columbia[68] to deliver energy to the B.C./U.S. border, and the remainder is for wholesale transmission in the United States to deliver energy from the B.C./U.S. border to the City of Seattle.

4.4.4 Columbia River Treaty Related Agreements

The Non-Treaty Storage Agreement[69] and a short-term coordination agreement related to the Libby Coordination Agreement[70] are coordination agreements related to the operation of the Columbia River Treaty reservoirs in Canada. These water coordination agreements provide for the release and storage of water to create mutual operational benefits in both Canada and the United States. The agreements are designed to create an average annual positive financial benefit to BC Hydro. The planned revenue in the fiscal 2022 Plan is higher than the fiscal 2021 Plan due to the lower amount of planned storage in fiscal 2022. The fiscal 2021 forecast revenue is higher than the fiscal 2021 Plan for the same reason.

[67] The Government of B.C. and the City of Seattle signed an agreement in 1984 concerning the supply of electricity to the City of Seattle (the Skagit River Valley Treaty). The Government of B.C. subsequently assigned certain rights and obligations under this agreement to BC Hydro. BC Hydro's domestic customers receive the benefit of revenues from sales to Seattle City Light, offset by the costs of serving this obligation. These revenues are included as Other Sector revenue as shown in Appendix A, Schedule 14, line 19.

[68] These domestic transmission costs are included in BC Hydro's Transmission Revenue Requirement and are recovered under the Open Access Transmission Tariff. These costs represent BC Hydro's use of point-to-point transmission service for the Skagit River Valley Treaty. In the Transmission Revenue Requirement, these costs are allocated to Cost of Energy via intersegment revenues which are reported in Appendix A, Schedule 3.4, line 21. This allocation of intersegment revenues ensures that costs are only recovered from ratepayers once.

[69] The Non-Treaty Storage Agreement is a coordination agreement between BC Hydro and the Bonneville Power Administration to operate non-treaty storage at Kinbasket Reservoir (Arrow Lakes).

[70] The Columbia River Treaty Short-term Entity Agreement on Coordination of Libby Project Operations between BC Hydro and Bonneville Power Administration and the U.S. Army Corps of Engineers.

4.4.5 Remissions and Other Serve to Offset Water Rental Costs

The *Water Sustainability Act* specifies remissions that are available to be applied against water rental payments. These remissions are compensation for restrictions or regulations imposed on the licensee arising from water use plans. Remissions are capped at $50 million per calendar year, with any excess associated with physical works requirements carried forward into future years.

Water Use Planning Remissions include:

- Remissions associated with the value of foregone energy, which are shown as a credit under Heritage Cost of Energy in Table 4-2; and
- Remissions associated with the recovery of operating costs incurred in delivery of monitoring and physical works programs, which are shown as a credit under operating costs.[71]

Total remissions associated with the value of foregone energy (offset in Cost of Energy) are planned to be $43.2 million in fiscal 2022, which is $16.5 million higher compared to the fiscal 2021 Plan. The forecast increase is primarily due to higher remissions collected at Bridge River and John Hart. The re-development project at John Hart and the anticipated water license renewal at Bridge River were expected to result in a decrease to BC Hydro's eligibility for remissions at the time that the fiscal 2021 Plan was prepared. However, remissions for these projects were subsequently approved by the Government of B.C. and therefore are included in the total remissions planned for fiscal 2022.

4.5 Cost of Non-Heritage Energy

Table 4-5 below provides a breakdown of the components of the Cost of Non-Heritage Energy. Each component is discussed in further detail in this section.

[71] The fiscal 2022 Plan amount is $13.9 million.

The fiscal 2022 Plan is $64.3 million higher than the fiscal 2021 Plan, primarily due to the higher forecast cost of IPPs and Long-Term Commitments, which is the largest component of Non-Heritage Energy costs.

Table 4-5 Cost of Non-Heritage Energy

Cost of Heritage Energy ($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
IPPs and Long-Term Commitments[1]	4.0 L33	1,294.7	1,314.0	1,410.8	1,388.7	1,475.7
Non-Integrated Area	4.0 L34	30.5	31.3	30.2	26.1	27.4
Gas & Other Transportation	4.0 L35	3.7	4.5	2.5	5.2	4.9
Water Rentals (Waneta 2/3)	4.0 L36	3.7	3.3	3.7	3.2	3.5
Total	4.0 L37	1,332.4	1,353.1	1,447.2	1,423.1	1,511.5

1 These values are after Accounting Adjustments.

4.5.1 IPPs and Long-Term Commitments

The IPPs and Long-Term Commitments category generally includes the costs of EPAs that BC Hydro has entered into with IPPs for supply to the integrated system. As of August 2020, on the integrated system, BC Hydro has EPAs with 120 IPPs in commercial operation and seven IPP projects in development. As discussed in section 4.2 above, other than some EPA renewals, BC Hydro is not acquiring new resources from IPPs (except for a small number of potential new First Nations energy projects).

The electricity supplied by IPPs on BC Hydro's integrated system is approximately 25 per cent of BC Hydro's electricity supply and helps to meet BC Hydro's load requirements. IPP projects are developed by companies specializing in power production, as well as by municipalities, First Nations and BC Hydro customers, using resources such as wind, water, biomass, solar and waste heat. A breakdown of the actual and forecast costs for BC Hydro's EPAs for the integrated system supply is provided in Table 4-6 below.

IPPs and Long-Term Commitment costs for the integrated system are forecast to increase by $64.9 million from the fiscal 2021 Plan to the fiscal 2022 Plan. The fiscal 2022 Plan costs are primarily associated with existing EPAs, the terms of which are set, but can be impacted by factors related to IPP operations and/or prescribed terms of an EPA being exercised by an IPP. The forecast increase in IPP energy costs from the fiscal 2021 Plan to the fiscal 2022 Plan is in large part due to predetermined factors, such as terms included in existing EPAs, increased forecast energy deliveries as permitted under existing agreements, and new IPP projects under existing EPAs reaching commercial operation. Approximately 75 per cent of BC Hydro's EPA portfolio is comprised of hydro and wind generation, and the amount of generation under these contracts is driven by environmental factors, and other operational factors, which may cause actual energy deliveries to vary significantly from year to year.

Table 4-6 below provides the IPP and Long-Term Commitment costs for the integrated system. For the purposes of Table 4-6, the volume associated with an EPA renewal is generally included in the total for the procurement call process, as listed below, in which the IPP project was originally provided an EPA by BC Hydro.

Table 4-6 IPP and Long Term Purchase Costs for the Integrated System

Call Process ($ Million)	No. of EPAs[1]	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
Pre-2003 Electricity Purchase Agreements[2]	29	293.5	275.6	281.0	277.6	284.0
2003 Green Power Generation Call	6	33.3	33.9	34.8	35.1	34.8
2006 Open Call	17	182.4	178.2	196.8	194.6	195.3
2008 Bioenergy Call - Phase 1	2	24.0	14.6	19.8	19.0	17.8
2008/10 Standing Offer Program[3]	27	44.3	45.5	54.6	48.8	61.4
2010 Bioenergy Call - Phase 2	4	75.1	65.8	78.4	75.2	88.0
2010 Clean Power Call	20	320.0	328.6	351.3	319.5	349.0
2010 Integrated Power Offer	7	153.3	157.1	146.2	142.4	132.4
Negotiated Electricity Purchase Agreements[4]	15	290.2	331.6	366.1	380.7	438.6
Expected Standing Offer Program Projects and other First Nations Commitments[5]	4	0.7	-	3.7	-	-
Total	**131**	**1,416.9**	**1,430.9**	**1,532.8**	**1,492.9**	**1,601.3**
Accounting Adjustments		(122.1)	(116.8)	(122.0)	(104.2)	(125.6)
IPPs and Long-Term Commitments	**131**	**1,294.7**	**1,314.0**	**1,410.8**	**1,388.7**	**1,475.7**

1 Number of EPAs with IPPs on the integrated system as of August 1, 2020. The numbers in this row may not align with the number of EPAs which were associated with fiscal 2020 and fiscal 2021 values because some EPAs expired/terminated, and some EPAs became operational since the filing of the Previous Application.

2 The costs in this row (Pre-2003 EPAs) also include miscellaneous energy purchases, such as energy purchases for border accommodations. The number of EPAs on this row has decreased from 31 EPAs in the Previous Application to 29 EPAs due to two EPAs which have been terminated.

3 The number of EPAs in this row (2008/10 Standing Offer Program) has increased by one since the Previous Application; two EPAs which have executed and one EPA that was terminated.

4 The costs in this row (Negotiated EPAs) also include two other energy supply contracts which are not considered to be IPP EPAs. These are the Surplus Power Rights Agreement between Teck and BC Hydro and the Residual Capacity Agreement between FortisBC Inc. and BC Hydro. The number of EPAs in this row has increased due to an EPA which was executed related to a First Nations Commitment.

5 The costs shown are expected costs for future EPAs. Once an EPA is executed, the costs are included in the appropriate call process.

The Accounting Adjustments shown in Table 4-6 above largely reflect energy costs for EPAs which are accounted for as capital leases under the current accounting standards. For those EPAs that are deemed to be capital leases, for accounting purposes, their costs are recorded as operating costs, taxes, amortization, finance charges as well as Cost of Energy.

4.5.2 Non-Integrated Areas

Fourteen communities in the Non-Integrated Areas are not connected to BC Hydro's integrated system and are served by local generating facilities and distribution networks. Generating capacity in these areas is provided by a combination of BC Hydro owned diesel generating stations, as well as six IPP facilities (five hydro and one biomass), and one BC Hydro owned hydro facility[72] in the Bella Coola region. While IPPs may displace a portion of diesel generation, the diesel generation facilities must be in place for supply reliability. The Non-Integrated Areas generation costs, as referenced in Table 4-6 above, are provided in Table 4-7 below with a further breakdown showing BC Hydro's diesel generating costs and IPP costs.

Table 4-7 Non-Integrated Areas Generation Costs

Non-Integrated Areas ($million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
NIA - BC Hydro Diesel Generating Stations		20.6	23.3	20.4	15.9	17.6
NIA - IPPs		9.9	8.0	9.8	10.1	9.9
Total	4.0 L34	30.5	31.3	30.2	26.1	27.4

Energy volumes in the Non-Integrated Areas are relatively stable with a slight decrease expected in the fiscal 2022 RRA Plan. Variations in costs are largely driven by fluctuations in fuel prices for BC Hydro's diesel generation facilities. Fuel prices are based on the Annual Energy Outlook Report issued by the U.S. Energy Information Administration. To the extent that diesel prices ultimately differ from the

[72] The BC Hydro owned hydro facility is the Clayton Falls Generating Station. The actual water rental costs for this facility, which are approximately $0.1 million per year, are included with Water Rentals for ease of reporting.

forecast prices, the variance will be captured in the Non-Heritage Deferral Account for future recovery from, or refund to, ratepayers.

4.5.3 Gas and Other Transportation Costs

Gas and other transportation costs, as shown in Table 4-6 above, include fuel costs related to certain generation agreements for transmission-related issues, such as fuel costs for temporary generation at Kitsault. It also includes external electricity transmission costs related to the servicing domestic load in Fort Nelson from energy imported from Alberta as well as wheeling charges to serve the domestic load in the Goodlow (Boundary Lake), Rogers Pass, and Duck Lake areas.

Total forecast costs for the fiscal 2022 Plan are $4.9 million, an increase of $2.4 million from the fiscal 2021 Plan. The increase is largely due to higher costs for certain wheeling agreements, including one wheeling agreement which was not included in the fiscal 2021 Plan as the contract had expired and there were no forecast costs for a renewal agreement. This wheeling agreement was renewed in fiscal 2021.

4.5.4 Water Rentals (Waneta Two-Thirds)

Water rentals associated with BC Hydro’s two-thirds interest in Waneta are shown in Table 4-6 above. However, BC Hydro’s two-thirds interest in Waneta is leased to Teck.[73] Teck is responsible for all operating costs, including paying for its share of water rentals. These costs are shown as an offset in Miscellaneous Revenues.[74]

4.6 Cost of Market Energy

BC Hydro engages in energy transactions with Powerex to optimize the system storage, and these purchases and sales are referred to as Market Energy. The categorization of Market Energy in the Application differs from the Previous

[73] In 2017, BC Hydro entered into a purchase agreement with Teck for the remaining two-thirds interest of the Waneta generation facility. The BCUC approved this purchase by BCUC Order No. G-130-18. The 2017 Waneta transaction includes a long-term lease agreement with Teck. Under the arrangements with Teck, BC Hydro continues to use its one-third interest in Waneta to serve its domestic load obligations.

[74] Refer to Appendix A, Schedule 15.0, line 22.

Application due to the 2020 TPA between BC Hydro and Powerex. The 2020 TPA came into effect on April 1, 2020, replacing the previous Transfer Pricing Agreement (**2003 TPA**), and contains two classifications of Market Energy (as opposed to three under the 2003 TPA). BC Hydro has submitted the 2020 TPA to the BCUC under section 71 of the *Utilities Commission Act* and it is being reviewed through a separate proceeding.

Transactions between BC Hydro and Powerex under the 2020 TPA are summarized in Schedule 4.0 of Appendix A and are included as components of Cost of Energy. In this respect, there is no difference between the accounting under the 2020 TPA and the 2003 TPA. However, as discussed further below, the classification of energy transactions has changed.

4.6.1 Classification of Energy Transactions in the Previous Application Under the 2003 TPA

Under the 2003 TPA, energy transactions were classified under the following three categories:

- **Market Electricity Purchases** – represented market purchases of electricity from Powerex by BC Hydro to meet domestic load requirements;
- **Surplus Sales** – represented sales of electricity by BC Hydro to Powerex, when BC Hydro generation exceeded domestic load requirements; and
- **Net Purchases (Sales) from Powerex** – represented purchases and sales between BC Hydro and Powerex for the purpose of trade related activities. These were presented on a net basis.

4.6.2 Classification of Energy Transactions in This Application Under the 2020 TPA

Under the 2020 TPA, energy transactions are classified under the following categories:

- **System Exports** – represents sales of electricity to Powerex by BC Hydro; and

- **System Imports** – represents purchases of electricity by BC Hydro from Powerex and thermal generation run for Powerex.[75]

While transactions under the 2020 TPA are categorized differently than under the 2003 TPA, the nature of the transactions has not changed. BC Hydro is still financially accountable for the sale of surplus energy and the purchase of energy to meet domestic load requirements, while Powerex is still financially accountable for purchases and sales to generate Trade Income. The ability to defer variances between forecast and actual System Exports and System Imports is covered by the scope of existing orders.[76]

Table 4-8 and Table 4-9 below show the breakdown of the Cost of Market Energy under both the 2003 TPA and the 2020 TPA. Table 4-8 is based on the 2003 TPA and provides the fiscal 2021 RRA values in column 3. As of April 1, 2020, BC Hydro has been operating under the 2020 TPA and therefore, Table 4-9 provides the values as of April 1, 2020, under the 2020 TPA. In Table 4-9, the fiscal 2021 RRA values have been reclassified to illustrate the categories into which transactions would be classified under the 2020 TPA. The total amount of $(98.4) million remains the same for fiscal 2021 RRA in both tables, as shown below. Only the classification of the components has changed.

[75] Powerex can purchase the gas for Island Generation at its cost and receive the electricity as an import into the Transfer Volume Account under the 2020 TPA.

[76] In accordance with BCUC Order No. G-96-04, Directive 11, BC Hydro deferred variances between forecast and actual Market Electricity Purchases and Surplus Sales to the Heritage Deferral Account, and in accordance with BCUC Order No. G-96-04, Directive 12, BC Hydro deferred variances between forecast and actual Net Purchases (Sales) from/to Powerex to the Non-Heritage Deferral Account. The scope of the variances covered by these existing orders is equivalent to the variances between forecast and actual System Exports and System Imports. Therefore, such variances will be deferred to the Non-Heritage Deferral Account. Refer to Appendix U, section 7.7.1 for a discussion of Cost of Energy Variance accounts.

Table 4-8 Cost of Market Energy – based on 2003 TPA

Cost of Energy ($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
		1	2	3	4	5
TPA Reference Agreement		**2003 TPA**	**2003 TPA**	**2003 TPA**		
Market Electricity Purchases	4.0 L38	150.6	133.1	43.7		
Surplus Sales	4.0 L39	(0.4)	(1.0)	(165.1)		
Net Purchases (Sales) from Powerex	4.0 L42	33.1	(35.2)	6.1		
Domestic Transmission – Export	4.0 L43	1.1	2.0	17.0		
Total	4.0 L44	184.4	99.0	(98.4)		

Table 4-9 Cost of Market Energy – based on 2020 TPA

Cost of Energy ($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA - Reclassified	F2021 Forecast	F2022 Plan
		1	2	3	4	5
TPA Reference Agreement				2020 TPA	2020 TPA	2020 TPA
System Imports	4.0 L40			153.9	37.8	77.1
System Exports	4.0 L41			(269.2)	(211.0)	(296.5)
Domestic Transmission – Export	4.0 L43			17.0	45.1	27.5
Total	4.0 L44	0.0	0.0	(98.4)	(128.1)	(191.9)

The Cost of Market Energy is forecast to decrease by $93.5 million in the fiscal 2022 Plan compared to the fiscal 2021 Plan, largely due to lower System Imports and higher System Exports driven by higher water inflows.

4.6.3 Domestic Transmission – Export

The costs associated with the use of BC Hydro's transmission system for System Export pursuant to the Open Access Transmission Tariff (**OATT**) is referred to as Domestic Transmission – Exports. Under the 2003 TPA, these costs were determined based on the forecast percentage of Surplus Sales relative to the total of Surplus Sales and trade related sales, using the historical average unit transmission cost for domestic exports. Under the 2020 TPA, since these activities are no longer separated, BC Hydro's forecast annual system surplus relative to forecast System Exports is used in the calculation of BC Hydro's domestic transmission costs. As shown in Table 4-9 above, due to a higher forecast annual system surplus, the fiscal 2022 Plan amount is $10.5 million higher than the fiscal 2021 Plan amount.

BC Hydro
Power smart

BC Hydro Fiscal 2022
Revenue Requirements Application

Chapter 5

Operating Costs

Table of Contents

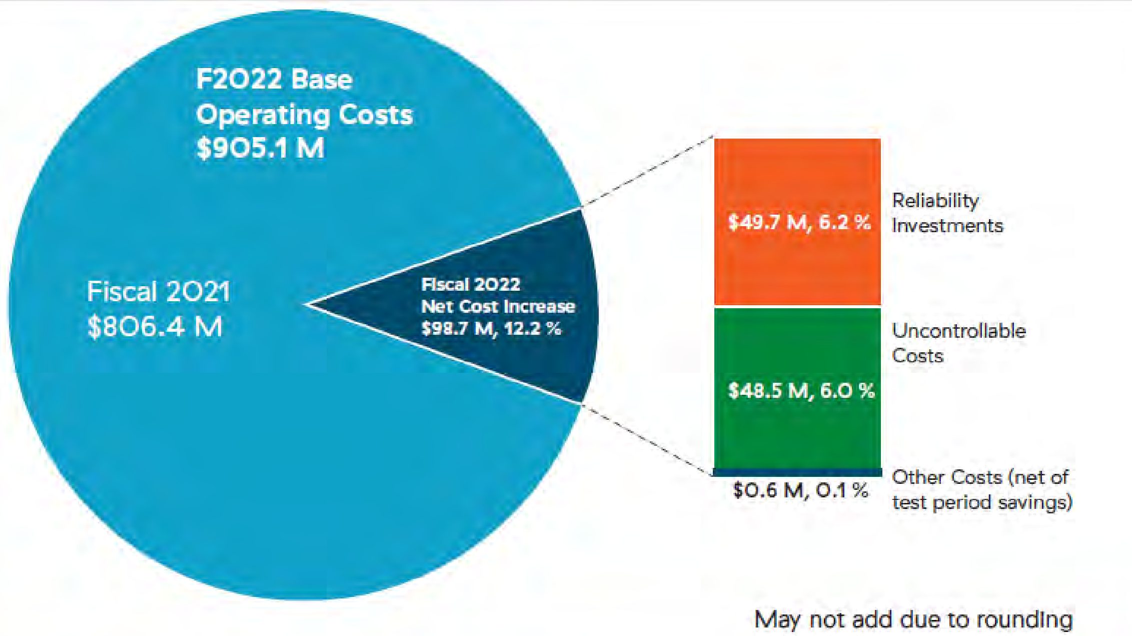
List of Figures

List of Tables

5.1 Introduction

This chapter describes our planned operating costs and full-time equivalents (**FTEs**) for the Test Period. BC Hydro's base operating costs[77] are increasing by $98.7 million (or 12.2 per cent) from fiscal 2021 to fiscal 2022. As shown in Figure 5-1 below, this increase is driven by reliability investments, as well as uncontrollable cost pressures that are increasing due to changing market conditions. Other cost pressures have been largely offset by identified cost savings.

Figure 5-1 Summary of Base Operating Cost Increases



Base Operating Cost – $ million	F2021	F2022	$ Increase	% Increase
Appendix A, Schedule 5.0, line 9	806.4	905.1	98.7	12.2 %
	a	b	c=b–a	c/a

77 Base operating costs continue to be, in BC Hydro's view, the relevant measure for the assessment of our efforts to control operating costs because they exclude costs that, among other things, vary according to changes in accounting rules and the mechanisms in place to recover regulatory account balances.

This chapter is organized around the following key points:

- Section 5.2 summarizes how BC Hydro has considered and responded to the directives and comments related to operating costs in the BCUC's Decision on the Previous Application;
- Section 5.3 explains that BC Hydro has maintained the Plan-Build-Operate-Support organizational structure. There have been limited organizational changes since the Previous Application, except for the centralization of BC Hydro's compliance function to enhance collaboration and consistency to address critical reliability standards work;
- Section 5.4 explains how BC Hydro's fiscal 2022 budgeting process was consistent with the process used in the Previous Application, accelerated to meet the regulatory cycle for this Application;
- Section 5.5 provides an overview of BC Hydro's operating costs during the Test Period:
  - Base operating costs are increasing primarily to fund:
    - Reliability investments to maintain and achieve compliance with Mandatory Reliability Standards (**MRS**) and to improve vegetation management and cybersecurity controls and processes;
    - Uncontrollable cost increases mainly due to discount rate changes for current service pension costs; and
    - Other cost increases to support employee training, Supply Chain Application sustainment and electric vehicle charging infrastructure.
  - BC Hydro has achieved reductions in costs through lease accounting changes, trainee savings due to reduced apprentice intakes, in-housing of the reliability coordinator function from Peak Reliability, and capital overhead savings as result of increased costs eligible for capitalization.

- ▶ BC Hydro has implemented mitigation strategies to manage cost pressures and avoid cost increases, such as freezing management and professional salaries for fiscal 2022 and re-deploying personnel to emergent issues as part of our response to the COVID-19 pandemic.

- Section 5.6 describes the increased funding during the Test Period to maintain and achieve compliance with MRS. BC Hydro regards these incremental costs as non-discretionary. They represent a significant step forward in BC Hydro's MRS program and will ensure the successful implementation of the latest version of the Critical Infrastructure Protection (**CIP**) standards. BC Hydro's actions are aligned with the BCUC's commentary in its Decision on the Previous Application;
- Section 5.7 describes our vegetation management program and how increased funding in fiscal 2022 is required because (i) vegetation that was cleared during a period of heightened activity over a decade ago has regrown, (ii) cost pressures have increased and can no longer be absorbed in existing budgets, and (iii) climate change is impacting the growth rate and health of vegetation. This responds to Directive 22 of the BCUC's Decision on the Previous Application;
- Section 5.8 explains our cybersecurity program and how increased funding in fiscal 2022 will address the growing sophistication of cybersecurity threats by improving the security system and addressing items identified through cybersecurity maturity assessments and audits. This responds to Directive 21 of the BCUC's Decision on the Previous Application;
- Section 5.9 explains how increased funding for employee training will help meet evolving safety, regulatory and technical training requirements. BC Hydro's actions are aligned with the BCUC's commentary in its Decision on the Previous Application;

- Section 5.10 explains how the COVID-19 pandemic has had a significant impact on BC Hydro's fiscal 2021 operating costs. Further financial impacts remain possible and are uncertain;
- Section 5.11 provides an overview of BC Hydro's FTEs and Labour Costs:
  - BC Hydro's total FTEs (excluding the Site C project) will remain flat during the Test Period. Operating FTEs have remained relatively flat since fiscal 2012. In the Test Period, operating FTEs are increasing due to investments in MRS, vegetation management and cybersecurity. The increase in operating FTEs is offset by a reduction in capital FTEs resulting from a reduction in apprentice and trainee intakes;
  - In response to the COVID-19 pandemic, BC Hydro redeployed employees to respond to emergent issues and to optimize our workforce;
  - In accordance with Directive 20 of the BCUC's Decision on the Previous Application, BC Hydro has analyzed the vacancy factor savings realized in the prior test period. The results of our analysis reinforce the reasonableness of the amount included in the Previous Application and the appropriateness of using the same forecast savings in the Test Period;
  - The increase in BC Hydro's standard labour rates is primarily due to an increase in current service pension costs as a result of a lower discount rate that is market driven. Current service pension costs relate to BC Hydro's pension program and represent the cost of the future benefits earned by the employees in the current year; and
  - In response to the COVID-19 pandemic, salaries for management and professional staff are frozen for the Test Period; and
- Section 5.12 provides an overview of BC Hydro's Power System maintenance costs, which have increased to support improvements to vegetation

management. This responds to Directive 22 of the BCUC's Decision on the Previous Application.

5.2 BC Hydro's Approach to Operating Costs Reflects the BCUC's Directives and Comments

In its Decision on the Previous Application, the BCUC accepted BC Hydro's forecast fiscal 2020 and fiscal 2021 operating costs. However, the BCUC also made directives and comments related to operating costs, to which BC Hydro has responded in this chapter. BC Hydro's approach to operating costs in the Application aligns with the BCUC's commentary. Specifically, BC Hydro has continued to focus on cost control, while investing in areas we had foreshadowed in the last proceeding and that were specifically identified in the Decision as potentially meriting further investment.

Table 5-1 below summarizes the BCUC's directives and comments on operating costs and our response. It also indicates where further information on BC Hydro's response can be found.

Table 5-1 Response to BCUC Directives and Comments on Operating Costs

Topic	BCUC Directives / Comments	Summary and Location of BC Hydro's Response
Tracking of Vacancy Factor Savings	BC Hydro applies a "vacancy factor" reduction to its forecast operating costs to recognize the savings that occur from positions being vacant for periods of time due to various factors. Directive 20 directed BC Hydro to begin tracking, measuring and reporting on the annual actual vacancy factor savings and to provide a rationale for any significant differences from the forecast savings.	Section 5.11.3 provides a summary of the estimated fiscal 2020 vacancy factor savings actual results, which reinforce the reasonableness of the forecast savings included in the Previous Application and the appropriateness of using the same forecast savings in the Test Period.

Topic	BCUC Directives / Comments	Summary and Location of BC Hydro's Response
Cybersecurity Funding	Directive 21 directed BC Hydro to address the adequacy of its cybersecurity programs with respect to its distribution and head office functions.	Section 5.8 explains our cybersecurity program and how increased funding in fiscal 2022 will address the growing sophistication of cybersecurity threats by improving the security system and addressing items identified through cybersecurity maturity assessments and audits.
Vegetation Management Funding	Directive 22 directed BC Hydro to address the adequacy of its vegetation management funding.	Section 5.7 describes our vegetation management program and how increased funding in fiscal 2022 is required because vegetation that was cleared during a period of heightened activity over a decade ago has regrown, cost pressures have increased and can no longer be absorbed in existing budgets and climate change is impacting the growth rate and health of vegetation.
Areas That May Require Additional Funding	The BCUC identified five areas where it was concerned that cost cutting may have been too aggressive or needed increases may have been put on hold. These areas were employee training, energy studies, vegetation management, cybersecurity and safety.	As noted above, section 5.8 addresses cybersecurity and section 5.7 addresses vegetation management. Section 5.9 explains how increased funding for employee training will help meet evolving safety, regulatory and technical training requirements. In section 5.11.1 we note that an additional FTE has been added to the Energy Studies team within the Generation System Operations Key Business Unit. Also, in our recent Compliance Filing to the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, we described work being advanced on additional enhancements to the Energy Studies models. In accordance with Directive 23, BC Hydro will consider the BCUC's comments with regard to safety in its Fiscal 2023 Revenue Requirements Application.

Topic	BCUC Directives / Comments	Summary and Location of BC Hydro's Response
Impact of the COVID-19 Pandemic	Directive 65 directed BC Hydro to report on the impact of the COVID-19 pandemic and plans to handle the resulting impact.	Section 5.10 provides a summary of the operating cost pressures and savings which were caused by the COVID-19 pandemic in fiscal 2021 and the cost reduction strategies BC Hydro has implemented in response. BC Hydro has not forecast any COVID-19 related cost pressure in the Test Period.

5.3 Overview of How BC Hydro is Organized

BC Hydro has six Business Groups, made up of 40 Key Business Units (**KBUs**). We continue to be organized based on a centralized organizational structure that aligns with the work functions that we perform. We refer to this structure as our Plan Build Operate Support model. This model is continuing to drive benefits throughout the organization and has been maintained with changes to improve our compliance efforts and meet evolving business needs.

Our Business Groups and their respective KBUs are summarized in Table 5-2 below.

Table 5-2 Business Groups and KBUs[78]

	Business Group	Key Business Unit
Plan	Integrated Planning	Energy Planning and Analytics
		Dam Safety
		Stations Asset Planning
		Line Asset Planning
		Interconnections and Shared Assets
		Engineering Design
		Engineering Services

[78] Each of the six Business Groups ("Other" is not a business group) also include a Business Unit Support KBU, which brings the total KBUs to 40. These KBUs are relatively small and primarily include funding for BC Hydro's Executive Team members and their support staff.

	Business Group	Key Business Unit
Build	Capital Infrastructure Project Delivery	Project Delivery
		Indigenous Relations
		Environment
		Properties
Operate	Operations	Program and Contract Management
		Line Field Operations
		Stations Field Operations
		Distribution Design and Customer Connections
		Construction Services
		Generation System Operations
		Transmission and Distribution System Operations
Support	Safety & Compliance	Safety Systems and Assurance
		Learning and Development
		Field Safety Services
		Security and Emergency Management
		Reliability Compliance
	Finance, Technology, Supply Chain	Finance
		Technology
		Supply Chain
	People, Customer, Corporate Affairs	Human Resources
		Customer Service
		Conservation and Energy Management
		Communications and Community Engagement
		Regulatory and Rates
		Ethics and Merit Office
	Other	Office of the General Counsel
		Office of the President and Chief Executive Officer

Since the Previous Application, there have been minimal notable organizational changes:

- Accountability for oversight of reliability compliance across the organization has been added to the re-named Safety and Compliance Business Group, led by the Senior Vice President of Safety and Compliance and Chief Compliance Officer. Given our increasing compliance responsibilities, centralization of the compliance function accountability enhances collaboration and consistency across the organization to address critical reliability standards work. This is discussed further in section 5.6 below;

- The Engineering KBU has been restructured into two distinct KBUs that group similar teams together to facilitate improved collaboration and consistency:
  - The Engineering Design KBU is responsible for design and engineering standards, and facilitates coordination on high risk, system-wide, and cross-discipline design, technical, and operational issues; and
  - The Engineering Services KBU is responsible for multi-disciplinary shared services across the company including Stations maintenance engineering, estimating and project engineering, quality, geomatics, and drafting;
- The functions of the Power Acquisitions and Contract Management KBU were integrated within other KBUs to align with other related work across the company, specifically:
  - The commercial analysis and negotiations function for complex commercial negotiations transitioned to the Treasury Department in the Finance KBU within the Finance, Technology, and Supply Chain Business Group. Centralization of this function within Treasury will enhance our ability to apply advanced financial analytics tools and consistency across the company. This Department also manages company-wide large, complex, non-standard transactions (e.g., the Waneta transaction); and
  - The IPP portfolio management function has transitioned to the Generation System Operations KBU in the Operations Business Group. This transition allows for greater alignment of energy sourcing accountabilities within Generation System Operations.

5.4 Fiscal 2022 Budgeting Process Was Consistent with Previous Application

BC Hydro's approach to its budgeting process was consistent with prior years, only accelerated due to the shift in the regulatory cycle.

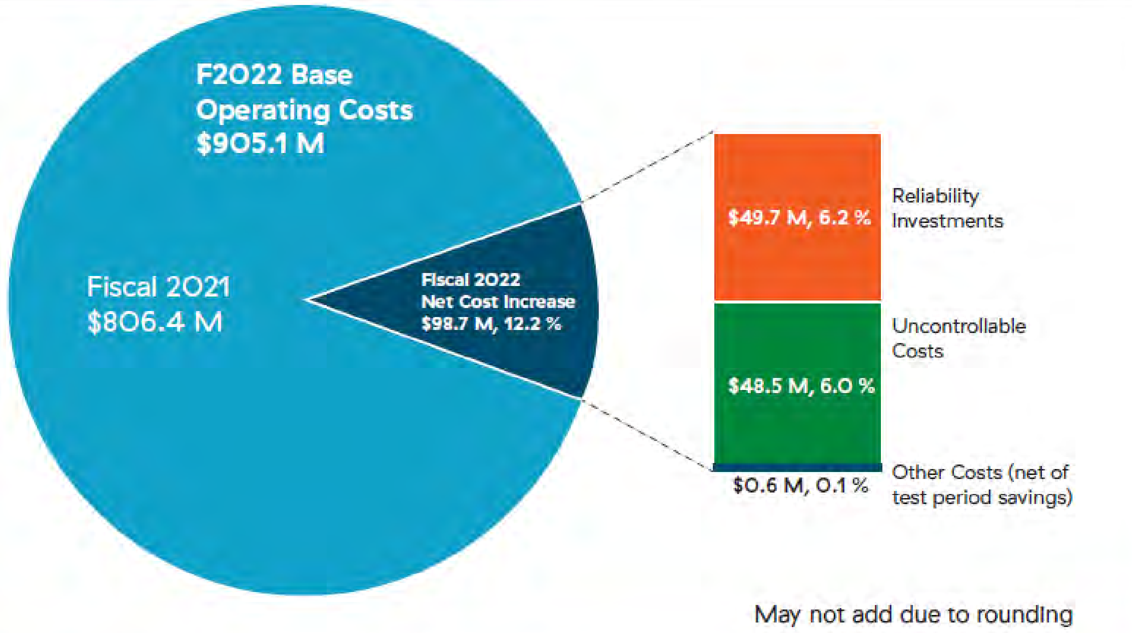
A description of BC Hydro's budgeting process can be found in section 5.4 of Chapter 5 of the Previous Application. The budgeting process again incorporated top-down and bottom-up elements. The Executive Team provided the necessary governance and oversight. The budgeting process incorporated expenditure reprioritization and trade-off decisions to respond to emerging cost pressures facing BC Hydro.

BC Hydro continues to have appropriate financial oversight processes in place, consistent with prior years, so that operating cost budgets determined through the budgeting process are maintained.

5.5 Fiscal 2022 Operating Costs Increases Are Primarily Driven by Reliability Investments and Uncontrollable Factors

This section outlines the fiscal 2022 forecast operating costs. BC Hydro's base operating costs are increasing by $98.7 million (or 12.2 per cent). This is shown in Figure 5-2 below. In the Previous Application proceeding, BC Hydro foreshadowed the need for increased funding for MRS, improvements to vegetation management, and enhancements to its cybersecurity programs. These incremental investments also respond to Directives 21 and 22 of the BCUC's Decision, which directed BC Hydro to address the adequacy of funding in these areas.

Figure 5-2 Summary of Base Operating Costs Increases



Base Operating Cost – $ million	F2021	F2022	$ Increase	% Increase
Appendix A, Schedule 5.0, line 9	806.4	905.1	98.7	12.2 %
	a	b	c=b−a	c/a

1. As discussed in section 5.1 and shown in Figure 5-2, the net increase in base operating costs in the Application can be separated into three categories: Reliability investments of $49.7 million (or 50.3 per cent of the increase), including:

   (i) Increased costs to maintain and achieve compliance with MRS, further described in section 5.6;

   (ii) Increased costs for vegetation management due to re-growth of previously cleared vegetation, increased cost pressures and impacts of climate change, further described in section 5.7; and

(iii) Increased costs to enhance cybersecurity programs, improve systems security and address items identified through the cybersecurity maturity assessments and audits, further described in section 5.8;

2. Uncontrollable cost increases of $48.5 million (or 49.1 per cent of the increase), including:

(i) Increased labour costs due to changing discount rates for current service pension costs[79] and a general wage increase for union employees mandated by existing union collective agreements. Pension benefits remain unchanged from the Previous Application, further discussed in section 5.11.5. Salaries for management and professional staff are frozen, further discussed in section 5.5.3 and section 5.11.4;

(ii) Increased costs for BCUC and Canada Energy Regulator Cost Recovery Levies to bring the fiscal 2022 forecast in line with actual fiscal 2021 levies assessed to BC Hydro by these entities, further described in section 5.5.3, Table 5-5; and

(iii) Increased costs for property, general liability, and Directors and Officers liability insurance coverage due to contracted coverage in the market and less competition among insurers, which has resulted in substantial premium increases, further described in section 5.5.3, Table 5-5; and

3. Other net cost increases of $0.6 million (or 0.6 per cent of the increase) comprised of the following:

(i) Other cost increases of $6.8 million, further described in section 5.5.3, including increased employee training costs (refer to section 5.9);

[79] Current Service Costs are for future pension benefits earned by employees in the current year and are determined by BC Hydro's external actuary. The present value of future pension benefits earned by employees in the current year are determined using the market discount rate determined at the date of the forecast. The market discount rate is based on AA Canadian Corporate bond yields. Current service costs are sensitive to changes in the market discount rate. A decrease in the market discount rate will increase current service costs, and vice versa. Current service costs are shown in section 5.11.5, including Table 5-19, which shows changes in discount rates and current service costs in recent years.

increased costs for the sustainment and maintenance of the recently implemented SAP Supply Chain Application; and, expenditures related to electric vehicle charging infrastructure which are prescribed undertakings under the Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**); nearly offset by

(ii) Savings of $6.2 million, further described in section 5.5.4, including reductions due to accounting changes, savings from the in-housing of the reliability coordinator function from Peak Reliability (**PEAK**) and reductions related to a delay in apprentice intakes.

5.5.1 Base Operating Costs Should be the Focus when Assessing BC Hydro's Cost Management

Consistent with the Previous Application, we use various terminologies when describing BC Hydro's operating costs. Table 5-3 below shows the various operating cost views. Base operating costs continue to be, in BC Hydro's view, the relevant measure for the assessment of our efforts to control operating costs because they exclude costs that, among other things, vary according to changes in accounting rules and the mechanisms in place to recover regulatory account balances.

BC Hydro reports its base operating costs as part of its Annual Service Plan.

Table 5-3 Explanation of Operating Cost Views

Cost Components	Base Operating Costs	Net Operating Costs	Gross Operating Costs	Current Operating Costs
Normal day to day operations of BC Hydro including costs such as Labour, Materials and Services.	✓	✓	✓	✓
Recoveries, Capitalized Costs, Re-Classification Adjustment	✓	✓	✓	✓
IPP Capital Leases, Capital overhead that can no longer be capitalized under IFRS, Cost related to BC Hydro's purchase of Teck's two-third interest in Waneta, Customer Crisis Fund		✓	✓	✓
Costs incurred in the current period but recovered in rates in future years consistent with the recovery mechanisms established for each regulatory account.			✓	
Costs incurred in prior periods to be recovered in the current period consistent with the recovery mechanisms established for each regulatory account.				✓

5.5.2 Overview of the Change in Base Operating Costs

Figure 5-3 below provides a visual breakdown of cost increases and savings for fiscal 2022.

Figure 5-3 Fiscal 2022 Base Operating Cost Changes

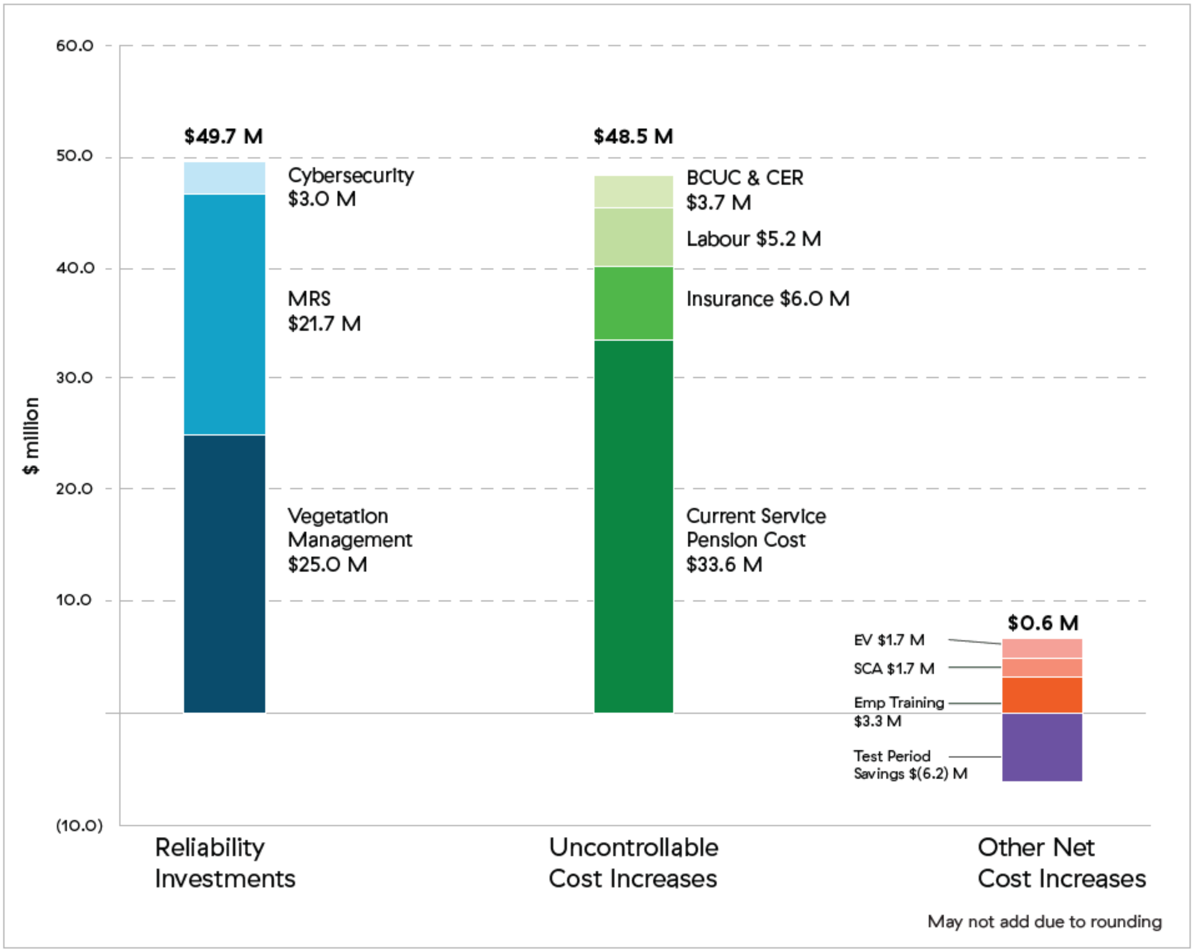


Figure 5-3 shows that the base operating cost increase can be characterized into three categories - reliability investments, uncontrollable cost increases and other net cost increases (other cost increases are nearly offset by cost savings).

Table 5-4 below provides a continuity table by Business Group that summarizes the changes to base operating costs in fiscal 2022 compared to fiscal 2021. Operating costs for each Business Group and Key Business Unit are provided in Schedule 5.1 to Schedule 5.7 of Appendix A – Financial Schedules.

Table 5-4 Summary of Changes to Base Operating Costs by Business Group[80]

	F2022 Plan ($ million)	Ref	BC Hydro	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	People, Customer, Corporate Affairs	Other
1	**F2021 Revenue Requirement Application Plan**	a	**1,007.5**	**293.0**	**81.1**	**246.0**	**57.5**	**264.8**	**117.2**	**(52.0)**
2	**Compliance Filing Adjustment**	b	**2.5**	**(1.0)**	**-**	**4.2**	**-**	**-**	**(0.7)**	**-**
3	Reorganizational Impact	c	-	9.1		(4.3)	1.0		(5.8)	
4	**F2021 Revenue Requirement Application Plan (Schedule 5.0, line 15)**	d = a+b+c	**1,010.0**	**301.1**	**81.1**	**245.8**	**58.5**	**264.8**	**110.7**	**(52.0)**
5	Reorganizational Impact	e	(0.0)	0.7	(0.1)	(2.8)	0.2	1.3	0.6	0.0
6	Budget Transfers Between Business	f	0.0	4.8	1.0	4.8	1.2	13.2	6.4	(31.3)
7	**Less:**									
8	IFRS Ineligible Capital Overhead	g	(192.5)	-	-	-	-	-	-	(192.5)
9	Waneta 2/3rd Operating Costs	h	(5.9)	(5.9)	-	-	-	-	-	-
10	Customer Crisis Fund Operating Costs	i	(5.3)	-	-	-	-	-	(5.3)	-
11		j = Σ g to i	**(203.6)**	**(5.9)**	**-**	**-**	**-**	**-**	**(5.3)**	**(192.5)**
12	**F2021 Base Operating Costs**	k= d+e+f+j	**806.4**	**300.7**	**82.0**	**247.8**	**60.0**	**279.2**	**112.3**	**(275.7)**
13	**Test Period Savings**	l	**(6.2)**		**(0.1)**	**(2.4)**	**(0.9)**	**(0.4)**		**(2.3)**
14	**Test Period Cost Increases**									
15	**Reliability Investments**									
16	Mandatory Reliability Standards		21.7	10.0	-	2.2	6.7	2.1	-	0.7
17	Vegetation Management		25.0	25.0	-	0.1	-	-	-	-
18	Cyber Security		3.0	-	-	-	-	3.0	-	-
19		m	**49.7**	35.0	-	2.3	6.7	5.1	-	0.7
20	**Uncontrollable Cost Increases**									
21	Current Service Pension Costs		33.6							
22	Other Labour Costs		5.2							
23	Current Service Costs and Other Labour Costs		38.8	9.5	2.4	10.4	2.5	7.6	5.0	1.4
24	Property, General Liability, and Directors and Officers Liability Insurance		6.0	-	-	-	-	6.0	-	-
25	BCUC and Canada Energy Regulator Cost Recovery Levies		3.7	-	-	-	-	-	3.7	-
26		n	**48.5**	9.5	2.4	10.4	2.5	13.5	8.7	1.4
27	**Other Cost Increases:**									
28	Employee Training		3.3	-	-	3.3	-	-	-	-
29	SCA sustainment		1.7	-	-	-	-	1.7	-	-
30	Electric Vehicle Infrastructure		1.7	1.0	-	-	-	-	0.7	-
31		o	**6.8**	1.0	-	3.3	-	1.7	0.7	-
32	**Total Test Period Cost Increases**	p = m+n+o	**104.9**	**45.5**	**2.4**	**16.0**	**9.2**	**20.3**	**9.4**	**2.1**
33	**Test Period Net Increase/(Decrease)**	q = l+p	**98.7**	**45.5**	**2.2**	**13.6**	**8.3**	**19.9**	**9.4**	**(0.2)**
34	**F2022 Base Operating Costs (Current Year) (Schedule 5.0, line 9)**	r = k + q	**905.1**	**346.2**	**84.3**	**261.4**	**68.3**	**299.1**	**121.8**	**(276.0)**
35	**Total Percentage Increase**	(r-k)/k	12.2%	15.1%	2.7%	5.5%	13.9%	7.1%	8.4%	0.1%

Table may not add due to rounding

80 Other includes Office of the President and Chief Executive Officer, Office of the General Counsel, Corporate Costs and Capitalized Costs.

5.5.3 The Forecast Base Operating Cost Increase is Primarily Driven by Three Key Cost Categories

Table 5-5 below provides a more detailed breakdown of the fiscal 2022 base operating cost increase.

Table 5-5 F2022 Base Operating Cost Increase

	Item	Description	Fiscal 2022 Incremental ($ million)
1	**Reliability Investments**		
2	Mandatory Reliability Standards	The operating cost increase of $21.7 million and an FTE increase of 21.5 is required to maintain and achieve compliance with Mandatory Reliability Standards. The costs are presented by driver: • $21.3 million relates to compliance activities. BC Hydro will be working to achieve compliance in certain areas where necessary mitigation measures have been identified. These investments lay a strong foundation (through improved processes, documentation, systems and training) that will make addressing new standards more efficient and effective; and • $0.4 million relates to the implementation of the next version of the Critical Infrastructure Protection standards (CIP version 7). MRS Standards, and the associated requirements, are updated and expanded through the adoption of new "versions". New versions of CIP standards have significantly expanded the scope and complexity of the obligations on BC Hydro. Mandatory Reliability Standards are further discussed in section 5.6.	21.7
3	Vegetation Management	The operating cost increase of $25.0 million and an FTE increase of 18 is required to address the vegetation accumulation on the system by establishing a long-term sustainable level of vegetation maintenance. Fiscal 2022 is a transition year that will see us taking immediate action on the highest vegetation related risk areas on the system and building a foundation for a new Vegetation Management Strategy. Vegetation management is further discussed in section 5.7.	25.0

	Item	Description	Fiscal 2022 Incremental ($ million)
4	Cybersecurity	The operating cost increase of $3.0 million and an FTE increase of four will enhance cybersecurity programs to improve the security system and address items identified through the cybersecurity maturity assessments and audits. Cybersecurity is further described in section 5.8.	3.0
5	**Reliability Investments Total**		**49.7**
6	**Uncontrollable Costs Increases**		
7	Current Service Costs	Current Service Costs relate to BC Hydro's pension plan and are increasing primarily due to the 74 basis points decrease in the discount rate from 3.33 per cent in fiscal 2021 to 2.59 per cent in fiscal 2022. The discount rate is provided by our external actuary. Changes in the discount rate are market driven and outside of BC Hydro's control. Our pension benefits plan remains unchanged (i.e., we have not changed the benefits we are providing employees and retirees). Current service costs are further discussed in section 5.11.5.	33.6
8	Labour	Labour costs are increasing primarily due to a 2.0 per cent general wage increase for union employees in the Test Period. This increase is per the union collective agreements that were also in place for the Previous Application and is consistent with the bargaining mandate set by the Public Sector Employers Council. Management and professional employee salaries will be frozen during the Test Period. Labour costs are further discussed in section 5.11.4.	5.2
9	Property, General Liability, and Directors and Officers Liability Insurance	Insurance costs are increasing due to the low supply of reasonably-priced insurance in the market along with steady demand (particularly for catastrophe insurance or large limit insurance which is a major component of BC Hydro's insurance costs). Due to these global market factors, insurers are increasing rates, and in some cases de-risking their portfolio and deploying less capacity (or in some cases exiting the market entirely). Less supply in the market and lack of competition among insurers resulted in substantial premium increases in fiscal 2021. This upward pressure on premiums is expected to continue into fiscal 2022.	6.0

	Item	Description	Fiscal 2022 Incremental ($ million)
10	BCUC and Canada Energy Regulator Cost Recovery Levies	Cost recovery levies represent the amounts billed to BC Hydro by regulators (BCUC and the Canadian Energy Regulator) to cover a portion of the regulators' budgets. The increase brings the fiscal 2022 forecast in line with actual fiscal 2021 levies that have been assessed to BC Hydro by the BCUC and the Canadian Energy Regulator.	3.7
11	**Uncontrollable Cost Increases Total**		**48.5**
12	**Other Cost Increases**		
13	Employee Training	This funding will provide additional employee training time for field crews so that BC Hydro meets its evolving safety requirements. Employee Training is further discussed in section 5.9.	3.3
14	Supply Chain Application sustainment	The SAP Supply Chain Application solution was deployed in August 2020. The incremental operating cost increase is for support and maintenance of application components and interfaces which are included in Appendix F of BC Hydro Supply Chain Applications Phase Two filing.[81]	1.7
12	Electric Vehicle Charging Infrastructure costs	This operating cost increase is due to expenditures related to electric vehicle charging infrastructure which are prescribed undertakings under the GGRR. Electric Vehicle charging Infrastructure costs are further discussed in Chapter 2, section 2.3.2.3 and Chapter 7, section 7.2.5.	1.7
13	**Other Cost Increases Total**		**6.8**
14	**Total Test Period Cost Increases**		**104.9**

5.5.4 Cost Savings Have Been Identified to Partially Offset the Cost Pressures

BC Hydro has implemented mitigation strategies to manage cost pressures, such as:

- A management and professional salary freeze for fiscal year 2022. We felt it was appropriate to initiate a salary freeze for management and professional employees in fiscal 2022 to help keep costs down, given the current economic climate. This results in avoided costs of approximately $4 million in fiscal 2022;

[81] BC Hydro Supply Chain Applications Phase Two filing (October 2018) and BC Hydro Supply Chain Applications Phase Two (2018) - Semi-Annual Report (October 2020), Appendix F.

- Bringing the Reliability Coordinator function in-house, as PEAK wound down operations and no longer provides reliability coordinator services. This has generated $1.6 million in savings and allows BC Hydro to have oversight of the entire BC Hydro and FortisBC transmission systems; and
- In response to the COVID-19 pandemic, BC Hydro redeployed employees to respond to emergent issues and to optimize our workforce. The redeployment of personnel to areas experiencing an increase in workload initially began with a large number directed towards the delivery of the COVID-19 Customer Relief Program, which became one of the urgent business priorities at the time. Resources were further redeployed to manage and assist with MRS and to support the delivery of Transmission and Distribution Work Programs within the Program and Contract Management KBU.[82]

Table 5-6 below provides a more detailed breakdown of savings that have been identified to partially offset the cost pressures identified in section 5.5.3. We continue to look for improvements and efficiencies to reduce costs; however, after several years of rigorous fiscal discipline, the opportunity to realize savings in the Test Period was limited.

Table 5-6 Cost Period Savings

	Item	Description	Fiscal 2022 Incremental ($ million)
1	Eligible Capital Overhead	This reduction is due to increased costs eligible for capitalization, primarily due to changes in Standard Labour Rates.	(2.3)

[82] Redeployment of personnel represents an avoided cost rather than a direct savings.

	Item	Description	Fiscal 2022 Incremental ($ million)
2	PEAK savings	In July 2018, PEAK, the existing Reliability Coordinator (**RC**) for British Columbia, announced that it would no longer provide reliability coordinator services after December 31, 2019. BC Hydro submitted its application for registration as the RC for British Columbia to the Western Electricity Coordinating Council (**WECC**) in September 2018. In August 2019, BC Hydro received approval from the BCUC for its RC registration. Effective September 2, 2019, BC Hydro commenced as the RC for British Columbia. As described in BC Hydro's response to BCUC IR 2.241.01 in the Previous Application proceeding, the estimated cost of providing RC services resulted in $1.6 million operating cost savings compared to the annual fees paid to PEAK.	(1.6)
3	Trainee Reduction	BC Hydro's apprentice and trainee FTE requirement in fiscal 2022 is reduced by 43 FTEs compared to fiscal 2021. This has been primarily implemented in response to the COVID-19 pandemic. BC Hydro determined that this action could help address COVID-19 cost pressures without impacting our ability to complete necessary work and without jeopardizing the long-term success of our apprentice and trainee programs.	(1.3)
4	Storm Restoration	BC Hydro continues to budget for storm restoration costs using a rolling five-year average of normal weather years. In fiscal 2020, we experienced below average storm related damage, which has caused the rolling five-year average of storm restoration costs to decrease[83]. The five-year average is based on fiscal 2016 to fiscal 2020 actuals.	(0.5)

[83] Five year rolling average for Storm Restoration costs:

Five Year Rolling Average ($ million)	F2014 Actual	F2015 Actual	F2016 Actual	F2017 Actual	F2018 Actual	F2019 Actual	F2020 Actual	Rolling 5-Year Average	Change
Fiscal 2020 - Fiscal 2021 RRA	4.6	12.9	23.5	25.3	22.9			**17.8**	
Fiscal 2020 - Fiscal 2021 RRA Decision, Directive #19		12.9	23.5	25.3	22.9	25.6		**22.0**	4.2
Fiscal 2022 RRA			23.5	25.3	22.9	25.6	10.1	**21.5**	**(0.5)**

	Item	Description	Fiscal 2022 Incremental ($ million)
5	Lease Accounting Change	This decrease in operating expenses is attributable to lease payments for three property leases being reclassified to depreciation expense and finance charges as they were recognized on balance sheet in accordance with accounting rules. Although leases for these properties existed at adoption of IFRS 16, the leases were not recognized on balance sheet as the amounts were immaterial due to short remaining terms. Lease renewals resulted in the leases meeting BC Hydro's threshold for being recorded on the balance sheet.	(0.4)
6	**Total Test Period Cost Savings**		**(6.2)**

5.5.5 Overview of the Change in Net Operating Costs and Reconciliation

Base operating costs are a component of net operating costs. Net operating costs also include capital overhead that can no longer be capitalized under IFRS, costs related to the 2017 Waneta Transaction and the Customer Crisis Fund. Net operating costs are a component of two operating cost views, gross operating costs and current operating costs, as follows:

- Net operating costs, combined with costs incurred in the current period that are to be recovered in rates in future years through the recovery mechanisms established for each regulatory account, represent BC Hydro's total gross operating costs.
- Net operating costs, combined with costs incurred in prior periods to be recovered in the current period through the recovery mechanisms established for each regulatory account, represent BC Hydro's total current operating costs.

Table 5-7 below provides a continuity table that summarizes the changes to BC Hydro's net operating costs. Operating costs for each Business Group and Key Business Unit are provided in Schedule 5.1 to Schedule 5.7 of Appendix A – Financial Schedules.

Table 5-7 Summary of BC Hydro’s Net Operating Costs[84]

	F2022 Plan ($ million)	Ref	BC Hydro	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	People, Customer, Corporate Affairs	Other
1	**F2021 Revenue Requirement Application Plan**	a	**1,007.5**	**293.0**	**81.1**	**246.0**	**57.5**	**264.8**	**117.2**	**(52.0)**
2	Compliance Filing Adjustment	b	2.5	(1.0)	-	4.2	-	-	(0.7)	-
3	Reorganizational Impact	c	-	9.1	-	(4.3)	1.0	-	(5.8)	-
4	**F2021 Revenue Requirement Application Plan (Schedule 5.0, line 15)**	d=a+b+c	**1,010.0**	**301.1**	**81.1**	**245.8**	**58.5**	**264.8**	**110.7**	**(52.0)**
5	Reorganizational Impact	e	(0.0)	0.7	(0.1)	(2.8)	0.2	1.3	0.6	0.0
6	Budget Transfers Between Business Groups	f	0.0	4.8	1.0	4.8	1.2	13.2	6.4	(31.3)
7	**Current Year Incremental Adjustments:**									
8	IFRS Ineligible Capital Overhead	g	22.4	-	-	-	-	-	-	22.4
9	Waneta 2/3rd Operating Costs	h	0.2	0.2	-	-	-	-	-	-
10	Customer Crisis Fund Operating Costs	i	(4.8)	-	-	-	-	-	(4.8)	-
11		j = Σ g to i	**17.8**	**0.2**	**-**	**-**	**-**	**-**	**(4.8)**	**22.4**
12	**Test Period Savings**	k	**(6.2)**		**(0.1)**	**(2.4)**	**(0.9)**	**(0.4)**		**(2.3)**
13	**Test Period Cost Increases**									
14	**Reliability Investments**									
15	Mandatory Reliability Standards		21.7	10.0	-	2.2	6.7	2.1	-	0.7
16	Vegetation Management		25.0	25.0	-	0.1	-	-	-	-
17	Cybersecurity		3.0	-	-	-	-	3.0	-	-
18		l	**49.7**	35.0	-	2.3	6.7	5.1	-	0.7
19	**Uncontrollable Cost Increases**									
20	Current Service Pension Costs		33.6							
21	Other Labour Costs		5.2							
22	Current Service Costs and Other Labour Costs		38.8	9.5	2.4	10.4	2.5	7.6	5.0	1.4
23	Property, General Liability, and Directors and Officers lLability Insurance		6.0					6.0		
24	BCUC and Canada Energy Regulator Cost Recovery Levies		3.7						3.7	
25		m	**48.5**	9.5	2.4	10.4	2.5	13.5	8.7	1.4
26	**Other Cost Pressures:**									
27	Employee Training		3.3			3.3				
28	Suppy Chain Application Sustainment		1.7					1.7		
29	Electric Vehicle Infrastructure		1.7	1.0					0.7	
30		n	6.8	1.0	-	3.3	-	1.7	0.7	-
31	**Total Test Period Cost Increases**	o = l+m+n	**104.9**	**45.5**	**2.4**	**16.0**	**9.2**	**20.3**	**9.4**	**2.1**
32	**Test Period Net Increase/(Decrease)**	p = l + k	**98.7**	**45.5**	**2.2**	**13.6**	**8.3**	**19.9**	**9.4**	**(0.2)**
33	**F2022 Net Operating Costs (Schedule 5.0, line 15)**	r = d+e+f+j+p	**1,126.5**	**352.2**	**84.3**	**261.4**	**68.3**	**299.1**	**122.3**	**(61.1)**

Table may not add due to rounding

84 Row 2 relates to BCUC Order No. G-246-20, Directive 19, which directed BC Hydro to use the fiscal 2015 to fiscal 2019 actual results for Storm Restoration costs for the fiscal 2020 to fiscal 2021 Test Period, and Directive 28, which directed BC Hydro to remove all forecast operating costs related to Electric Vehicle charging infrastructure in the fiscal 2020 to fiscal 2021 test period;

Rows 3, 5 and 6 relate to restructuring impacts and budget transfers between Business Groups. On a consolidated basis they net to zero;

Row 8 represents IFRS ineligible capital overhead costs that are being phased in to operating costs over a ten-year period (the final year being fiscal 2022);

Row 9 relates to costs related to BC Hydro’s purchase of Teck’s two-thirds interest in Waneta, per BCUC Order No. G-130-18;

Row 10 relates to the Customer Crisis Fund operating costs (administrative costs to run the program and grants) which are offset in miscellaneous revenues, approved by BCUC Order No. G-166-17.

Table 5-8 below shows the reconciliation of base operating costs to the net operating costs as shown in Appendix A.

Table 5-8 Reconciliation of Base Operating Costs to Net Operating Costs

($ million)	F2022 Plan
Base Operating Costs (Schedule 5.0, line 9)	**905.1**
IFRS Ineligible Capital Overhead (Schedule 5.0, line 10)	214.9
Waneta 2/3rd Operating Costs (Schedule 5.0, line 12)	6.1
Customer Crisis Fund Operating Costs (Schedule 5.0, line 13)	0.5
Net Operating Costs (Schedule 5.0, line 15)	**1,126.5**

5.6 Mandatory Reliability Standards

BC Hydro is subject to Mandatory Reliability Standards (**MRS** or **Standards**) that are in place to ensure the reliable operation of the Bulk Electric System[85] throughout North America. Ongoing compliance with these standards is, as the name MRS suggests, mandatory. The scope and complexity of the requirements under these Standards is increasing. The work that we must undertake to achieve and maintain compliance is increasing commensurately.

BC Hydro's fiscal 2022 plan includes an operating cost increase of $21.7 million and an FTE increase of 21.5 to maintain and achieve compliance with MRS. In this section, the costs are presented by driver, which is primarily compliance related activities.

BC Hydro regards the incremental costs outlined in this section as non-discretionary. They represent a significant step forward in BC Hydro's MRS program and will ensure the successful implementation of the latest and future versions of the Critical Infrastructure Protection (**CIP**) standards. This investment builds a foundation that

[85] The Bulk Electric System is defined as the electrical generation resources, transmission lines, interconnections with neighbouring systems and associated equipment, generally operated at voltages of 100 kV or higher.

will make addressing new, future standards more efficient and effective. BC Hydro anticipates further expansion of our MRS program and investments in future years as our efforts mature and new standards and iterations of existing standards are implemented.

5.6.1 Confidential MRS Appendix Includes Information that Is Security-Sensitive or Subject to BCUC Confidentiality Requirements

The content of the discussion on MRS has been split between this section, intended for public viewing, and a confidential appendix (Appendix Z) that is being made available to the BCUC only. There are two related reasons for this:

- First, information related to the protection of cyber infrastructure is highly security sensitive and could compromise the safety and reliability of the Bulk Electric System by exposing it to physical attacks by malicious actors or cyberattacks; and
- Second, the BCUC’s MRS Rules of Procedure, including the Compliance Monitoring Program Rules and Penalty Guidelines, make the framework and processes for reporting, auditing and oversight of MRS compliance confidential. While certain information about an entity’s violations, if confirmed, may become public after the fact, there remains a presumption of confidentiality. The presumption of confidentiality is especially important where the subject-matter relates to a cyber-security incident or may otherwise jeopardize the security of the Bulk Electric System.

As a result, BC Hydro is limiting circulation of such information to the BCUC only. We understand the challenge this represents for interveners. However, we believe very strongly that it is in the public interest to impose strict limitations on the circulation of security sensitive information to reduce the potential for inadvertent disclosure, as well as to respect the compliance processes and rules that the BCUC has put in place for MRS.

5.6.2 MRS Background

The following subsections explain the importance of MRS for the reliable operation of the Bulk Electric System and the framework in place to ensure compliance with the Standards. The growing complexity and number of MRS obligations provide context for why BC Hydro is increasing investment in MRS in the Test Period.

5.6.2.1 Standards Specify Requirements for Reliable Operation and Protection of Bulk Electric System

MRS define the reliability requirements for planning and operating the Bulk Electric System. This includes requirements for the operation of existing Bulk Electric System facilities, including physical and cyber security protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for the reliable operation of the Bulk Electric System. There are 13 MRS standard areas approved for adoption in British Columbia which apply to BC Hydro's operations.

Each standard area will typically include multiple Standards, and each Standard will include a number of specific requirements. For example, the CIP standard area includes 11 currently effective standards with 39 requirements. Each requirement includes a number of elements for which BC Hydro must develop operating processes in order to achieve the requirement. Developing, implementing and sustaining these processes represent the majority of the work we must undertake to achieve and maintain compliance.

Table 5-9 below provides a list of the Standards grouped by the areas that they cover as well as the number of Standards that are effective in B.C.[86] within those areas of coverage.

[86] As of December 9, 2020.

1 **Table 5-9 Mandatory Reliability Standards by Area**

Abbreviation	Summary of Coverage	Standard Area	Number of Standards
BAL	Covers areas from Real power Balancing Control Performance to Automatic Time Error Correction and Automatic Generation Control.	Resource and Demand Balancing	6
CIP	Covers areas from Sabotage Reporting to Cyber Security standards in the areas of Critical Asset Identification, Security Management Controls and Electronic and Physical Security of Cyber Assets.	Critical Infrastructure Protection	11
COM	Covers Telecommunications, Communications and Coordination	Communications	2
EOP	Covers areas from Emergency Operations Planning and Load Shedding Plans, to System Restoration Coordination and Restoration from Blackstart Resources.	Emergency Preparedness and Operations	7
FAC	Covers areas from Facility Connection Requirements and Transmission Vegetation Management, to System Operating Limits Methodologies and Transmission Maintenance.	Facilities Design, Connections and Maintenance	9
INT	Covers areas from Interchange Transaction Implementation to Interchange Coordination Exemptions.	Interchange Scheduling and Coordination	5
IRO	Covers areas from Reliability Coordination – Responsibilities and Authorities, to Operations Planning and Transfer Path Unscheduled Flow Relief.	Interconnection Reliability Operations and Coordination	11
MOD	Covers areas from the Development of Steady-State and Dynamics System Models of the interconnected transmission system and Transmission Reliability Margin Calculation Methodologies, to the development and documentation of transfer capability calculations in the support of system operations.	Modeling, Data and Analysis	13
PER	Covers Operating Personnel Training and Certification procedures and requirements.	Personnel Performance, Training and Qualifications	3

Abbreviation	Summary of Coverage	Standard Area	Number of Standards
PRC	Covers areas from System Protection Coordination among operating entities and Disturbance Monitoring, to the Development and Documentation of Under Frequency/Voltage Load Shedding Programs and associated Maintenance and Testing programs.	Protection and Control	20
TOP	Covers areas from Normal Operations Planning to Planned Outage Coordination and System Operating Limits along Major WECC Transfer Paths.	Transmission Operations	8
TPL	Covers areas from Transmission System Planning Performance Requirements under normal conditions to System Performance Planning Following Loss of Single/Multiple Bulk Electric System Element(s).	Transmission Planning	1
VAR	Covers areas from Voltage and Reactive Control in real time to protect equipment, to Power System Stabilization (PSS) on synchronous generators.	Voltage and Reactive	3
Total Standards Adopted in B.C.			**99**

Currently, there are 99 Standards effective in British Columbia comprised of a total of 457 requirements that apply across 3,250 BC Hydro assets.

Across North America, the electrical grid is becoming more complex and therefore more challenging to manage. There is more intermittent generation, increased frequency and severity of weather events impacting the grid, digital technologies are replacing mechanical equipment, and attempts to access and disrupt systems are becoming more sophisticated. As a result of this changing environment, the Standards have increased over time in both number and complexity. For example, the next iteration of the CIP-003 Standard (CIP-003-8, which comes in to effect in October 2023) will greatly expand the scope of compliance requirements.

A number of different entities are involved in the development, approval, adoption, administration, and monitoring of MRS in British Columbia. The process, at a high level, unfolds as follows:

- The North American Electric Reliability Corporation[87] and the six Regional Reliability Organizations are responsible for developing Standards;
- The Federal Energy Regulatory Commission (**FERC**) is responsible for adopting Standards in the United States;
- BC Hydro assesses FERC-adopted MRS for adoption, administration and operation in British Columbia in accordance with section 125.2 of the *Utilities Commission Act* and the Mandatory Reliability Standards Regulation (B.C. Reg. 32/2009);
- The BCUC is responsible for the adoption and administration of the Standards in British Columbia which includes monitoring compliance;
- The Western Electricity Coordinating Council (**WECC**) is one of the six Regional Reliability Organizations in North America tasked with MRS oversight responsibility of certain aspects of the North American Bulk Electric System. WECC is the regional entity for the geographic area known as the Western Interconnection which extends from Canada to Mexico and includes the provinces of British Columbia and Alberta, the northern portion of Baja California, Mexico and all or portions of the 14 Western U.S. states between. WECC is also the administrator for and appointed by the BCUC in the administration of the approved MRS program in British Columbia and, in that capacity, assists the BCUC in carrying out the registration of parties and compliance monitoring.

[87] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces reliability standards; annually assesses seasonal and long-term reliability; monitors the Bulk Electric System through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental US, Canada and the northern portion of Baja California, Mexico.

Standards adopted by the BCUC apply to every owner, operator and user of various components of the Bulk Electric System.[88] Entities that perform these functions are required to register and comply with Standards adopted by the BCUC. BC Hydro is the largest and most complex of these entities to which the MRS standards apply.

The following section provides a brief history of how the Standards were developed and became mandatory in British Columbia.

5.6.2.2 Blackouts Led to the Development of MRS and their Adoption in British Columbia

In 1965, a Northeast blackout impacting over 30 million people in parts of Ontario and the Northeastern United States led to the creation of NERC as well as Regional Reliability Organizations including the Western Systems Coordinating Council, the predecessor organization to the WECC.[89]

This arrangement remained relatively stable throughout the 1970s and 1980s. However, during the 1990s, deregulation increased the number of utilities operating in the electricity industry. With the number of utilities increasing, there was a greater need for consistent and coordinated reliability standards across jurisdictions. In response, WECC implemented the voluntary Reliability Management System compliance program in 1999.

In 2003, there was another Northeast blackout, this time impacting about 50 million people. A joint Canada-United States task force was created to investigate the cause of the blackout and found that a lack of compliance with the existing voluntary reliability standards was a contributing factor. The task force recommended that reliability standards be made mandatory and enforceable.

88 Defined by NERC as “All Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.”

89 In 2002, the Western Systems Coordinating Council merged with the Southwest Regional Transmission Association and the Western Regional Transmission Association to create the Western Electricity Coordinating Council.

In 2005, the *Energy Policy Act* in the U.S. called for the creation of Mandatory Reliability Standards for the electricity grid to replace the voluntary standards. It also established that an Electricity Reliability Organization (**ERO**), appointed by FERC, would be responsible for developing the standards and submitting them to FERC for adoption, at which point the standards would become mandatory and enforceable. In 2006, NERC was certified as the ERO in the United States and was directed to take the steps necessary to become certified as the ERO in Canada and Mexico.

In 2007, NERC approved WECC and other Regional Reliability Organizations to act as delegates to monitor compliance and enforce the Standards within their regional footprints in the U.S.

In 2008, the *Utilities Commission Act* was amended to create the framework for the adoption of the Standards in British Columbia. Specifically, section 125.2 was added to provide the BCUC with exclusive jurisdiction to determine whether a reliability standard is in the public interest and should be adopted in British Columbia and with responsibility for monitoring and enforcing compliance with the Standards.

While the first set of Standards was adopted in British Columbia in 2009, the Standards became auditable and enforceable in British Columbia in 2010.

5.6.2.3 The BCUC's Compliance Monitoring Program

The BCUC is responsible for auditing, monitoring and enforcing compliance with MRS in British Columbia. Its compliance framework, referred to as the Compliance Monitoring Program, is summarized below.

- Regardless of the form of discovery, where a possible violation has occurred, an entity must take reasonable steps to mitigate the impact that the breach may have caused on reliability and remediate the possible violation;
- Where a possible violation has been identified, an entity is also strongly encouraged (and in some cases required) to prepare and submit to WECC (in its role as administrator) a Mitigation Plan which outlines an entity's action plan

to correct and prevent recurrence of the possible violation. If the Mitigation Plan is accepted by WECC, it is provided to the BCUC for approval; and

- Once accepted, an entity must provide updates to WECC on both the progress of the Mitigation Plan and completion evidence by each milestone due date. Upon completion of the plan, an entity is required to provide an attestation to WECC that all required actions described in the plan have been completed. If WECC agrees that the plan has been completed, it recommends approval by the BCUC. If WECC disagrees, it provides detailed reasons and requests a revised Mitigation Plan.

5.6.3 Fiscal 2022 Budget Addresses Compliance

Table 5-10 presents the incremental MRS investments for fiscal 2022. The primary driver in fiscal 2022 is compliance-related activities.

Table 5-10 Incremental MRS Investments (Fiscal 2022)

Business Group	Compliance ($ million)	Future CIP Standards ($ million)	MRS Total ($ million)	FTE
Integrated Planning	9.9	0.1	**10.0**	**0**
Finance, Technology and Supply Chain	1.8	0.3	**2.1**	**6**
Safety and Compliance	6.7	-	**6.7**	**15.5**
Operations	2.2	-	**2.2**	**0**
General Counsel	0.7	-	**0.7**	**0**
Total	**21.3**	**0.4**	**21.7**	**21.5**

5.6.3.1 Compliance-Related Activities in Fiscal 2022

BC Hydro will be working to achieve compliance in certain areas where necessary mitigation measures have been identified, generally in conjunction with WECC as the BCUC's administrator of the B.C. MRS program. Compliance-related matters are subject to confidentiality requirements under the BCUC's MRS compliance rules, so we are providing further information in confidential Appendix Z for the BCUC only.

5.6.3.2 Implementation of CIP Version 7 Will Require Additional Investment for Long Term Sustainment

MRS Standards, and the associated requirements, are updated and expanded through the adoption of new standards and “versions”. As described below, new versions of CIP standards have significantly expanded the scope and complexity of the obligations on BC Hydro. A new version of CIP-003 (CIP-003-8, also commonly referred to as CIP Version 7) has been adopted and will be effective in October 2023; sustainment activities for the new version will begin in fiscal 2023.

Initially, the cyber assets governed by CIP Standards were narrow and included only four of BC Hydro’s generating stations and two control centres.

The adoption of CIP Version 5 in British Columbia in July 2015 brought about a step change in the number of requirements, the complexity of these requirements and the number of facilities and assets to which the requirements applied. Assets covered by these standards grew to include cyber protection for cyber assets at 43 transmission substations that were previously exempt.

On October 1, 2018, BC Hydro implemented CIP Version 5. To support this work, BC Hydro initiated a set of projects within different Business Groups to develop procedures, update documentation of the assets governed by the new standards, implement work flows and software to facilitate the changes, and coordinate change management and training to sustain compliance within the organization. This work occurred from July 2015 through October 2018. Currently, BC Hydro has over 3,250 assets that must comply with physical and cyber protection requirements set out by the CIP standards.

On October 1, 2019, BC Hydro implemented a standard that protects transient cyber assets such as laptops, removable media such as USB keys and other devices that may temporarily connect to its system to meet the requirements of CIP-010-2 R4 (for Transient Cyber Assets and Removeable Media).

BC Hydro is now in the process of implementing CIP Version 7, which increases the scope of cyber and physical security protection to include an additional 18 generating stations and 115 transmission substations to those already addressed by CIP Version 5. These protections will cover cyber security awareness and incident response, physical security controls, electronic access controls and use of transient cyber assets and removable media. The investment of $21.7 million in fiscal 2022 lays a strong foundation (through improved processes, documentation, systems and training) that will make CIP Version 7 easier to implement.

The implementation of CIP Version 7 and other standards will require ongoing investment in future years.

5.7 Vegetation Management

In the Previous Application proceeding, BC Hydro identified vegetation management as an area that would require additional investment going forward. The BCUC, in its Decision on the Previous Application, directed BC Hydro to address the adequacy of its vegetation management funding in the Application.[90]

BC Hydro has included an additional $25 million[91] and 18 FTEs[92] to support the vegetation management program in fiscal 2022, bringing the total vegetation budget to $74.4 million. This additional investment is associated with a variety of factors, notably:

1. Vegetation that was cleared during a period of heightened activity over a decade ago has regrown and is now reaching maturity size that poses a risk to the system;

90 Directive 22; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 73.

91 BC Hydro shares a portion of the cost to maintain utility poles with TELUS and based on the current work program, an additional $800,000 is estimated in recoveries from TELUS (see section 5.7.7.1). This amount will be used towards vegetation maintenance work in addition to the base plan amount (see Table 5-11).

92 Two planning resources, three foresters, four distribution coordinators, one distribution specialist and eight imaging specialists in support of system modeling and dynamic LiDAR surveys.

2. Cost pressures (described in section 5.7.4.2) have increased with electrical system expansion, new regulatory requirements and general cost inflation associated with vegetation maintenance activities, and these costs pressures can no longer be absorbed in existing budgets; and
3. Climate change is impacting the growth rate and health of vegetation across the province.

This additional budget will improve BC Hydro's overall vegetation management capacity and capability to meet transmission and distribution system needs in fiscal 2022. It will lay the foundation for our new Vegetation Management Strategy going forward, described in section 5.7.5.

5.7.1 Key Terms and Definitions Regarding Vegetation Management

There are a number of vegetation management-related trade terms used in this section, which are set out below for ease of reference.

Term	Description / Definition
Edge Tree	Refers to a tree at the edge of the right-of-way that was identified as a potential risk as a result of its condition or other observable factors. Edge trees are removed to reduce the risk of them falling onto transmission assets.
Distribution Vegetation Management	Managing the vegetation on the distribution system. The vast majority of vegetation is on private or public land in proximity to the power system.
Hot-Spotting	Selective and targeted removal of a tall tree(s) or area within the transmission system to address an immediate risk or area of concern.
Hazard Tree	A tree that has a defect or adverse environmental condition that predisposes it to failure and that can cause damage if it falls (e.g., a power line, electrical equipment, buildings, people, etc.).
Light Detection and Ranging (**LiDAR**)	A LiDAR sensor uses infrared and ultraviolet light to map out the environment around it. It can get a sense of both the physical dimensions and motion (if any) of objects in its vicinity.
Rights-of-Way (**ROW**)	The legal right to the area below and surrounding transmission lines where BC Hydro is responsible for vegetation management and maintenance.
Riparian	The area of land adjacent to a water body that contains vegetation that is distinctly different from the vegetation of adjacent upland areas due to the presence of water.
Right-of-Way Clearing	Full clearing of vegetation within the right-of-way beneath and adjacent to the transmission system.

Term	Description / Definition
Transmission Vegetation Management	Managing the vegetation in proximity to high voltage transmission lines, including directly underneath and adjacent to conductors and structures.
Vegetation Management	The practice of reducing the risk of contact between vegetation (e.g., trees, shrubs, etc.) and electrical assets by proactively removing vegetation or reducing it in size or height.
VegNET	A mobile field application used to facilitate and spatially locate all tasks and activities related to transmission vegetation and access for BC Hydro staff, consultants and contractors.
On-Cycle Distribution Vegetation Management Work	Vegetation maintenance activities performed according to the standard work plan that aligns to vegetation growth rates and regional needs. Results in efficient area-based management and addresses vegetation risks in the area specified within the work plan.
Off-Cycle Distribution Vegetation Management Work	Off-cycle work often involves triage of required vegetation needs and highest risk areas receiving treatment versus full area maintenance. It results from a deviation from the optimal work plan in response to unplanned impacts. Average cost of off-cycle work is higher than on-cycle work.
Vegetation Accumulation	Vegetation growth on the system that has not been addressed within the current work plan and requires attention. Vegetation in this state constitutes an accumulation of vegetation material and work effort is necessary for removal.
High Voltage Transmission Circuits (**HVTC**)	Vegetation management description of transmission lines above 138 kV (but includes the 138 kV interties to Alberta) that are subject to a number of reliability standards due to system criticality.
Low Voltage Transmission Circuits (**LVTC**)	Vegetation management description of transmission lines at or below 138 kV.

5.7.2 Budget Overview for Fiscal 2022 – Transitioning to the New Vegetation Management Program

A heightened level of vegetation clearing activity over a decade ago had ongoing benefits, allowing BC Hydro to absorb significant cost pressures on the vegetation management program during a period of fiscal constraint (i.e., multiple government reviews and the 2013 10 Year Rates Plan). In recent years, while BC Hydro has observed an increase in vegetation related outages, overall system performance has met BC Hydro's Service Plan targets. Performance against reliability targets has been bolstered by innovative system improvements (e.g., reclosers and automated switching), that have improved both reliability and safety and mitigated the impact of the accumulated vegetation growth.

While targeted work can address emerging risks, trees continue to grow each year. Eventually, all remaining vegetation requires extensive maintenance to maintain safe clearances to energized equipment and support reliable system operations. The vegetation on the system has now reached a point where a vegetation accumulation exists, and the benefits obtained by extensive clearing a decade ago have been fully realized. We need to address this accumulation to ensure future reliability and safety performance. BC Hydro believes that future system performance and safety will be negatively impacted if the *status quo* persists.

We are taking action to address the vegetation accumulation on the system by establishing a long-term sustainable level of vegetation maintenance where accumulation does not pose a risk. Fiscal 2022 is a transition year that will see us (a) taking immediate action on the highest vegetation-related risk areas on the system, and (b) building a foundation for a new Vegetation Management Strategy, described in section 5.7.6 below, that will guide future vegetation management efforts.

Overall funding for the Vegetation Management Program of $74.4 million, which includes the planned increase of $25 million, can be broken out as follows:

- Vegetation Maintenance in support of high voltage transmission circuits (**HVTC**) totalling $30.4 million, which includes:
    - Transmission vegetation maintenance supporting HVTC totalling $25.5 million;
    - Light Detection and Ranging (**LiDAR**) surveys to improve dynamic imaging and modelling for 20 per cent of the transmission system in fiscal 2022, totalling $4 million; and
    - Incremental planning and forester resources, totalling $0.9 million.

- Vegetation Maintenance in support of safety and reliability for lines described as low voltage transmission circuits (**LVTC**) and distribution circuits totalling $43.9 million which includes:
  - Transmission vegetation maintenance supporting voltages 138 kV and below, totaling $7.8 million; and
  - Distribution vegetation maintenance totaling $36.1 million.

The overall funding amount described above includes a funding increase of $25 million from fiscal 2021 to fiscal 2022. This increased funding is being allocated as follows:

- HVTC focused support totalling $16.9 million which includes:
  - $12 million in additional funding for transmission vegetation maintenance supporting HVTC areas;
  - $4 million supporting LiDAR; and
  - $0.9 million for incremental planning and forester resources;
- Vegetation management on LVTC and distribution totalling $8.9 million which includes:
  - $4.7 million in incremental distribution vegetation maintenance to address hazard trees and more costly off-cycle work volumes;
  - $0.7 million in incremental distribution planning resources to support distribution vegetation field delivery and work programs; and
  - $3.5 million in incremental transmission vegetation maintenance for improvements in safety and reliability (including wildfire prevention compliance) on lower voltage circuits (below 138 kV).

Fiscal 2021 and fiscal 2022 Vegetation Management funding is summarized in Table 5-11 below.

Table 5-11 Fiscal 2021 and Fiscal 2022 Vegetation Program Funding Summary[93]

($ million)	F2021 RRA	Standard Labour Rate Increase	Incremental Funding	F2022 Plan
Transmission Vegetation Maintenance	17.8	0.1	15.5	**33.3**
Distribution Vegetation Maintenance	30.6	0.2	5.4	**36.1**
LiDAR	-	-	4.0	**4.0**
Planning Resources	-	-	0.9	**0.9**
Total Gross	**48.4**	**0.2**	**25.8**	**74.4**
Distribution Vegetation Recoveries (TELUS)	(6.1)	-	(0.8)	**(6.9)**
Total Net of Recoveries	**42.2**	**0.2**	**25.0**	**67.4**

Included within the increase of $25 million are 18 additional FTEs, as follows:

- Two planning resources – required to adequately plan the incremental vegetation management volume on both the transmission and distribution systems;
- Three professional foresters – required to address the professional requirements of delivering transmission vegetation management work in British Columbia;
- Four distribution coordinators – required to efficiently plan distribution vegetation work effort, facilitate customer acceptance and perform work quality assurance;
- One vegetation specialist – required to support distribution level vegetation management requirements (e.g., riparian plans, etc.); and
- Eight LiDAR resources – required for processing and modelling of LiDAR data to form a complete dynamic system view. For further information, refer to section 5.7.6.3.

[93] May not add due to rounding.

5.7.3 Vegetation Management is a Critical Undertaking for BC Hydro

BC Hydro's significant annual investment in vegetation management reflects the importance of this area to the safe and reliable operation of the BC Hydro system and the Western Bulk Electric System.

BC Hydro is responsible for the ongoing maintenance and safe operation of over 76,000 kilometers of power lines (18,000 kilometers of transmission lines and 58,000 kilometers of distribution lines). There are over 76,000 hectares of right-of-way beneath BC Hydro's transmission lines.[94]

British Columbia is one of the most densely forested utility jurisdictions in Canada. Most of BC Hydro's power system is built in proximity to vegetation owned by customers, the public and other third-parties. BC Hydro must undertake ongoing vegetation management efforts to:

- Minimize vegetation related outages and maintain reliability for customers;
- Address public and worker safety risks and the risk of wildfire ignition;
- Meet policy, regulatory and legislative requirements, including environmental regulations and MRS; and
- Enable unimpeded access to our assets to perform the work necessary to operate and maintain the system.

Vegetation is a major cause of outages to both transmission and distribution systems. In North America, transmission outages caused by vegetation growing into high voltage lines have historically caused some of the largest cascading failures on the Bulk Electric System. A significant example is the 2003 black-out in eastern North America, discussed further in section 5.6.2.2 above. Transmission lines sagging into overgrown trees in Ohio led to 50 million people losing power for up to two days in Canada and the U.S.

[94] Distribution lines do not have a specific right-of-way.

Vegetation has led to significant wildfires and has had a major impact in places like California and Australia. A recent example was the devastating 2018 Camp Fire that destroyed the town of Paradise, California and led to 84 fatalities. The fire was caused by a transmission conductor falling and contacting vegetation in a dry forested area. These events have reinforced the importance of BC Hydro's vegetation management program to mitigate wildfire impacts in the years ahead. Vegetation management plays a key role in minimizing the wildfire risk as a result of electrical contact in British Columbia.

On BC Hydro's system, there were two wildfires caused by vegetation contact with transmission lines in 2017. Although both were small in scale, the incidents highlight a risk that vegetation continually poses to the system. The risk must be mitigated through robust and active vegetation management efforts.

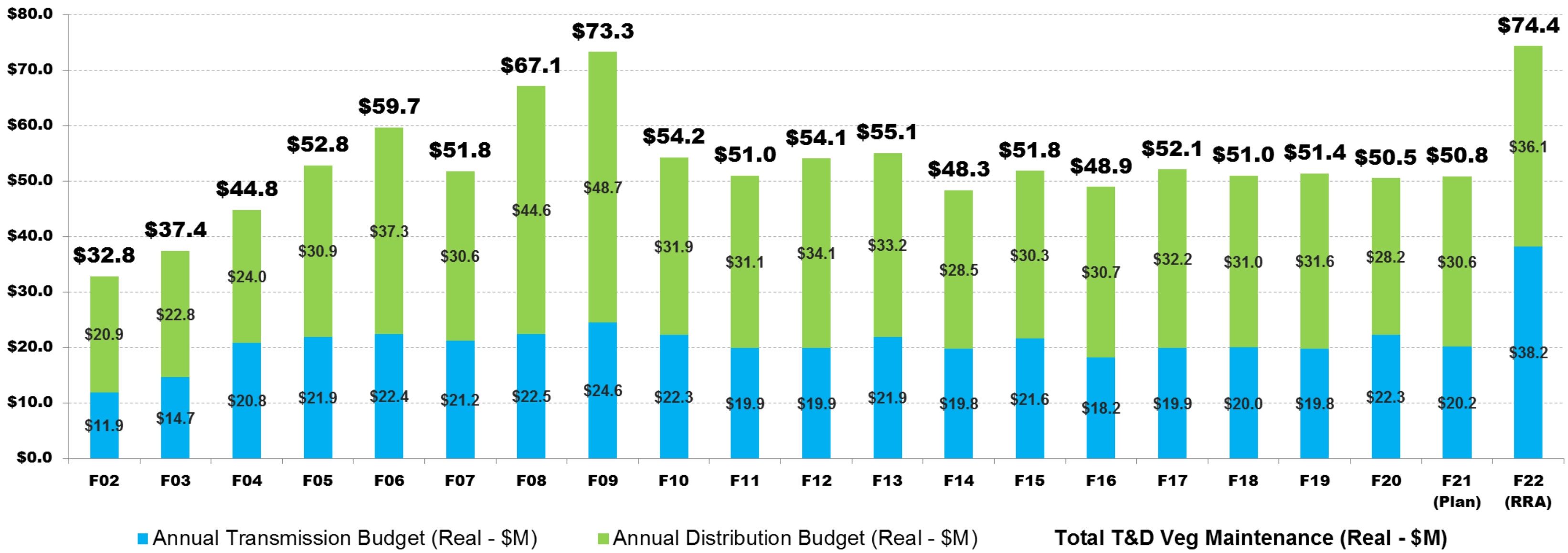
5.7.4 There Are Three Key Drivers of the Fiscal 2022 Budget Increase

Three primary factors are contributing to the need for a significant increase in vegetation management investment, each of which is discussed below: (1) vegetation growth across the system has regrown back to levels that existed prior to the significant clearing activities that took place a decade ago; (2) cost pressures have increased with electrical system expansion, new regulatory requirements and general cost inflation associated with vegetation maintenance activities, and can no longer be absorbed; and (3) climate change is impacting the growth rate and health of vegetation across the province.

5.7.4.1 The Localized Approach Taken Over Past Decade is No Longer Effective in the Face of Regrowth

Significant clearing activities occurred a decade ago that had lasting benefits. This is reflected in Figure 5-4 below, which shows that investment in vegetation management increased between fiscal 2002 and fiscal 2009, before remaining largely static (in terms of real dollars) at a lower level for the last decade. However, regrowth has occurred over the past decade, such that the benefits from the peak clearing period have diminished.

Figure 5-4 Historical Investment in Transmission and Distribution Vegetation Management



The chronology of BC Hydro's investment in transmission and distribution vegetation management from 2005 to 2009 was as follows:

- In its Fiscal 2005 to Fiscal 2006 Revenue Requirements Application, BC Hydro identified vegetation-related reliability issues and benchmarking showed that BC Hydro was in the third quartile with respect to its performance on reliability and cost. BC Hydro increased funding to address vegetation related issues at that time;
- From fiscal 2007 to fiscal 2009, investment in vegetation management increased again due to: the removal of Mountain Pine Beetle impacted trees, lessons learned following the aftermath of the 2006 severe windstorm in the Lower Mainland (often referred to as the "Stanley Park" windstorm) and preparation for the 2010 Winter Olympic Games (which saw work activities concentrated in the Lower Mainland to Whistler). All of these factors increased the overall volume of vegetation work completed which, based on the regrowth cycles of the fastest growing tree species, meant that overall system risk from vegetation was reduced for a period of time; and
- From fiscal 2009 to present, the vegetation program remained near $50 million per year in real terms. The program absorbed significant cost pressures during this period.

5.7.4.2 Growing Cost Pressures Can No Longer Be Absorbed

In addition to the challenges of vegetation regrowth, a number of cost pressures developed over the last decade. The measures BC Hydro has been using to mitigate the impacts of these pressures within the fixed vegetation budget are no longer sufficient and these costs can no longer be absorbed within existing budgets.

There are many examples of individual contributors to increased vegetation management costs over the past decade as summarized in Table 5-12 below:

Table 5-12 Cost Pressures by Category

Category of Cost Pressures	Examples
Increased compliance requirements	• Introduction of MRS in 2009 • Fire prevention equipment, training and regulations
Increased safety requirements	• WorkSafeBC requirements • Growing safety practices
Increased climate impacts and environmental factors	• Increased extreme weather events • Multi-year drought, increasing tree mortality • Warm and wet summers, increasing tree growth rates
Non-vegetation events impacting regular vegetation work cycles	• Wildfires • Environmental and Wildlife Requirements
Increased market rates for program delivery	• Inflation • Increased market demand for vegetation services
System expansion	• +6 per cent increase in system size

While many of these cost pressures were not significant individually, the aggregate effect, when combined with a flat budget, resulted in a reduced overall work output.

The long-term benefit provided by the extensive vegetation activity and clearing that occurred from fiscal 2007 to fiscal 2009 avoided immediate system impacts (e.g., reliability, safety or regulatory consequences) associated with reduced work volumes in the following years. Over time, BC Hydro shifted vegetation maintenance efforts to targeting localized emergent risks rather than completing more extensive clearing on a regular management cycle. While this was generally sustainable for a period of time, it led to an accumulation of general vegetation maintenance needs that will now need to be addressed.

Cost pressures challenge our ability to absorb unplanned events (both vegetation and non-vegetation related) impacting the system. For example, efforts to mitigate wildfire risk or recover from wildfire damage can shift vegetation management efforts into an off-cycle state, since there are no resources available to support unplanned work. Another regular example includes adjusting work plans to the avoid impacting the nesting of migratory species by moving work from spring to fall once they leave nesting sites. These types of examples force the standard work plan off-cycle, reducing cost-effectiveness for a prolonged period of time and introducing incremental risk to the system. Off-cycle work, in addition to being more costly, also contributes to long term supply and demand imbalances as external vendors allocate resources to other customers or require a premium to reactively adjust delivery to non-continuous work.

BC Hydro has worked hard to minimize impacts caused by external events and cost pressures. We have found efficiencies, prioritized work and innovated to extend our ability to preserve system performance without additional resources. Examples include:

- **Distribution Automation** – deployment of smart assets on the system (e.g., reclosers, automated switchgear, etc.) that significantly improve reliability and safety performance through rapid response and localization of system disturbances;
- **Transmission System Redundancy** – the majority of the transmission system design includes networked connections where multiple transmission lines feed a particular area (with the exception of radial lines feeding remote communities). BC Hydro has continued this approach to system design as it ensures reliability if a portion of the system is compromised, avoiding customer interruptions. Automated remedial action schemes and manual restoration operations also support rapid response to transmission outages;
- **Category Management** – development of vendor management plans that ensure competitive rates for vegetation work delivery and securing supply of the necessary resources to perform the work;
- **Work Delivery Management** – optimization of delivery methods through program and contract management efforts combined with regional expertise in vegetation management, including professional foresters. This also includes

use of innovative systems to better analyze, track and document vegetation needs (e.g., VegNET); and

- **Targeted Work Delivery** – utilization of a targeted method for visually identifying high risk vegetation through patrols, leading to the development of the vegetation work plan. This approach was highly successful until the general vegetation on the system exceeded the point at which it could continue to be effective.

Although BC Hydro has actively mitigated the impacts associated with absorbing cost pressures within a fixed vegetation budget, this approach is no longer sustainable. The accumulation of vegetation on the system needs to be addressed to preserve system and safety performance in the future.

5.7.4.3 Climate Change is Impacting Vegetation in British Columbia

Climate change over the last two decades is impacting vegetation management. Over this time, we have seen greater frequency and severity of storms in addition to localized weather pattern changes. For example, in the Lower Mainland and Vancouver Island regions, we have generally seen much warmer and wetter summers in recent years causing vegetation to grow more quickly than expected. In other regions of the province, we have seen increased tree mortality due to summer droughts and insect infestations related to warmer winters. General climate impact to vegetation across B.C. is dynamic in nature and BC Hydro has absorbed the associated costs of managing these changes through various measures.

BC Hydro’s approach to absorbing cost pressures has been effective in balancing system performance and cost for the past 10 years. While targeted work can address emerging risks, trees continue to grow each year and eventually all remaining vegetation requires extensive maintenance to maintain safe clearances to energized equipment and support reliable system operations. As the sub-sections below explain, BC Hydro believes that we have now reached this point and as a result, increased investment is required.

5.7.5 The System Has Reached the Point Where a New Strategy is Required

Although the focused targeting of work had proven to be successful and cost effective for a number of years, events in fiscal 2020 and fiscal 2021 indicated that the overall canopy growth had reached a point where it is no longer an effective means of managing overall system risk for transmission. Grow-ins, where trees grow into existing lines, have occurred on the transmission system and are described in section 5.7.6.2 below. BC Hydro has also experienced increased outages due to vegetation on the distribution system and the cumulative cost pressures and impacts from climate change need to be more proactively addressed.

In response to these needs, BC Hydro conducted an internal analysis to assess the requirements to enable a sustainable vegetation program that will reduce the risk of vegetation related system events. The analysis quantified the accumulation of vegetation clearing that needs to be addressed over the next few years to support reliability and safety. It also confirmed the need for a new Vegetation Management Strategy for a sustainable vegetation management program. Further details are provided in section 5.7.6 below (for transmission vegetation management) and section 5.7.7 below (for distribution vegetation management).

5.7.5.1 The New Vegetation Management Strategy Will Inform Future Budgeting

The new Vegetation Management Strategy will be developed during fiscal 2022 and will inform vegetation management funding in future test periods. The initial goals of the new Vegetation Management Strategy are as follows:

1. Sustain a level of vegetation management where the current accumulation is addressed and no longer re-accumulates;
2. Improve visibility of vegetation across the system and adopt a more dynamic approach of assessing annual workplans that take into account variable growth rates, system conditions and climate impacts;

3. Optimize vegetation management delivery by improving our system visibility and assurance processes, validating best practices and adopting new innovations;
4. Engage the market to seek economies of scale or delivery efficiencies, reducing unit costs;
5. Expand our suite of metrics to facilitate oversight and compliance with both internal and external requirements; and
6. Maintain compliance with regulatory, safety and reliability standards and goals.

BC Hydro believes the achievement of these goals is required to adequately maintain the transmission and distribution systems in the future with respect to vegetation management. BC Hydro will also be developing a suite of metrics and associated targets to assess the ongoing performance of the strategy following its implementation in fiscal 2023 and beyond. These will be made available in subsequent years to communicate the progress and performance of the new Vegetation Management Strategy.

Through the implementation of the new strategy, BC Hydro expects to see a series of improvements to how vegetation is managed on the BC Hydro system. Some of the initial outcomes identified include:

- A reduction of impacting events because of vegetation contacting the power system (e.g., fewer vegetation related outages, fewer wildfire ignitions, improved public safety, improved reliability performance, etc.);
- An improvement in unit costs through delivery efficiencies (remaining on-cycle, improved planning and targeting of work, etc.);
- Reduced risk to the Bulk Electric System from vegetation grow-in through predictive analytics and modelling because of improved visibility; and
- Reduction of vegetation accumulation.

5.7.5.2 Fiscal 2022 Is a Transition Year to the New Vegetation Management Strategy

Fiscal 2022 is a transition year from the past program to the new strategy. As such, the anticipated changes to the program (e.g., increased transmission vegetation maintenance, introduction of LiDAR, etc.) will begin to occur within the Test Period. The subsequent sections describe, for the transmission and distribution systems respectively, the changes in vegetation approach, scope and delivery. These are all considered important changes that will bring further insight into the development of the new Vegetation Management Strategy.

5.7.6 BC Hydro's Transmission Vegetation Management Program Contemplates Significant Activity in Fiscal 2022

BC Hydro's transmission vegetation management program includes transmission corridor vegetation maintenance within the BC Hydro rights-of-way, surrounding edge trees and within facilities (i.e., stations). Broadly speaking, there are three approaches to vegetation management on the transmission system, and our transmission vegetation program uses (and will continue to use) all three:

- **Right-of-way clearing** involves removing nearly all vegetation within the right-of-way below and adjacent to the transmission conductors. Clearing is measured in hectares cleared and additional treatments following the clearing (e.g., herbicide) can be applied in accordance with published usage plans;
- **Hot-Spotting** is selective removal of specific tall trees or small areas, within the right-of-way, where tall vegetation poses a risk. Localized in nature, hot-spotting is most effective when addressing small numbers of large and fast growing tree species. Hot-spotting is not effective in addressing overall tree canopy growth, where full clearing is an effective approach; and
- **Edge tree removal** is focused on the areas at the edge of the right-of-way and not beneath the conductors. These trees pose a risk to the system by falling down on a conductor or structure during a storm event or other vegetation

stability failure (e.g., erosion, wind, mortality due to infestation or drought, etc.). Identifying and proactively removing high risk trees improves safety and reliability of the system.

In this section, we first describe BC Hydro's current approach to transmission vegetation management. Over the last decade, BC Hydro has cleared approximately 5,000 hectares per year on average, augmented with right-of-way tree hot-spotting and edge tree removal. Costs of program delivery have increased by approximately 20 per cent in the last five years whereas the annual expenditure has remained relatively unchanged (consistent year over year in real dollars). BC Hydro has absorbed cost pressures, including costs associated with system growth, to maintain a stable program budget by evolving and innovating program approach in response to the growing vegetation.

Although this approach has been successful for nearly a decade, there have been recent events that indicate that the current level of clearing and approach of hot-spotting is no longer able to sustain the required system performance.

Beginning in fiscal 2022, a period of incremental work to remove the accumulation of vegetation on the transmission system will be needed before reaching a new stable, lower risk, vegetation clearing cycle. The new Vegetation Management Strategy, to be submitted as part of our Fiscal 2023 Revenue Requirements Application, will describe this work further.

5.7.6.1 Current Approach Uses System Patrols to Target Localized Issues

The current approach for the transmission system is characterized by system patrol cycles that occur at least once annually and in greater frequency for lines that service large population communities. BC Hydro uses these patrols to target localized issues, rather than prioritizing full right-of-way clearing.

At present, BC Hydro patrols each transmission line at least once and, in most cases, twice per year. Typically, one patrol is completed by ground and the other is completed from helicopter. Both methods are considered manual patrols and rely on experienced personnel to identify and document the state of the vegetation.

These patrols provide a static inspection of the system at the time of the patrol and the information gathered is used for developing the work plan for transmission vegetation management. Individuals performing these patrols document their findings in a system called VegNET for analysis and prioritization. VegNET is a mobile field application used to facilitate and spatially locate all tasks and activities related to transmission vegetation. It is accessed by BC Hydro staff, consultants and contractors to ensure planning and work alignment.

Based on the result of the initial patrol, a work plan is developed from the patrol information that prioritizes needs and emergent risks. Work is prioritized primarily on the basis of risk and then aggregated by region and adjusted based on annual access requirements (e.g., no access during winter due to high elevation, etc.). The work plan is shared with the contractors who complete the work that is typically executed during the spring to fall of the following year. If the patrols identify work that requires immediate attention, work can be expedited for completion within hours or days of the observation. As additional information becomes available through further patrols during the year, the plan is adjusted to address the emergent needs such as vegetation in proximity of the lines (as a result of the combination of greater than expected growth and increased line sag or sway, edge trees with deteriorating health, etc.).

Vegetation management is achieved through brushing, mowing, herbicide application, pruning and hazard tree removal. When several of these approaches are used in the right-of-way (often across a number of consecutive hectares), this is defined as clearing as all of the vegetation posing a risk to the system below the conductor spans is removed. When these same approaches are focused on a specific large tree or small area of vegetation, it is considered hot-spotting. Factors such as riparian treatments, species at risk analysis, archeology and heritage and similar requirements are addressed as part of regular work delivery and post cutting treatments (such as the use of herbicide or debris removal) follow documented plans that are in accordance with regional needs and processes. Once contractors communicate completion of work, BC Hydro audits a sample of the work completed. Work records are also documented in VegNET by capturing and maintaining vegetation logs for future planning and analysis efforts.

Over the last 10 years, BC Hydro has achieved system wide coverage by a combination of reduced right-of-way clearing (approximately 5,000 hectares per year) and hot-spotting, rather than by full right-of-way clearing that is more costly and was not yet required over this period. The extensive clearing performed in the past (between fiscal 2006 and 2009) and the age of the lines (where trees were fully cleared for initial construction) had left the vegetation on the transmission system in a state that had only recently grown to a point of concern.

Hot-spotting is more reactive to growth and focused on specific areas of tall vegetation, addressing the highest risks observed. This approach is effective when the overall canopy remains low or vegetation accumulation remains within the scope of what hot-spotting can address. Extensive use of hot-spotting in lieu of clearing is not sustainable in the long term as, eventually, too many trees become tall and general right-of-way clearing is necessary to address the area fully. After a decade of using the hot-spotting approach, it is now time again to begin managing the average height of vegetation on the system through clearing to meet future system performance and compliance requirements.

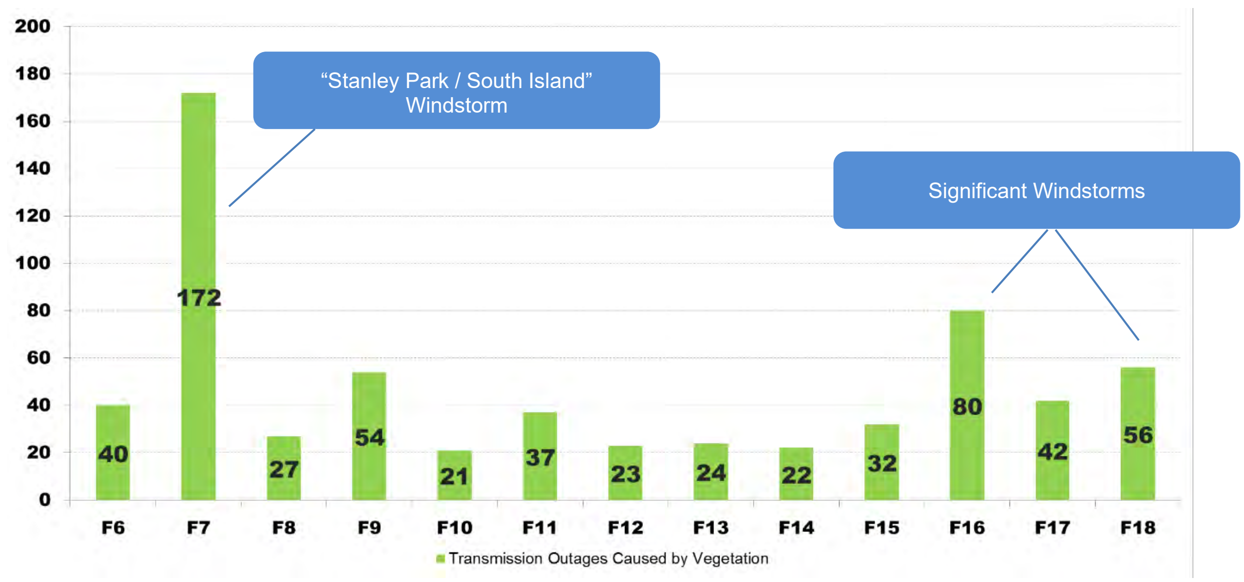
BC Hydro has identified numerous opportunities to improve which are outlined in section 5.7.6.3 below.

5.7.6.2 Fiscal 2020 and Fiscal 2021 Grow-ins Are Indicators that a Different Approach is Now Necessary

BC Hydro measures the performance of its transmission vegetation maintenance program by the number and duration of outage events involving vegetation and the event type (i.e., tree grow-in vs. trees falling-into lines). Recent experience with vegetation related outages on the transmission system are indicators that a change in approach is now necessary.

As shown in Figure 5-5 below, following the significant clearing work completed up to fiscal 2008, the number of vegetation related outages on the system was significantly reduced until the end of fiscal 2015. However, since fiscal 2016 we have seen increased transmission outages from fallen trees, mostly due to major storms.

Figure 5-5 Number of Transmission Outages Caused by Vegetation (Full System)



Note: Transmission outages do not always translate to customer outages due to system redundancy.

5.7.6.3 BC Hydro's Internal Analysis Shapes Planning for Transmission Vegetation in Fiscal 2022

As mentioned in section 5.7.1, BC Hydro initiated an internal analysis of the current state of vegetation maintenance with the aim of informing a new long-term strategy. For the transmission system, the analysis examined current and historical work records and reliability statistics dating back nearly 20 years to understand the multi-decade direction of the vegetation program.

The following key transmission improvement opportunities, identified by the vegetation program analysis, will be areas of focus for the fiscal 2022 work plan and new Vegetation Management Strategy:

1. Shift from static inspections to dynamic surveys and modelling (**LiDAR**) to ensure all system and vegetation growth conditions are considered when planning work;
2. Achieve a sustainable ongoing program, after addressing the current accumulation, which allows the vegetation management work performed annually to reach a point of equilibrium with system growth;
3. Continue to engage market processes (e.g., increased rate competitiveness due to higher work volume) and explore innovations (e.g., continued distribution automation expansion) to mitigate cost pressure increases and build more flexibility for vegetation management to address emergent events and climate change impacts; and
4. Expand vegetation planning and professional resources to improve program delivery and ensure compliance with all requirements.

Each of these opportunities is discussed below.

Dynamic Surveys and Modelling Will Enhance System Visibility

A key insight from the analysis, described in section 5.7.6.3, was the need for improved system surveys and modelling. An ongoing LiDAR program (~$4 million per year) will be introduced in fiscal 2022 to inform future planning through enhanced visibility of vegetation on the system and by predicting future vegetation growth through modelling.

The analysis recognized that manual patrols (either on foot or by helicopter) only provide a static view into the current state of the system and vegetation clearances. This static view can change when system loading increases or decreases (line sag or contraction), when wind blows (sway) or when vegetation grows at variable rates (growth rate is dependent on environmental conditions and tree species). These influencing factors (e.g., temperature, loading, wind, ice load, vegetation height, vegetation growth rates, etc.) are dynamic and are difficult to accurately capture from the current approach of using patrols. This can be a factor, for instance, when patrols must be conducted in warmer seasons (due to limited winter access) when loading is not at peak. Many utilities have sought alternate approaches to improve the dynamic imaging and modelling of their electrical systems and a common industry practice is now the use of LiDAR.[95]

Given the information from the analysis, long term vegetation growth on the system, BC Hydro is implementing an ongoing LiDAR program. This program will capture accurate system surveys that can be integrated with system models to perform scenario-based analysis incorporating multiple factors (e.g., demonstrating clearances based on a specific segment of line under multiple loading and weather scenarios in addition to vegetation growth modelling). These models will improve BC Hydro's capability to prioritize transmission vegetation management each year and enable focused targeting of the vegetation program on the highest risk areas.

An ongoing LiDAR program represents a significant investment. BC Hydro is planning to undertake a complete system view every five years in order to provide the visibility necessary to prevent grow-ins (based on maximum expected tree growth and line clearances). As such, the LiDAR program is expected to cover 20 per cent of the system each year, resulting in a five-year full system cycle, beginning in fiscal 2022. Once the full system view is completed, it will complement ongoing visual inspections by providing a consistent and objective source of information on tree growth to inform vegetation management planning.

[95] For example, it is BC Hydro's understanding that Bonneville Power and PG&E use LiDAR for full system surveys.

Sustainable Long-Term Need on the Transmission System

Another key outcome of the analysis was determining the optimized level of right-of-way clearing and hot-spotting based on the current size of the system and the specific needs of the vegetation at a sub-region level.

The analysis included identification of the fastest growing tree species for each sub-region, their typical growth rate and the height clearances of the transmission system for each voltage class. This indicated a full clearing need of approximately 19 per cent to 22 per cent of the system annually if no hot-spotting work was completed. Although full clearing would assure the transmission system is not at risk from grow-in vegetation, it is not a realistic approach to sustainable system management when considering cost, environmental impact, general invasiveness and resource availability.

This view was augmented with specific line details and regional knowledge to determine how the benefit of full clearing could be extended by hot-spotting specific risk areas (e.g., centre span between two towers where sag is most pronounced, conductors adjacent to steep inclines, etc.). When combined, a net clearing and total hot-spotting volume was determined, extending the annual clearing cycle. This resulted in an assessed ongoing need for approximately 6,700 hectares (approximately 8.7 per cent of the full system versus the 19 per cent to 22 per cent noted above) cleared annually and augmented with approximately 40,000 hot-spotted trees to maintain a sustainable vegetation management level across the transmission system.

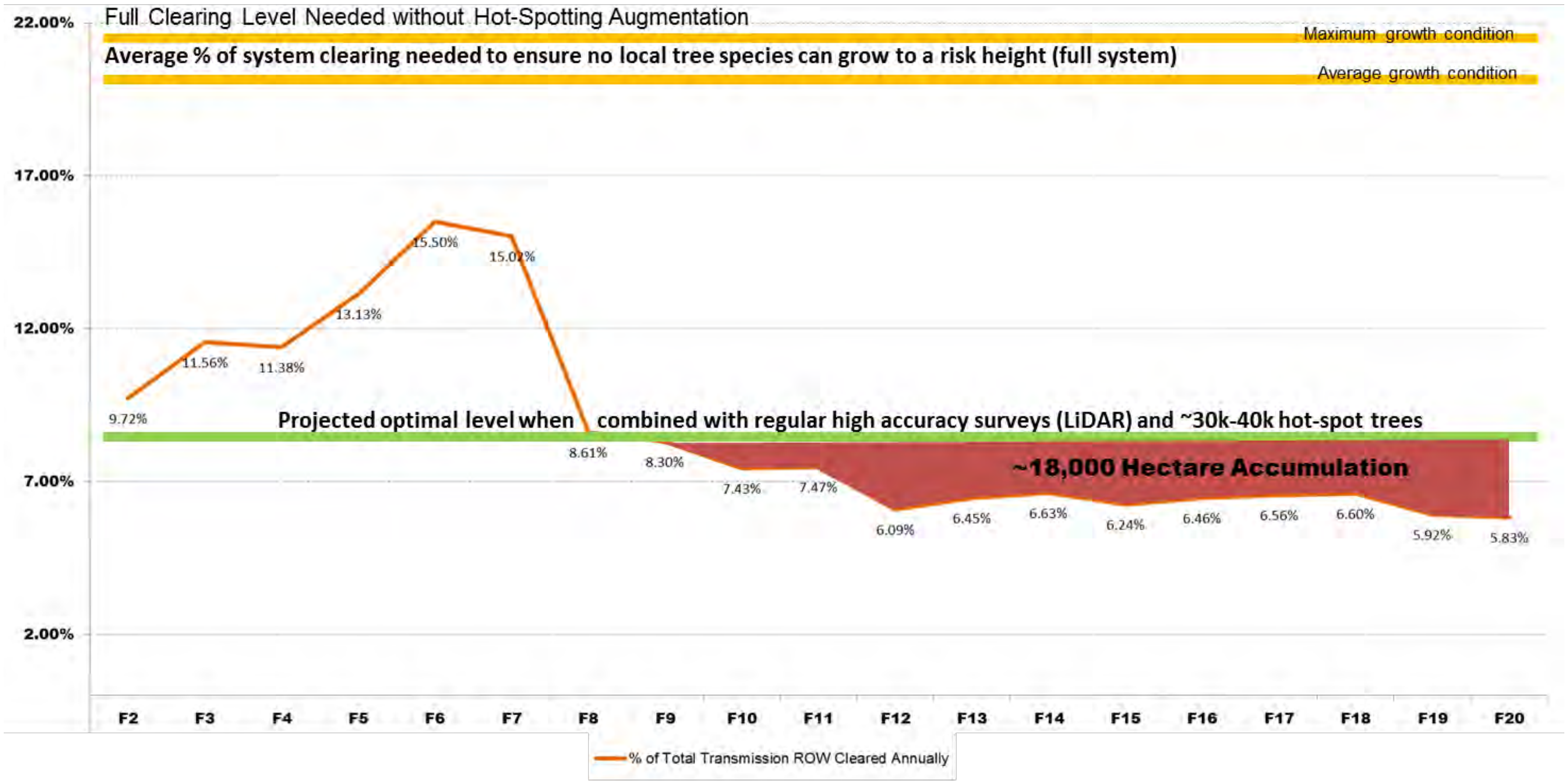
In Figure 5-6 below, the total system statistics are shown by voltage class and the corresponding modified cycle for clearing and clearing hectares. A further breakdown is provided to show how the total of approximately 6,700 hectares is allocated across HVTCs and LVTCs.

Figure 5-6 Summary of Sustainable Transmission Vegetation Cycles

System Statistics by Voltage Class							Modified Sustainable Cycle (with hot-spotting ~40k trees system wide annually)		
Region / Area	Voltage Class	Circuit Length (km)	Structure km	ROW Length (km)	Gross ROW Area	Edge (km)	Modified Cycle (Years)	Modified % Cleared Annually	Modified Area Treated Annually (hectares)
ALL	69 kV	3,442	3,329	2,955	5,618	5,660	6.75	9.62%	541
	138 kV	4,655	4,337	3,494	12,546	6,734	6.84	9.51%	1,193
	230 kV	3,578	3,373	2,440	15,755	4,616	6.25	10.40%	1,638
	287 kV	627	627	626	2,479	1,167	6.50	10.00%	248
	345 kV	237	237	228	1,427	441	5.55	11.72%	167
	500 kV	5,844	5,847	3,653	38,573	6,316	8.65	7.51%	2,897
System Totals		**18,550**	**17,846**	**13,460**	**76,671**	**25,026**	**7.43**	**8.74%**	**6,703**
				MRS	**58,507**	**12,632**		**MRS**	**5,102**
				Non-MRS	**18,164**	**12,394**		**Non-MRS**	**1,601**

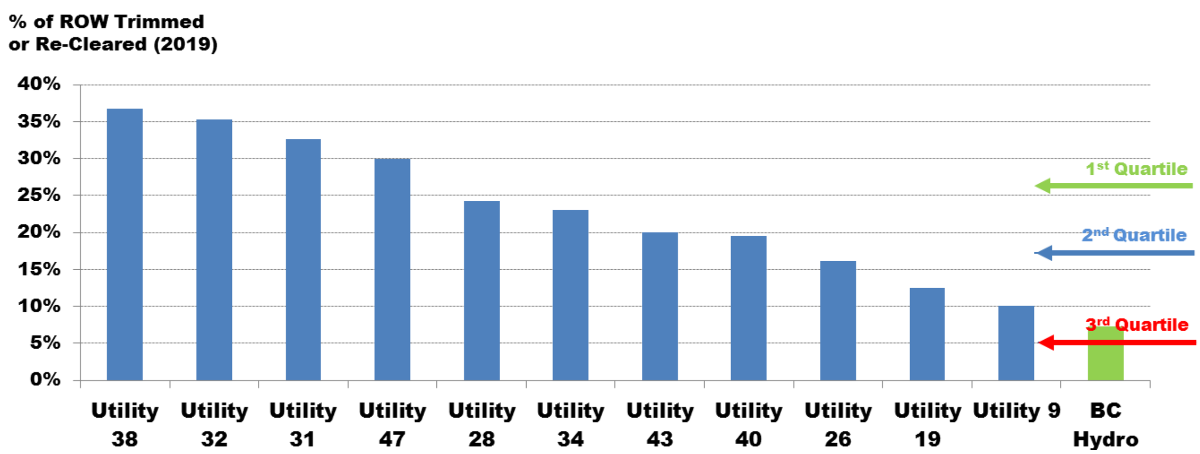
Once the sustainable level of 8.7 per cent of annual clearing combined with 40,000 trees removed through hot-spotting was determined, it was used to compare against historical clearing to assess the maximum extent of the existing accumulation. This is shown in Figure 5-7 below. This analysis suggested that the current system accumulation is up to approximately 18,000 hectares. Further refinement of the vegetation volume will be undertaken when LiDAR surveys quantify the vegetation clearances under various loading scenarios across the system in future years. This will inform the new Vegetation Management Strategy and future annual work plans.

1 **Figure 5-7 Historical Clearing Volumes Versus Projected Sustainable Level**



Benchmarking also suggests that an increase in clearing is required. When comparing the amount of right-of-way clearing that BC Hydro undertakes versus utility peers, BC Hydro clears less on average as a percentage of total right-of-way. BC Hydro is currently in the third quartile and nearing the fourth quartile in right-of-way clearing. Figure 5-8 shows an excerpt from the 2020 First Quartile[96] Benchmarking Study that compares BC Hydro to similar utilities.

Figure 5-8 First Quartile Benchmarking Results 2020 Percentage of Transmission Right of Way Trimmed or Re-Cleared



As a result of the analysis and benchmarking, the proposed fiscal 2022 budget for transmission vegetation management is $33.3 million, an increase of $15.5 million compared to the fiscal 2021 plan. In addition, $4 million is allocated for LiDAR and $0.9 million for incremental planning and forester resources in fiscal 2022. This level of expenditure will support:

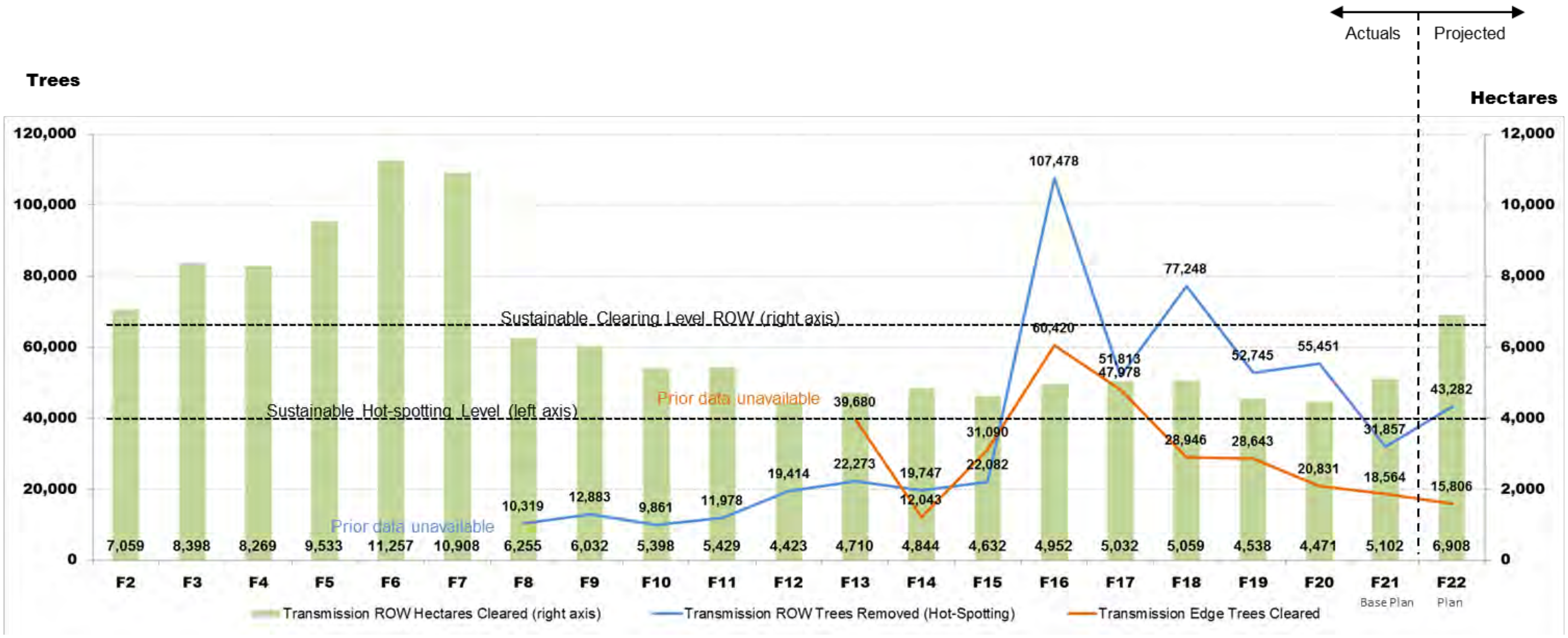
- Development of the expanded annual work plan;
- Clearing of 6,900 hectares (slightly greater than the 6,700 long-term sustainable level);

[96] First Quartile is a benchmarking company that does utility industry surveys.

- Hot-spotting 43,000 trees (slightly greater than the 40,000 long-term sustainable level);
- Removal of approximately 15,000 high risk edge trees;
- 20 per cent system imaging by LiDAR and modelling; and
- Regular patrols, clearing layouts and helicopter time.

The fiscal 2022 plan will enable BC Hydro to address immediate areas of risk while not allowing the vegetation accumulation to grow. As LiDAR modelling provides a more robust and dynamic view of the system, funding requirements beyond fiscal 2022 will be developed in accordance with system conditions and will form the basis of a new Vegetation Management Strategy. Figure 5-9 shows the increase in clearing and hot-spotting in context of historic work volumes to illustrate where the increases would be focused.

1 **Figure 5-9 Transmission Vegetation Management Work Volumes with Fiscal 2022 Plan**



Reducing the Impact of Cost Pressures through Exploring Market Processes and Innovations

In fiscal 2022, contractors will continue to be the primary method of vegetation management delivery across the province. BC Hydro will examine the current market strategy on how resources are contracted to perform vegetation maintenance work. Although our current contracts are delivering at fair market value through our procurement processes, the increase in the program size in fiscal 2022 provides opportunities to improve efficiency and contractor co-ordination. We will begin working closely with our contractors, municipal partners and the market in fiscal 2022 to shape the long-term resourcing portion of the new Vegetation Management Strategy.

Another important activity in fiscal 2022 will be to solicit input into the new Vegetation Management Strategy related to best practices, insights and innovations from both utilities and related forestry focused industries. BC Hydro is continuing to engage with external experts to help assess whether any innovations can be adopted in B.C. that can help improve the efficient planning, resourcing and delivery of vegetation management. External expertise will continue to be solicited using a combination of existing means (e.g., Canadian Electricity Association member surveys, direct utility to utility discussions and publications) and deliberate engagements (external consultations). The information garnered from external sources will then be assessed as the new Vegetation Management Strategy is developed.

Need for More Planning and Professional Resources

The fiscal 2022 transmission vegetation workplan includes a significant increase in maintenance work. As such, incremental resources are required to manage planning and ongoing professional needs (certified forestry professionals certifying plans and delivery practices). These additional resources will work with our external contractors to ensure efficient delivery of the program in accordance with the workplan and standards.

As more system information is made available from the use of LiDAR and patrols, the additional planning resources will be able to target work effort to the highest priory areas and reduce overall system risk from vegetation. BC Hydro expects immediate benefits from this additional oversight during the fiscal 2022 transition year and in subsequent years following the implementation of the new Vegetation Management Strategy.

5.7.7 BC Hydro's Distribution Vegetation Management Program Incremental Additions for Fiscal 2022

Distribution Vegetation Management supports maintaining the vegetation across the 58,000 kilometers of line comprising the distribution system. Distribution Vegetation Management forecast operating costs are increasing by $4.7 million from fiscal 2021 to fiscal 2022 to support an increase in the level of work performed on the distribution system. An additional $0.7 million will be allocated for incremental distribution coordinators to increase BC Hydro's field capability to deliver the work plans efficiently. The increase will bring the distribution vegetation management program to a level that is more sustainable over the long-term.

5.7.7.1 Overview of Distribution Vegetation Management Program

Distribution vegetation management primarily includes routine tree maintenance (e.g., pruning) along distribution lines and hazard tree removal. A small portion of the program is allocated to re-greening grants to municipalities (to compensate for boulevard tree removals and replace removed trees with more appropriate species to reduce future ongoing maintenance). As part of the joint use program with TELUS, BC Hydro receives cost recoveries on routine maintenance and hazard tree removals. The estimated TELUS recoveries for fiscal 2022 are $6.9 million on a total program budget of $36.1 million.

Distribution vegetation maintenance can be categorized into two primary areas: pruning and hazard tree removal, each with its own unique delivery requirements:

- Pruning involves cutting vegetation back from the power system to distances safely outside of the limits of approach, which is the safe distance between the electrical conductor and vegetation. This work requires certified utility arborists, when in proximity to conductors, and also uses other vegetation management workers for areas away from the conductors (e.g., mowing access to transformers or other ground level work); and
- Hazard tree removal involves addressing high risk trees in proximity to the electrical system. Trees that are dead, dying or leaning are a focus as they pose the most risk for downing wires, especially during storms. Removing those trees most likely to fail in advance is a proven method to preserving system performance and ensuring public safety. Proactively addressing these trees is much safer and costs significantly less than addressing them as part of an outage and repairing the system following a vegetation related failure.

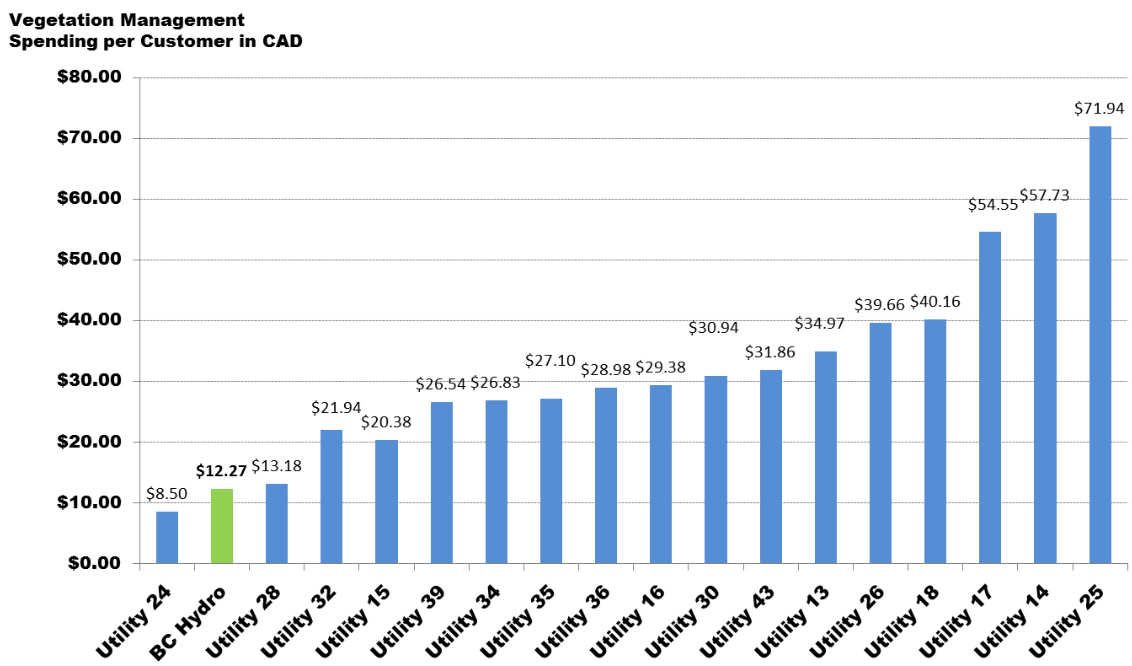
Unlike the majority of transmission vegetation work, distribution vegetation management is highly visible to our customers and often involves trees that customers or the public own or that the community enjoys. As such, there is significantly more engagement with customers and municipalities during program delivery and this has substantially increased over the last decade. Vegetation program coordinators and contractors often work directly with the public to determine the best method of managing the risk their trees pose while respecting individual and community perspectives.

For the overhead distribution system, among all outage causes, trees have the highest impact on customer reliability. In fiscal 2011, trees accounted for 5,194 distribution outages (23 per cent of all outages) resulting in 3.4 million Customer Hours Lost (35 per cent of total hours lost). In fiscal 2020, trees accounted for 7,322 of all distribution outages (26 per cent of all outages) and 3.9 million Customer

Hours Lost (49 per cent of total hours lost). Customer impacts are highly correlated with the severity of the annual storm season and British Columbia has experienced some very significant wind, ice and major winter storms in the past five years.

Benchmarking indicates that BC Hydro’s annual distribution vegetation management spending per customer is low compared to utility peers. This is shown in Figure 5-10 below.

Figure 5-10 First Quartile Benchmarking Results 2020 Vegetation Management Spending per Customer in C$



Customers highly impacted by outages (e.g., those connected by rural feeders susceptible to dense vegetation, wind and storms) have expressed concerns to the BCUC and BC Hydro in recent years about increased power interruptions caused by trees and have requested improvements to performance. BC Hydro regularly identifies ways to improve performance, such as use of re-closers to isolate damaged sections of line to make the system more resilient to storms. Despite these other system performance improvement efforts, addressing vegetation remains critical in managing system reliability.

5.7.7.2 New Cost Pressures Have Reduced Distribution Clearing Per Dollar Spent

Similar to transmission vegetation management, a series of increased delivery complexities over the last decade have increased market rates. These increases have reduced the overall amount of vegetation work completed per dollar spent, resulting in cost pressures. For distribution specifically, the most pronounced cost pressures include safety and compliance requirements in addition to increased processes and delivery support. These pressures are further exacerbated by climate change impacts and insect infestations.

The following is a summary of significant impacts to distribution vegetation management:

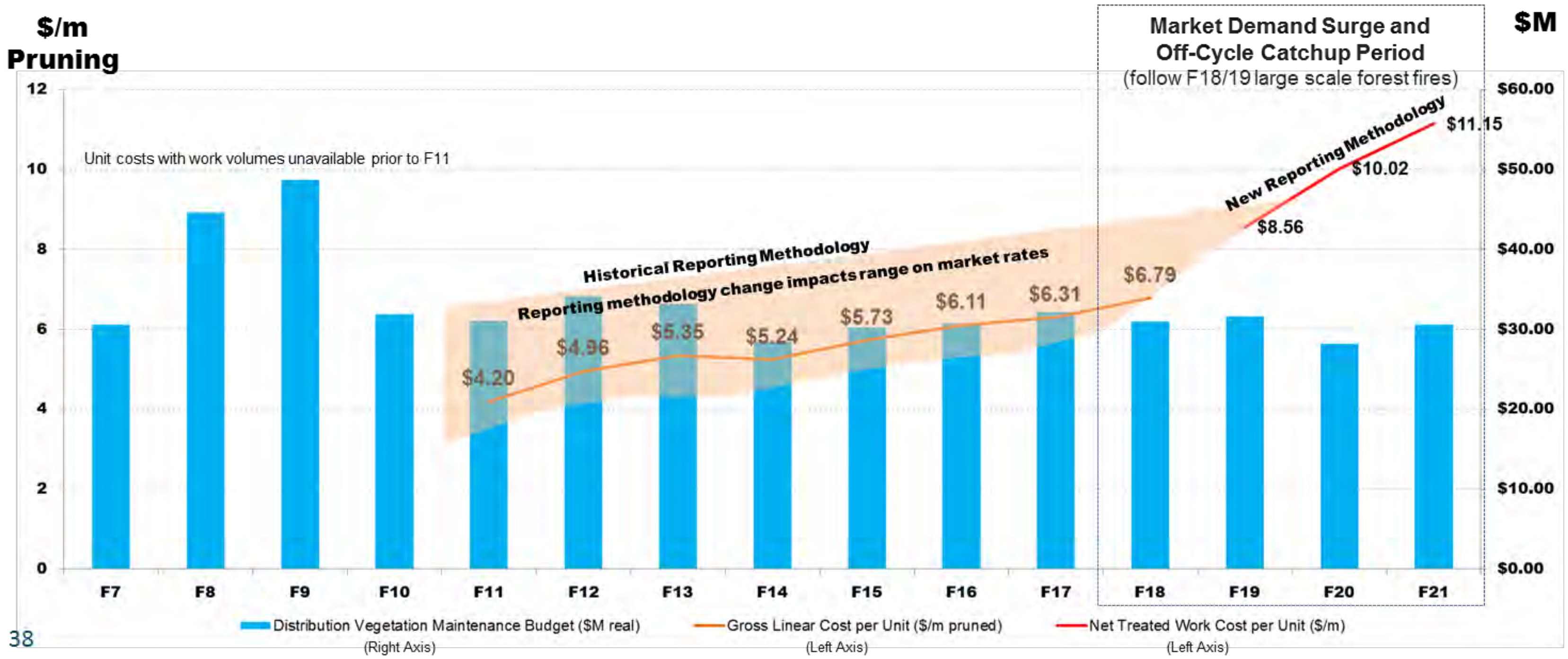
- Increases in market rates (driven by factors such as general demand increases, wildfires, regulations including safety and compliance requirements, etc.), resulting in higher bid prices for work;
- Increased customer coordination due to expectations for consultation and collaboration when addressing privately owned vegetation;
- Exogenous events (e.g., wildfires, market demand, etc.) impacting regular cycle work delivery and cost effectiveness; and
- More being asked of vegetation workers and contractors (e.g., incremental processes, regulatory and safety requirements, documentation and permitting).

These cost pressures translated directly into budget impacts as BC Hydro uses a competitive bid process for distribution work. Competitive bids ensure we achieve the best available pricing aligned to market rates; however, market rates have increased as a result of the cost pressures. Average market rates for pruning increased from $8.56 per meter in fiscal 2019 to $11.15 per meter in fiscal 2021, representing a 30 per cent increase over the last three years alone.

BC Hydro has been able to maintain reliability and safety performance, even with significant unit price increases by identifying improvements to innovate and improve delivery efficiency. Beyond the examples of key activities delivered by BC Hydro teams to mitigation system impacts described in section 5.7.4.2, another example in fiscal 2019 was an improvement to distribution work quantification (how BC Hydro issues market bids and describes the work involved). As shown in Figure 5-11 below, work quantification changed in fiscal 2019 to provide a more detailed view into what work is needed in a specific area, providing the ability for precise unit costing. Prior to this change, BC Hydro would identify an area and contractors would bid for that area, obscuring specific unit costs. Now, BC Hydro identifies specific work units (specific pruning needs, areas of mowing, etc.) within an area and contractors can then bid on actual work required versus a general area description. This improves BC Hydro's ability to determine cost-effectiveness per work unit and creates a more stable method to evaluate bid responses. It also increases overall visibility of the work required, helping to focus prioritization and enabling better cost analysis.

Figure 5-11 below shows unit pricing for pruning (in dollars per meter of vegetation pruned) versus the total annual program budget. Regular price increases were observed between fiscal 2011 and fiscal 2021. Although the reporting methodology changed in fiscal 2019, the trend persists and is directly connected to market rates and work cycles. This demonstrates that BC Hydro had absorbed cost pressures for a decade while maintaining the system.

1 **Figure 5-11 Distribution Unit Costs Over Time[97]**



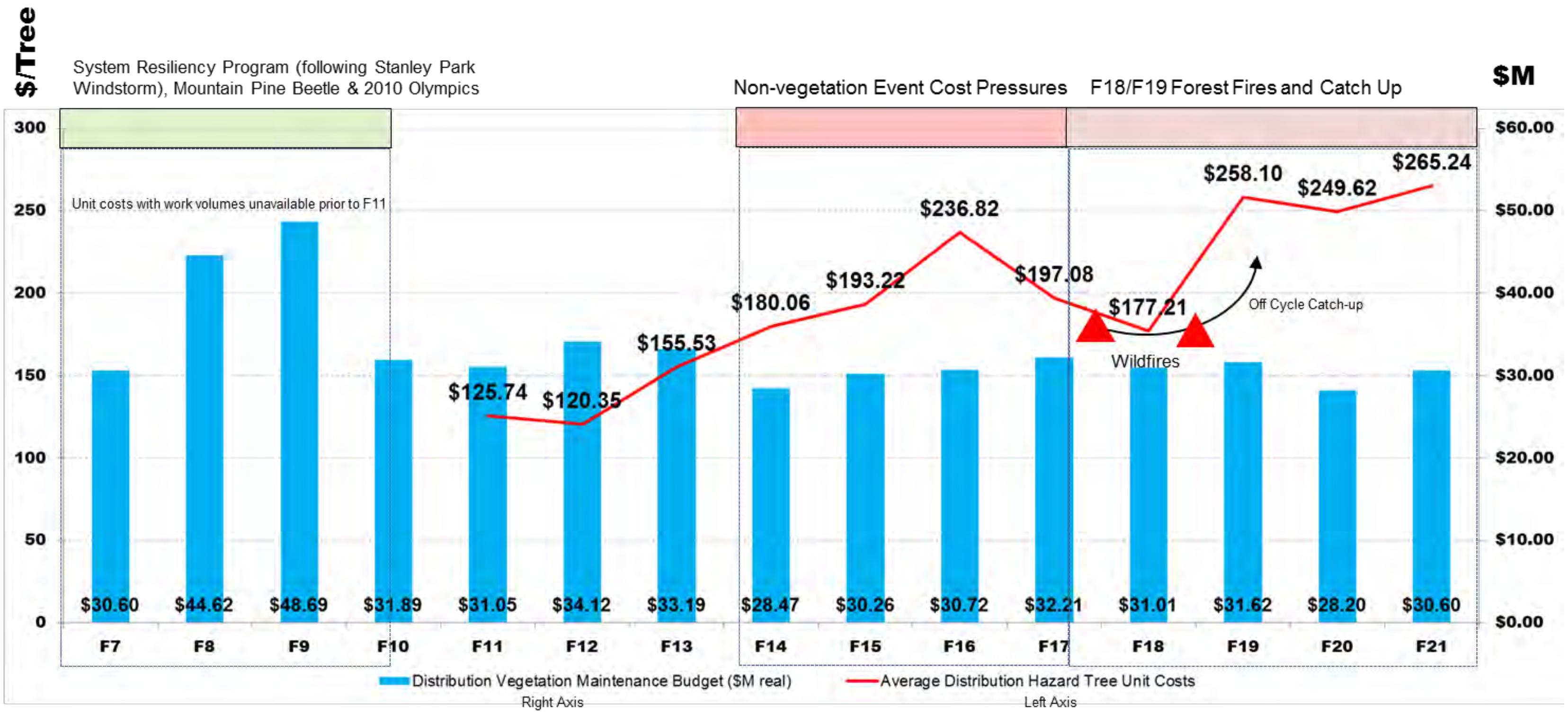
97 In fiscal 2019, work quantification changed from gross linear meters to net treated meters to increase work unit precision. Although beneficial for work cost analysis, this change does not allow for a single consistent evaluation line prior to fiscal 2019 (differential estimated at +/- ~30 per cent). However, the upward trend on pricing remains a key theme as a result of documented cost pressures and the market response to these pressures.

Another key factor that impacts delivery costs within the distribution system is work timing. When the program operates on a regular cycle (where specific identified areas are managed on schedule), cost efficiencies are gained through proactive booking of resources and addressing vegetation when it is more easily managed (e.g., not overgrown). For example, if there is a small tree with a five inch or less diameter trunk, cost of removal is typically less than $50. If that tree is not addressed that year and grows to a six inch or more diameter trunk in subsequent years, it can cost more than $150 to remove as it now requires a certified faller.

Similarly, if vegetation (either trees, bushes or shrubs) is outside of limits of approach for a conductor, it can be addressed at a lower cost than if it is near or within limits of approach where a certified utility arborist is required. Ultimately, when the regular cycles are disturbed by significant events, years of off-cycle work occur, and cost efficiencies are eroded. The distribution vegetation program in its current form cannot absorb any disruptions or events, which impacts delivery efficiency. When these disruptions or events occur, work is forced off-cycle and can perpetuate for years until the program returns to a regular cycle, resulting in reduced cost efficiency.

For example, the significant provincial wildfires during fiscal 2018 and fiscal 2019, combined with successive drought years (in the South and North Interior) have significantly impacted the distribution vegetation program. Due to extremely dry conditions, regular vegetation maintenance could not be undertaken to minimize ignition risk from operations (machinery and personnel) and resources were reallocated to addressing immediate fire risks versus regular maintenance. The program has not yet been able to return to on-cycle work. Figure 5-12 below illustrates the cost impact of off-cycle work following these events.

1 **Figure 5-12 Average Hazard Tree Removal Costs**



Increased distribution vegetation management spending in fiscal 2022 will address a portion of the outstanding maintenance work impacted by the wildfires and will enable an eventual return to on-cycle routine maintenance. Future Revenue Requirements Applications will address program stabilization timing as work volumes and system needs are evaluated and a sustainable long-term program is defined.

Another factor impacting current costs is the market capacity change as a result of the severe wildfires in fiscal 2018 and fiscal 2019. Following the wildfires, there was growth in general market demand for vegetation services from other organizations (e.g., municipalities, Wildfire Service, private entities, governments, etc.) and unit prices accordingly increased due to the elevated demand. Vegetation contractors sought higher rates as demand for services outpaced supply and additional investments in new resources and equipment were made. In fiscal 2022, BC Hydro will be seeking new contracts with distribution vegetation suppliers to stabilize costs and address the growing unit prices.

5.7.7.3 BC Hydro's Internal Analysis Has Shaped Planning for Distribution Vegetation in Fiscal 2022

As a result of the internal analysis we undertook in 2020, BC Hydro will begin to implement changes to distribution vegetation management beginning in fiscal 2022 and in subsequent fiscal years as the new Vegetation Management Strategy is developed. The initial changes during the Test Period include the following initiatives, each of which is discussed below:

- Accelerating the return of on-cycle program delivery to ensure cost effectiveness and performance;
- Increased emphasis on fire prevention;
- Address hazard trees and reduce the hazard tree backlog; and
- Market engagement on unit-based contracts.

Accelerating the return to on-cycle program delivery by increasing program size and resources

In fiscal 2022, the incremental funds and resources allocated for distribution vegetation will accelerate the return of the more cost-effective and efficient on-cycle work plan delivery. Activities undertaken in fiscal 2022 will help to determine the correct size of distribution vegetation management and will inform the new Vegetation Management Strategy.

Of the $4.7 million increase to distribution vegetation management, approximately $2 million will be allocated to hazard tree removal (discussed further below) and the remaining will be added to the existing pruning work planned on the system.

Evaluation and documentation of the distribution system and the state of vegetation will be conducted in fiscal 2022 and this refreshed view will enable improvements in work planning and delivery. BC Hydro will be adding four more distribution coordinators and one vegetation specialist to the existing complement of 25 staff in order to increase the oversight and productivity of third-party contractors. This will also accelerate the return of on-cycle work and improve delivery efficacy.

Fire Prevention is a Priority for Distribution Vegetation Management

Vegetation contacting electrical infrastructure can lead to significant fire risk or direct ignition of a fire. Fire prevention is a critical component of vegetation work and crews require more training and equipment today than in the past. The forecast increase in vegetation work on the distribution system will reduce fire risk from vegetation ignition sources.

Similar to transmission, climate change appears to be having an effect on the distribution system both in increased risks for igniting wildfires from tree contact and damage to the system from wildfires and storms that affect customer reliability. Based on the provincial data provided by the BC Wildfire Service, BC Hydro estimated that approximately 30 to 40 small fires each year (from 2015 to 2017) were started on the distribution system from trees contacting the lines. In fiscal 2021, given the significant risk that fires pose to public and employee safety, BC Hydro began a monitoring program that identifies, evaluates and documents fires on the electrical system. This information will also help improve regional targeting of future vegetation work and other capital and maintenance programs.

Most of the fires on BC Hydro’s system occur during wind events that push vegetation into contact with an energized conductor. BC Hydro’s vegetation management program is a key mitigation factor to electrical system ignition events that helps preserve public safety and protect electrical assets from damage. One of our primary goals in the Test Period is to increase the amount of hazard trees removed (as discussed further below) from the system to further reduce the risk of vegetation contact with distribution lines.

Increased Focus on Hazard Tree Removal

Although a relatively modest portion of overall distribution vegetation management budget, hazard trees will be an important focus for BC Hydro in fiscal 2022. Historically, hazard tree removal represented approximately 10 per cent of the distribution vegetation management program. The proportion of the program dedicated to hazard tree removal will be approximately doubled in the Test Period. This additional investment will help to start eliminating the accumulation of hazard trees on the system.

Hazard trees exist on private or public property and many are a result of weather events (e.g., drought, storms) and infestations that can reduce vegetation health. The accumulation of hazard trees has been managed by addressing the highest priority trees each year within the annual vegetation management budget. However, the growing number of hazard trees is now outpacing the ability of existing budgets to address the highest priority issues, resulting in accumulation. Trees remaining in the identified inventory are monitored and further prioritized against the additional hazard trees identified through the delivery of the annual program.

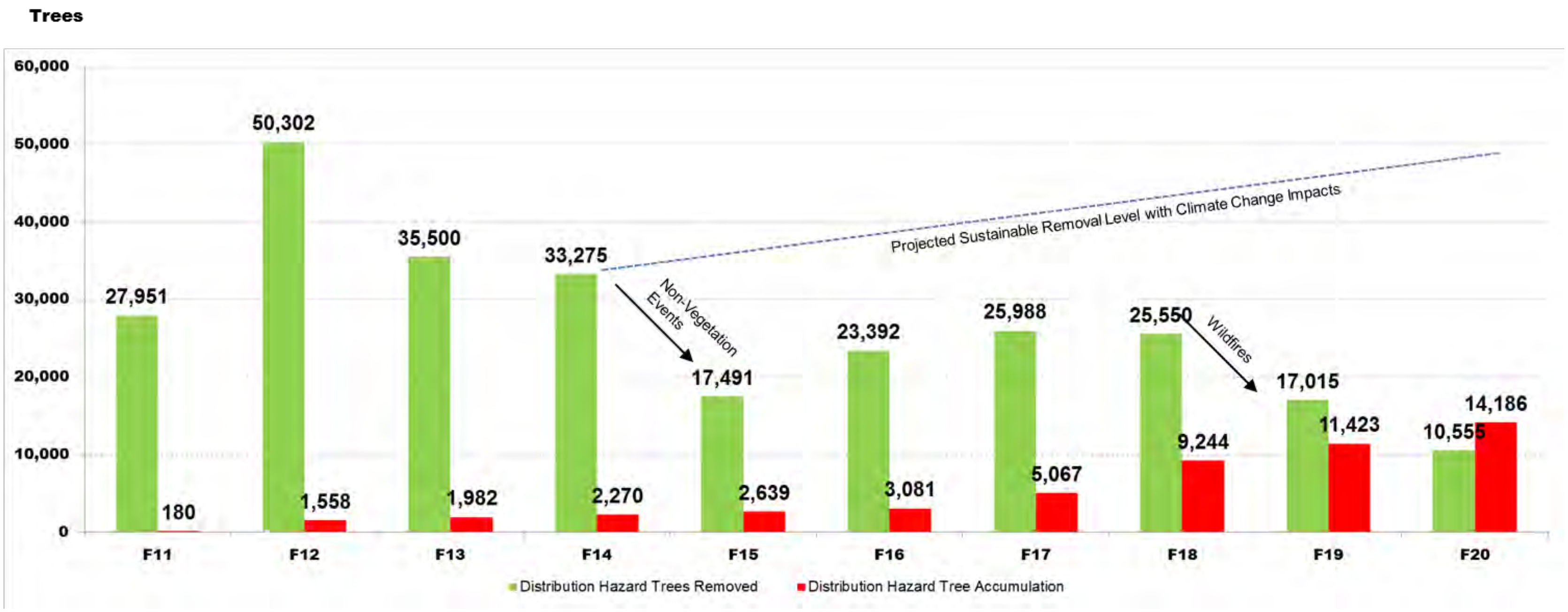
Today, there is a documented inventory of approximately 18,000 hazard trees.[98] The highest risk hazard trees (those that are deemed to pose an imminent risk to public safety or the electrical system) are prioritized and addressed first. The next level of risk within the inventory includes the hazard trees that will pose a risk in the near future through degradation or could be impacted by severe weather events. Historically, the program was only able to fund the removal of the highest priority hazard trees.

Beyond the current documented inventory, trees also exist that are likely to pose a risk in the future and are not documented as hazard trees yet. Once the accumulation of documented hazard trees has been eliminated in the coming years, focus will shift to inventorying the full spectrum of potential hazard trees. Proactively addressing degrading trees is more cost-effective than addressing them when they become a problem for the system.

Figure 5-13 below shows the number of hazard trees removed and the growing number of high-risk hazard trees accumulating in the inventory. In addition, the graph shows how the events mentioned in section 5.7.7.2 in 2018 and 2019 (provincial wildfires) impacted the total volume of hazard trees cleared.

98 As of approximately mid-2021.

1 Figure 5-13 Hazard Tree Clearing and Accumulation Levels Over Time



Approximately half of the $4.7 million increase for distribution vegetation management will be allocated to hazard tree removal to begin to address this accumulation and increase the number of hazard trees cleared in fiscal 2022. BC Hydro expects that a number of years of similar incremental investment in the distribution system will be required to fully address the accumulation and return hazard trees to a regular annual cycle.

Market Engagement on Unit-based Contracts

In fiscal 2022, BC Hydro will begin to use unit-based fixed price contracts versus the current approach of active market rates. The goal is to reduce the volatility of pricing while also ensuring market supply for needed services. Insights gained in fiscal 2022 will inform the procurement strategy that will be a component of the new Vegetation Management Strategy.

5.8 Cybersecurity

The cybersecurity threat landscape is growing in sophistication and the environment is constantly changing. During the proceeding for the Previous Application, BC Hydro indicated that additional investment would likely be required for cybersecurity management. Directive 21 of the BCUC's Decision on the Previous Application directed BC Hydro to address the adequacy of its cybersecurity programs in the Application. BC Hydro's fiscal 2021 base operating budget for Cybersecurity in the Technology KBU is $4.6 million. BC Hydro's planned increase for fiscal 2022 is $3.0 million which will be directed to areas identified for improvement in assessments and audits of BC Hydro's cybersecurity capability. The Technology KBU has also internally repurposed $0.4 million for two FTE positions to focus on cybersecurity activities. This additional funding and reallocated internal resources will result in a total Technology KBU base operating budget for Cybersecurity of $8.0 million to enhance BC Hydro's overall cybersecurity management capacity and capability to meet cybersecurity management needs.

Table 5-13 below provides a continuity of BC Hydro's cybersecurity base operating budget.

Table 5-13 Cybersecurity Base Operating Budget

$ million	F21 RRA Plan	Planned Increase	Internal Changes	F22 RRA Plan
Base operating budget	$4.6	$3.0	$0.4	$8.0
FTE	19	4	2	25

5.8.1 What is Cybersecurity and How Does it Differ from NERC Critical Infrastructure Protection (CIP) Compliance?

Cybersecurity is the practice of securing our digital systems against unauthorized access and potential loss of data or disruption to our business. As our dependency on digital systems (e.g., the internet and digital communications) increases, cybersecurity is a growing global challenge. As new technologies emerge, opportunities for innovation are created but the landscape of cyber threats is also expanded. Cyber threats also continue to grow in both volume and sophistication. A successful cyber attack on BC Hydro could have serious consequences including the release of sensitive information, disruption of data or systems needed to run our day-to-day business operations, disruption of our grid operations or even the security of our employees or the public.

Managing cybersecurity risk involves a multilayer approach that includes the technical capabilities to:

- Detect potential threats;
- Protect our information and systems;
- Respond to cyber incidents should the attack penetrate our protections; and
- Recover from any incident by restoring our information and systems.

Successful cyber risk management requires skilled cybersecurity teams, well-architected Information Technology (**IT**) and Operational Technology (**OT**) environments, specialized hardware and software to detect threats and protect our environment, and strong response and recovery plans. In addition, we must ensure our employees, contractors, vendors, and customers are well-trained to identify and respond to evolving cyber threats.

Although enterprise cybersecurity must be managed across our entire digital landscape, some digital systems, if disrupted, could impact the operation of the Bulk Electric System and potentially disrupt electricity supply to customers. These digital systems must be protected in a manner that is compliant with the NERC CIP standards, which are part of MRS.[99] The majority of these systems are OT systems, residing in our control centres and our most critical generating and transmission stations.

Achieving and maintaining compliance with the CIP standards is mandatory and challenging as both cyber threats and the CIP standards themselves evolve over time. New standards will typically encompass more of our digital systems and/or introduce new protection requirements so achieving and maintaining compliance takes considerable on-going efforts. Compliance with NERC CIP requires specialized people, processes, and technologies to be in place to meet the necessary requirements of the standards. FTE and funding requirements related to CIP compliance are identified in section 5.6.

5.8.2 BC Hydro Created a New Cybersecurity Department

Prior to 2016, BC Hydro had a largely outsourced cybersecurity operations team provided by TELUS. In 2016, the Technology KBU established a Cybersecurity Planning and Compliance team of five employees and a Cybersecurity Operations team of eight employees. The Operations team was funded through a repatriation of the function from TELUS in August 2017.

Since 2016, BC Hydro has increased its focus on cybersecurity, and this is reflected in the growth of the Cybersecurity team. During fiscal 2021, BC Hydro formed a new,

99 Mandatory Reliability Standards are discussed further in section 5.6.

consolidated Cybersecurity Department, bringing together Cybersecurity Planning and Cybersecurity Operations, and creating a separate CIP Compliance team. The Cybersecurity Department (not including Compliance, the resources for which are covered in the MRS section 5.6) currently consists of 19 employees, with an additional two resources in the Technology Project Delivery team dedicated to implementing cybersecurity investments, and an additional cybersecurity architect in the Enterprise Architecture team. The Cybersecurity Department has reached its capacity in terms of workload. BC Hydro reallocated two resources within the Technology KBU to the department in fiscal 2021 to enhance program and risk management. In fiscal 2022, the department requires additional FTEs to expand and enhance cybersecurity practices into the OT environment and address the complexity and growing volume of cyber attacks that BC Hydro is experiencing.

5.8.3 BC Hydro is Improving the Maturity and Breadth of Cybersecurity Practices

BC Hydro's cybersecurity controls and staff have been effective in keeping our systems secure. Since 2016, BC Hydro has not experienced any notable cybersecurity incidents beyond lost laptops or limited-impact phishing attempts.

BC Hydro tracks our daily BitSight Security Rating[100] to assess BC Hydro's security health from an external perspective. BC Hydro's Security Rating has been consistently rated as "Advanced" over the past 12 months.

However, cybersecurity threats are constantly evolving, and our expanding footprint of digital technologies means we must continuously improve the maturity and breadth of our cybersecurity practices to appropriately manage the risk, especially within the OT domain.

[100] To generate the ratings, BitSight gathers and evaluates publicly available data on security behaviors from collection points across the globe. BitSight's algorithms analyze the data for severity, frequency, duration, and confidence to create an overall rating of that organization's current security health. Ratings are between 250 and 900 (a higher score is better) and are described as Basic, Intermediate and Advanced. All of the data used to derive a BitSight Security Rating is externally available and collected without any intrusive testing on an organization.

In this context, “maturity” refers to the level to which cybersecurity risk management capability is practiced within BC Hydro. In referring to the “breadth” of our cybersecurity practices, we are referring to the extent to which these practices are implemented across BC Hydro’s digital environments.

BC Hydro has used two frameworks to assess the maturity and breadth of its capability: The National Institute of Standards and Technology (**NIST**) Cybersecurity Risk Management Implementation Framework and the U.S. Department of Energy, Electricity Subsector Cybersecurity Capability Maturity Model (**C2M2**). Both the NIST framework and the C2M2 model are well-established within the industry and across the cybersecurity domain as a means to guide and measure the implementation of cybersecurity practices within an organization.

Evolving cybersecurity practices are required to maintain the security of BC Hydro’s IT and OT environments. Risk assessments, maturity self-assessments, audits and CIP compliance requirements all play into identifying areas for BC Hydro to improve our practices. The following sections describe how BC Hydro has identified the need for additional resources and funding within the Test Period. These additional resources and funding are required to bring the Cybersecurity team up to a level of capacity, capability and maturity to fulfill BC Hydro’s evolving responsibilities in managing cybersecurity risk.

5.8.4 Planned Resource Additions Reflect Results of Cybersecurity Assessments and Audits

BC Hydro has determined its requirement for additional resources and funding in the Test Period with reference to the results of self-assessments performed according to widely recognized standards and models, internal audits and third-party assessments.

5.8.4.1 Industry Standard Maturity Self-Assessments Identify Areas of Focus

BC Hydro uses a combination of the NIST Framework and C2M2 model to assess its cybersecurity capability.

The NIST framework identifies cybersecurity risk management practices across five phases of an event which are: Identify, Protect, Detect, Respond and Recover. BC Hydro used this framework to make a subjective assessment of our level of cybersecurity risk management practice implementation across the breadth of BC Hydro's digital environment. BC Hydro's self-assessment using this framework shows a reasonable[101] level of practice implementation across the IT environment and those OT environments that fall under the CIP Requirements. Additional resources are required to address a lack of uniformity in practice implementation across BC Hydro's environments.

The C2M2 model assesses implementation of cybersecurity management practices across ten functional domains. BC Hydro's self-assessment shows the need for improvement across the domains, specifically in the areas of Risk Management, Threat and Vulnerability Management, Situational Awareness, Program Management and Supply Chain and External Dependencies Management.

- The areas of **Risk Management** and **Program Management** require more senior and experienced resources to provide expert judgement and make decisions with implications for enterprise level risk management. Two FTE were reallocated to the Cybersecurity Department from within the Technology KBU to provide experience and seniority. Additional funding is required for operational

[101] Reasonable is gauged as an average "level 2 – performed" using the implementation maturity levels defined for the C2M2 model. Practices are documented, stakeholders are involved, adequate resources are provided, standards and guidelines are in place.

activities such as additional penetration testing,[102] training and awareness programs and risk assessments.

- In the area of **Threat and Vulnerability Management**, the Cybersecurity Operations team uses cybersecurity detection tools to regularly scan for vulnerabilities across the IT environment. Additional capacity is required to thoroughly assess and respond to the results of these scans and to extend this practice across the OT environment.
- **Situational Awareness** for the OT environment requires extension of systems currently used for detection of attacks in the IT environment, into the OT environment. Expanding this function also requires additional resources to monitor the systems and respond to alerts.
- **Supply Chain and External Dependencies Management** requires additional process and systems development to ensure that all IT and OT supplier and customer dependencies are identified, and significant cybersecurity risks are addressed. This capability will be advanced through the work required to achieve compliance by April 2023 with MRS CIP-013.

5.8.4.2 2019 Internal Audit and External Assessment Echoed Results of Maturity Self-Assessments

BC Hydro’s internal audit team, using external subject matter experts, conducted an audit of our cybersecurity practice in early 2019. The audit identified opportunities for improvement in areas similar to those identified through our maturity self-assessments:

- Governance;
- Threat and Vulnerability Management;
- Incident Response; and

[102] A simulated cyber-attack against your computer system to check for exploitable vulnerabilities.

- Vendor Risk Management.

In March 2019 the Office of the Auditor General (**OAG**) submitted an audit report on BC Hydro's cybersecurity practices and controls related to its Industrial Control Systems (**ICS**) located in BC Hydro control centres and all transmission and generation facilities. As a result of the OAG audit, BC Hydro initiated a third-party risk assessment of the ICS environment that identified similar areas of focus for BC Hydro's OT/ICS environment as well as some specific technical recommendations.

5.8.5 BC Hydro Requires Additional Cybersecurity Resources and Funding

Incremental funding is required to address the complexity and growing volume of cyber attacks and to address the cybersecurity capability self-assessments and audits undertaken over the past two years. Additional FTEs and funds are required to:

- Enhance cybersecurity practices and functions in OT areas, specifically ICS as identified in the OAG audit;
- Enhance identity and access management processes, practices and tools to improve cybersecurity controls for electronic and physical access;
- Enhance and extend monitoring and detection to address the evolving cyber threat landscape. The growing digitization of the utility requires BC Hydro to extend cybersecurity monitoring across our environment;
- Provide cybersecurity thought leadership and improve training and awareness programs for employees and contractors. This type of activity is fundamental in maintaining the security of our systems given that our people are the first line of defence for cybersecurity;
- Extend regular risk assessments and penetration testing across expanding digital and cloud environments. As new systems and tools are deployed, they

must be assessed for possible vulnerabilities to attack. We must develop expertise in managing cybersecurity risks associated with cloud deployments and services and as threats evolve, we must continually test our defences against new methods of attack; and

- Enhance response plans to identify specific scenarios and test through scheduled exercises. BC Hydro continues to evolve its response plans in line with evolving threats. A recent spike in ransomware activity is a good example of a specific scenario for which we define a playbook response and exercise.

Table 5-14 below shows how the additional four FTEs and $3.0 million in operating costs for the Test Period are aligned to these focus areas.

Table 5-14 Additional Resources Required for Cybersecurity Function in Fiscal 2022

Focus Area	FTE	Labour Funding ($'000's)	Non-labour Funding ($'000's)	Total Funding ($'000's)
Cyber security enhancements for OT and ICS environments	1	205	960	1,165
Enhance identity and access management	1	165	110	275
Extend cybersecurity monitoring and detection	1	165	360	525
Enhanced training and awareness	-	-	100	100
Extend risk assessments and penetration testing	1	165	570	735
Enhance response and recovery plans	-	-	200	200
Total	**4**	**700**	**2,300**	**3,000**

5.9 Employee Training

During the Previous Application proceeding, BC Hydro identified employee training as an area that is critical to BC Hydro's ability to continue to operate effectively and provide safe and reliable service and where increased investment may be required in future test periods.[103] In its Decision, the BCUC expressed concern that employee training was one of five areas where cost cutting may have been too aggressive or needed increases were being put on hold.

We have reviewed BC Hydro's current training plan and have determined that further investment is required in this area. Specifically, training budgets are no longer sufficient to allow IBEW employees in the Operations Business Group to complete both the mandatory safety and regulatory training, as well as the technical and leadership training to maintain their current skills required to work safely and efficiently and maintain system reliability. These employees, such as Power Line Technicians, Electricians and Communications and Protection and Control Technicians, make up a large component of the Operations Business Group. They are critical to operate and maintain the stations and lines equipment to deliver safe and reliable power.

Historically, the Operations Business Group has budgeted an average of 10 training days per IBEW employee to complete annual safety and regulatory, as well as technical and leadership training. There has been continuous growth in safety and regulatory expectations, which is often accompanied by detailed training components, including those related to MRS, asbestos, confined space and environmental due diligence. This has resulted in the budgeted 10 days of training becoming consumed by the growing mandatory safety and regulatory training requirements, causing the technical and leadership training to often get delayed due to budget constraints and the need to maintain field resources utilization.

Technical and leadership training is vital to support safe, reliable and efficient operations by crews. Equipment at stations is becoming increasingly complex with a variety of new and legacy equipment to maintain and operate.

[103] Fiscal 2020 to Fiscal 2021 Revenue Requirement Oral Hearing Transcript Volume 5, p. 358 to p. 359. https://www.bcuc.com/Documents/Transcripts/2020/DOC_56867_2020-01-20-TranscriptVolume5-OralHearing.pdf.

As a result, BC Hydro has included an increase of $3.3 million in the Test Period, which will provide an average of an additional three-and-a-half training days per IBEW employee for a total of 13.5 days of training. These additional days of training in fiscal 2022 will focus on both safety leadership training as well as the procedures to ensure that employees have the skills to commission, maintain, operate and decommission equipment. Technical training includes helicopter, switching, and equal potential grounding and bonding/blocking in addition to training on critical protection and control and telecommunications equipment.

This increase in fiscal 2022 will allow IBEW employees to catch-up on required technical and leadership training, while continuing to meet the evolving safety and regulatory training requirements. This approach aligns with our focus on the frontline, since it represents an important investment in frontline people where strong technical skill sets are critical. BC Hydro will monitor these training plans in fiscal 2022 and adjust as necessary in future years as training requirements continue to evolve.

5.10 COVID-19 Has Increased Forecast Operating Costs in Fiscal 2021

As described in Chapter 1, section 1.4, the COVID-19 pandemic significantly impacted BC Hydro’s operations. It resulted in both operating cost pressures and savings and cost reduction strategies, which largely occurred during the first two quarters of fiscal 2021.

The largest operating cost pressure was caused early in the pandemic by a temporary pause on field and project work while safe working practices were developed. This resulted in a period of time where BC Hydro’s field crews were unable to charge their labour costs to the capital or maintenance work programs while the programs were on hold and reprioritized. In addition, unplanned operating costs were incurred to expand technology functionality for remote working, enhance cleaning, increase security guard presence, and procure and distribute personal protective equipment.

The cost pressures described above are largely offset on a forecast basis by associated savings and cost reduction strategies in fiscal 2021 such as reduced travel to field work sites, fuel and transportation cost reductions and lower employee benefit usage. In addition, BC Hydro implemented a number of cost reduction strategies to further mitigate the cost pressures. These included not catching-up the line and stations maintenance work that was temporarily paused in fiscal 2021 in response to the onset of the COVID-19 pandemic, a temporary hold on non-field work travel, deferral of filling vacancies and cancellation of initiatives such as safety events and the employee engagement survey.

The net COVID-19 pandemic related impact is a forecast cost pressure of $4.8 million, which will continue to be monitored through the monthly financial results review process.

While future costs and savings associated with the COVID-19 pandemic are uncertain (e.g., impacts of potential future waves of the virus), many of BC Hydro's KBUs returned to normal work levels in the second and third quarter of fiscal 2021. Accordingly, BC Hydro has not forecast any cost pressures related to the COVID-19 pandemic in the Test Period.

5.11 FTE and Labour Costs

This section reviews BC Hydro's FTEs[104] and operating labour costs. Excluding the Site C Project, BC Hydro's fiscal 2022 FTEs are lower by three from the Previous

[104] Full Time Equivalents (**FTEs**) are calculated by taking the total number of hours (regular and overtime) worked in a given year, divided by the average number of hours a full-time employee would work per year. These averages differ by affiliation. Consistent with the Previous Application, for the fiscal 2022 Test Period, these averages are 1,621 hours for Management and Professional employees (including Executive), 1,535 hours for MoveUp employees and 1,461 hours for International Brotherhood of Electrical Workers employees.

Application, on a total workforce of 6,996 FTEs.[105] The change is primarily a result of increased resources relating to investments in MRS, vegetation management and cybersecurity, partially offset by a reduction in apprentice and trainee FTEs related to a reduction in intakes.

Base operating labour costs are increasing by $38.8 million, of which:

- $33.6 million relates to an increase in current service costs associated with a change in the market-driven pension discount rate, further discussed in section 5.11.5; and
- $5.2 million relates primarily due to a 2.0 per cent general wage increase for union employees in the Test Period under existing collective agreements, further discussed in section 5.11.4.

In this section, we make the following points:

- BC Hydro's operating FTEs have remained relatively flat since fiscal 2012 and total FTEs (excluding the Site C Project) will remain flat during the Test Period, further discussed in section 5.11.1;
- The Test Period FTE change over the Previous Application is primarily a result of increased resources relating to the Site C Project and investments in MRS, vegetation management and cybersecurity, partially offset by a reduction in apprentice and trainee FTEs related to a reduction in intakes, further discussed in section 5.11.1;
- In response to the COVID-19 pandemic, BC Hydro redeployed employees to respond to emergent issues and to optimize our workforce. The redeployment of personnel to areas experiencing an increase in workload initially began with a large number directed towards the delivery of the COVID-19 Customer Relief Program, which became one of the urgent business priorities at the time.

[105] Total fiscal 2022 FTEs of 7,500 (Figure 5-4) less Site C FTEs of 504.

Resources were further redeployed to manage and assist with MRS and to support the delivery of Transmission and Distribution Work Programs within the Program and Contract Management KBU. Redeployment of personnel is further discussed in section 5.1.1;

- The results of our vacancy factor analysis reinforced the reasonableness of the amount included in the Previous Application and the appropriateness of using the same forecast savings in the Test Period, further discussed in section 5.11.3;
- In fiscal 2022, Standard Labour Rates are increasing due to BC Hydro's bargaining mandate for union employees, inflationary cost increases to employee benefits, and an increase in current service pension costs due to discount rate changes. A salary freeze for management and professional employees has been implemented for fiscal 2022, further discussed in section 5.11.4; and
- Current service pension costs relate to BC Hydro's pension program and represent the cost of the future benefits earned by the employees in the current year. The increase in current service pension costs is driven by a lower discount rate. Current service costs are further discussed in section 5.11.5.

5.11.1 BC Hydro's Operating FTEs Have Remained Relatively Flat Between Fiscal 2012 and Fiscal 202

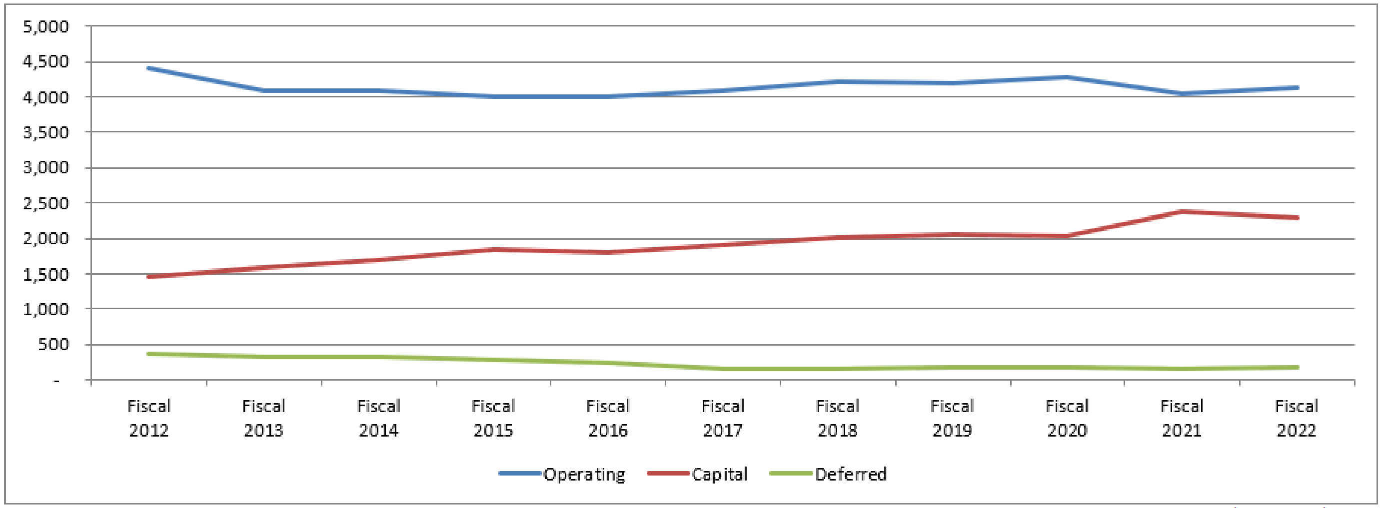
Figure 5-14 below illustrates that BC Hydro's operating FTEs,[106] depicted in the top blue line, have remained relatively flat since fiscal 2012. In the Test Period, operating FTEs are planned to increase due to investments in MRS, vegetation management and cybersecurity. The increase in operating FTEs is offset by a

[106] FTEs related to the Accenture Repatriation, the Smart Metering Infrastructure Project and the Site C Project were removed to avoid skewing the trend line. All FTEs related to the Workforce Optimization Program, are Included.

reduction in capital FTEs, depicted in the middle red line, resulting from a reduction in apprentice and trainee intakes.

Figure 5-14 shows the trend in BC Hydro's FTEs by work function (i.e., operating (top blue line), capital (middle red line) and deferred (bottom green line)).

Figure 5-14 FTEs (Excluding Site C Project, Smart Metering Infrastructure Project, Accenture Repatriation FTEs),[107] (Fiscal 2012 to Fiscal 2022)



											a	b	b-a
	FTEs Including Regular and Overtime Hours	Fiscal 2012 Actual	Fiscal 2013 Actual	Fiscal 2014 Actual	Fiscal 2015 Actual	Fiscal 2016 Actual	Fiscal 2017 Actual	Fiscal 2018 Actual	Fiscal 2019 Actual	Fiscal 2020 Actual	Fiscal 2021 RRA	Fiscal 2022 RRA	Change F2021 - F2022
1	Operating	4,415	4,096	4,089	4,003	3,997	4,082	4,209	4,185	4,287	4,043	4,121	78
2	Capital	1,460	1,582	1,686	1,835	1,811	1,905	2,013	2,061	2,043	2,370	2,286	(84)
3	Deferred	377	330	325	293	250	161	162	171	170	164	166	2
4	**Sub-total**	**6,252**	**6,008**	**6,101**	**6,131**	**6,058**	**6,148**	**6,385**	**6,416**	**6,501**	**6,576**	**6,573**	(3)
5	SMI	80	118	111	85	69	-	-	-	-	-	-	-
6	Site C Project	56	82	92	97	107	167	226	322	445	472	504	32
7	Accenture Repatriation	-	-	-	-	-	-	-	423	423	423	423	-
8	**Total FTEs, Appendix A, Schedule 16 Line 53**	**6,388**	**6,208**	**6,303**	**6,312**	**6,234**	**6,315**	**6,611**	**7,161**	**7,369**	**7,471**	**7,500**	29
9	Total FTEs, Excluding Site C Project	6,332	6,126	6,211	6,215	6,127	6,148	6,385	6,839	6,924	6,999	6,996	(3)

May not add due to rounding

[107] "Deferred" FTEs refers to FTEs whose work is charged to regulatory accounts. Almost all of BC Hydro's current deferred FTEs are charged to the DSM Regulatory Account

As shown in the table above, excluding Site C Project FTEs, total fiscal 2022 RRA FTEs of 6,996 are lower by three compared to the fiscal 2021 RRA FTEs of 6,999. The following points further explain the net decrease of three FTEs:

- Row 1 shows an increase of 78 operating FTEs compared to fiscal 2021 RRA plan and is primarily due to:
  - 44 FTE[108] increase relating to Reliability Investments, including MRS (21.5 FTEs), further described in section 5.6, Vegetation Management (18 FTEs), further described in section 5.7, and Cybersecurity (4 FTEs), further described in section 5.8;
  - 24 FTE increase relating to an increase in the Operations Business Group employee training hours resulting in a shift in work hours to operating from capital, further described in section 5.9;
  - 6 FTE[109] increase relating to approved Technology KBU Workforce Optimization conversions;
  - 1 FTE[110] added to the Energy Studies team within the Generation System Operations KBU; and
  - 5 FTE increase relating to other miscellaneous increases between fiscal 2021 RRA and fiscal 2022 RRA FTEs; and offset by,
  - 2 FTE decrease due to a functionalization shift from operating to the deferred relating to Indigenous Relations work.
- Row 2 shows a decrease of 84 capital FTEs compared to fiscal 2021 RRA plan and is primarily due to:
  - 52 FTE[111] decrease related to a reduction in apprentice and trainee intakes primarily implemented in response to the COVID-19 pandemic (43 regular

[108] Refer to Table 5-13 rows 4, 5 and 6 for fiscal 2022 increase by Business Group.
[109] Refer to Table 5-13 row 8 for fiscal 2022 increase by Business Group
[110] Refer to Table 5-13 row 7 for fiscal 2022 increase by Business Group.

hour FTEs plus nine overtime hour FTEs). BC Hydro determined that this action could help address COVID-19 cost pressures without impacting our ability to complete necessary work and without jeopardizing the long-term success of our apprentice and trainee programs;

- ▶ 24 FTE decrease relating to an increase in the Operations Business Group employee training hours resulting in a shift in work hours from capital to operating, further discussed in section 5.9;
- ▶ 13 FTE[112] decrease primarily related to approved Capital Infrastructure Project Delivery Business Group Workforce Optimization conversions that were determined to no longer be required; and offset by,
- ▶ 3 FTEs[112] increase primarily relating to approved Operations Business Group Workforce Optimization conversions; and
- ▶ 2 FTEs related to an increase of other miscellaneous changes.

- Row 3 shows an increase of deferred FTEs compared to the fiscal 2021 RRA. This increase is primarily due a functionalization shift from operating FTEs to deferred FTEs related to Indigenous Relations work.

As discussed throughout this chapter, costs related to MRS, vegetation management and cybersecurity are increasing. In its Decision on the Previous Application, the BCUC identified these areas as requiring additional investment. The net new FTEs reflect the additional investment in these areas.

Table 5-15 and Table 5-16 below provide two additional views for the change in FTEs compared to previous fiscal years.

Table 5-15 below provides an FTE continuity schedule which highlights the key drivers for the net new change from the Previous Application by Business Group.

[111] Refer to Table 5-13 rows 1 and 10 for fiscal 2022 decrease by Business Group. (nine of the 10 overtime FTEs relate to apprentice and trainee intakes).

[112] Refer to Table 5-13 row 8 for fiscal 2022 decrease by Business Group.

FTEs for each Business Group and Key Business Unit are provided in Schedule 16.0 of Appendix A – Financial Schedules.

Table 5-15 Continuity Schedule of Planned FTEs (Fiscal 2021 RRA Plan to Fiscal 2022 RRA Plan)

	FTEs Including Regular and Overtime Hours	Integrated Planning	Capital Infrastructure Project Delivery	Operations	Safety & Compliance	Finance, Technology, Supply Chain	People, Customer, Corporate Affairs	Other	Total Excluding Site C	Site C	Total BCH
1	**F2021 RRA Plan FTEs (Schedule 16, line 53)**	967	739	2,995	452	946	856	45	6,999	472	7,471
2	Reduction to Apprentices and Trainees				(43)				(43)		(43)
3	Reliability Investments:										
4	Mandatory Reliability Standards				16	6			22		22
5	Vegetation Management	13		5					18		18
6	Cybersecurity					4			4		4
7	Energy Studies			1					1		1
8	Workforce Optimization		(13)	3		6			(4)		(4)
9	Site C Project									32	32
10	Miscellaneous changes for overtime hour FTEs	2	1	(2)	(10)	(1)	9		(1)		(1)
11	Miscellaneous changes for regular hour FTEs	(2)	(1)	(16)	1	11	7		-		-
12	**F2022 RRA Plan (Schedule 16, line 53)**	**980**	**726**	**2,985**	**416**	**972**	**873**	**45**	**6,996**	**504**	**7,500**

May not add due to rounding

Table 5-16 below provides a breakdown of FTEs into operating, capital and deferred functions.[113]

[113] FTEs related to capital overhead are shown within the Operating category. For further details on FTEs, please see Appendix A, Schedule 16.0

Table 5-16 FTEs by Function

FTEs (including Overtime)	F2017 RRA	F2017 Actual	F2018 RRA	F2018 Actual	F2019 RRA	F2019 Actual	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
Operating											
Integrated Planning	450	493	451	498	449	513	549	589	548	551	565
Capital Infrastructure Project Delivery	301	267	303	287	302	299	316	305	318	306	305
Operations	1,683	1,779	1,683	1,793	1,683	1,838	1,655	1,801	1,658	1,623	1,675
Safety & Compliance	382	425	382	420	382	401	345	379	338	380	352
Finance, Technology, Supply Chain	737	767	744	823	750	879	874	902	874	889	899
People, Customer, Corporate Affairs	282	313	280	353	280	639	691	691	691	699	707
Other	37	39	38	36	38	38	40	42	40	40	40
Total (Schedule 16 line 70)	3,872	4,082	3,881	4,209	3,884	4,608	4,470	4,710	4,466	4,489	4,544
Percentage Change		5%	-5%	8%	-8%	19%	-3%	5%	-5%	1%	1%
Capital											
Integrated Planning	370	326	369	347	371	366	419	360	419	416	415
Capital Infrastructure Project Delivery	276	307	301	360	302	381	418	387	417	414	414
Operations	1,211	1,076	1,214	1,099	1,214	1,112	1,340	1,108	1,337	1,324	1,310
Safety & Compliance	186	154	188	152	188	129	124	111	114	66	63
Finance, Technology, Supply Chain	31	36	39	46	44	66	70	71	70	72	72
People, Customer, Corporate Affairs	8	6	8	8	8	7	8	7	8	7	7
Other	189	168	192	227	202	322	465	444	477	502	508
Total (Schedule 16 line 71)	2,269	2,072	2,311	2,239	2,329	2,382	2,843	2,488	2,841	2,801	2,790
Percentage Change		-9%	12%	-3%	4%	2%	19%	-12%	14%	-1%	0%
Deferred											
Integrated Planning	0	0	0	0	0	1	0	1	0	0	0
Capital Infrastructure Project Delivery	3	7	3	5	3	6	4	7	4	6	6
Operations	0	1	0	0	0	1	0	0	0	0	0
Safety & Compliance	0	0	0	0	0	0	0	0	0	0	0
Finance, Technology, Supply Chain	2	2	2	2	2	2	2	3	2	2	2
People, Customer, Corporate Affairs	150	150	147	153	147	160	158	159	158	158	158
Other	1	1	1	1	1	1	0	1	0	0	0
Total (Schedule 16 line 72)	155	161	152	162	152	171	164	170	164	166	166
Percentage Change		4%	-5%	7%	-6%	12%	-4%	4%	-4%	1%	0%
Total											
Integrated Planning	820	820	820	845	820	880	967	950	967	967	980
Capital Infrastructure Project Delivery	579	581	607	652	607	686	739	699	739	726	726
Operations	2,894	2,855	2,898	2,893	2,898	2,951	2,995	2,910	2,995	2,947	2,985
Safety & Compliance	568	579	570	572	570	530	469	490	452	446	416
Finance, Technology, Supply Chain	769	805	784	871	795	947	946	975	946	963	972
People, Customer, Corporate Affairs	439	469	435	513	435	806	856	857	856	864	872
Other	227	208	231	264	241	361	505	487	516	542	548
Total (Schedule 16 line 73)	6,296	6,315	6,344	6,611	6,365	7,161	7,477	7,369	7,471	7,455	7,500
Percentage Change		0%	0%	4%	-4%	13%	4%	-1%	1%	0%	1%

5.11.2 Workforce Management Focuses on Redeploying People to Sustain Business Continuity and Deliver Essential Services

Since the beginning of the COVID-19 pandemic, BC Hydro has ensured that all efforts were made to safely utilize its workforce.

Office employees were set-up to work from home where possible. Procedures were put in place to allow employees to safely continue working in the office or field. As an example, field workers such as Powerline Technicians were provided personal protective equipment and worked in small cohorts, which we referred to as pods, to reduce the potential for COVID-19 transmission at the workplace.

The COVID-19 pandemic impacted work volumes differently across the business. In some areas, it resulted in higher work volumes and, in others, lower work volumes. In early April 2020, the Executive Team endorsed an initiative to facilitate temporary assignments across Business Groups. The initiative (Resource Matching Phase I) matched employees with a temporarily reduced workload due to the impacts of the pandemic to other business areas experiencing a temporary increase in workload. This allowed us to handle higher work volumes in certain areas without hiring additional employees and increasing labour costs. Approximately 205 temporary redeployments resulted from this effort. Many employees were redeployed to assist with administering the COVID-19 Customer Relief Program, which became one of the urgent business priorities at the time.

In addition, to manage significant emerging cost pressures, BC Hydro implemented restrictions on hiring new staff to fill vacancies. In the summer months, when it was apparent the pandemic would be continuing through the fall, we began a second, more comprehensive phase (Resource Matching Phase II). To address ongoing resource needs, the company undertook an organization-wide process to proactively identify employees who have existing capacity or who could be made available to do other work, and to determine which areas of the company were most critically in need of resources to deliver on business priorities. The goal was to redeploy those employees to support the priority areas.

The Executive Team confirmed the key priority areas as the MRS and Compliance programs and the Program and Contract Management Department. Redeployment of approximately 16 employees with suitable transferable skills has been targeted to those areas. For example, four members of the Work Smart team were redeployed to manage and assist with pressing needs of BC Hydro's MRS CIP program. BC Hydro remains committed to Work Smart but implemented this redeployment since (1) Work Smart events are difficult to carry out without in-person collaboration, (2) MRS is a top company priority and (3) the redeployment is a good fit for the skillsets of the Work Smart team. Resources redeployed to the Program and Contract Management Department are supporting the delivery of transmission and distribution Work Programs which have expanded in volume as well as supporting the changes in work flow process resulting from the SAP Supply Chain Applications that were launched in August 2020.

An additional 25 resources have been temporarily redeployed to fill vacancies in other KBUs where their skills were a suitable match.

Extensive redeployment has also occurred within KBUs to manage vacancies and assume the work of contractors whose assignments were ended. This has taken the form of realignment of work among existing resources, assignment of additional duties, and the temporary delay or slow-down of other work.

5.11.3 Vacancy Factor Savings is Supported by Data Analysis

This sub-section responds to Directive 20 of the BCUC's Decision on the Previous Application which directed BC Hydro to begin tracking, measuring and reporting on the annual vacancy factor savings and to provide a rationale for any significant differences from the forecast savings.

The results of our analysis reinforce the reasonableness of the amount included in the Previous Application and the appropriateness of using the same forecast savings in the Test Period.

In preparing this analysis, BC Hydro employed a methodology which included the following steps:

1. Tabulate the twelve-month average vacancies which occurred in each KBU in in the fiscal year;
2. Apply the average standard labour rate per FTE in each KBU to estimate the total cost savings associated with those vacancies; and
3. Deduct the average amount of time FTEs in each KBU charge to work programs (capital, deferred, maintenance) to calculate the operating cost portion of vacancy factor savings achieved.

The forecast savings include labour budget reductions some Business Groups had previously made to recognize that positions will not remain filled 100 per cent of the time, as well as the $5.6 million in vacancy factor savings included in the Previous Application.[114]

Table 5-17 below provides by Business Group, the vacancy-related savings included in previous budgets (referred to as ‘Baseline’), the incremental $5.6 million vacancy factory savings included in the Previous Application, and the estimated actual vacancy factor savings realized in fiscal 2020.

[114] This is discussed further in BC Hydro’s response to BCUC IR 2.230.4 from the Previous Application proceeding.

Table 5-17 Fiscal 2020 Vacancy Factor Savings Results

Business Group ($ million)	Budget Baseline	Budget F20-F21 RRA	Budget Total	Actual F20	Variance
Capital Infrastructure Project Delivery	0.7	1.6	2.3	2.4	0.1
Integrated Planning	1.2	1.1	2.3	2.2	(0.2)
Operations	0.7	0.5	1.2	0.2	(0.9)
Safety and Compliance	0.3	0.2	0.5	0.7	0.2
People, Customer & Corporate Affairs	0.2	0.5	0.7	0.9	0.3
Finance, Technology, Supply Chain	0.3	1.4	1.7	1.7	(0.1)
Other	0.1	0.3	0.4	0.5	0.1
Total	3.5	5.6	9.0	8.5	(0.5)

The table shows that estimated operating cost vacancy factor savings (calculated using the methodology described above) in fiscal 2020 is $8.5 million versus a plan of $9.0 million. The largest driver of the lower than planned savings is temporary journeypersons in holding, largely assigned to the Operations Business Group. These are graduates of BC Hydro's apprentice program who are only budgeted until their scheduled graduation date. In fiscal 2020, there were a number of apprentice graduates who took longer than expected to secure a permanent journeyperson role, resulting in a temporary reduction to the vacancy factor savings realized.

This analysis reinforced the reasonableness of the amount included for fiscal 2020 in the Previous Application. BC Hydro will carry out its analysis related to fiscal 2021 once that fiscal year has completed and will report on the results in the next application.

As a result of the minimal change in FTEs in fiscal 2022 (as shown in Table 5-15 above), BC Hydro has used the same amount of vacancy factor savings for fiscal 2022.

5.11.4 Standard Labour Rates in the Test Period Have Increased Primarily Due to the Current Service Costs

As in the Previous Application, the Test Period revenue requirements reflect Standard Labour Rates calculated by BC Hydro. BC Hydro uses the Standard Labour Rates to assign payroll, benefits, and Current Service Costs to departments, work activities, projects, and work orders. The methodology for calculating the Standard Labour Rates remains unchanged from the Previous Application.

Table 5-18 below provides the weighted average Standard Labour Rate and the Standard Labour Hours for each affiliation. The increases to the Standard Labour Rates reflect the following:

- Operating cost increases of $33.6 million for current service costs, which (as described in section 5.11.5) are
- Driven by a lower discount rate; and
- $5.2 million for a 2.0 per cent general wage increase for union employees under existing collective agreements, and inflationary cost increases for benefits in the Test Period.

The Standard Labour Hours remain unchanged from the Previous Application.

Table 5-18 Standard Labour Rates by Affiliation

Affiliation	Standard Labour Hours	F2021 Forecast ($)	F2022 Plan ($)
MoveUp	1,535	63.17	68.25
International Brotherhood of Electrical Workers	1,461	85.44	90.99
Management and Professionals	1,621	105.72	111.59

The percentage increase in Standard Labour Rates from fiscal 2021 forecast to fiscal 2022 plan is lower for management and professionals than for union affiliated groups because no salary increase is being provided to management and professional employees in fiscal 2022. The increase for management and professionals is solely attributable to inflationary cost increases in benefits and Current Service Costs.

5.11.5 Current Service Costs Have Increased Due to Lower Discount Rate

Current service costs relate to BC Hydro's pension program and represent the cost of the future benefits earned by the employees in the current year. Pension benefits remain unchanged from the Previous Application. The increase in current service costs is driven by a lower discount rate.

Current service costs are included in the Standard Labour Rates and charged to current work (capital and operating). Therefore, current service costs are reflected in the costs presented throughout the Application.

Current service costs are sensitive to changes in the discount rate. A decrease in the discount rate will increase current service costs while an increase in the discount rate will decrease current service costs. Current service costs are for future pension benefits earned by employees in the current year and are determined by BC Hydro's external actuary. The present value of future pension benefits earned by employees in the current year are determined using the market discount rate at the date of the forecast. The market discount rate is based on AA Canadian Corporate bond yields. Current service costs are sensitive to changes in the market discount rate. Table 5-19 below, shows changes in discount rates and current service costs in recent years.

Table 5-19 Current Service Costs

($ million)	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan	Change from F2021 RRA
Current Service Costs	130.0	128.5	132.5	122.8	188.5	56.0
Discount Rate	3.33%	3.33%	3.33%	3.83%	2.59%	(0.74)

The $56.0 million increase in planned current service costs for fiscal 2022 compared to the fiscal 2021 RRA Plan is primarily due to:

- The 74 basis points decrease in the discount rate from 3.33 per cent (based on discount rates at March 31, 2019) in fiscal 2021 to 2.59 per cent (based on discount rates at July 31, 2020) in fiscal 2022. The discount rate has been decreasing due to a number of factors such as a low inflation environment and recent efforts of the Bank of Canada to keep interest rates low to stimulate economic growth to deal with the economic crisis brought on by the Covid-19 pandemic; and
- A slight increase in planned FTEs in fiscal 2022 when compared to the FTEs from the Previous Application, as shown in in section 5.11.1, Table 5-13.

The operating cost portion of the total increase is $33.6 million (i.e., $56.0 million total increase multiplied by 60 per cent). The remaining portion is charged to capital.

The discount rate used to measure the current service costs is obtained from BC Hydro’s external actuary. Changes in the discount rate are market-driven and outside of BC Hydro’s control.

5.12 BC Hydro's Power System Maintenance

Ongoing maintenance of the Power System is necessary for assets to achieve their expected performance throughout their lifecycle. As mentioned in the Previous Application, the Integrated Planning Business Group holds the Power System maintenance budget and is responsible for maintenance investment decisions. The Operations Business Group is responsible for executing maintenance work. We have included in Appendix R the sections from the Previous Application that describe the various activities involved in Power System Maintenance; these descriptions remain applicable. Power System maintenance is budgeted at $268 million for fiscal 2022, an increase of $33.2 million from the fiscal 2021 RRA plan. The increase is primarily due to increased funding for vegetation management, further discussed in section 5.7.

Table 5-20 Maintenance Cost Increases - Fiscal 2020 to Fiscal 2022 Plan

($ million)	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan	Change from F2021 RRA to F2022 Plan
Line Asset Maintenance	104.0	107.4	104.7	105.7	128.7	24.0
Stations Asset Maintenance	85.4	84.3	86.4	79.9	91.1	4.7
Distribution Emergency Response	46.7	47.0	47.1	47.6	48.4	1.4
Total Maintenance	236.1	238.7	238.1	233.2	268.2	30.1

Table 5-21 below shows the drivers of the budget increase from fiscal 2021 RRA to fiscal 2022 plan. These budget increases are included in the operating cost increases shown in Table 5-4.

Table 5-21 Maintenance Cost Increases - Fiscal 2021 RRA to Fiscal 2022 Plan

($ million)	Line Asset Maintenance	Stations Asset Maintenance	Distribution Emergency Response	Total
Storm Restoration Five Year Average[115]	-	-	(0.5)	(0.5)
Standard Labour Rate Increases[116]	2.5	4.0	1.8	8.3
Vegetation Management[117]	20.1	-	-	20.1
Other[118]	1.5	0.7	-	2.2
Total	24.1	4.7	1.3	30.1

[115] Storm Restoration cost savings are included in Table 5-4 Line 13 under the Operations Business Group and further discussed in Table 5-6 Line 4 Storm Restoration.

[116] Standard Labour Rate cost increases are included in Table 5-4 Lines 3 and 23 under the Integrated Planning and Operations Business Groups. Labour cost increases are further discussed in Table 5-5 Line 7 Current Service Costs and Table 5-5 Line 8 Labour.For Distribution Emergency Response. The Standard Labour rate increase is only applicable to Routine Trouble and Damage to Plant programs, and not Storm Restoration.

[117] The vegetation management cost increase is included in Table 5-4 Line 17 under the Integrated Planning Business Group and further discussed in section 5.7. The remaining $4.9 million of the total $25 million increase for vegetation management is related to costs for Light Detection and Ranging (**LIDAR**) surveys and planning and forester resources.

[118] Other cost increases are included in Table 5-4 Line 30 under the Integrated Planning Business Group and Table 5-4 Line 3 under the Integrated Planning and Operations Business Groups. Electric Vehicle Infrastructure is further discussed in Table 5-5 Line 12 Electric Vehicle Infrastructure costs.

BC Hydro
Power smart

BC Hydro Fiscal 2022
Revenue Requirements Application

Chapter 6

Capital Expenditures and Additions

PUBLIC

Table of Contents

List of Tables

6.1 Introduction

This chapter discusses BC Hydro's capital planning and delivery processes as well as BC Hydro's planned capital expenditures and additions[119] in fiscal 2022 with a focus on material changes since the Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (**Previous Application**). The capital forecasts in this chapter are derived from BC Hydro's fiscal 2021 to fiscal 2030 Capital Plan (**Capital Plan**). Our forecast capital expenditures and additions for fiscal 2022 are based on the same processes described in the Previous Application and are lower than the amounts planned for fiscal 2021, primarily due to the completion of major projects in fiscal 2021.

This chapter is organized around the following key points:

- Section 6.2 explains that we continue to use well-established and robust processes to plan and deliver our capital investments and can respond to new information so that changes are managed appropriately. In its Decision on the Previous Application, the BCUC determined that BC Hydro's capital planning process is reasonable;[120]
- Section 6.3 explains that our capital investments balance multiple objectives. It provides data on asset performance and project delivery to demonstrate that our investments are appropriate and that we continue to meet our performance target[121] for delivering the capital projects;
- Section 6.4 describes our Power System capital investments, which includes Generation, Transmission and Distribution assets, for the Test Period. We

[119] The forecast capital "additions" are the capital investments that are affecting rates during the Test Period and occur when the capital assets enter service. The forecast capital "expenditures" represent spending incurred on capital assets that will not affect rates until the capital assets enter service, which may be in the same fiscal year or a future fiscal year.

[120] BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020). The BCUC found that BC Hydro's capital planning process is reasonable (pages 78 and 96), properly considers factors including reliability and safety (page 79) and balanced the desire for cost containment with the risks to system performance and reliability (pages 86 and 96).

[121] Target refers to the Project Budget to Actual Cost metric that is discussed in section 6.3.2.

continue to manage investments on the Power System with an appropriate level of investment in system growth, asset sustainment and risk mitigation, while supporting the delivery of safe, reliable, affordable, clean electricity;

- Section 6.5 describes our forecast Technology, Properties, Fleet and Business Support and other capital investments for the Test Period, showing how we are making investments to support how we run our business; and
- Section 6.6 describes Site C expenditures and additions impacting the Test Period, and how we are appropriately managing construction during the COVID-19 pandemic.

6.1.1 Capital Appendices in the Application

In the Application, BC Hydro provides information on its planned capital investments with a focus on changes from the Previous Application. The information in this chapter is supplemented by capital-related information in the following appendices:

- Appendix A, Schedule 13 provides planned and actual capital expenditures and additions for fiscal 2020, planned and forecast capital expenditures and additions for fiscal 2021, and planned capital expenditures and additions for fiscal 2022;
- Appendix E provides a summary of BC Hydro's Capital Plan including major investments, related risks, and opportunities. It provides an overview of the capital investments that BC Hydro expects to undertake in the Test Period, within the context of BC Hydro's Capital Plan from fiscal 2021 to fiscal 2030;
- Appendix F provides BC Hydro's Technology Strategy and Five-Year Plan. This document provides guidance and direction for BC Hydro's future technology investments to manage compliance and security, manage risk and sustain productivity, and enhance business capability. BC Hydro's Technology Strategy remains the same as the Previous Application. The plan is updated annually in order to remain current and was last updated in September 2020;

- Appendix G provides asset health indices for BC Hydro's generation assets. Compared to the Previous Application, the net asset health ratings have remained stable across Key generation facilities, improved across Strategic facilities and remained stable across Available Energy facilities;
- Appendix H provides asset health indices for BC Hydro's transmission and distribution assets. The asset health indices indicate that the majority of assets are in Good to Fair condition. Approximately 9 per cent are in Poor or Very Poor condition, which is similar to the Previous Application. At any point in time, it is expected that a certain portion of assets will be in Poor or Very Poor condition because, as the risks associated with the most critical and poorest health assets are addressed, other assets will continue to age and degrade;
- Appendix I provides capital investment information for projects that are greater than $2 million for Technology projects, and greater than $5 million for other projects, with planned capital expenditures or additions in the Test Period. In the Application, BC Hydro has provided additional project related information, consistent with the 2018 Capital Filing Guidelines,[122] such as the risk and value scores for individual projects;[123]
- Appendix P, section 10 provides explanations for material variances between planned and actual capital expenditures and additions for fiscal 2020.[124] As discussed in the appendix, variances are generally due to the timing of project cash flows or changes in project schedules;
- Appendix S is a verbatim copy of the relevant sections of Chapter 6 of the Previous Application, regarding BC Hydro's capital planning and delivery

[122] The Capital Filing Guidelines were approved by BCUC Order No. G-313-19. Section 3.3 of the Decision provides direction on information included in a Revenue Requirements Application. https://www.bcuc.com/Documents/Proceedings/2019/DOC_56448_2019-12-02-BCH-Review-of-BCH-Capital-Expenditures-Decision.pdf

[123] Appendices J and K are not included in the Application. Refer to section 6.1.1.1 for more information.

[124] This information was also provided in BC Hydro's Fiscal 2020 Annual Report to the BCUC. Variance explanations for fiscal 2021 will be provided in BC Hydro's Fiscal 2021 Annual Report to the BCUC.

processes. BC Hydro has not made any significant changes to these processes since the Previous Application; and

- Appendix T provides a copy of our annual reporting on reliability indices. BC Hydro's reliability metric results are similar to previous years.

6.1.1.1 We Have Adjusted the Capital Evidence to Support a Streamlined Filing

As a result of the shortened timeline to develop the capital-related evidence for the Application, BC Hydro has not included descriptions of projects with capital expenditures greater than $20 million (Appendix J in the Previous Application) or summaries of strategies, plans and studies (Appendix K in the Previous Application).[125] However, in order to provide the BCUC with information on significant projects, BC Hydro provides information in section 6.4 below on projects that meet the following criteria:

- Planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J ($20 million for Power System investments);
- Did not appear in Appendix J of the Previous Application; and
- Have planned capital expenditures or additions in the Test Period.

This includes eight Generation projects, seven Transmission projects, and two Distribution projects.

In addition, in section 6.5 we provide a summary description of all Technology projects listed in Appendix I. One of these projects meets the criteria for inclusion in Appendix J ($10 million for Technology investments) and it is identified accordingly.

[125] BC Hydro will resume filing these appendices in the next revenue requirements application in line with the 2018 Capital Filing Guidelines.

6.1.2 Summary of BC Hydro’s Actual and Planned Capital Expenditures and Additions

BC Hydro’s capital investments generally fall into two broad categories - sustaining and growth:

- Sustaining investments address reliability, asset condition, regulatory, safety, security and environmental risks, issues and opportunities associated with existing assets. Sustaining investments also include all business support expenditures such as those related to Property, Technology and Fleet assets; and
- Growth projects help meet load and system growth through the addition of system capacity and by connecting new electricity supply. Growth projects may also add new infrastructure to the system to mitigate other risks such as reliability performance.

BC Hydro’s actual and planned capital expenditures and additions for fiscal 2020 to fiscal 2022 are provided in Table 6-1 and Table 6-2 below.

1 **Table 6-1 Actual and Planned Capital Expenditures**
2 **(Fiscal 2020 to Fiscal 2022)[126]**

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Generation					
Growth (Schedule 13, Line 1)	3.2	2.6	-	4.6	5.0
Sustaining (Schedule 13, Line 3)	341.8	302.5	435.5	346.6	383.4
Total Generation	345.1	305.1	435.5	351.2	388.4
Site C Project (Schedule 13, Line 8)	1,530.0	1,619.1	1,535.5	1,626.0	1,361.0
Transmission					
Growth (Schedule 13, Line 4)	185.0	159.6	198.9	101.2	142.9
Sustaining (Schedule 13, Line 5)	222.6	223.3	286.5	270.3	325.6
Total Transmission	407.6	382.9	485.4	371.5	468.5
Distribution					
Growth (Schedule 13, Line 6)	300.0	339.7	284.6	343.2	306.7
Sustaining (Schedule 13, Line 7)	187.5	176.2	176.8	175.9	219.3
Total Distribution	487.5	515.9	461.4	519.1	526.1
Business Support					
Technology (Schedule 13, Line 9)	95.6	133.0	56.0	71.2	69.2
Properties (Schedule 13, Line 10)	58.9	56.4	55.3	65.1	75.6
Fleet / Other (Schedule 13, Line 11)	63.6	59.0	75.1	82.0	70.3
Total	2,988.3	3,071.4	3,104.1	3,086.0	2,959.0
Less: Contribution in Aid	(157.8)	(178.8)	(148.4)	(159.7)	(214.2)
TOTAL	2,830.5	2,892.6	2,955.7	2,926.4	2,744.8

126 The amounts shown in Table 6-1 and Table 6-2 differ from the amounts shown in Appendix E because the tables exclude capital expenditures and additions for BC Hydro's subsidiaries. In addition, there was an adjustment to the fiscal 2021 Technology capital expenditures and additions due to a material change in cost and schedule for the Supply Chain Application project, after the Capital Plan was finalized.

Table 6-2 Actual and Planned Capital Additions (Fiscal 2020 to Fiscal 2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Generation					
Growth	2.7	-	-	-	-
Sustaining	312.0	359.5	297.0	244.3	272.4
Total Generation (Schedule 13, Line 13)	314.7	359.5	297.0	244.3	272.4
Site C Project (Schedule 13, Line 17)	27.9	12.9	189.4	197.5	-
Transmission					
Growth	97.9	88.0	83.3	92.3	168.1
Sustaining	195.9	111.6	146.3	191.4	272.6
Total Transmission (Schedule 13, Line 15)	293.8	199.7	229.6	283.7	440.7
Distribution					
Growth	306.9	307.6	344.2	325.3	301.7
Sustaining	195.3	162.0	196.5	199.0	201.2
Total Distribution (Schedule 13, Line 16)	502.2	469.6	540.7	524.3	502.9
Business Support					
Technology (Schedule 13, Line 18)	147.6	93.7	75.5	143.4	94.3
Properties (Schedule 13, Line 19)	39.9	44.3	55.6	60.8	59.8
Fleet / Other (Schedule 13, Line 20)	64.9	56.4	71.3	74.4	75.2
Total	1,391.0	1,236.1	1,459.1	1,528.3	1,445.2
Less: Contribution in Aid	(146.1)	(140.5)	(165.8)	(165.7)	(187.2)
TOTAL	1,244.9	1,095.6	1,293.2	1,362.7	1,258.0

Capital expenditures and additions are lower in fiscal 2022 compared to fiscal 2021 primarily due to the completion of major projects and programs in fiscal 2021, such as the Supply Chain Applications project and some Distribution programs.[127] Section 6.2.3 provides a discussion of the impacts of the COVID-19 pandemic on the capital portfolio. We do not expect the pandemic to have a material impact on the fiscal 2022 forecast capital additions.

[127] The variances between actual and planned capital expenditures and additions for fiscal 2020 are explained in Appendix P, section 10. As discussed in Chapter 7, section 7.2.2, any differences between the forecast and actual amortization of capital additions are captured in the Amortization of Capital Additions Regulatory Account. This means that the actual amount recovered from ratepayers is ultimately based on the actual capital additions.

6.1.3 We Have Responded to the BCUC's Decision on the Previous Application

In its Decision on the Previous Application, the BCUC commented on certain aspects of BC Hydro's capital investments and made several directives. We explain below how we have responded to these aspects of the Decision.

6.1.3.1 We Have Cancelled the Asset Investment Tool Project

In its Decision, the BCUC encouraged BC Hydro to pursue the Asset Investment Planning Tool project if it appears cost-effective.[128] BC Hydro recently cancelled the Asset Investment Planning Tool project considering the cost-effectiveness of the project based on new information on the expected total project cost. More information on this decision is included in section 6.2.3.2 of this chapter.

6.1.3.2 We Have Included Capital Expenditures for Electric Vehicles as a Prescribed Undertaking

BC Hydro owns and operates electric vehicle charging stations in British Columbia. In its Decision, the BCUC directed that these stations be removed from rate base. It disallowed the forecast operating costs and cost of energy associated with these stations because the stations were not part of BC Hydro's utility service.[129]

As discussed in Chapter 7, section 7.2.5, BC Hydro is seeking to establish an Electric Vehicle Costs Regulatory Account to recover, in the Test Period, its fiscal 2020 and fiscal 2021 costs related to electric vehicle charging stations that are prescribed undertakings.

For fiscal 2022, costs with respect to the prescribed undertakings are included in the revenue requirements in the categories of cost to which they relate. For further information on BC Hydro's electric vehicle charging stations that meet the requirements of a prescribed undertaking, refer to Chapter 2, section 2.3.2.3.

[128] Refer to Order G-246-20, page 80.

[129] Directive 27; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 93.

Further information on capital expenditures for electric vehicle charging stations is provided in section 6.4.3.2 of this chapter.

6.1.3.3 We Will be Providing Additional Information on the Interconnection Process

BC Hydro will submit a compliance filing in accordance with Directive 34[130] and host a workshop[131] that will provide more information on our interconnection process.

6.1.3.4 We Have Responded to Directives 29 and 31 of the BCUC's Decision

In its Decision, the BCUC directed BC Hydro to file a joint CPCN application for the Bridge River 1 Units 1-4 Generators / Governors Project and the Bridge River Transmission Project.[132] BC Hydro expects to file this application by mid-2021. The BCUC also removed the requirement for BC Hydro to file a CPCN for the cancelled Northwest Substation project but noted that there may be other successor projects to the Northwest Substation project which do require CPCNs.[133] BC Hydro confirms that there may be successor projects to the Northwest Substation project but the related customers have not made final investment decisions. At present, the projects are not expected to meet the materiality threshold for a CPCN application to the BCUC.

[130] In Directive 34, the BCUC directed BC Hydro to submit a filing to the BCUC, by December 31, 2020, explaining its progress to date in implementing each of the recommendations included in the Black and Veatch report, plus any other initiatives BC Hydro has or is undertaking to improve its interconnections process.

[131] In Directive 35, the BCUC directed that BC Hydro conduct a workshop, by March 31, 2021, with BCUC staff present, to present the information in this filing to current and potential interconnection customers and current and potential IPPs.

[132] Directive 29; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 100.

[133] Directive 31; BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 103.

6.2 Planning and Delivery Processes for Capital Investments Are Well Established, Effective and Result in Appropriate Investments

BC Hydro has well established and effective processes for the planning and delivery of our capital investments, as presented in the Previous Application. These processes are robust and responsive to changing conditions and priorities. We continue to meet our performance target[134] for delivering capital projects and look for opportunities to improve our planning and delivery practices, where it makes sense to do so.

6.2.1 BC Hydro Continues to Use the Enterprise Capital Planning Process to Update the Capital Plan on a Regular Basis

The Capital Plan was developed according to our enterprise-wide capital planning process.[135] This is consistent with the process used to develop the fiscal 2020 to fiscal 2024 Capital Plan (**Previous Plan**) that was an input to the Previous Application.[136] In its Decision on the Previous Application, the BCUC stated that BC Hydro's capital planning process is reasonable.[137] BC Hydro continues to believe its capital planning and delivery processes are appropriate, and has not made significant changes to the capital planning and delivery processes since the Previous Application.

The currency date of the Capital Plan refers to the month that a forecast was taken for all active projects used in the development of the plan. The currency date is April 2019 for Power System, Properties, and Fleet capital plan forecasts and July 2019 for Technology. The Capital Plan was presented to the Capital Projects

134 Target refers to the Project Budget to Actual Cost metric that is discussed in section 6.3.2.

135 The enterprise-wide capital planning process is described in Appendix S, section 6.3.

136 BC Hydro's 10 Year Capital Plan memo, provided in Appendix E, includes a description of how the enterprise-wide capital planning process was applied to develop the Capital Plan.

137 Refer to BCUC Order No. G-246-20. The BCUC found that BC Hydro's capital planning process is reasonable (pages 78 and 96), properly considers factors including reliability and safety (page 79) and balanced the desire for cost containment with the risks to system performance and reliability (pages 86 and 96).

Committee of BC Hydro's Board of Directors in November 2019 and subsequently reviewed by the Board of Directors as part of BC Hydro's 5-Year Financial Forecast in January 2020. The Capital Plan is the latest approved version that is available for supporting the capital-related evidence contained in the Application. It provides a reasonable estimation for the amortization and finance charges related to BC Hydro's capital investments that are included in the Application. The Amortization of Capital Additions Regulatory Account will continue to capture any differences between forecast and actual amortization of capital additions for future refund to, or recovery from, ratepayers.

The currency date means that BC Hydro may have submitted more up to date information for certain capital projects to the BCUC in other proceedings or filings.[138] For the purposes of consistency of the capital related evidence, BC Hydro has maintained the integrity of the currency date of the Capital Plan to the extent possible in this chapter, in both the financial tables and the discussion of capital investments. We have noted specific exceptions to this currency date in the Application, specifically in sections 6.4 for Power System investments and 6.5 for Technology investments as well as in Appendix I, where differences are material.

6.2.2 Our Project Delivery Practices Remain Consistent

BC Hydro's project delivery practices remain consistent with the practices discussed in the Previous Application.[139]

Power System investments are generally delivered by three Key Business Units (**KBUs**) within BC Hydro: Project Delivery, Program and Contract Management and Distribution Design and Customer Connections. Each KBU utilizes a set of delivery processes suited to the types of investment that they are responsible for.

[138] For example, Exhibits B-26 and B-29 in the Previous Application or BC Hydro's Fiscal 2020 Annual Report to the BCUC.

[139] A detailed discussion of those practices is provided in Appendix S, sections 6.4.6 to 6.4.8.

The Project Delivery KBU continues to use the Project and Portfolio Management System (**PPM**) to manage project risk, scope, schedule and cost when delivering larger, more complex projects.[140]

While the PPM processes are mature and stable, BC Hydro continues to identify opportunities for improvement and updates. A recent example is that we have documented our Quality Management and Change Management practices into our Project Management, Design, Procurement, and Construction Management practices.

A key metric that demonstrates BC Hydro's performance in the delivery of capital projects is the comparison of the Actual Costs for in-service projects to the Original Approved Expected Cost, aggregated over a rolling five-year period. We have consistently met the performance target, as we continue to prudently manage capital expenditures. Details of the Project Budget to Actual Cost performance results are provided in section 6.3.2.

6.2.3 Capital Planning and Delivery Processes Allow Flexibility to Manage New Developments Such as COVID-19

BC Hydro manages changes to the forecast capital expenditures based on the latest available information. Changes may include updates to project scope, schedule and costs resulting in fluctuations in the fiscal year forecast for capital expenditures and additions, the need to initiate new investments to address emerging risks and changes to the investment justification through the life of a project.

The Capital Delivery Management Committee monitors the plan on an on-going basis.[141] Changes to the forecast capital expenditures due to factors impacting project schedules, such as the COVID-19 pandemic, are managed at the capital portfolio level within available capital budgets. If required, adjustments can be made

[140] PPM is described in more detail in Appendix S, section 6.4.7.
[141] For further information, refer to Appendix S, section 6.3.5.

to re-direct the capital budget, within the overall Capital Plan, as new information becomes available.

6.2.3.1 BC Hydro is Responding to the COVID-19 Pandemic

While the COVID-19 pandemic did impact the delivery of BC Hydro's capital investments these changes are not expected to have a material impact on the forecast capital additions that affect the fiscal 2022 revenue requirement.

Projects and programs with active construction or field work this year were required to incorporate new safety protocols which resulted in slowing or delaying aspects of some projects and programs. We temporarily implemented a COVID-19 prioritization process to decide which construction activities were required to proceed because of their importance to achieving system performance and risk mitigation objectives and could safely proceed under the COVID-19 safety protocols. This corporate wide prioritization process was in place from April 2020 through July 2020. The process remains available and could be re-established at any time if required.

There were 80 projects in construction within the Project Delivery portfolio of projects that were reviewed as part of the COVID-19 prioritization process. Many projects either continued with limited impact or were delayed and have now resumed.

BC Hydro tracked all Project Delivery project schedule and cost impacts related to the COVID-19 pandemic using PPM Scheduling and Change Control practices, enabling portfolio level COVID-19 impact reporting. As of September 2020, the change control practice logged 61 projects that had a schedule or cost impact primarily driven by the COVID-19 pandemic. Of these 61 projects, six experienced a delay in their In-Service Date. The remainder experienced cost related impacts or schedule delays on interim milestones that did not impact an In-Service Date.

BC Hydro also reviewed routine power system and customer driven work as part of the COVID-19 prioritization process. This type of work was typically not impacted by the COVID-19 safety protocols. Where there were impacts, due to the short duration and low complexity of the investments as well as the ability to redirect planned resource allocations reserved for emergencies such as summer wildfires, it was generally possible to reschedule impacted work for later in fiscal 2021.

BC Hydro's ex-plan governance process[142] allows investments that address emerging needs to be added to the capital portfolio, outside of the annual enterprise wide capital planning process. For example, Technology investments required to facilitate remote working by BC Hydro's employees during the COVID-19 pandemic were added to the portfolio through the ex-plan governance process. We reallocated funding so that the overall portfolio remained aligned with the capital budget.

6.2.3.2 Responding to Changing Needs and Information

BC Hydro's project delivery processes[143] revisit project needs and justification throughout the life of a project. For example, after the publication of the June 2019 Load Forecast, further analysis on the need to increase the load supply capability in the Metro Vancouver region was conducted. This analysis supported the decision to cancel the Metro North Transmission Project in early 2020.[144] Where applicable, similar analysis is being conducted on other load growth driven projects based on the latest load forecast described in Chapter 3 of the Application. Appropriate actions to adjust the scope or schedule of projects will be taken where necessary.

The overall justification and timing of Technology investments is also revisited throughout the project lifecycle.[145] For example, BC Hydro recently decided to cancel the Asset Investment Planning Tool project in light of new information on the expected total project cost. When considered within the overall technology roadmap for BC Hydro, it will be more cost-effective to pursue this project following the consolidation of BC Hydro's asset data repositories and implementation of an

142 BC Hydro's ex-plan governance process is described in Appendix S, section 6.3.5.

143 BC Hydro's capital delivery processes for larger, more complex Power System projects are described in Appendix S, section 6.4.7.

144 As submitted to the BCUC in Exhibit B-29 of the Previous Application.

145 BC Hydro's Technology-specific delivery framework is described in Appendix S, section 6.5.4.

enterprise asset management platform so that the required inputs to improve asset investment planning and prioritization can be directly integrated with the asset health information. Additionally, the availability of subject matter expertise within our planning groups to successfully support the project is limited given other corporate wide priorities. BC Hydro will revisit the need for a similar investment when greater benefit can be derived. Notwithstanding the cancellation of this project, BC Hydro continues to improve its capital planning process.

In subsequent sections of this chapter we refer to other material project cancellations and changes due to new information on project needs.

6.3 Capital Investments Continue to Balance Affordability with System Performance and Risk

As described below, BC Hydro's planned capital investments for the Test Period achieve an appropriate balance between the objectives of safety and reliability and keeping rates affordable for customers. BC Hydro is also making important investments, including with respect to Mandatory Reliability Standards (**MRS**). We continue to meet our performance target for delivering the capital projects.[146]

6.3.1 The Power System Continues to Perform Well and We Are Investing in Important Areas

The Capital Plan continues to manage expenditures with an appropriate level of investment in system growth, asset sustainment and risk mitigation, while supporting the delivery of safe, reliable, affordable, clean electricity. Updated load forecasts support the decision in the Previous Plan to moderate investments to expand and reinforce the Power System. However, new growth investments continue to be required for both distribution and transmission infrastructure to meet regional customer demand growth, to connect new supply of electricity, to support CleanBC electrification initiatives, and to mitigate other risks such as reliability performance.

[146] Target refers to the Project Budget to Actual Cost metric that is discussed in section 6.3.2.

6.3.1.1 BC Hydro Continues to Perform Well on Reliability Metrics

BC Hydro continues to monitor the performance of the system.[147] Our most recent customer reliability and satisfaction indices indicate that we continue to have appropriate system performance. Like the performance shown in the Previous Application, in the past two years, BC Hydro's unadjusted system average duration (**"all-events" SAIDI**) and unadjusted system average frequency (**"all-events" SAIFI**) trends have performed as well as, or better than, the Canadian Electricity Association (**CEA**) composite.[148]

Similarly, when outage impacts related to uncontrollable major weather events are removed, normalized SAIDI and SAIFI metrics have performed well against our Service Plan targets.[149] The reliability scores in BC Hydro's Customer Satisfaction Index indicate that customers continue to be satisfied with the level of reliability they are receiving.[150]

Appendix T includes BC Hydro's annual report to the BCUC on reliability indices for Transmission, Distribution and Generation performance.

6.3.1.2 BC Hydro is Making MRS Investments in Physical and Cyber Security

As discussed in Chapter 5, section 5.6, BC Hydro recognizes the importance of protecting the physical and cyber security of our assets and achieving and maintaining compliance with MRS. We are increasing planned operating expenses for this purpose. Within the Power System portfolio, the Capital Plan includes funding for the successful implementation of the latest version of Critical Infrastructure Protection (**CIP**) standards (CIP version 7), as well as security

[147] BC Hydro's monitoring efforts are further described in Appendix S, section 6.3.2.3.

[148] BC Hydro's performance as measured against the CEA composite is shown in Appendix S, Figure 6-6 and Figure 6-7. BC Hydro is included in the CEA composite.

[149] A copy of BC Hydro's most recent Service Plan is provided as Appendix Q.

[150] BC Hydro's Customer Satisfaction Index on Reliability is shown in Appendix S, Figure 6-10. This figure does not include data on customers in BC Hydro's Non-integrated areas. In response to Directive 25 of the BCUC's Decision on the Previous Application, BC Hydro will begin including customers from Non-integrated areas in the survey process for fiscal 2022, starting April 1, 2021.

improvements at various substations. The Technology portfolio includes upgrades and enhancements to existing systems in place to support MRS compliance.

Appendix Z provides confidential information regarding areas of focus for BC Hydro in fiscal 2022. This work may result in the identification of additional capital expenditures that will be included in future capital plans. If additional required investments are identified, BC Hydro has options to respond in the Test Period, including:

- Adjusting the level of compliance-driven investments by redirecting funding from other parts of the BC Hydro capital investment portfolio;
- Updating operational or maintenance practices; and
- Bringing forward investments through our ex-plan governance process.

6.3.1.3 BC Hydro Continues to Invest in Other Regulatory Compliance

The Capital Plan also includes investments that will address regulatory compliance requirements such as the Federal Polychlorinated Biphenyl (**PCB**) Regulation deadline to remove oil-filled equipment with greater than 50 parts per million of PCBs by December 31, 2025.[151]

6.3.2 We Continue to Deliver our Capital Program Within the Service Plan Target of +/- 5 Per Cent of Expected Cost

BC Hydro includes, in its Service Plan,[152] a capital program metric[153] targeting aggregate Actual Costs falling within +5 per cent to -5 per cent of the aggregate Original Approved Expected Costs, excluding project reserve amounts. The metric is calculated using the results of generation[154] and transmission projects, as well as major distribution and properties projects.

[151] Power System compliance investments are further described in section 6.4 and Technology compliance investments are described in section 6.5.

[152] A copy of BC Hydro's most recent Service Plan is provided as Appendix Q.

[153] Performance measure *3.b (Project Budget to Actual Cost)* in the BC Hydro Service Plan.

[154] The Site C Project is not included in the metric.

Since 2014, when BC Hydro began using this metric, the performance results have been consistently within the targeted range. In the last five years, the aggregate Actual Costs have ranged from -2.23 per cent to +0.40 per cent of the Original Approved Expected Cost. Projects included in this metric for the five-year period, fiscal 2016 to fiscal 2020, had aggregate Actual Costs of $7,022 million, which is 2.23 per cent lower than the aggregate Original Approved Expected Cost of $7,182 million. Table 6-3 below summarizes the results of this metric over the past five reporting periods.

Table 6-3 Project Budget to Actual Cost Metric Results (2012 to 2020)

	F2012 to F2016	F2013 to F2017	F2014 to F2018	F2015 to F2019	F2016 to F2020
# of Projects	563	540	493	426	377
Original Approved Expected Costs ($ million)	6,491	6,363	6,936	8,000	7,182
Actual Costs ($ million)	6,479	6,303	6,963	8,028	7,022
Cost Variance ($ million)	-12.0	-59.9	27.9	27.1	-160.2
% Variance from Original Approved Expected Costs	-0.18	-0.94	0.40	0.34	-2.23

Of the 377 projects included in this analysis for the fiscal 2016 to fiscal 2020 five-year period, 70.0 per cent had an Actual Cost less than the Original Approved Expected Cost. The median project was 7.4 per cent below the Original Approved Expected Cost.

In fiscal 2020, BC Hydro completed a total of 40 projects with aggregate Original Approved Expected Costs of $364.3 million and aggregate Actual Costs of $340.9 million, which was a variance of -$23.4 million (-6.4 per cent).

6.3.3 We Are Making Investments to Support How we Run Our Business

Compared to the Previous Plan, the Capital Plan includes small amounts of increased funding for Technology, Properties, Fleet and Tools/Other (Supporting Portfolios) investments. Changes in business requirements, the increasing prevalence of technology, and ongoing changes in work spaces to support employee needs are driving these investments.

Investment in these areas support the BC Hydro-wide initiative to "make it easier to get work done." Across the Capital Plan period, a total of $172 million in capital was re-directed to Technology, Properties, Fleet Services, and the Tools/Other portfolio to address changes in business-driven needs. This redirection will fund investments such as a number of mid-sized sustainment and business enablement Technology investments, projects at medium criticality facilities most in need of end-of-life replacement such as Chilliwack and Campbell River, and replacement of previously deferred vehicles at end-of-life condition. In addition, increased funding for Technology projects will manage requirements for new cybersecurity and compliance investments. These increases were offset by reductions in the Power System portfolio. Further discussion on BC Hydro's enterprise capital planning process and how we determined the allocations of capital across the portfolios is provided in Appendix E.[155]

6.4 Power System Capital Investments Continue to Be Managed at an Appropriate Level

BC Hydro's planned capital expenditures and additions over the Test Period for the Power System are discussed in the following sub-sections. This includes the capital investments for BC Hydro's Generation, Transmission and Distribution assets. We continue to manage investments on the Power System with an appropriate level of investment in system growth, asset sustainment and risk mitigation, while supporting the delivery of safe, reliable, affordable, clean electricity. Throughout this section we have provided commentary on how the fiscal 2022 planned capital expenditures and additions compare to the planned amounts in fiscal 2020 and fiscal 2021 included in the Previous Application.

155 Details on Supporting Portfolio investments for fiscal 2022 are provided in section 6.5.

6.4.1 Generation Capital Expenditures & Additions

During the Test Period, capital investments in Generation assets include asset sustainment, dam safety and growth investments. Generation capital expenditures represent approximately 24 per cent of the Capital Plan during the Test Period.[156] Investment in the Hydroelectric Generation portfolio represents 98 per cent of Generation capital expenditures during the Test Period. This is similar to the overall allocation of expenditures across Generation investments in the Previous Application.

6.4.1.1 Summary of Generation Capital Expenditures and Additions

Actual and planned capital expenditures and capital additions for Generation assets for fiscal 2020 to fiscal 2022 are presented in Table 6-4 and Table 6-5, below.[156]

[156] Capital expenditures and additions related to the Site C Project are excluded from the tables and discussion in this section. The Site C Project is discussed in section 6.6 of this chapter.

Table 6-4 Generation Actual and Plan Capital Expenditures (Fiscal 2020 to Fiscal 2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Hydroelectric Generation					
Growth	3.2	2.6	-	4.6	5.0
Redevelopment / Rehabilitation	28.6	29.5	-	10.2	-
Dam Safety	68.8	44.7	130.0	79.0	107.8
Sustaining - Other	241.0	220.8	361.1	274.9	287.2
Total Hydroelectric Generation	341.7	297.6	491.1	368.7	400.0
Non Integrated Areas					
Growth					
Sustaining	8.7	5.8	5.0	5.9	4.7
Total Non Integrated Areas	8.7	5.8	5.0	5.9	4.7
Thermal Generation					
Growth			-	-	-
Sustaining	6.6	1.7	4.5	4.4	4.3
Total Thermal Generation	6.6	1.7	4.5	4.4	4.3
Total Gross Generation	357.0	305.1	500.6	378.9	409.0
Less: Portfolio Risk Adjustment	(11.9)	-	(65.2)	(27.8)	(20.7)
Total Generation	345.1	305.1	435.5	351.2	388.4
Less: Contribution in Aid	-	-	-	-	-
TOTAL	345.1	305.1	435.5	351.2	388.4

Table 6-5 Generation Actual and Plan Capital Additions (Fiscal 2020 to Fiscal 2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Hydroelectric Generation					
Growth	2.7	-	-	-	-
Redevelopment / Rehabilitation	42.8	96.2	-	10.2	-
Dam Safety	49.3	7.4	44.4	31.7	30.6
Sustaining - Other	199.4	253.4	315.3	196.1	340.7
Total Hydroelectric Generation	294.1	357.0	359.7	238.1	371.3
Non Integrated Areas					
Growth					
Sustaining	7.9	1.2	5.8	6.5	5.0
Total Non Integrated Areas	7.9	1.2	5.8	6.5	5.0
Thermal Generation					
Growth			-	-	-
Sustaining	3.8	1.4	6.1	4.5	3.1
Total Thermal Generation	3.8	1.4	6.1	4.5	3.1
Total Gross Generation	305.8	359.5	371.5	249.1	379.4
Less: Portfolio Risk Adjustment	8.9	-	(74.6)	(4.8)	(107.0)
Total Generation	314.7	359.5	297.0	244.3	272.4
Less: Contribution in Aid					
TOTAL	314.7	359.5	297.0	244.3	272.4

Generation gross capital expenditures of $409.0 million are forecast for fiscal 2022, compared to $357.0 million planned for fiscal 2020 and $500.6 million planned for fiscal 2021. The portfolio is mainly comprised of a large number of Dam Safety and Sustaining Other investments. Fiscal 2022 capital expenditures are an increase from fiscal 2020, and a decrease from fiscal 2021 due to year-over-year fluctuations as investments progress through the phases of the project life cycle.

Generation gross capital additions of $379.4 million are forecast for fiscal 2022, compared to $305.8 million for fiscal 2020 and $371.5 million for fiscal 2021. Fiscal 2022 capital additions are an increase from fiscal 2020, and in line with fiscal 2021. Capital additions also fluctuate over the period as projects progress through the project life cycle.

6.4.1.2 Generation Growth Projects Expenditures and Additions Are Minimal in Fiscal 2022

Generation growth projects are advanced to meet anticipated customer demand or are improvements at existing generating stations to increase supply side efficiency.[157] In fiscal 2022, Hydroelectric Generation Growth capital expenditures are minimal and there are no capital additions.

Subsequent to the finalization of the Capital Plan, BC Hydro decided to pause the Revelstoke Install Unit 6 project. This provides time for BC Hydro to consider how both the load forecast and resource options are changing and preserves a fiscal 2030 earliest in-service date, if required. A decision on whether to continue the project will be informed by the resource analysis undertaken as part of BC Hydro's next Integrated Resource Plan.

Table 6-6 below provides a summary of the fiscal 2022 Hydroelectric Generation Growth capital additions and capital expenditures.[158]

Table 6-6 Hydroelectric Generation Growth Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
G000594	Revelstoke Install Unit 6	-	5.0
	Programs and Projects Less than $5 million	-	-
	Total	-	5.0

6.4.1.3 There Are No Hydroelectric Generation Redevelopment and Rehabilitation Projects Planned in Fiscal 2022

Generation redevelopment and rehabilitation projects are to redevelop facilities or significant elements of facilities that are at end of life.

[157] These projects are often referred to as Resource Smart projects.

[158] More information on the Revelstoke Install Unit 6 project can be found in Appendix I, page 1, line 1.

There are no planned Hydroelectric Generation redevelopment or rehabilitation capital expenditures and additions in fiscal 2022. A number of projects, including the John Hart Generating Station Replacement and the Ruskin Dam Safety and Powerhouse Upgrade, were completed in prior periods.

6.4.1.4 Dam Safety Expenditures Continue to Focus on Key Areas of Risk

Dam Safety projects focus on mitigating safety risks associated with dams and other water conveyance or retention infrastructure within a hydroelectric setting. Dam Safety represents 27 per cent of the Generation expenditures over the Test Period.

Aging and normal wear and tear of our dams present constant challenges. BC Hydro's aim is to manage the whole fleet of dams so there is no significant deterioration in the risk position and the overall level of risk is kept well within tolerable limits.

The key drivers of Dam Safety projects are consistent with those discussed in the Previous Application.[159] Whenever it is possible to make improvements or necessary to take remedial measures, BC Hydro first refers to international and Canadian best practices, seeking to achieve as large an improvement to safety as possible, and at the very minimum, not to accept any reduction in the level of safety. BC Hydro seeks to balance the cost of each possible improvement against the added safety benefits it would achieve.

Table 6-7 below provides a breakdown of the fiscal 2022 Dam Safety capital additions and capital expenditures that were summarized in Table 6-4 and Table 6-5 above.

[159] Further information on the key drivers of Dam Safety projects is provided Appendix S, section 6.4.1.3.

Table 6-7 Dam Safety Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
G000246	Revelstoke Improve Left Bank Slope Stability	10.4	0.6
G000001	Alouette - Environmental Flow Discharge Upgrade and LLO Sealing	-	0.6
G000011	Alouette Improve Headworks & Surge Tower Seismic Stability	-	8.2
G003467	Bridge River 1 - Improve Slope Drainage	-	13.2
G003852	Bridge River 1 - Mitigate Surge Spill Hazard	5.9	2.9
G003554	W.A.C. Bennett Dam Recommission / Seal Spillway Sluice Gates	-	1.2
G003555	W.A.C. Bennett Dam Seal Low Level Outlets	-	3.2
G000585	John Hart Dam Seismic Upgrade	-	10.1
G000459	La Joie - Dam Improvements	-	2.9
G000668	Ladore Spillway Seismic Upgrade	-	1.8
G003365	Mica - Discharge Facilities Seismic and Reliability Upgrades	-	1.8
G003127	Peace Canyon Install Piezometers and Drains in Concrete Dam	-	1.9
G000657	Comox - Puntledge Flow Control Improvements	-	5.9
G003129	Revelstoke Replace Downie Slide Instrumentation	-	9.7
G000525	Strathcona Upgrade Discharge	-	9.8
G000467	Terzaghi - Spillway Chute Access Improvement	-	6.4
G004132	W.A.C. Bennett Dam - Spillway Concrete Upgrades	0.1	0.1
G004209	W.A.C. Bennett Dam - Stoplogs Upgrade	-	5.0
G000556	Hugh Keenleyside - Spillway and Low Level Outlets Concrete Upgrade	-	1.9
G003653	Various Sites - Reservoir Booms Replacement - F2020	6.6	8.7
G004172	Various Sites - Spillway Gate Standby Power Improvements	-	1.1
	Programs and Projects Less than $5M	7.6	11.0
	Total	30.6	107.8

Capital investments in the Programs and Projects Less than $5 million line include projects to install, replace or rehabilitate instrumentation in dams and to implement miscellaneous upgrades of water conveyances and gates.

A significant portion of fiscal 2022 expenditures in this category can be attributed to the early design progression of a number of large projects, including: Strathcona – Upgrade Discharge, John Hart Dam Seismic Upgrade, Bridge River 1 – Improve Slope Drainage, and Various Sites - Reservoir Booms Replacement.

The following projects have planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, have capital expenditures or additions in the Test Period, and were not included in Appendix J in the Previous Application:

- **La Joie – Dam Improvements:** The project will address identified static and seismic deficiencies associated with the La Joie Dam and intake structure.[160]

6.4.1.5 Other Hydroelectric Generation Sustaining Projects Expenditures and Additions in Fiscal 2022 Are Targeting Key Risks

Generation sustaining investments classified as Other Projects are initiated to mitigate or resolve key risks identified with existing assets through replacement or upgrade of equipment.[161]

Sustaining - Other represents 72 per cent of the Hydroelectric Generation expenditures over the Test Period.

Table 6-8 below provides a summary of the fiscal 2022 capital additions and capital expenditures for Hydroelectric Generation Sustaining Other Projects.[162]

[160] Additional information on the La Joie – Dam Improvements is provided in Appendix I, page 1, line 10.
[161] Further discussion of these risks is provided in Appendix S, section 6.4.1.2.
[162] More information on the projects listed can be found in Appendix I, pages 1 and 2, lines 23 to 76.

Table 6-8 Generation Sustaining - Other Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
G000057	Cheakamus Recoat Units 1 and 2 Penstocks (Interior and Exterior)	-	0.4
G000571	Cheakamus Replace Units 1 and 2 Turbine Inlet Valves	9.9	1.1
G000127	G.M. Shrum G1 to 10 Control System Upgrade	7.0	3.9
G000172	Mica Modernize Controls	8.8	10.0
G003207	Mica Replace Units 1 to 4 Generator Transformers	16.5	14.6
G003456	Mica Upgrade 600V Circuit Breakers	4.3	4.3
G000241	Puntledge Recoat Interior and Exterior of Steel Penstock	12.7	6.8
G000792	Seven Mile Replace Unit 1-4 Exciter Transformers	2.5	2.5
G000342	Wahleach Recoat Penstock (Interior and Exterior)	-	2.7
G000493	Bridge River 2 Upgrade Units 7 and 8	77.0	21.3
G000114	G.M. Shrum Upgrade HVAC System	-	0.7
G003515	Various - Water License Renewal	-	3.1
G003035	Hugh Keenleyside Recoat Navlock Gates	-	4.4
G000158	Jordan - Upgrade Governor & PRV Controls	-	2.5
G000640	Lake Buntzen 1 Coquitlam Tunnel Gates Refurbishment	22.6	14.9
G000801	Mica Upgrade HVAC System	-	16.2
G000220	Peace Canyon - 600V Circuit Breaker Upgrades	-	3.2
G001008	Revelstoke - 600V Circuit Breaker Upgrades	10.9	6.2
G003373	Revelstoke Replace Fire Alarm System	9.5	2.2
G000334	Wahleach Refurbish Generator	41.7	13.4
G000042	Ash River Extend Life of Steel Penstock	-	0.7
G000776	Bridge River 1 Replace Units 1-4 Generators / Governors	-	3.7
G000485	Bridge River 1 - Strip and Recoat Penstocks 1-4 Interior	-	0.0
G000489	Bridge River 2 - Strip and Recoat Penstock 2 Interior	24.7	12.6
G000952	Kootenay Canal Modernize Controls	5.9	5.9
G000168	Lake Buntzen 1 - Generator Replacement	-	2.0
G000169	Lake Buntzen 1 Penstock Exterior Recoat	-	1.5
G000741	Ladore - Redevelop Unit 1	-	6.6
G003835	Peace Canyon - U1 - U4 Exciter Replacement	-	0.3

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
G000252	Revelstoke - U1 - U4 Stator Replacement	-	1.8
G000834	Seven Mile - Replace T1 Transformer	-	1.4
G000822	Seven Mile Upgrade Powerhouse Crane Controls	-	4.5
G003026	Seton - Upgrade Unit	-	9.0
G003449	Various Facilities Replace Water Level Gauges	-	0.4
G001047	Waneta U3 Life Extension	-	19.0
G000219	Peace Canyon Upgrade HVAC System	-	0.7
G000035	Ash River - Generator Replacement	-	0.6
G000131	G.M. Shrum - Intake Operating Gate and Intake Maintenance Gate Refurbishment	-	0.3
G003336	G.M. Shrum - Intake Operating Gate Hydraulic Upgrade	-	0.4
G003826	G.M. Shrum - Pauwels Transformer Life Extension	-	0.4
G000133	G.M. Shrum - Transformers Phase 4 Replacement	-	3.1
G000130	G.M. Shrum - U1, 2, 4, 7, 8, 9, 10 Water Passage Refurbishment	-	0.7
G003837	G.M. Shrum - U5 Stator Replacement	-	0.1
G000966	Kootenay Canal - Fire Detection and Alarm System Replacement	-	0.2
G003296	La Joie - South Penstock Refurbishment	-	0.6
G000195	Mica - Intake Gantry Crane Refurbishment	-	4.1
G003211	Mica - Reactor 5RX3 Replacement	18.6	2.1
G000183	Mica - U1 - U2 Turbine Overhaul	-	1.1
G000181	Mica - U1 - U4 Circuit Breaker and Iso-phase Bus Replacement	-	2.5
G000231	Peace Canyon - High and Low Pressure Piping Replacement	-	0.4
G000436	Seven Mile - U1 - U4 Controls Upgrade	-	1.1
G004166	Various Sites - PCB Lighting Remediation	-	2.3
G003338	Various Sites - Cutler Hammer Exciters Upgrade	-	0.6
G003584	Whatshan - Governor Replacement	-	2.3
	Programs and Projects Less than $5M	68.2	59.8
	Total	340.7	287.2

Capital investments in the Programs and Projects Less than $5 million line include a large number of smaller, less complex investments. In general, these are targeted sustaining investments for specific components or systems that support the generation of electricity. Examples of investments include replacement or upgrade of auxiliary equipment or building infrastructure.

The following projects have planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, have capital expenditures or additions in the Test Period, and were not included in Appendix J in the Previous Application.[163]

- **Ash River - Generator Replacement:** This project will mitigate the reliability risk due to the Unsatisfactory condition of the generator at this single-unit generating station;
- **Mica – U1 – U4 Circuit Breaker and Iso-Phase Bus Replacement:** This project will mitigate the reliability risk associated with the unit circuit breakers for which spare parts and Original Equipment Manufacturer support are no longer available and includes a potential upgrade of the iso-phase-bus (which interfaces directly with the unit circuit breakers) after completing an evaluation of the risk mitigation and opportunity benefits associated with an intervention;
- **Mica – U1 – U2 Turbine Overhaul:** This project will mitigate the reliability risk due to the Poor condition turbines. The project will also consider the technical and commercial case for replacing the turbine runners during this major intervention;
- **Mica - Upgrade HVAC System:** This project will mitigate the life safety risks associated with the design and condition of the existing HVAC system in the underground powerhouse and emergency egress tunnels;
- **Mica – Upgrade 600 V Circuit Breakers:** This project will address the equipment reliability and arc flash safety risks related to the low voltage station

[163] Additional information on these projects is provided in Appendix I, pages 1 to 2, lines 23 to 76.

service circuit breakers and will upgrade the diesel generators to ensure power supply to essential facility loads in the event of a power outage;

- **Bridge River 2 – Strip and Recoat Penstock 2 Interior:** This project will mitigate the financial risk due to the Unsatisfactory condition coating on the internal surface of the penstock; and
- **G.M. Shrum – U5 Stator Replacement:** This project will mitigate the reliability risk due to the Poor condition of the generator.

6.4.1.6 Non-Integrated Areas – Investments to Sustain Existing Assets

All expenditures in fiscal 2022 in Non-Integrated Areas are to sustain existing assets. Non-Integrated Areas are separate self-contained areas. Each area has its own source of generation, associated switchyard, support buildings and distribution network. As the assets age and deteriorate they need to be replaced so that a safe and reliable level of service can be maintained to Non-Integrated Area customers.

Table 6-9 below provides a summary of the fiscal 2022 capital additions and capital expenditures for Non-Integrated Areas Generation Projects.

Table 6-9 Non-Integrated Areas Generation Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Non-Integrated Area		
	Projects & Programs Less than $5M	5.0	4.7
	TOTAL Non-Integrated Area	**5.0**	**4.7**

The forecast fiscal 2022 capital expenditures and additions are similar to the Previous Application.

BC Hydro is working with several Indigenous communities on potential community-owned renewable energy options which could reduce diesel consumption at BC Hydro Generating Stations in the Non-Integrated Areas and contribute to other community benefits. The long-term strategic approach to diesel reduction in the Non-Integrated Areas portfolio will be informed by Phase 2 of the Comprehensive Review of BC Hydro. It is expected that this long-term strategic approach, as well as estimates for related capital and/or operating expenditures, will be provided in the Fiscal 2023 Revenue Requirements Application.

6.4.1.7 Thermal Generation Sustainment Investments Expenditures and Additions are Minimal in Fiscal 2022

Thermal Generation investments mitigate or resolve key risks identified with existing Thermal Generation assets. Table 6-10 below provides a summary of the fiscal 2022 capital additions and capital expenditures.

Table 6-10 Thermal Generation Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
G003189	Burrard - Modify for Post Generation Operations	-	3.3
	Programs and Projects Less than $5 million	3.1	1.0
	Total	3.1	4.3

Expenditures related to the Burrard – Modify for Post Generation Operations project are focused on mitigating safety and environmental risks with equipment and infrastructure. The option to sustain Burrard as a synchronous condense facility to meet the long-term power reinforcement needs for the Lower Mainland is being considered as part of the Lower Mainland - Capacitive and Reactive Power Reinforcement project.[164]

The remaining Thermal Generation capital investments fall within the Programs and Projects Less than $5 million line. The only project in the Test Period in this line is an

[164] The Lower Mainland – Capacitive and Reactive Power Reinforcement Project has expenditures listed in Table 6-15.

upgrade of the Burrard roof to mitigate reliability risks associated with ongoing roof leaks.

6.4.2 Transmission Capital Expenditures and Additions

Transmission capital expenditures are approximately 40 per cent for growth and 60 per cent for sustain investments.[165] This represents an increase to sustain expenditures as a percentage of the portfolio compared to the overall allocation of expenditures across Transmission investments in the Previous Application. This percentage increase is related to increases in investment in most sustain categories. In particular, there have been increases in Protection and Control, Stations Auxiliary Equipment, Other Power Equipment, and Overhead Life Extension, with decreases in growth driven investments.

The actual and plan capital expenditures and additions for fiscal 2020 to fiscal 2022 for Transmission, classified by Growth and Sustain categories, are provided in Table 6-11 and Table 6-12 below.

[165] Transmission capital investments continue to be driven by the needs described in Appendix S, sections 6.4.3 and 6.4.4.

Table 6-11 Transmission Actual and Plan Capital Expenditures (Fiscal 2020 to Fiscal 2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Transmission Growth					
Regional System Reinforcement	107.9	79.6	91.1	33.1	80.6
Bulk System Reinforcement	12.0	5.9	43.3	7.6	17.0
Station Expansion & Modification	11.9	9.1	22.5	25.6	61.3
Feeder Positions / Section Additions	1.6	0.6	2.1	1.3	3.0
Generator Interconnections	5.1	8.3	3.6	3.9	5.3
Transmission Load Interconnections	58.7	56.1	46.3	58.7	28.7
Growth Total	197.2	159.6	208.9	130.2	195.9
Transmission Sustain - Stations					
Circuit Breakers	16.3	20.5	28.2	17.6	16.3
Other Power Equipment	63.5	52.3	104.6	67.0	87.6
Protection and Control	18.4	7.6	16.3	24.1	30.9
Stations Auxiliary Equipment	25.6	25.9	29.8	25.3	43.8
Stations Risk Mitigation	12.9	8.9	10.0	13.3	6.6
Telecommunications	25.4	20.4	25.1	22.8	33.5
Sustain Stations Total	162.1	135.6	214.0	170.1	218.8
Transmission Sustain - Lines					
Cable Sustainment	5.0	7.5	8.9	5.4	16.5
O/H Lines Life Extension	45.5	51.9	70.1	66.8	62.2
O/H Lines Performance Improvement	1.4	1.7	1.4	1.5	1.5
O/H Lines Risk Mitigation	10.7	16.2	3.6	7.4	5.6
ROW Sustainment	9.7	10.6	9.8	9.2	9.1
Third Party Requested Transmission Line Relocatio	10.0	(0.2)	7.8	10.1	12.0
Sustain Lines Total	82.3	87.7	101.6	100.2	106.8
Less: Portfolio Risk Adjustment	(34.0)	-	(39.0)	(29.0)	(53.0)
Total Transmission	407.7	382.9	485.5	371.5	468.5
Less: Contribution in Aid	(23.7)	(17.9)	(14.8)	(11.2)	(14.0)
Total Net	383.9	365.0	470.7	360.4	454.5

Table 6-12 Transmission Actual and Plan Capital Additions (Fiscal 2020 to Fiscal 2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Transmission Growth					
Regional System Reinforcement	83.8	84.5	58.2	131.5	178.0
Bulk System Reinforcement	0.1	1.2	-	0.0	1.5
Station Expansion & Modification	2.5	2.0	0.5	-	1.3
Feeder Positions / Section Additions	2.5	0.5	0.2	-	4.8
Generator Interconnections	1.2	-	10.3	13.3	4.3
Transmission Load Interconnections	7.8	-	16.1	10.5	133.3
Growth Total	97.9	88.1	85.3	155.3	323.1
Transmission Sustain - Stations					
Circuit Breakers	28.0	6.9	11.3	15.3	13.9
Other Power Equipment	21.9	5.7	50.4	51.8	60.8
Protection and Control	11.2	3.6	13.1	8.9	8.3
Stations Auxiliary Equipment	40.1	8.0	26.8	18.1	39.9
Stations Risk Mitigation	4.0	3.7	20.0	6.3	16.3
Telecommunications	13.6	6.1	37.4	15.6	31.3
Sustain Stations Total	118.8	34.0	159.0	116.1	170.6
Transmission Sustain - Lines					
Cable Sustainment	4.1	6.7	2.3	5.0	2.8
O/H Lines Life Extension	49.1	38.6	41.8	45.1	68.1
O/H Lines Performance Improvement	1.4	1.1	1.4	1.4	1.5
O/H Lines Risk Mitigation	16.2	19.4	10.2	8.5	7.6
ROW Sustainment	19.3	11.6	9.8	9.4	9.1
Third Party Requested Transmission Line Relocatio	9.0	0.3	9.8	5.9	13.0
Sustain Lines Total	99.1	77.6	75.3	75.3	102.0
Less: Portfolio Risk Adjustment	(22.0)	-	(90.0)	(63.0)	(155.0)
Total Transmission	293.8	199.7	229.6	283.7	440.7
Less: Contribution in Aid	(15.2)	(3.0)	(29.2)	(12.9)	(36.9)
Total Net	278.6	196.7	200.4	270.8	403.8

Transmission Growth capital expenditures are relatively stable, ranging from $197.2 million planned in fiscal 2020 to $195.9 million planned in fiscal 2022. This is primarily due to decreases in Regional and Bulk System Reinforcement being offset by increased expenditures for Station Expansion & Modification as projects at the Clayburn, Capilano and Mount Lehman substations enter the later stages of their project lifecycle. Transmission Sustain capital expenditures increase from

$244.4 million planned in fiscal 2020 and $315.6 million planned in fiscal 2021 to $325.6 million planned in fiscal 2022. The increase is primarily due to increased investment in Protection and Control related to the NERC CIP V7 project, Stations Auxiliary Equipment to address end of life equipment and other risks at Wood Pole Substations, as well as Cable Sustainment, related to the ongoing Gulf Islands Transmission Reinforcement and the Coquitlam – 2L51 Partial Replacement projects.

Transmission Growth capital additions increase from $97.9 million planned in fiscal 2020 and $85.3 million planned in fiscal 2021 to $323.1 million planned in fiscal 2022 primarily due to the forecast completion of the Peace Region Electric Supply project and the MIN to LNG Canada Interconnection project, which is partially offset by Contribution in Aid. Transmission Sustain capital additions increase from $217.9 million planned in fiscal 2020 and $234.3 million planned in fiscal 2021 to $272.6 million planned in fiscal 2022 primarily due the forecast completion of the 2L13/14 Circuit Refurbishments Overhead Lines Life Extension project, the Williston Station Service Transfer & AC Panels Stations Auxiliary Equipment project and the Barnard 50/60 Feeder Section Replacement Other Power Equipment project.

6.4.2.1 Transmission Assets Growth Capital Expenditures are Decreasing Slightly While Additions are Increasing

In the Test Period, Growth capital expenditures for Transmission Assets are decreasing slightly while additions are increasing. Further information is provided in the sub-sections below.

Regional System Reinforcement

The regional transmission systems generally comprise a large portion of the 230 kV system and all of the 138 kV and 60 kV systems. Regional transmission systems include transmission facilities that service localized geographic areas. Transmission Growth projects at this level often involve the installation of additional regional capacity in order to support area load growth and to maintain area supply reliability. These projects can include upgrades of, and additions to, lines or substation equipment.

Table 6-13 below provides a summary of the fiscal 2022 capital additions and expenditures.[166]

Table 6-13 Transmission Regional System Reinforcement Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Regional System Reinforcement		
92216	Peace Region Electric Supply (PRES)	177.9	39.4
93845	Metro North Transmission (MNT)	-	6.0
92423	Bridge River Transmission Project	-	7.0
901572	North Montney Region - Electrification	-	1.6
900598	West End - Substation Construction and System Reinforcement	-	17.5
94034	West Kelowna Transmission and Westbank Upgrade Projects	-	7.0
901573	Bear Mountain Terminal – T4 Transformer Addition	-	0.6
900994	Kamloops - Area Reinforcement	-	1.4
	Programs and Projects Less than $5M	0.0	0.2
	TOTAL Regional System Reinforcement	**178.0**	**80.6**

Although the Metro North Transmission project is included in Table 6-13 because it was included in the Capital Plan, BC Hydro has since cancelled the Metro North Transmission project.[167]

BC Hydro initiated the Metro North Transmission Project in fiscal 2013 to meet the forecast need to increase the load supply capability in the Metro Vancouver region. The project advanced to the Definition phase in fiscal 2017, and BC Hydro selected the leading alternative, with a forecast total project cost range of $300 million to $530 million, and a forecast in-service date of fiscal 2025.

166 More information on the projects listed can be found in Appendix I, page 4, lines 1 to 8.
167 As submitted to the BCUC in Exhibit B-29 of the Previous Application.

Based on the June 2019 Load Forecast and planning studies conducted over subsequent months, BC Hydro determined that the need to increase the load supply capability in the Metro Vancouver region could be deferred until after fiscal 2029, due to a reduction in the forecast load growth in the Metro Vancouver region. As a result, BC Hydro has cancelled the Metro North Transmission Project, and will continue to evaluate the need to increase the load supply capability in the Metro Vancouver region for the future.

The following projects have planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, have capital expenditures or additions in the Test Period, and were not included in Appendix J in the Previous Application:[168]

- **Bear Mountain Terminal – T4 Transformer Addition:** This project will further increase the capacity of the electricity supply to the Dawson Creek Area. This project was originally named "Bear Mountain (**BMT**) to Dawson (**DAW**) Transmission Voltage Conversion" because the initial leading alternative was to convert the two 138 kV lines (1L348 and 1L350) between BMT and DAW substations to 230 kV operations. An updated assessment based on the June 2019 Load Forecast indicated that the lower cost alternative of adding a new transformer at BMT substation could meet future needs for the most likely load forecast scenario in the Dawson Creek area. Thereafter, the name of the project has been updated to Bear Mountain Terminal – T4 Transformer Addition to reflect the change of leading alternative. This project enables BC Hydro to supply reliable power to industrial customers in Dawson Creek as well as help to achieve the Province's CleanBC Plan goals of increasing access to clean electricity for large industrial operations and reducing greenhouse gas (**GHG**) emissions.

168 Additional information on these projects is provided in Appendix I, page 4, lines 4, 7, and 8.

- **North Montney Region – Electrification:** This project will provide transmission facilities in the North Montney area to supply future natural gas industrial loads. A number of gas producers in the North Montney area have expressed interest in grid supply service from BC Hydro. Currently, there are no transmission facilities in the area north of the G.M. Shrum Generating Station (**GMS**), which presents a significant barrier for gas producers to connect to BC Hydro's grid. This project proposes a 230 kV transmission system extension into the North Montney area that would reduce interconnection costs and encourage the upstream gas producers to electrify their operations. Moreover, this transmission extension would contribute to the Province's CleanBC Plan goals of increasing access to clean electricity and reducing in GHG emissions.
- **Kamloops – Area Reinforcement:** This project will bring additional power from 1L219 into West Kamloops Substation as the existing lines will be reaching their thermal limits under single contingency conditions in winter 2026 given the forecasted load growth in the area. The project involves expanding the substation as well as thermal upgrades to 1L219.

Bulk System Reinforcement

The bulk system comprises high voltage transmission lines and related equipment that interconnect the large remote generating stations in the Peace River and Columbia River areas with the major load centres in the Lower Mainland and on Vancouver Island. The bulk system includes the 500 kV transmission system, the transmission connections to Vancouver Island, and interconnections with other utilities through interties to FortisBC Inc., Rio Tinto Alcan, Alberta and the United States.

Table 6-14 below provides a summary of the Transmission Bulk System Reinforcement fiscal 2022 capital additions and capital expenditures.[169]

[169] Additional information on the projects listed is provided in Appendix I, page 4, lines 9 to 10.

Table 6-14 Transmission Bulk System Reinforcement Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Bulk System Reinforcements		
900992	Lower Mainland - Capacitive and Reactive Power Reinforcement	-	1.5
90957	Peace to Kelly Lake Capacitors	-	15.0
	Programs and Projects Less than $5M	1.5	0.5
	TOTAL Bulk System Reinforcements	**1.5**	**17.0**

Although the Peace to Kelly Lake Capacitors (**PKCP**) project is included in Table 6-14 because it was included in the Capital Plan, BC Hydro has since cancelled the project.[170] In December 2019, BC Hydro determined that the need for an increase in the transfer capability along the Peace Region to Kelly Lake transmission corridor to deliver power to the load centers in the south of the Province could be deferred until after fiscal 2031. This was due to the June 2019 Load Forecast, which showed surplus generation capacity available in the system and the capability to reliably serve load with the current transfer capability beyond fiscal 2031. As a result, BC Hydro cancelled the PKCP project and initiated a separate project to address the sustainment scope of the PKCP project associated with the aging assets and reliability risks on the existing infrastructure. This new project is named the Peace to Kelly Lake Station Sustainment project. This project will be included in future revenue requirement applications as a sustaining project.

Station Expansion and Modifications

Station expansion and modification projects replace, upgrade, or add capacity to existing substations to alleviate operational constraints or limitations resulting from local load growth. These projects impact transmission and distribution assets within the substation, and may involve installing additional transformer capacity, adding

[170] As submitted to the BCUC in Exhibit B-26 of the Previous Application.

switchgear, converting to higher voltages, and reconfiguring existing facilities to accommodate increased capacity requirements.

Table 6-15 below provides a summary of the capital additions and capital expenditures for fiscal 2022.[171]

Table 6-15 Station Expansion and Modification Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Station Expansion & Modification		
93788	Capilano Substation Upgrade	-	15.4
92907	Mount Lehman Substation Upgrade	-	24.5
92910	Clayburn Substation Upgrade	-	18.8
900816	Pemberton - Substation Upgrade	-	2.0
	Programs and Projects Less than $5M	1.3	0.6
	TOTAL Station Expansion & Modification	**1.3**	**61.3**

Feeder Position/Section Additions

Feeder positions and feeder sections are located within substations and supply the interface between the substation and the distribution system for BC Hydro's distribution connected customers. These projects provide additional capacity for distribution customer load growth or for increased operational flexibility.

Table 6-16 below provides a summary of the capital additions and capital expenditures for fiscal 2022.

[171] More information on the projects listed is provided in Appendix I, page 4, lines 11 to 14.

Table 6-16 Feeder Position/Section Additions Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Feeder Positions / Section Additions		
	Programs and Projects Less than $5M	4.8	3.0
	TOTAL Feeder Positions / Section Additions	**4.8**	**3.0**

All Feeder Positions/Section Additions investments within the Test Period are included in the Programs and Projects Less than $5 million line. Station Expansion and Modifications projects, such as the Mount Lehman Substation Upgrade and the Capilano Substation Upgrade will also address additional feeder position requirements within the Test Period.

Generator Interconnections

Generator Interconnections Projects continue to decrease, as there are no active calls for energy and the Standing Offer Program (**SOP**) has been indefinitely suspended. Several projects that were previously accepted under the SOP continue to proceed through the interconnection process.

Until recently, the majority of new IPP interconnections resulted from BC Hydro's SOP. The program limited the funding BC Hydro provided for network upgrades to a pre-determined threshold amount. The forecasts for interconnection costs for projects already in the program include only the estimated network upgrade costs up to the threshold. They do not include the costs of the network upgrade above the threshold.

Table 6-17 below provides the Generation Interconnections Projects forecast capital additions and expenditures for fiscal 2022. There are no projects with capital expenditures over the $5 million threshold.

Table 6-17 Generator Interconnection Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Generator Interconnections		
	Programs and Projects Less than $5M	4.3	5.3
	TOTAL Generator Interconnections	**4.3**	**5.3**

Transmission Load Interconnections

BC Hydro continues to see a high volume of Transmission Load Interconnections requests, including requests from large loads in the Liquefied Natural Gas (**LNG**), Oil and Gas, and Data Centers/Cryptocurrency industries. Although the overall number of requests has remained fairly consistent over the last two years, the number of requests and the associated loads in a particular industry sector changes over time in response to market conditions and other factors influencing customer decisions.[172]

In an effort to provide greater transparency into the number of interconnection studies, the average timelines to complete the studies, and the percentage of time we met our targets, BC Hydro is now posting interconnection metrics on a quarterly basis on our external website at: https://app.bchydro.com/accounts-billing/electrical-connections/industrial-connections.html.

Capital investments to interconnect transmission customers are difficult to forecast. Due to uncertain timing, location and scope, only known transmission interconnection projects are included as specifically identified projects in the forecast capital expenditures for the Test Period. There will be changes in expenditures as

[172] A discussion of the main drivers of Transmission Load Interconnection projects is provided in Appendix S, section 6.4.3.5.

customer requests move through the interconnection process and new projects are added or removed.[173]

Table 6-18 below provides a summary of the fiscal 2022 capital additions and expenditures for Transmission Interconnection projects.[174]

Table 6-18 Transmission Load Interconnections Projects – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)[175]

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Transmission Load Interconnections		
93786	MIN to LNG Canada Interconnection	77.0	2.1
94003	UBC Load Increase Stage 2	48.5	6.0
901580	Customer IPID - 901580: [redacted]	-	3.2
901581	Customer IPID 901581: [redacted]	-	9.1
	Programs and Projects Less than $5 million	7.8	8.3
	TOTAL Transmission Load Interconnections	133.3	28.7

6.4.2.2 Transmission Sustaining Capital Expenditures Are Consistent While Additions Are Increasing

Circuit Breakers

Circuit breakers are used to isolate sections of the transmission and distribution system and to interrupt high currents under fault conditions. They are the primary protection device on the transmission and distribution system and must be capable of reliably interrupting both load currents and fault currents. The system currently

173 These changes are managed through on-going monitoring of the capital portfolio forecast as described in Appendix S, section 6.3.5.

174 More information on the projects listed is provided in Appendix I, page 4, lines 15 to 18.

175 Customer driven interconnection projects include commercially sensitive information. Accordingly, the names of the specific Transmission Load Interconnection projects are filed in confidence with the BCUC.

has over 3,900 circuit breakers made up of a variety of different equipment in terms of voltage classes (from 4 kV to 500 kV).

The planned expenditures for the Test Period are for the replacement of individual circuit breakers and circuit breakers within a station. The timing of the replacements is based on condition, failure rates and risk to the system. Refurbishment of circuit breakers is considered but is usually not possible due to obsolescence. In addition, oil filled circuit breakers with PCB levels at or above 50 ppm are being proactively replaced to ensure all units in the category are removed by the December 31, 2025 Federal Polychlorinated Biphenyl Regulation deadline.

Table 6-19 below provides a summary of the planned capital additions and capital expenditures for fiscal 2022.[176]

Table 6-19 Circuit Breaker – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Circuit Breakers		
900243	SPG Metalclad Switchgear Replacement	-	4.4
	Programs and Projects Less than $5M	13.9	11.9
	TOTAL Circuit Breakers	**13.9**	**16.3**

Capital investments included in the Programs and Projects Less than $5 million line include individual replacements that are delivered as part of an annual recurring capital program. In some cases, there are specific projects to address circuit breaker risks.

Other Power Equipment

Other power equipment expenditures are for the replacement or refurbishment of disconnect switches, surge arrestors, power transformers, instrument transformers,

[176] Additional information on this project is provided in Appendix I, page 4, line 19.

shunt reactors, shunt capacitors, synchronous condensers, high-voltage direct current systems, series capacitor stations, cable terminations, and load tap changers. Some of the investments in this category include the replacement of oil filled equipment with PCB levels at or above 50 ppm that are being proactively replaced to ensure all units in the category are removed by the December 31, 2025 Federal Polychlorinated Biphenyl Regulation deadline.

Table 6-20 below provides a summary of the capital additions and capital expenditures for fiscal 2022.[177]

Table 6-20 Other Power Equipment – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Other Power Equipment		
900575	Barnard 50/60 Feeder Section Replacement	38.9	10.6
92073	American Creek - Capacitor Protection Control Upgrade	-	3.7
900564	Hundred Mile House T1/T2 EOL Replacement	-	7.1
93731	Jordan River - Switchyard Upgrade	-	10.0
92166	SC Excitation Systems Upgrade - VIT/KLY	-	2.0
92618	VIT & KLY Hydrogen Gas Sys - Safety Upgrade	-	2.1
900247	Bridge River - T4 Transformer Replacement	-	6.8
93705	KI1 60Kv Renovation, 4Kv Decommission & Control Room	-	0.4
92478	Mainwaring Station Upgrade	-	6.4
900152	Natal Sub - NTL 60-138 kV Rebuild	-	1.0
94079	Sandspit Substation Replacement	-	2.4
94081	Ah-sin-heek - Substation Replacement	-	4.2
901618	Kelly Lake - Reactor Installation	-	0.5
901248	Kimberley to Marysville - Substation Relocation	-	1.0
901613	Maple Ridge - Feeder Section 60 Series Refurbishment	-	0.1
901034	Norgate - Substation Upgrade	-	0.5
92759	Patricia - Substation Upgrade	-	2.8
900185	Peace Region to Kelly Lake - Reactor Replacement (Phase 2)	-	5.3
	Programs and Projects Less than $5M	21.9	20.8
	TOTAL Other Power Equipment	**60.8**	**87.6**

The following projects have planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, have capital expenditures or

177 Additional information on the projects listed is provided in Appendix I, page 4, lines 20 to 37.

additions in the Test Period, and were not included in Appendix J in the Previous Application.

- **Patricia – Substation Upgrade:** This project will extend the life of Patricia Substation by replacing the end-of-life transformers, circuit breakers, and feeder section equipment.[178]

Capital investments included in the Programs and Projects Less than $5 million line include a number of smaller capital investments such as the Dunsmuir Substation Synchronous VAR Control Upgrade, the Fort St. James No. 2 Substation DVAR Upgrade, and the Sandspit Substation Replacement, as well as programs to address the replacement of disconnects, instrument transformers, metering kits and substation voltage regulators.

Protection and Control

Protection and Control expenditures are for the replacement of end of life protective relaying and control systems at substations. Protection and Control assets are used to isolate transmission equipment from electrical faults, ensure stability and reliability of the power system, and provide local and remote control and monitoring of the transmission system.

Table 6-21 below provides a summary of the fiscal 2022 capital additions and expenditures.[179]

[178] Additional information on the Patricia – Substation Upgrade project is provided in Appendix I, page 4, line 36.
[179] Additional information on the projects listed is provided in Appendix I, page 4, lines 38 to 41.

Table 6-21 Protection and Control – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Protection and Control		
900625	NERC CIP V5 Compliance at Medium Impact T&D Stations	-	2.0
900250	Control PLC984 and RTU Replacement (WSN)	-	3.5
93687	GMS Substation - Control Systems Upgrade	-	4.4
901592	Various Sites - NERC CIP-003v7 Implementation	-	12.8
	Programs and Projects Less than $5M	8.3	8.3
	TOTAL Protection and Control	**8.3**	**30.9**

The following projects have planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, have capital expenditures or additions in the Test Period, and were not included in Appendix J in the Previous Application.[180]

- **Various Sites - NERC CIP-003v7 Implementation:** This project will address the security requirements required at low impact Transmission stations, with the introduction of CIP version 7 standards.

Expenditures within the Programs and Projects Less than $5 million line include programs to replace end of life Protection and Control assets in various substations including Protection Relays, Supervisory Control and Data Acquisition Remote Terminal Units and Digital Fault Recorders.

Stations Auxiliary Equipment

Auxiliary equipment expenditures are for the replacement of station equipment used to support the Power System, including station cables, bus work and insulators, steel and wood pole structures, equipment foundations, grounding systems, station power

[180] Additional information on the project is provided in Appendix I, page 4, line 41.

supplies, batteries and chargers, air compressors and dryers, buildings and HVAC equipment, perimeter fences, drainage systems, and gravel.

Table 6-22 below provides a summary of the fiscal 2022 capital additions and capital expenditures.[181]

Table 6-22 Stations Auxiliary Equipment – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Stations Auxiliary Equipment		
93690	Stn Service Transfer & AC panels - WSN	15.3	3.5
900726	Joseph Creek (JOE) Substation Upgrade	-	5.5
901045	Canal Flats - Substation Wood Pole Replacement	-	1.0
901244	Cathedral Square - Substation HVAC Upgrade	-	2.1
901249	Elko – Switchyard Replacement	-	1.9
901048	Lumby #2 - Substation Wood Pole Replacement	-	2.2
901040	Port Alberni - Substation Refurbishment	-	1.6
901049	Skookumchuck - Substation Wood Pole Replacement	-	1.6
900724	Woss - Substation Wood Pole Replacement	-	1.8
	Programs and Projects Less than $5M	24.6	22.6
	TOTAL Stations Auxiliary Equipment	**39.9**	**43.8**

The following projects have planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, have capital expenditures or additions in the Test Period, and were not included in Appendix J in the Previous Application:

- **Port Alberni – Substation Refurbishment:** This project will extend the life of Port Alberni Substation by replacing the end-of-life control room and circuit breakers.[182]

181 Additional information is provided in Appendix I, page 4, lines 42 to 50.

182 Additional information on the Port Alberni – Substation Refurbishment project is provided in Appendix I, page 4, line 48.

Capital investments in the Programs and Projects Less than $5 million line include program expenditures to replace substation wood poles, cables, insulators, diesels, building roofs and battery banks.

Stations Risk Mitigation

Stations Risk Mitigation expenditures address safety, seismic, environment, severe weather and security risks. Each risk is evaluated based on business impact (e.g., reliability, financial, environmental, safety) and probability of occurrence to determine the appropriate magnitude and duration of investment that is required to mitigate the risk.

Table 6-23 below provides a summary of the capital additions and capital expenditures in fiscal 2022.[183]

Table 6-23 Stations Risk Mitigation – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Stations Risk Mitigation		
92158	Oil Spill Containment - F17/F18 (ALZ / MDN)	7.8	1.4
94052	Stations Seismic Upgrade -F16/17 (9 Stations)	-	0.4
900766	Project IPID - 900766: [redacted]	-	1.1
901407	Various Sites - Substation Security Upgrades (F2021)	6.0	-
	Programs and Projects Less than $5 million	2.5	3.7
	TOTAL Stations Risk Mitigation	**16.3**	**6.6**

Capital investments in the Programs and Projects Less than $5 million line include programs for fire protection, security and seismic upgrades at various substations.

183 Additional information on the projects listed is provided in Appendix I, page 5, lines 51 to 54.

Telecommunications

BC Hydro operates a telecommunications network to support operation of the transmission, distribution, and generation systems and to provide radio voice communications for staff in the field.

Telecommunications expenditures are for the replacement of telecommunication infrastructure including microwave radio, power line carrier, fibre optic cable, and VHF/UHF radio. The expenditures are optimized to address the replacement of assets with the poorest health where failure represents a risk to the safe operation of the Power System.

Table 6-24 below provides a summary of the capital additions and capital expenditures in fiscal 2022.[184]

Table 6-24 Telecommunications – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Telecommunications		
92183	Vancouver Island Radio System	25.6	4.0
92768	Various Sites - Telecom MPLS and DACS Upgrade	-	13.4
900709	Various Sites - Telecom Analog Private Line Replacement	-	5.0
900019	Various Sites - Microwave Radio Replacement	-	2.5
	Programs and Projects Less than $5M	5.7	8.6
	TOTAL Telecommunications	**31.3**	**33.5**

The following projects have planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, have capital expenditures or additions in the Test Period, and were not included in Appendix J in the Previous Application:

[184] Additional information on the projects listed is provided in Appendix I, page 5, lines 55 to 58.

- **Various Sites – Microwave Radio Replacement:** This project will replace equipment at end-of-life and preserve telecommunication reliability and safe operation of the power system. Equipment to be replaced includes microwave radios, SONET multiplexors, and synchronization distribution units.[185]

Capital investments in the Programs and Projects Less than $5 million line include programs to address microwave tower corrosion, and telecom battery, charger and power line carrier line matching unit replacements.

Cable Sustainment

Underground and submarine cables are generally used where overhead lines are not feasible or where there is a particular requirement of the site to use cables. There are over 400 km of underground or submarine cables on the transmission system. Most of these circuits are located in Vancouver, Burnaby, Coquitlam and Victoria, and include 69 kV, 138 kV, 230 kV and 500 kV voltage levels. These circuits also include the Strait of Georgia crossings from the mainland to Vancouver Island. Cable sustainment expenditures are for the replacement of cables and ancillary equipment (e.g., pumping equipment and duct banks).

Table 6-25 below provides a summary of the capital additions and capital expenditures in fiscal 2022.[186]

[185] Additional information on the Various Sites – Microwave Radio Replacement project is provided in Appendix I, page 5, line 58.

[186] Additional information on the projects listed is provided in Appendix I, page 5, lines 59 to 61.

Table 6-25 Cable Sustainment – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Cable Sustainment		
901002	2L146 - Cable Replacement	-	1.6
94057	Gulf Islands - Transmission Reinforcement	-	6.8
901623	Coquitlam - 2L51 Partial Replacement	-	5.0
	Programs and Projects Less than $5M	2.8	3.1
	TOTAL Cable Sustainment	**2.8**	**16.5**

Capital investments in the Programs and Projects Less than $5 million line include investments such as programs to address cable instrumentation upgrades and pumping plant refurbishments.

Overhead Lines Life Extension

The overhead transmission network consists of conductor systems, metal support structures, wood poles, and associated equipment which includes spacer dampers, aircraft warning markers, and disconnect switches. The overhead network has over 18,400 km of transmission lines. These circuits include approximately 23,000 metal support structures and approximately 116,000 wood poles. Life extension expenditures for overhead lines cover the replacement or refurbishment of line components.

Table 6-26 below provides a summary of the capital additions and capital expenditures in fiscal 2022.[187]

[187] Additional information on the projects listed is provided in Appendix I, page 5, lines 62 to 65.

Table 6-26 Overhead Lines Life Extension – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	O/H Lines Life Extension		
92840	Circuit Refurbishments - F15 - 2L13/14	17.8	1.0
93729	Long Span Crossing Refurbishment - F17/F18 (1L37)	-	2.6
94035	5L63 Telkwa Relocation	-	9.8
901789	Various Sites - Transmission Copper Conductor Replacement - F2021	5.0	-
	Programs and Projects Less than $5M	45.4	48.8
	TOTAL O/H Lines Life Extension	**68.1**	**62.2**

Capital investments in the Programs and Projects Less than $5 million line include the replacement of transmission anchor rods, crossing markers, spacer dampers, line disconnect switches, and insulator replacements. The largest of these programs is devoted to wood structure and framing replacements, which includes pole replacements, bracing and crossarms.

Overhead Lines Performance Improvement

Investments in this category address transmission lines subject to localized weather conditions causing performance issues. This work is intended to bring the line back to its designed reliability level. Examples include local sections subject to unequal ice loading, high instances of lightning strikes, or salt fog. Currently, the focus of the expenditures in this area is on reducing lightning-caused outages by installing transmission arcing horns.

Table 6-27 below provides a summary of the capital additions and capital expenditures in fiscal 2022.

Table 6-27 Overhead Lines Performance Improvement – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	O/H Lines Performance Improvement		
	Programs and Projects Less than $5M	1.5	1.5
	TOTAL O/H Lines Performance Improvement	**1.5**	**1.5**

Overhead Lines Risk Mitigation

Overhead Lines Risk Mitigation expenditures address issues and potential events which could put the system at risk of a prolonged outage or pose safety concerns. Currently, the focus is on reducing the risk to public safety and operating concerns associated with deficient transmission line to ground clearances. Civil protective work to protect transmission structures against flooding and slides are also addressed under this category.

Table 6-28 below provides a summary of the capital additions and capital expenditures in fiscal 2022.

Table 6-28 Overhead Lines Risk Mitigation – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	OH Lines Risk Mitigation		
	Programs and Projects Less than $5M	7.6	5.6
	TOTAL OH Lines Risk Mitigation	**7.6**	**5.6**

Capital investments in the Programs and Projects Less than $5 million line include programs to address the replacement of automatic splices, civil protective works, and the refurbishment of overhead guy wires.

Rights-of-Way Sustainment

BC Hydro is responsible for managing the rights-of-way and infrastructure that allow access to the Power System, including over 16,000 km of resource roads. This includes roads located along BC Hydro's corridors where BC Hydro is the sole maintainer, and also includes industry-maintained roads leading to the Power System facilities where BC Hydro has shared obligations for road maintenance (such as forest service roads, telecom station roads, and other types of permit roads on Crown land). The Rights-of-Way Sustainment program restores roads in poor condition and replaces road structures if required (such as bridges, gates, culverts, and retaining walls). The program also acquires and renews legal status of rights-of-way for overhead transmission lines throughout the province.

Table 6-29 below provides a summary of the capital additions and capital expenditures in fiscal 2022.

Table 6-29 ROW Sustainment – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	ROW Sustainment		
	Programs and Projects Less than $5M	9.1	9.1
	TOTAL ROW Sustainment	**9.1**	**9.1**

Rights-of-Way Sustainment investments within the Programs and Projects Less than $5 million line include work programs for access repairs and rights acquisition.

Third-Party Requested Transmission Line Relocations

Third-party requested line relocations are expenditures initiated when BC Hydro enters into an agreement with a third-party who wishes to have transmission lines relocated. With the exception of relocations requested by the Ministry of Transportation and Infrastructure for highway rerouting or improvement projects, the third-party will pay for all costs incurred, resulting in an offsetting Contributions in Aid of construction for the capital expenditure. For relocations requested by the Ministry of Transportation and Infrastructure, BC Hydro recovers costs based on a protocol agreement. Under this protocol agreement, BC Hydro recovers approximately 50 per cent of the costs incurred for the relocation of 69 kV transmission lines. This cost sharing arrangement recognizes the benefit of rights-of-way provided to BC Hydro by the Ministry at no cost. Costs for the relocation of transmission lines greater than 100 kV are recovered from the Ministry at full direct cost. BC Hydro may also relocate transmission lines where legally or contractually obligated.

Table 6-30 below provides a summary of capital additions and capital expenditures in fiscal 2022.

Table 6-30 Third-Party Requested Transmission Line Relocations – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Third Party Requested Transmission Line Relocations		
901232	60L029 - Transmission Relocation (MoTI Protocol Agreement)	-	2.4
	Programs and Projects Less than $5M	13.0	9.6
	TOTAL Third Party Requested Transmission Line Relocations	**13.0**	**12.0**

Most of the Third-Party Requested Transmission Line Relocations investments in fiscal 2022 are included in the Programs and Projects Less than $5 million line. As the number of requests from third-parties can vary between fiscal years, a provision, based on historical averages, is included within the Capital Plan to account for future requests.

Contributions in Aid

Contributions in Aid are periodic or lump-sum payments or consideration received from customers or third-parties to provide funding towards the cost of construction or acquisition of an asset where the ownership, operation and maintenance responsibilities remain with BC Hydro.

6.4.3 Distribution Capital Expenditures and Additions

Distribution capital investments in fiscal 2022 are approximately 60 per cent for growth and 40 per cent for sustain investments.[188] This is similar to the overall allocation of expenditures across Distribution investments in the Previous Application.

The Distribution actual and planned capital expenditures and additions for fiscal 2020 to fiscal 2022 are provided in Table 6-31 and Table 6-32 below.

188 Distribution capital expenditures and additions continue to be driven by the needs described in Appendix S, sections 6.4.3 and 6.4.4.

Table 6-31 Distribution Actual and Plan Capital Expenditures Fiscal 2020 to Fiscal 2022

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Distribution Growth					
Customer Driven					
Customer Connections	214.2	222.5	216.3	216.4	213.5
Major Customer Connections	15.1	54.6	15.4	56.0	29.0
IPP	2.6	1.8	2.3	2.3	2.2
Customer Driven Total	231.9	279.0	234.0	274.7	244.8
System Expansion and Improvement	67.5	60.3	50.0	67.8	61.2
Uneconomic Extension Assistance	0.6	0.4	0.6	0.7	0.7
Growth Total	300.0	339.7	284.6	343.2	306.7
Distribution Sustain					
System Expansion and Improvement	56.4	50.5	57.2	30.3	62.0
Asset Replacement					
Poles	76.1	36.5	63.3	60.2	63.2
Overhead Equipment	14.4	27.7	15.6	30.3	43.0
Underground Equipment	21.6	32.1	19.4	32.1	30.0
Trouble	17.7	20.1	18.0	19.8	20.2
Asset Replacement Total	129.8	116.4	116.3	142.3	156.3
Electric Vehicle Charging Infrastructure	0.2	4.6	2.2	2.2	(0.2)
Beautification	1.1	4.8	1.1	1.1	1.2
Sustain Total	187.5	176.2	176.8	175.9	219.3
Total Distribution	487.5	515.9	461.4	519.1	526.1
Less: Contribution in Aid	(134.0)	(160.9)	(133.7)	(148.5)	(200.2)
Total Net	353.5	355.0	327.7	370.6	325.9

Table 6-32 Distribution Actual and Plan Capital Additions Fiscal 2020 to Fiscal 2022

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Distribution Growth					
Customer Driven					
Customer Connections	214.0	222.6	216.2	211.2	213.3
Major Customer Connections	9.9	28.9	20.7	40.3	20.2
IPP	2.6	3.0	2.4	2.3	2.2
Customer Driven Total	226.5	254.6	239.3	253.8	235.7
System Expansion and Improvement	79.8	52.5	104.3	70.8	65.3
Uneconomic Extension Assistance	0.6	0.5	0.6	0.7	0.7
Growth Total	306.9	307.5	344.2	325.3	301.7
Distribution Sustain					
System Expansion and Improvement	64.6	34.0	74.1	45.2	46.2
Asset Replacement					
Poles	75.9	56.3	65.9	71.5	62.6
Overhead Equipment	13.4	19.9	15.4	28.3	40.4
Underground Equipment	22.5	28.7	19.8	30.7	30.4
Trouble	17.6	20.1	18.0	19.7	20.1
Asset Replacement Total	129.4	124.9	119.1	150.2	153.5
Electric Vehicle Charging Infrastructure	0.2	2.4	2.2	2.5	0.3
Beautification	1.1	0.7	1.1	1.1	1.2
Sustain Total	195.3	162.0	196.5	199.0	201.2
Total Distribution	502.2	469.6	540.7	524.3	502.9
Less: Contribution in Aid	(131.0)	(137.5)	(136.6)	(152.7)	(150.4)
Total Net	371.2	332.1	404.1	371.6	352.5

Distribution capital expenditures increase from $487.5 million planned in fiscal 2020 and $461.4 million planned in fiscal 2021 to $526.1 million planned in fiscal 2022 primarily due to an increase in larger distribution customer projects and an increase in Overhead Equipment Asset Replacements. The increase in Overhead Equipment Asset Replacements is due to the LED Street Light Conversion project and the need to address equipment on the overhead system with PCB (polychlorinated biphenyl) levels at or above 50 ppm. The increase in distribution customer projects is offset by increased Contributions in Aid.

Distribution Growth capital additions will increase from $306.9 million planned in fiscal 2020 to $344.2 million planned in fiscal 2021 and then decrease to $301.7 million planned in fiscal 2022. This is primarily due to the expected completion of a number of voltage conversion projects throughout the Lower Mainland as well as an increase in the number of larger distribution customer projects, offset by Contributions in Aid. Distribution Sustain capital additions are relatively stable compared to the prior test period, ranging from $195.3 million planned in fiscal 2020 to $201.2 million planned in fiscal 2022.

6.4.3.1 Distribution Growth Capital Expenditures & Additions – Fiscal 2022 Expenditures Are Decreasing

Customer Driven Expenditures

Within the Customer Driven category, the majority of planned capital expenditures are for Programs and Projects Less than $5 million. These expenditures include residential and commercial load customer connections (approximately 5,000 design connections and 35,000 simple “express” connections annually). The level of economic activity in the province is the single largest driver of these customer capital expenditures. Customer activity trends in the first two quarters of fiscal 2021 have not indicated any slowdown in activity.

Impacts associated with the COVID-19 pandemic caused a slow down in new customer service requests in April and May 2020, but they have since returned to normal levels, and in some cases increased above the trends for fiscal 2021. Customer development investments may slow down in fiscal 2022; however, all indicators continue to show growing housing sales. Presales for multi-residential and commercial developments also continue to show a normal level of activity.

There are three projects greater than $5 million with expenditures in the Test Period. These projects are listed in Table 6-33 below.[189]

---

[189] Additional information on the projects listed is provided in Appendix I, page 6, lines 1 to 3.

Table 6-33 Customer Driven – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Customer Driven		
DY-1545	Customer IPID - DY-1545: [redacted]	-	0.4
901588	Customer IPID - 901588: [redacted]	-	5.6
901589	Customer IPID - 901589: [redacted]	-	3.2
	Programs and Projects Less than $5 million	235.7	235.6
	TOTAL Customer Driven	**235.7**	**244.8**

System Expansion and Improvement - Growth

Growth driven system expansion and improvement expenditures address existing capacity constraints and anticipated load growth. BC Hydro is undertaking several projects to increase the capacity and transfer load at the highest risk locations.

Table 6-34 below provides a summary of the fiscal 2022 capital additions and capital expenditures.[190]

[190] Additional information on the projects listed is provided in Appendix I, page 6, lines 4 to 16.

Table 6-34 System Expansion and Improvement – Growth Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	System Expansion and Improvement		
92802	Glenmore Voltage Conversion (LM-NSC-088)	5.3	5.3
93650	Two new CBN Feeders (LM-FVE-606)	-	4.2
93669	Three new MLE Feeders to offload CBN (LM-FVE-607)	-	4.1
900347	CAP distribution voltage conversion for 51,52,58 (LM-NSC-124)	3.8	3.7
900364	CAP distribution voltage conversion for 57, and 59 (LM-NSH-040)	3.4	3.4
901132	Two Fleetwood feeders to offload McLellan (FV-FVW-723)	-	0.5
900309	Burnaby - Voltage Conversion Horne Payne 12F316 & 12F59 to 25F123 (LM-BBY-075)	-	2.6
900310	Burnaby - Voltage Conversion and Transfer Horne Payne 12F312 & 12F74Q to 25kV (LM-BBY-076)	-	2.8
900431	Oldfield (OFD) Voltage Conversion 12 to 25kV (NI-NEW-273)	-	3.5
900541	Vancouver Island - Saltspring 25F61 Submarine Cable Extension to North Pender Island (VI-GUL-005)	-	0.8
901354	Glenmore - Voltage conversion of GLR 452, 454, 461, 462, 463 & 464 (LM-NSH-047)	-	2.4
901355	Norgate - Offload NOR loads to NVR feeders (LM-NSH-074)	-	6.5
901356	North Vancouver - Offload NVR loads to LYN new feeders (LM-NSH-075)	-	3.0
	Programs and Projects Less than $5M	52.8	18.4
	TOTAL System Expansion and Improvement	**65.3**	**61.2**

This category of investments is subject to year-over-year fluctuations as a result of the prioritization of work to adjust to changes in the forecast load growth. The majority of capital additions and expenditures in the growth System Expansion and Improvement category, including Programs and Projects Less than $5 million, are made up of the following:

- **New Feeders:** These are projects to construct new feeders and infrastructure to offload heavily loaded existing feeders or to supply distribution customer load growth. Areas with significant new feeder projects include Abbotsford, Delta, Surrey, and North Vancouver. BC Hydro is forecasting capital expenditures of $15.5 million and capital additions of $16.8 million in fiscal 2022; and

- **Voltage Conversions:** These are projects to convert the distribution primary voltage from 4 kV to 12 kV or from 12 kV to 25 kV. The objective of these investments is to increase existing distribution infrastructure capability to:
  - Enable transmission and substation plans for expansion or redevelopment requiring feeder loads to be transferred to other feeders or substations;
  - Increase system capacity to supply distribution customer load growth;
  - Increase operating flexibility for restoration and planned outages aligned with substation and transmission plans;
  - Increase system efficiency by reducing electrical system losses and improving customer service voltages;
  - Reduce congestion in heavily populated corridors; or
  - Minimize equipment additions and its environmental footprint.

  Areas with significant voltage conversion projects within the Test Period include Vancouver, Burnaby, North Vancouver, Richmond, Surrey and Prince Rupert. BC Hydro is forecasting capital expenditures of $40.4 million and capital additions of $41.4 million in fiscal 2022.

The following projects have planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, have capital expenditures or additions in the Test Period, and were not included in Appendix J in the Previous Application.

- **Vancouver Island – Saltspring 25F61 Submarine Cable Extension to North Pender Island (VI-GUL-005):** This project will extend a new feeder from Saltspring Island to Pender Island to increase system capacity to supply load growth.[191]

[191] Additional information on the Vancouver Island – Saltspring 25F61 Submarine Cable Extension to North Pender Island (VI-GUL-005) project is provided in Appendix I, page 6, line 13.

6.4.3.2 Distribution Sustaining Capital Expenditures & Additions – Fiscal 2022 Expenditures Are Increasing Compared to Fiscal 2021

System Expansion and Improvement - Sustain

System expansion and improvement sustaining expenditures maintain and improve distribution system performance including addressing customer reliability, safety risks and regulatory and legal requirements. Table 6-35 below provides a summary of fiscal 2022 capital additions and capital expenditures.[192]

Table 6-35 System Expansion and Improvement – Sustaining Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	System Expansion and Improvement		
900391	Downtown Vancouver - Underground Murrin Feeders to Eliminate H-Frames in Gastown	-	10.4
900557	H-Frame Elimination - Chinatown	0.5	0.1
	Programs and Projects Less than $5M	45.7	51.5
	TOTAL System Expansion and Improvement	**46.2**	**62.0**

Year-over-year fluctuations are the result of the prioritization of work with the timing of lower priority work being adjusted. The majority of the sustaining System Expansion and Improvement investments are captured in the line Programs and Projects Less than $5 million line and are for various small projects that relate to the following three areas:

- **Customer Reliability:** The objective of customer reliability expenditures is to improve reliability on targeted distribution circuits that are performing poorly. The scope of customer reliability projects may include new standby feeders, feeder ties, as well as circuit undergrounding or reconfiguration, line relocations

[192] Additional information on the projects listed is provided in Appendix I, page 6, lines 17 to 18.

and protection upgrades. BC Hydro is forecasting capital expenditures of $4.7 million and capital additions of $3.8 million in fiscal 2022;

- **Distribution Automation:** Automation of distribution devices provide operating personnel with remote visibility of system parameters and system status, facilitate remote operability, and enable greater flexibility to efficiently operate the system. Expenditures in fiscal 2022 are focused on automation of reclosing and switching devices to enable faster fault isolation and outage restoration in order to enhance service reliability, and on automation of voltage management devices to improve power quality. BC Hydro is forecasting expenditures of $20.7 million and capital additions of $17.4 million in fiscal 2022; and
- **Downtown Vancouver Redevelopment:** The Downtown Vancouver Redevelopment Plan is a long-term strategic plan, aligned with the Downtown Vancouver Electric Supply plan (described in Appendix K in the Previous Application) to convert the downtown core from a 12 kV dual-radial system to a 25 kV open loop system over the next 30-plus years. The Cathedral Square transformer failure in 2007, the manhole fire in 2008, and the Murrin transformer failure in 2013 have demonstrated the considerable supply risk and vulnerability of the aging and congested distribution system in the Downtown Vancouver area. This initiative addresses the risk of long, high consequence outages in the area. The plan replaces assets in poor condition with equipment that meets current standards and introduces automation to provide operational flexibility, reduce congested circuits and reduce outage restoration times. In conjunction with the Downtown Vancouver Redevelopment, BC Hydro will continue with a safety initiative in downtown Vancouver to eliminate potential hazards to the public. The replacement circuits will be an underground automated open loop system to align with the overall redevelopment initiative. BC Hydro is forecasting expenditures of $12.3 million and capital additions of $8.8 million in fiscal 2022.

The following program of projects has planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, has capital expenditures or additions in the Test Period, and was not included in Appendix J in the Previous Application.

- **Downtown Vancouver – Underground Murrin Feeders to Eliminate H-Frames:** This program of projects will mitigate safety risks with public or worker clearances to energized equipment on H-Frame structures.[193]

Asset Replacement

Distribution asset replacements expenditures address equipment that has reached end-of-life.

Table 6-36 below provides a summary of the fiscal 2022 capital additions and capital expenditures.[194]

Table 6-36 Asset Replacement – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Asset Replacement		
900556	Various Sites - LED Street Light Conversion	25.1	28.9
	Programs and Projects Less than $5M	128.4	127.4
	TOTAL Asset Replacement	**153.5**	**156.3**

The majority of capital additions and expenditures in this category consist of recurring capital programs in the Programs and Projects less than $5 million line to address the replacement of assets in the following four categories:

[193] Additional information on the Downtown Vancouver – Underground Murrin Feeders to Eliminate H-Frames in Gastown project is provided in Appendix I, page 6, line 17.

[194] Additional information on the project listed is provided in Appendix I, page 6, line 19.

- **Poles:** This category covers wood poles as well as elevated platforms. Poles and platforms at end of life pose a significant risk to crews and the general public and may cause outages on the system. An increasing number of BC Hydro's approximately 900,000 distribution system wood poles are reaching end of life. More than 102,000 poles are currently greater than 50 years of age compared to 67,000 poles that were greater than 50 years of age in fiscal 2014. Overall, from fiscal 2014 to fiscal 2020, the average age of wood poles increased from 28.2 years to 29.1 years.

  Wood pole end-of-life is identified by a series of inspection programs that run throughout the fiscal year. BC Hydro is forecasting expenditures of $63.2 million in fiscal 2022, after recoveries from TELUS;[195]

- **Overhead System:** Overhead system assets include transformers, voltage regulators, circuit reclosers, conductors, and switches including porcelain fuse cut-out switches. BC Hydro also manages a fleet of street lights as part of the distribution overhead system. A three-year deployment of light-emitting diode (**LED**) street lights began in fiscal 2021 to replace the current fleet of existing high pressure sodium and mercury vapour units. Equipment on the overhead system with polychlorinated biphenyl levels at or above 50 parts per million (ppm) is being proactively replaced to ensure all units in the category are removed by the December 31, 2025 federal Polychlorinated Biphenyl Regulation deadline. BC Hydro is forecasting capital expenditures of $43.0 million in fiscal 2022 to address end of life replacements on the overhead system;

- **Underground System:** Underground system assets include feeder cables, submarine cables, residential distribution cables and equipment, transformers and switchgear. Underground systems typically supply densely populated

[195] Approximately 85 per cent of the poles on the distribution system are jointly owned by TELUS and BC Hydro. TELUS pays 40 per cent of pole-in-place replacement costs for jointly owned poles.

areas. Equipment in poor condition can pose a significant risk to system reliability and to public and worker safety. Detailed condition assessments combined with risk assessments are used to identify when replacements of underground system assets are required. Older Paper Insulated Lead Sheathed Cables (**PILC**) entering substations are at or reaching end of life and need to be replaced to mitigate reliability and worker safety issues. Transformers and other oil filled equipment with polychlorinated biphenyl levels at or above 50 ppm are being proactively replaced to ensure all units in the category are removed by the December 31, 2025 federal Polychlorinated Biphenyl Regulation deadline. BC Hydro is forecasting capital expenditures of $30.0 million in fiscal 2022 to address end of life replacements on the underground system; and

- **Trouble:** Trouble capital expenditures are for equipment replacements that meet capitalization rules and resulting from: routine trouble calls, which are day to day restoration of power outages; storms, which are events causing outages over a large geographic area or affecting a large number of customers, or of extended duration; or damage to plant, which are events where a third-party may be liable for the cost of the system repairs. BC Hydro and contractor crews respond to between 40,000 and 60,000 dispatched calls per year regarding the distribution system. The forecast expenditures are based on historical levels. BC Hydro is forecasting expenditures of $20.2 million in fiscal 2022 to respond to trouble calls.

Electric Vehicle Charging Infrastructure

BC Hydro's forecast expenditures on electric vehicle (**EV**) charging infrastructure are for installing and sustaining a network of EV direct current fast charging (**DCFC**) stations. For fiscal 2022, BC Hydro is including costs related to EV DCFC infrastructure that meet the requirements for a prescribed undertaking under section 5 of the Greenhouse Gas Reduction (Clean Energy) Regulation. For further discussion, refer to Chapter 2, section 2.3.2.3.

Table 6-37 Electric Vehicle Charging Infrastructure – Plan Capital Additions and Expenditures Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Electric Transportation Infrastructure		
	Programs and Projects Less than $5M	0.3	(0.2)
	TOTAL Electric Transportation Infrastructure	**0.3**	**(0.2)**

Annual capital expenditures and additions are net of contributions from the Government of B.C. and National Resources Canada. The expenditures will vary between fiscal years based on the timing of receipt of those contributions.

Contributions in Aid

Contributions in Aid are periodic or lump-sum payments or consideration received from customers or third parties to provide funding toward the cost of construction or acquisition of an asset, where the asset ownership, operation and maintenance responsibilities remain with BC Hydro. Distribution Contributions in Aid are mostly received under the Customer Driven Program for new connection requests in accordance with the Electric Tariff and payments are made in advance of costs being incurred. Contributions in Aid are also received under the Beautification and Uneconomic Extension Assistance programs.

6.5 Supporting Portfolio Investments Are Increasing to Support How We Run Our Business

BC Hydro's planned capital expenditures and additions over the Test Period for our Supporting Portfolio Investments are discussed in the following sub-sections. This includes the investments in BC Hydro's Technology, Properties, Fleet and Corporate/Other capital portfolios. As discussed in section 6.3.3 above, compared to the Previous Plan, the Capital Plan includes increased funding for Technology, Properties, Fleet and Tools/Other investments. This supports the BC Hydro-wide initiative to "make it easier to get work done" and is driven by changes in business requirements, the increasing prevalence of technology, and ongoing changes in work spaces to support employee needs. Throughout this section we have provided commentary on how the fiscal 2022 planned capital expenditures and additions compare to the planned amounts in fiscal 2020 and fiscal 2021 included in the Previous Application.

6.5.1 Technology Capital Expenditures & Additions

The Technology KBU is responsible for the planning, design, delivery and operation of BC Hydro's information technology systems and several operational technology systems.

6.5.1.1 BC Hydro's Operations Depend on Technology Capital Assets

BC Hydro's business operations are enabled by an extensive technology asset portfolio that includes data centres, networks, enterprise software platforms and applications, business group applications, mobile phones and mobile applications, geographic information systems, personal devices and desktop software, cyber security devices and monitoring applications, business intelligence and analytics platforms, and operational technology systems.[196]

Our level of investment in technology varies from year to year in response to numerous strategic drivers including: BC Hydro's Service Plan objectives; direction from the Government of B.C.; regulation and compliance; utility industry digitization and need for cybersecurity; desired business unit outcomes; technology asset health; technology market direction; and technology trends.

6.5.1.2 Strategic Drivers Impact Technology Capital Investments

Appendix F provides BC Hydro's Technology Strategy and 5-Year Plan (Technology Plan). BC Hydro's Technology Strategy remains the same as the Previous

[196] Operational technology systems include a range of digital information systems to monitor and control elements of the Power System.

Application. The plan is updated annually in order to remain current and was last updated in September 2020.

In fiscal 2021, two areas have emerged that require us to advance elements of our investment plan.

The first is the need to enhance our existing tools and information technology systems in support of new MRS requirements.

The second is the need to adapt to the COVID-19 pandemic and working from home. Initially this meant equipping our employees to work from home, including some of our customer contact centre staff. We also deployed an application to support customer bill relief and payment options. In addition, we have accelerated our roll out of Windows 10 and advanced our investment in collaboration tools such as Cisco WebEx (required for videoconferencing and to support remote training for the Supply Chain Applications project) and Microsoft Teams (a robust platform for workspace chat, videoconferencing, whiteboard and other capabilities).

6.5.1.3 We Are Making Good Progress Implementing the Technology Plan

Over the past 12 months BC Hydro has made significant progress implementing the Technology Plan.

We have focussed on BC Hydro’s priority to “Make it easier to get work done”. Several mobile apps for front-line workers were delivered to make it easier to gather and access information from the field. These apps were delivered using an iterative, rapid development approach to accelerate deployment and received very positive feedback from employees. In addition, Robotic Process Automation was deployed for the Site C Project to automate high volume and routine business processes allowing workers to focus on higher-value tasks.

In fiscal 2021, BC Hydro completed implementation of the Supply Chain Applications (**SCA**) project on our SAP platform. This project has successfully gone live and is now in stabilization and sustainment. The SCA project improves our supply chain capabilities and efficiency and will bring benefits in the future.

BC Hydro also completed the IT Service Management (**ITSM**) project. This project implemented a new cloud-based solution to manage our information technology operations and services. By no longer outsourcing this capability to TELUS, BC Hydro expects to improve standardization across our external service providers and reduce potential switching costs.

In fiscal 2021, BC Hydro expects to complete the upgrade of our desktop computing environment to Windows 10 and deployment of Microsoft Teams.

6.5.1.4 Technology Capital Expenditures and Additions

Technology capital expenditures and capital additions for fiscal 2020 to fiscal 2022 are presented in Table 6-38 and Table 6-39 below.

Table 6-38 Technology Actual and Plan Capital Expenditures by Investment Category, Fiscal 2020 to Fiscal 2022

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Manage Compliance and Security	14.8	14.6	8.1	5.8	9.9
Manage Risk and Sustain Productivity	68.8	83.1	53.1	68.0	60.6
Enhance Business Capability	34.4	34.4	4.8	14.3	8.5
Total Gross	118.1	132.2	66.0	88.1	79.0
Portfolio Adjustment	(24.6)	-	(10.5)	(19.0)	(10.0)
Total Net	93.5	132.2	55.5	69.1	69.0

Table 6-39 Technology Actual and Plan Capital Additions by Investment Category, Fiscal 2020 to Fiscal 2022

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Manage Compliance and Security	19.7	6.3	7.6	10.7	9.9
Manage Risk and Sustain Productivity	72.6	64.9	65.7	71.6	79.2
Enhance Business Capability	73.3	22.5	12.3	76.1	8.5
Total Gross	165.6	93.7	85.5	158.4	97.6
Portfolio Adjustment	(24.6)	-	(10.5)	(15.0)	(10.0)
Total Net	141.0	93.7	75.0	143.4	87.6

Note: Capital additions variances in the Enhanced Business Capability category in fiscal 2020 and fiscal 2021 are primarily due to a change in the in-service date for the SCA project from March 23, 2020 to August 4, 2021. The SCA project was delayed, with schedule extensions for build, testing and training activities, due to several contributing factors including the COVID-19 pandemic. Refer to Appendix P, section 10 for additional discussion of variances.

As shown in the tables above, BC Hydro's forecast Technology capital investments are grouped into the following three categories:

- **Manage compliance and security:** This category includes investments that address regulatory requirements, periodic foundational cybersecurity improvements, cybersecurity hardware replacements and software license renewals, and growing cybersecurity threats;
- **Manage risk and sustain productivity:** This category includes investments that address asset failure risk. It also includes new investments to help manage operational and business risks and expand information technology services as needed; and
- **Enhance business capability:** This category includes investments for new or improved business capabilities.

The tables below provide a breakdown of fiscal 2022 Technology capital expenditures and additions by investment category.

Table 6-40 provides the planned capital additions and expenditures in the Manage Compliance and Security category.

Table 6-40 Technology Capital Expenditures and Additions – Manage Compliance and Security (Fiscal 2022)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Projects Over $2 million		
T001604	FileNet Records Retention and Disposition	3.3	0.9
	Programs over $2 million		
	Programs and Projects less than $2 million	6.6	9.0
	TOTAL Compliance and Security	**9.9**	**9.9**

As shown in the table above, there is one project and no programs over $2 million in this category:

- The FileNet records Retention and Disposition project will configure BC Hydro's enterprise record-keeping IT system and content with retention and disposition rules aligned to company records management policies.

Programs and Projects less than $2 million address investments in cybersecurity systems upgrades and improvements.

In response to new MRS requirements, BC Hydro is planning compliance initiatives that have investment in fiscal 2022 but were identified after the currency date. These initiatives include projects to meet the future NERC CIP-013 (supply chain risk management) requirements, expand the use of BC Hydro's Compliance Management System and streamline contractor electronic and physical access management.

Table 6-41 below describes the planned capital additions and expenditures in the Manage Risk and Sustain Productivity category.

Table 6-41 Technology Capital Expenditures and Additions – Manage Risk and Sustain Productivity (Fiscal 2022)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Projects over $2 million		
T001572	Windows 2008 Upgrade to Windows 2016	1.8	2.2
T001682	PSSP/WPP Replacement	2.7	0.3
T001397	Contact Centre Technology Foundation	11.3	1.0
T001719	SharePoint Workspaces Upgrade	6.0	0.5
T002085	Advanced Metering Software Upgrade	-	0.7
T002036	Energy Management System (EMS) 3.X Upgrade	5.5	2.4
T002258	SAP Customer Front End Replacement	0.7	0.7
T002317	Secondary Data Centre Network Refresh	-	4.0

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
T002321	Primary Data Centre Network Refresh	-	3.3
T002324	Primary Operations Centre Network Refresh	-	1.0
T002483	Windows Server 2016 Upgrade	3.0	3.0
	Programs over $2 million		
T002208	Storage Capacity Growth	3.5	3.5
T002304	PC Device Purchase	3.8	3.8
	Programs and Projects less than $2 million	40.9	34.3
	TOTAL Manage Risk and Sustain Productivity	**79.2**	**60.6**

As shown in the table above, there are 13 projects or programs over $2 million in this category:

- The Windows 2008 Upgrade to Windows 2016 project will upgrade the operating systems of BC Hydro servers from Windows 2008 to Windows 2016;
- The PSSP/WPP Replacement Project is to replace the Power System Safety Protection (**PSSP**) and Work Protection Practices (**WPP**) application that manages training and authorizations for BC Hydro employees and contractors. This project is now expected to be cancelled. It will be replaced with a future project that focuses on managing contractor identity, access management and training;
- The Contact Centre Technology Foundation project is based on retiring the existing call centre telephony infrastructure and replacing it with a new solution with improved reliability and increased capabilities. This project has been delayed and is now expected to be in-service in fiscal 2024. The project has planned total capital expenditures greater than the materiality threshold for inclusion in Appendix J, has capital expenditures or additions in the Test Period, and was not included in Appendix J in the Previous Application;
- The SharePoint Workspaces Upgrade project is to upgrade the PPM Workspace and Supply Chain Workspace SharePoint applications to the latest

supported version of SharePoint. This project is now expected to be in service in fiscal 2021;

- The Advanced Metering Software Upgrade project is to maintain vendor support by migrating the Itron OpenWay meter solution to OpenWay Operations Centre;
- The Energy Management System (**EMS**) Upgrade project is to upgrade the existing EMS, a regulated operational technology used to monitor and control the Bulk Electric System;
- The SAP Customer Front-end Replacement project is an end-of-life replacement for the existing SAP customer service user interface. This project is now expected to be in-service in fiscal 2024;
- The Secondary Data Centre Network Refresh project is to refresh the IT portion of the Secondary Data Centre equipment. The Secondary Data Centre is BC Hydro’s disaster recovery site for the Primary Data Centre. It is important to keep the equipment up to date and in-line with the Primary Data Centre equipment to ensure proper function in the event of an emergency;
- The Primary Data Centre Network Refresh project is to refresh the IT portion of the Primary Data Centre equipment. The equipment at the Primary Data Centre is updated on a defined cycle (usually five years) to ensure it is supported by product vendors. Support is important to ensure the availability of the latest security patches and issue resolution services;
- The Operations Centres Network Refresh project is to refresh the IT portion of the Primary Operations Centre and Secondary Operations Centre data centre equipment. The equipment at the data centres is updated on a regular cycle to ensure it is supported by product vendors;
- The Windows Server 2016 Upgrade project will upgrade the operating systems of BC Hydro servers from Windows 2012 to Windows 2016;

- The Storage Capacity Growth work program is for data centre storage expansion to meet business application needs; and
- PC Device Purchase is an annual purchase of replacement personal computers used by BC Hydro employees for business purposes. This investment is in line with previous annual projects to replace personal computers and has since been reduced slightly due to the purchase of additional equipment in response to the COVID-19 pandemic and employees working from home in fiscal 2021.

Programs and Projects less than $2 million address investments in business applications upgrades such as Web Platform Authorization Refresh to maintain vendor support for the web platform database, and enterprise applications upgrades including annual SAP technical upgrades to keep the SAP platform current.

Table 6-42 below describes the planned capital additions and expenditures in the Enhance Business Capability category.

Table 6-42 Technology Capital Expenditures and Additions – Enhance Business Capability (Fiscal 2022)

Planning ID	Name of Project	Capital Additions Plan F2022	Capital Expenditures Plan F2022
	Projects over $2 million		
T001127	Supply Chain Applications	0.3	0.3
	Programs over $2 million		
	Programs and Projects less than $2 million	**8.2**	**8.2**
	TOTAL Manage Risk and Sustain Productivity	**8.5**	**8.5**

As shown in the table above, there is only one project, and no programs, over $2 million in this category:

- The Supply Chain Applications project is to address process and technology capability gaps to achieve operational efficiencies, reduced material and service costs and an overall reduction in risk. The project is substantially in-service in fiscal 2021. There is a small amount of trailing costs in fiscal 2022.

Programs and Projects less than $2 million are for enhancements to business applications such as Hydroclimate Data Acquisition System to improve the reliability and performance of BC Hydro's near real-time reservoir information system. They also include enhancements to enterprise applications such as a Financial Planning and Forecasting Solution to automate financial planning and forecasting in order to increase finance process efficiencies.

BC Hydro is planning a future initiative to meet BC Hydro's objective to improve work planning and scheduling. Pre-initiation work, started in fiscal 2021, will provide us with the information we need on costs, benefits and approach to proceed with an enterprise asset and work management platform designed to achieve our productivity and cost efficiency objectives.

Pre-initiation work is also underway for migrating our core SAP system to S4/HANA. SAP HANA is SAP's in-memory database which is designed to run transactions much faster and provide simpler access to the data. SAP S/4 HANA has a dramatically simplified data model, faster processing, advanced real-time data analytics capabilities and a modern user experience. It also provides options for robotic process automation, machine learning and artificial intelligence capabilities.

Both initiatives are in the very early planning phases and will be estimated and prioritized through the capital planning process.[197]

6.5.2 Properties Capital Expenditures & Additions

Properties investments are driven by the need to address the issues and risks associated with the existing headquarters and field facilities.[198] Properties capital investments fall into two general categories:

- **Building Development:** major refurbishing or rebuilding of field buildings in locations where BC Hydro's existing facilities are inadequate; and

[197] Further information on the capital planning process is provided in Appendix S, section 6.3.5.
[198] Further information on Properties assets are provided in Appendix S, section 6.6.

- **Building Improvement:** projects at existing facilities to address operational deficiencies as well as end-of-life replacements of aging building components and systems.

To establish a long-term capital plan, the Properties capital planning process focuses on assessing the health of existing assets and determining operational requirements that cannot be met by the existing asset portfolio. The Properties planning process continues to follow the same three-step, bottom-up approach, as described in the Previous Application: identify the asset needs; form a draft capital plan; and review the investments in the capital plan period.[199]

The Properties KBU will deliver approximately $76 million of BC Hydro's capital expenditures in fiscal 2022.[200]

Table 6-43 and Table 6-44 below provide actual, forecast and planned Properties capital expenditures and additions for fiscal 2020 to fiscal 2022.

Table 6-43 Properties Actual and Plan Capital Expenditures (Fiscal 2020 to Fiscal 2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Properties					
Building Development	37.8	14.7	39.7	42.8	53.8
Building Improvements and Other	21.1	41.7	15.6	22.3	21.8
Total	58.9	56.4	55.3	65.1	75.6

199 The Properties planning process is described in Appendix S, section 6.6. Proposed Properties capital investments are subject to the BC Hydro enterprise-wide framework, and the overall top down planning guidelines discussed in Appendix S, section 6.6.2.

200 Additional information on Properties capital expenditures for fiscal 2022 are provided in Appendix I, page 9. Capital Delivery processes for Properties projects align with the standard BC Hydro project lifecycle for managing projects, as outlined in section 6.6.3 of Appendix S.

Table 6-44 Properties Actual and Plan Capital Additions (Fiscal 2020 to Fiscal 2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Properties					
Building Development	18.9	10.2	40.0	38.5	38.0
Building Improvements and Other	21.1	34.1	15.6	22.3	21.8
Total	40.0	44.3	55.6	60.8	59.8

Properties capital expenditures in fiscal 2022 are planned to be higher than fiscal 2020 and fiscal 2021 primarily due to the commencement of several Building Development projects, which are identified in Table 6-45 below. Capital additions in fiscal 2022 are planned to be similar to fiscal 2021, and higher than fiscal 2020 due to the planned completion of several Building Development projects in fiscal 2021 and fiscal 2022.

6.5.2.1 Building Development Projects

The planned capital expenditures and additions for fiscal 2022 Building Development projects are provided in Table 6-45 below.

Table 6-45 Building Development Projects Plan Capital Expenditures and Addition for Fiscal 2022 ($ million)

Planning ID	Name of Project	Capital Addition Plan F2022	Capital Expenditure Plan F2022
	Building Development		
P201703	Chilliwack Field Building Redevelopment	-	11.2
P201704	Materials Classification Facility Building Redevelopment	38.0	22.6
P201901	Kamloops Field Building Redevelopment	-	6.0
P201902	North Vancouver Field Building Redevelopment	-	2.0
P202001	Campbell River II Building Redevelopment	-	9.0
P202101	Duncan Field Building Redevelopment	-	1.0
P202102	Cranbrook Field Building Redevelopment	-	2.0
	TOTAL Building Development	**38.0**	**53.8**

6.5.2.2 Building Improvement Projects

The planned capital expenditures and additions for fiscal 2022 for Building Improvement projects are provided in Table 6-46 below. There are approximately 20 individual projects planned over the Test Period, at locations across the province. These are grouped below by project type, based on the asset categories the individual projects are addressing. The majority of these projects are less than $2 million.

Table 6-46 Building Improvements Projects Plan Capital Expenditures and Additions for Fiscal 2022 ($ million)

Name of Project Type	Capital Addition Plan F2022	Capital Expenditure Plan F2022
Building Improvements		
Interiors	8.8	8.8
Life/Safety	1.8	1.8
Roofs	4.0	4.0
Yards	7.3	7.3
TOTAL Building Improvements	**21.8**	**21.8**

6.5.3 Fleet Capital Expenditures & Additions

Investments in the Fleet portfolio are driven by the need to address the issues and risks associated with the BC Hydro's existing fleet asset base. BC Hydro has approximately 3,600 vehicle, trailer and equipment assets.

To establish a long-term capital plan, BC Hydro's fleet capital planning process focusses on assessing the health of existing assets and prioritizing the replacement of assets that have reached end of life. The Fleet capital planning approach is the same as prior years: identify asset needs; form a draft capital plan; and review the investments in the capital plan period.[201]

The Fleet Department will deliver approximately $27 million of BC Hydro's capital expenditures over the Test Period and will also have capital additions of approximately $27 million.

Table 6-47 Fleet's Plan Capital Expenditures - Fiscal 2020 to Fiscal 2022

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Fleet	26.2	27.0	27.8	31.4	27.2

Table 6-48 Fleet's Plan Capital Additions - Fiscal 2020 to Fiscal 2022

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Fleet	26.2	29.2	27.8	31.4	27.2

6.5.4 Business Support and Other Technology Capital Expenditures & Additions

Business Support and Other Technology includes capital expenditures and additions related to Land Purchases, Materials Management upgrades, Field Operations tools and equipment, Control Centre system upgrades, and workforce training equipment.

With the exception of land purchases, the individual plans for these different areas are generally less than $5 million per year.

Business Support and Other Technology Capital actual and plan expenditures for fiscal 2020 to fiscal 2022 are provided in Table 6-49 below.[202]

Table 6-49 Business Support and Other Technology Actual and Plan Capital

[201] Further information on BC Hydro's Fleet capital planning and delivery processes is provided in Appendix S, section 6.7. Fleet investments are subject to the BC Hydro enterprise-wide framework, and the overall top-down planning guidelines, as discussed in Appendix S, section 6.3.3.

[202] Additional information is provided in Appendix I, page 10, line 1 and lines 3 to 6.

Expenditures (Fiscal 2020 to Fiscal 2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Business Support – Other	37.4	32.0	47.3	50.6	43.1
Other Technology	2.1	0.8	0.5	2.0	0.2

Fiscal 2022 capital expenditures and additions for Business Support include upgrades to the oil management operating infrastructure, constructing an energized training substation, and equipment for commissioning new power system assets.

Business Support and Other Technology actual and plan capital additions for fiscal 2020 to fiscal 2022 are provided in Table 6-50 below.[203]

Table 6-50 Business Support and Other Technology Actual and Plan Capital Additions (Fiscal 2020 to Fiscal 2022)

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Business Support – Other	38.8	27.2	43.5	43.0	48.0
Other Technology	6.6	-	0.5	-	6.7

The Learning & Development - Energized Training Substation project is included in Table 6-49 and Table 6-50, and Appendix I under Business Support – Other because it was included in the Capital Plan. However, BC Hydro has now cancelled this project due to shifting priorities and uncertainty with regard to the site location.

6.6 Site C Project

The Site C Project actual and planned capital expenditures for fiscal 2020 to fiscal 2022 are provided in Table 6-51 below. Actual and planned capital additions for fiscal 2020 to fiscal 2022 are provided in Table 6-52 below.[204]

203 Additional information is provided in Appendix I, page 10, line 1 and lines 3 to 6.
204 Additional information is provided in Appendix I, page 11.

Table 6-51 Site C Project Actual and Plan Capital Expenditures Fiscal 2020 to Fiscal 2022

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Deferred Capital	16.8	17.0	17.8	25.8	27.4
Construction Capital	1,530.0	1,619.1	1,535.5	1,626.0	1,361.0
Total	1,546.8	1,636.1	1,553.3	1,651.8	1,388.4

Table 6-52 Site C Project Actual and Plan Capital Additions Fiscal 2020 to Fiscal 2022

($ millions)	F2020		F2021		F2022
	RRA	Actual	RRA	Forecast	Plan
Deferred Capital					
Construction Capital	27.9	12.9	189.4	197.5	-
Total	27.9	12.9	189.4	197.5	-

The Site C Project is constructing a third dam and hydroelectric generating station on the Peace River in northeast B.C. to provide 1,100 megawatts of capacity and produce about 5,100 gigawatt hours of electricity per year. In December 2014, the Project received approval from the Government of B.C. to proceed to construction. On November 1, 2017, the BCUC issued its final report on the Site C Project. This led to a decision from the Government of B.C. on December 11, 2017 announcing its approval to proceed with the Site C Project. As part of this announcement, BC Hydro provided a revised cost estimate of $10.7 billion, consisting of a BC Hydro project budget of $9.992 billion and a project reserve of $0.708 billion subject to Treasury Board control. Construction of the Site C Project started in summer 2015.

In fiscal 2020, $12.9 million of transmission related assets were placed in service and in fiscal 2021, $197.5 million of transmission assets are forecast to be placed in service. The next asset additions are expected when the first generating unit is placed into operation, at which point, they will begin to be recovered in rates.

In response to the COVID-19 pandemic, work at the dam site was scaled back in mid-March 2020 to focus on essential activities and critical work required to meet river diversion during the fall of 2020. This brought the overall workforce staying at camp down by about 50 per cent and helped de-densify the work site and worker accommodation.

On May 14, 2020, BC Hydro started increasing construction activities at the Site C dam site in a gradual phased approach. The phased approach is based on the provincial health guidelines for industrial camps, and BC Hydro worked with project contractors and unions to begin ramping up construction activities. The first increase in work focused on restarting some of the main civil works on the earthfill dam and roller-compacted concrete dam buttress. As of October 2020, BC Hydro continues to restart work activities at Site C consistent with provincial health guidelines and is working with our contractors to prepare plans for work that has been delayed and not yet restarted.

The Project achieved river diversion in the fall of 2020. However, there is uncertainty with the project's overall schedule and in-service date as this will depend on the ability to re-start and accelerate work that was halted due to the pandemic.

At the end of December 2019, a previously identified project geological risk materialized on the right bank when investigations and analysis of geological mapping and monitoring activities completed during construction identified that some foundation enhancements would be required to increase the stability below the powerhouse, spillway and future dam core areas. BC Hydro continues to work with the independent Site C Technical Advisory Board and the Project Assurance Board to determine the appropriate right bank enhancement measures. The estimated cost and schedule impacts will be known with more certainty once the enhancement measures are selected.

For fiscal 2022, the Site C Project forecasts capital expenditures are $1.361 billion.

In July 2020, BC Hydro started the process of updating the project cost and schedule and will seek approval from the Board of Directors and the Government of B.C. when this process is finalized.

BC Hydro Fiscal 2022
Revenue Requirements Application

Chapter 7

Regulatory Accounts

Table of Contents

List of Tables

7.1 Introduction

This chapter describes BC Hydro's use of deferral and regulatory accounts (collectively referred to as regulatory accounts) and our proposals to change or close those accounts or to establish new regulatory accounts.

This chapter is organized around the following key points:

- Section 7.2 describes BC Hydro's requests related to regulatory accounts in the Application, which are limited, and outlines the reasons for each request;
- Section 7.3 explains that BC Hydro's use of regulatory accounts is in accordance with International Financial Reporting Standards (**IFRS**) and in compliance with BCUC Orders;
- Section 7.4 presents our actual and forecast regulatory account balances from fiscal 2020 to fiscal 2026; and
- Section 7.5 provides a discussion of the impacts of the COVID-19 pandemic on BC Hydro's regulatory accounts.

The Previous Application included additional information on the types of regulatory accounts and recovery mechanisms used by BC Hydro, as well as a description of each regulatory account. A copy of this information is provided in Appendix U for reference.

Additional information on the regulatory accounts is also provided in Appendix A, Schedules 2.1 and 2.2 of the Application.

7.2 BC Hydro's Proposed Changes to Regulatory Accounts are Limited

BC Hydro is requesting approval for: three changes related to existing regulatory accounts; a recovery mechanism for one regulatory account; the establishment of one new regulatory account; and, the closing of one existing regulatory account.

The sections below provide the rationale for each proposed change to existing and new regulatory accounts.

7.2.1 Cost of Energy Variance Accounts

BC Hydro has five Cost of Energy Variance Accounts that capture the differences between forecast and actual revenues and costs for recovery or refund to ratepayers in future periods: the Heritage Deferral Account, the Non-Heritage Deferral Account, the Load Variance Regulatory Account, the Biomass Energy Program Variance Regulatory Account, and the Trade Income Deferral Account.

7.2.1.1 Trade Income

In its Decision on the Previous Application, the BCUC directed that no actual Powerex net income be captured in the Trade Income Deferral Account absent further review and approval by the BCUC.[205] On December 1, 2020, BC Hydro filed a reconsideration application in response to this directive.[206] In the reconsideration application, BC Hydro requests that the BCUC rescind and vary its directive so that BC Hydro can continue to record variances between forecast and actual Trade Income in the Trade Income Deferral Account and make a proposal for the disposition of any balance in the account from the fiscal 2020 to fiscal 2021 test period in this Application.[207]

In fiscal 2020, actual Trade Income was $13 million higher than the fiscal 2020 RRA Plan.[208] BC Hydro deferred this favorable variance to the Trade Income Deferral Account to the benefit of ratepayers and for inclusion in the determination of the Deferral Account Rate Rider (**DARR**), as proposed in section 7.2.1.2 below. In

---

[205] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 17.

[206] Application to Reconsider and Vary Directives Relating to Powerex Net Income in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Decision (December 1, 2020).

[207] Application to Reconsider and Vary Directives Relating to Powerex Net Income in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Decision (December 1, 2020), page 6.

[208] Actual Trade Income was $189.2 million compared to the fiscal 2020 RRA Plan of $176.3 million as shown in Appendix A, Schedule 1.0, line 18.

fiscal 2021, BC Hydro is not forecasting any variance to plan with respect to Trade Income and therefore has not forecast additions to the Trade Income Deferral Account.

For further information on the Cost of Energy Variance Accounts, refer to Appendix U, section 7.7.1.

7.2.1.2 Recovery Mechanism

BC Hydro has typically recovered the balances in the Cost of Energy Variance Accounts using the DARR. In its Decision on the Previous Application, the BCUC approved BC Hydro's request to amortize the balances in the Cost of Energy Variance Accounts over the fiscal 2020 to fiscal 2021 test period based on the large credit balance and the unique situation in the Previous Application, which was, in part, due to a one-time accounting adjustment as a result of the adoption of a new IFRS revenue standard in fiscal 2019.

In the Previous Application, BC Hydro noted that it expected to propose to return to the DARR table mechanism approved by the BCUC in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application in the subsequent test period starting in fiscal 2022.[209] Therefore, in this Application, BC Hydro is proposing to return to the DARR table mechanism to recover the balances in the Cost of Energy Variance Accounts going forward.

One clarification is that BC Hydro proposes to determine the level of the DARR based on the <u>forecast</u> net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year. In the Previous Application BC Hydro discussed this approach and other approaches, including the pros and cons of each. [210] As discussed, BC Hydro believes that determining the level of the DARR based on the forecast net balance uses more up-to-date information at the time the revenue

[209] Refer to BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application, page 7-27.
[210] Refer to BC Hydro's response to BCUC IR 3.296.2 (Exhibit B-16) in the Previous Application.

requirements application is prepared. It considers amortization and forecast additions and reductions to the Cost of Energy Variance Accounts for the remaining six months of the fiscal year and is appropriate to use for rate-setting purposes.

For example, for the Test Period, the DARR percentage for fiscal 2022 would be based on the forecast net balance of the Cost of Energy Variance Accounts at the end of fiscal 2021. In the next revenue requirements application, assuming a three-year test period as an example, the DARR for fiscal 2023 would be based on the forecast net balance at the end of fiscal 2022. The DARR for fiscal 2024 would be based on the forecast net balance at the end of fiscal 2023, and so on.

As shown in Table 7-3 in section 7.4, the forecast net balance in the Cost of Energy Variance Accounts at the end of fiscal 2021 is ($14) million and therefore based on the above proposal and applying the DARR table mechanism, the DARR would be set at 0 per cent for fiscal 2022.

Table 7-1 Deferral Account Rate Rider Table Mechanism

Forecast Net Balance at the end of the Preceding Fiscal Year		% Rate Rider Effective Following April 1
> $ million	<= $ million	
-	(500)	(5.0)
(500)	(450)	(4.5)
(450)	(400)	(4.0)
(400)	(350)	(3.5)
(350)	(300)	(3.0)
(300)	(250)	(2.5)
(250)	(200)	(2.0)
(200)	(150)	(1.5)
(150)	(100)	(1.0)
(100)	(50)	(0.5)
(50)	0	0.0
0	50	0.0
50	100	0.5
100	150	1.0
150	200	1.5
200	250	2.0
250	300	2.5
300	350	3.0
350	400	3.5
400	450	4.0
450	500	4.5
500	-	5.0

The thresholds and rate rider shown in Table 7-1 are unchanged from those previously approved by the BCUC in its Decision on the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application (BCUC Order No. G-16-09).

In its Decision on the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application, the BCUC supported BC Hydro’s proposed DARR mechanism and stated:

> “The Commission Panel finds that the proposed DARR mechanism presents a more structured approach to clearing the net balances, meets the stated objectives, and that the estimated amortization period of 4–6 years is reasonable, and

> accordingly accepts the DARR mechanism as proposed by BC Hydro."[211]

BC Hydro considers that the rationale for the DARR table mechanism that was presented in the Fiscal 2009 to Fiscal 2010 Revenue Requirements Application continues to remain valid, as it will:

1. Minimize intergenerational inequity by being responsive to the changing net balance in the Cost of Energy Variance Accounts;
2. Maintain rate stability for customers to the extent practicable; and
3. Be administratively simple and transparent.

Therefore, BC Hydro requests BCUC approval to recover the balances in the Cost of Energy Variance Accounts through the DARR using the DARR table mechanism as described in this section; specifically, starting in fiscal 2022 and on an ongoing basis, set the DARR percentage effective April 1 of a given year based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the Cost of Energy Variance Accounts at the end of the preceding fiscal year. Following this approach, the DARR percentage would be set at 0 per cent as of April 1, 2021 and for fiscal 2022.

7.2.2 Amortization of Capital Additions Regulatory Account

The Amortization of Capital Additions Regulatory Account was established by BCUC Order No. G-16-09 and captures variances between forecast and actual amortization of capital additions. For further information on the Amortization of Capital Additions Regulatory Account, refer to Appendix U, section 7.8.2.

In accordance with Directive 36 from the BCUC's Decision on the Previous Application, BC Hydro is conducting a deprecation study which is expected to be complete during fiscal 2022. Any asset useful life and salvage value percentage

[211] BCUC Decision and Order No. G-16-09, Fiscal 2009 to Fiscal 2010 Revenue Requirements Application Decision (March 13, 2009), page 172.

changes recommended in the study are required to be recognized in BC Hydro's financial statements prospectively in the period of the change and future periods. Accordingly, any such changes will result in variances in depreciation expenses in fiscal 2022. The magnitude of these impacts could be positive or negative, are not yet known and will not be known until the depreciation study is complete.

BC Hydro is proposing to defer the variances arising in fiscal 2022 as a result of any changes determined in the depreciation study, positive or negative, to a regulatory account, for future recovery from or refund to ratepayers.

BC Hydro proposes to defer the variances to the Amortization of Capital Additions Regulatory Account, for recovery in the next test period consistent with other balances in that account. We are proposing to use the Amortization of Capital Additions Regulatory Account rather than a new regulatory account as this is an existing regulatory account, with an approved recovery mechanism, and the impacts of the depreciation study are similar in nature to the variances already deferred to that account. As the Amortization of Capital Additions Regulatory Account attracts interest, these variances would also attract interest and would be recovered under the same recovery mechanism for this account (i.e., over the next test period). BC Hydro will identify the fiscal 2022 impacts related to the deprecation study after fiscal 2022 is complete and will provide those impacts during the next Revenue Requirements Application proceeding.

Therefore, BC Hydro requests BCUC approval to defer the variances arising in fiscal 2022 as a result of any changes determined in the depreciation study to the Amortization of Capital Additions Regulatory Account, with interest charges and recovery of these amounts being on the same basis as previously approved for this account.

7.2.3 Dismantling Cost Regulatory Account

The Dismantling Cost Regulatory Account was established by BCUC Order No. G-47-18 and captures variances between forecast and actual dismantling costs. For further information on the Dismantling Cost Regulatory Account, refer to Appendix U, section 7.7.2.

In its Decision on the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, the BCUC approved the use of this account for the fiscal 2017 to fiscal 2019 test period.[212] In its Decision on the Previous Application, the BCUC approved the use of this account for the fiscal 2020 to fiscal 2021 test period. In its Decision, the BCUC stated:

> "The Panel accepts that dismantling costs are largely driven by the capital plan and are impacted by capital project schedules. Given this and the magnitude of the variances in the last test period, the Panel agrees that variances between forecast and actual dismantling costs should be provided deferral treatment similar to the treatment of variances between forecast and actual amortization of capital asset additions."[213]

As dismantling costs have been increasing, the BCUC directed BC Hydro to provide, in its next Revenue Requirements Application, an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational inequity, and options on how BC Hydro could calculate and collect dismantling costs to better promote intergenerational equity.[214] Given the intergenerational equity concerns, the BCUC also directed BC Hydro to include, in the depreciation study, a net salvage study and to report on the results and

[212] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 62.

[213] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 124.

[214] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 39.

recommendations, as well as BC Hydro's plan to implement those recommendations.[215]

As directed by the BCUC, BC Hydro is including a net salvage study in the depreciation study. In addition, BC Hydro is requesting that the depreciation study consultant review BC Hydro's current method and other methods of recovering dismantling costs and provide a recommendation for methods appropriate for BC Hydro that may better promote intergenerational equity.

BC Hydro's initial assessment of its current practice is that it does not collect dismantling costs from the customers who benefit from the assets, but instead collects them after the assets have been taken out of service so that customers pay for dismantling costs as they are incurred. Over time, all customers are paying dismantling costs, but, as costs rise or fall over time, this could lead to some intergenerational inequities.

An alternative to our current practice is to collect net salvage costs over the lives of the assets. A net salvage cost approach entails recovering forecast dismantling costs over the life of the asset. Net salvage estimates are customarily prepared with the aid of depreciation expert. Any change from our current practice to a net salvage approach will likely entail rate impacts, as there will be a time when current ratepayers are paying dismantling costs under the current approach, and through net salvage rates. A net salvage cost approach may involve significant administration effort and so costs and benefits will also need to be considered. To analyze and compare the two approaches, including the potential rate impact, we require our consultant's net salvage report. Once the potential net salvage rates are known, we can further assess this alternative and make a recommendation to the BCUC on a preferred approach. Therefore, we propose that the next Revenue

[215] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 40.

Requirements Application would be the appropriate time to more fully assess the options.

However, until the depreciation and net salvage study is complete and filed with the BCUC, BC Hydro proposes to continue to defer variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account in fiscal 2022.

Therefore, BC Hydro requests BCUC approval to continue to defer any variances between forecast and actual dismantling costs in fiscal 2022 to the Dismantling Cost Regulatory Account; continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; continue to recover the forecast interest charged to the account each year from the account each year; and, continue to recover the forecast account balance at the end of a test period over the next test period.

7.2.4 Project Write-off Costs Regulatory Account

In response to Directive 33 of the BCUC's Decision on the Previous Application, BC Hydro made a separate application for approval to establish a new Project Write-off Costs Regulatory Account to capture the portion of actual project write-off costs in each fiscal year for which BC Hydro believes future recovery from ratepayers is appropriate.[216] BC Hydro's request to establish the Project Write-off Costs Regulatory Account was approved by BCUC Order No. G-337-20 dated December 17, 2020.

In its Decision on the Previous Application, the BCUC accepted that some project write-offs are reasonable and to be expected in a utility's normal course of business,[217] but disallowed the recovery of any forecast amounts for project write-offs in the test period revenue requirements as proposed by BC Hydro.

---

[216] Refer to: https://www.bcuc.com/ApplicationView.aspx?ApplicationId=833.

[217] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 107.

However, the BCUC stated that it was willing to consider a regulatory account to capture write-off costs, as follows:

> "The Panel, however, is willing to consider a mechanism, such as the establishment of a regulatory account, to capture BC Hydro's actual project write-off costs for future recovery, provided that in future RRAs BC Hydro also lists all of the projects and costs that have been written-off and captured in the regulatory account along with a description of each project, the rationale for incurring the costs and the rationale for the decision to not continue with the project. In the Panel's view, this would provide the BCUC and interveners with an opportunity to review the reasonableness of these costs. The Panel acknowledges that this would cause a delay between when the write-offs were incurred and when they are recovered. However, if the regulatory account balance is to be cleared over each test period, this would result in minimal intergenerational equity issues and balances the need for BC Hydro to recover these costs from ratepayers and the BCUC's ability to examine these costs prior to their recovery."[218]

BC Hydro agrees with the BCUC's suggestion. Appendix L provides the requested listing and description of the amounts that have been written-off in fiscal 2020 for which BC Hydro believes recovery from ratepayers is appropriate. BC Hydro has captured these amounts in the Project Write-off Costs Regulatory Account.

Consistent with the BCUC's recommendation, BC Hydro proposes that the actual project write-off amounts deferred to the Project Write-off Costs Regulatory Account for fiscal 2020 be recovered in fiscal 2022 (i.e., the next test period), subject to BCUC review and approval of the recovery of these amounts in the Application. As shown in Appendix L, in fiscal 2021 BC Hydro has deferred $9.3 million in actual project write-offs costs to the Project Write-off Costs Regulatory Account related to fiscal 2020 and is seeking approval to recover this amount in fiscal 2022.

[218] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), pages 107 to 108.

Similarly, BC Hydro will defer actual project write-off costs to the Project Write-off Costs Regulatory Account related to fiscal 2021 for which BC Hydro believes future recovery from ratepayers is appropriate and will seek approval to recover these amounts in its Fiscal 2023 Revenue Requirements Application.

Therefore, BC Hydro requests BCUC approval to recover amounts deferred to the Project Write-off Costs Regulatory Account in respect of completed fiscal years over the next test period, starting in fiscal 2022 and on an ongoing basis, subject to BCUC review and approval of the recovery of these amounts; apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and, recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period.

7.2.5 Electric Vehicle Costs Regulatory Account

BC Hydro is requesting approval of an Electric Vehicle Costs Regulatory Account to recover, pursuant to section 18 of the *Clean Energy Act*, its fiscal 2020 and fiscal 2021 costs related to Electric Vehicle charging stations that are prescribed undertakings as defined under section 5 of the Greenhouse Gas Reduction (Clean Energy) Regulation (**GGRR**).

As discussed in Chapter 2, section 2.3, the GGRR was amended in June 2020 to include expenditures for eligible electric vehicle charging stations constructed/purchased and operated by a public utility as prescribed undertakings for the purpose of section 18 of the *Clean Energy Act*.[219] In its Decision on the Previous Application, the BCUC noted that BC Hydro had not demonstrated, subsequent to the GGRR amendment, that the electric vehicle charging stations are prescribed undertakings, and thus denied BC Hydro recovery of related costs for the fiscal 2020 and fiscal 2021 test period. In accordance with the Decision, and as shown in the Compliance Filing to the Previous Application, BC Hydro has removed

[219] Refer to Section 5 of the Greenhouse Gas Reduction (Clean Energy) Regulation.

the capital additions from rate base and the associated amortization, operating costs as well as the cost of energy to serve BC Hydro-owned electric vehicle charging stations from its revenue requirements for fiscal 2020 and fiscal 2021.

However, in its Decision on the Previous Application, the BCUC encouraged BC Hydro to apply for recovery of its prescribed undertaking costs:

> “The Panel encourages BC Hydro to apply to the BCUC if it wishes to have any of its prior, current or future EV capital expenditures considered as possible prescribed undertakings under the GGRR.”[220]

In Chapter 2, section 2.3.2.3, BC Hydro provides information on electric vehicle charging stations constructed/purchased and operated by BC Hydro that meet the definition of a prescribed undertaking under section 5 of the GGRR.

BC Hydro expects total costs of $4.8 million over fiscal 2020 to fiscal 2021 for electric vehicle charging stations that are prescribed undertakings under the GGRR. In order for BC Hydro to recover the expenditures incurred with respect to electric vehicle charging station prescribed undertakings over fiscal 2020 and fiscal 2021, these costs were deferred to a new regulatory account. Under section 18 of the *Clean Energy Act*, the BCUC must set rates that allow BC Hydro to collect sufficient revenue to recover costs incurred for implementing prescribed undertakings.

Therefore, BC Hydro requests BCUC approval to establish an Electric Vehicle Costs Regulatory Account to defer any actual operating costs, amortization, and cost of energy amounts related to electric vehicle charging stations that meet the definition of a prescribed undertaking under the GGRR for fiscal 2020 and fiscal 2021; apply interest to the balance of the account based on BC Hydro’s current weighted average cost of debt and recover the forecast interest charged to the account each year from the account each year; and, starting in fiscal 2022, recover the forecast

[220] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Page 94.

balance at the end of a test period over the next test period, until such time that the actual amounts deferred to the account for fiscal 2020 and fiscal 2021 are recovered in rates.

7.2.6 Rock Bay Remediation Regulatory Account

The Rock Bay Remediation Regulatory Account was established by BCUC Order No. G-75-11 for the deferral of expenditures related to the remediation of the BC Hydro's Rock Bay property. For further information on the Rock Bay Remediation Regulatory Account, refer to Appendix U, section 7.8.4.

Remediation of the Rock Bay property was completed in fiscal 2019 and BC Hydro is not forecasting the deferral of any further remediation costs to this account over the Test Period.

Therefore, BC Hydro requests BCUC approval to close the Rock Bay Remediation Regulatory Account at the end of fiscal 2022 as its balance will be fully amortized into rates at that time.

7.3 BC Hydro's Use of Regulatory Accounts is in Accordance with IFRS and BCUC Orders

BC Hydro's use of regulatory accounts is in accordance with IFRS and is compliant with BCUC Orders and government directions. BC Hydro applies rate-regulated accounting in accordance with IFRS 14, *Regulatory Deferral Accounts*.

Regulatory accounts are commonly used in the utility industry in North America. The general purpose of a regulatory account is to defer costs or revenues for future recovery or refund. For example, regulatory accounts are used to defer differences between forecast and actual costs or revenues, or to better match costs and benefits for customers. In the absence of rate-regulated accounting, these costs or revenues would be recognized in the current accounting period.

Regulatory accounts can either be regulatory assets (amounts to be recovered from ratepayers) or regulatory liabilities (amounts to be refunded to ratepayers). Regulatory accounts are not debt, though BC Hydro has often incurred debt to fund the expenditures in regulatory accounts that have not yet been recovered from ratepayers.

In its Decision on the Previous Application, the BCUC maintained our existing regulatory accounts and the amortization periods associated with them. The BCUC also approved the closure of four regulatory accounts and directed the establishment of the following two new regulatory accounts:

- Load Variance Regulatory Account, to capture variances between forecast and actual domestic customer load (referred to as the Domestic Revenue Variance, which was previously captured in the Non-Heritage Deferral Account);[221] and
- Biomass Energy Program Variance Regulatory Account, to capture all variances between forecast and actual amounts related to the Biomass Energy Program.[222]

These new regulatory accounts will allow for the separation of certain components of BC Hydro's existing Cost of Energy Variance Accounts for enhanced transparency.

7.4 Regulatory Account Balances

Table 7-2 below shows BC Hydro's actual and forecast total regulatory account balances for the fiscal 2020 to fiscal 2022 period, including the changes applied for in the Application.

Actual balances will be different than presented as BC Hydro's Cost of Energy Variance Accounts and several of our cash and non-cash variance accounts capture

[221] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 15.

[222] BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 38.

variances between forecast and actual costs and are impacted by non-controllable factors such as weather, interest rates and discount rates.

Table 7-2 Summary of Regulatory Account Balances, Fiscal 2020 Actual and Fiscal 2021 to Fiscal 2022 Forecast

	($ million)	F2020 Actual	F2021 Forecast	F2022 Forecast
		1	2	3
1	Opening Balance	4,193	5,004	6,266
2	Additions	932	414	97
3	Interest	17	22	24
4	Recoveries / Other	(138)	827	(341)
5	Net Change	811	1,262	(220)
6	**Closing Balance**	**5,004**	**6,266**	**6,047**

As shown in Table 7-2, the total regulatory account balance is forecast to be $6.047 billion at the end of fiscal 2022, which is an increase of $1.043 billion from the fiscal 2020 actual balance of $5.004 billion. The increase in the forecast is primarily due to additions to the Non-Current Pension Costs Regulatory Account and the Debt Management Regulatory Account caused by changes in uncontrollable, market-driven factors (i.e., discount rates and interest rates).

The balance in the Non-Current Pension Costs Regulatory Account is forecast to increase from fiscal 2020 to fiscal 2022 primarily due to a decrease in the discount rate used to measure BC Hydro’s pension liability.

The balance in the Debt Management Regulatory Account is forecast to increase from fiscal 2020 to fiscal 2022 due to a decrease in the value of interest rate hedges on future debt as a result of a decrease in interest rates. These hedges were put in place to lock in future interest rates related to future debt issuances, in support of BC Hydro’s capital program, and the decrease in the value of interest rate hedges will act as an offset against lower interest costs on the associated future debt issuances.

These account balances will change if discount and interest rates change. Therefore, the amounts to be recovered from or returned to ratepayers will also change.

Table 7-3 below presents the fiscal 2020 actual and fiscal 2021 to fiscal 2026 forecast balances of BC Hydro's regulatory accounts.

Table 7-3 Regulatory Account Balances Fiscal 2020 Actual and Fiscal 2021 to Fiscal 2026 Forecast

	($ million)	Schedule Reference	F2020 Actual	F2021 Forecast	F2022 Forecast	F2023 Forecast	F2024 Forecast	F2025 Forecast	F2026 Forecast
			1	2	3	4	5	6	7
	Cost of Energy Variance Accounts								
1	Heritage Deferral Account	2.1 L34	(300)	114	118	122	125	129	133
2	Non-Heritage Deferral Account	2.1 L35	205	(265)	(289)	(303)	(313)	(325)	(337)
3	Trade Income Deferral Account	2.1 L36	(174)	(14)	(15)	(15)	(16)	(16)	(17)
4	Load Variance	2.1 L37	0	159	164	169	174	179	185
5	Biomass Energy Program Variance	2.1 L38	0	(8)	(8)	(9)	(9)	(9)	(9)
	Total	2.1 L39	(269)	(14)	(30)	(36)	(38)	(42)	(45)
	Other Cash Variance Accounts								
6	Storm Restoration Costs	2.2 L200	21	(13)	(0)	(0)	(0)	(0)	(0)
7	Amortization of Capital Additions	2.2 L202	9	(2)	(0)	0	0	0	0
8	Total Finance Charges	2.2 L203	11	(74)	0	0	0	0	0
9	Rock Bay Remediation	2.2 L208	(10)	(0)	(0)	(0)	(0)	(0)	(0)
10	Remediation	2.2 L213	(34)	(3)	(0)	0	0	0	0
11	Real Property Sales	2.2 L215	56	48	49	51	52	52	52
12	Dismantling Cost	2.2 L218	16	(3)	(0)	0	0	0	0
13	Customer Crisis Fund	2.2 L220	(5)	33	34	23	11	(0)	(0)
14	Mining Customer Payment Plan	2.2 L221	0	7	7	5	2	(0)	(0)
15	Project Write-off Costs	2.2 L222	0	9	0	0	0	0	0
16	Electric Vehicle Costs	2.2 L223	0	5	0	0	0	0	0
	Total		63	7	91	79	66	52	52
	Non-Cash Variance Accounts								
17	Foreign Exchange Gains/Losses	2.2 L198	17	13	11	9	6	6	5
18	Non-Current Pension Costs	2.2 L206	210	1,136	1,021	906	792	677	563
19	PEB Current Pension Costs	2.2 L219	(2)	(7)	0	0	0	0	0
20	Debt Management	2.2 L217	953	1,150	1,141	1,112	1,082	1,052	991
	Total		1,178	2,293	2,173	2,027	1,880	1,735	1,558
	Benefit Matching Accounts								
21	DSM	2.2 L193	907	890	880	857	836	826	809
22	First Nations Costs	2.2 L194	69	54	38	20	2	7	14
23	Site C	2.2 L196	508	524	533	541	545	537	529
24	Pre-1996 Contributions in Aid of Construction	2.2 L199	78	73	68	63	58	53	47
25	Capital Project Investigation Costs	2.2 L201	5	(0)	(0)	(0)	(0)	(0)	(0)
26	SMI	2.2 L204	195	173	151	130	108	87	65
	Total		1,763	1,714	1,670	1,611	1,549	1,509	1,465
	Non-Cash Provisions								
27	First Nations Provisions	2.2 L195	426	432	435	439	444	443	439
28	Environmental Provisions	2.2 L207	305	344	286	244	202	178	168
	Total		731	776	721	683	647	621	607
	IFRS Transition Accounts								
29	IFRS Property, Plant and Equipment	2.2 L209	1,079	1,071	1,039	1,007	976	944	913
30	IFRS Pension	2.2 L210	459	421	382	344	306	268	229
	Total		1,538	1,491	1,421	1,352	1,282	1,212	1,142
	Total	2.1 L39+2.2 L224	**5,004**	**6,266**	**6,047**	**5,715**	**5,386**	**5,087**	**4,779**

As shown in the table above, the total net balance in the accounts is forecast to decline to $4.8 billion by the end of fiscal 2026.

BC Hydro has approved recovery mechanisms or has proposed regulatory mechanisms to recover the balances of all but three of its regulatory accounts in rates, within the rate increase proposed for the Test Period.[223] The following three regulatory accounts do not have approved recovery mechanisms, as they are not yet required:

1. Mining Customer Payment Plan Regulatory Account – BC Hydro expects to propose a recovery mechanism for this account in its next revenue requirements application;
2. Customer Crisis Fund Regulatory Account – BC Hydro expects to propose a recovery mechanism for this account in its next revenue requirements application, as the three-year pilot program which commenced in May 2018 will have completed at that time; and
3. The Site C Regulatory Account - BC Hydro will request a recovery mechanism for this account in a future revenue requirements application, as the project is not yet in-service.

Table 7-4 below sets out the fiscal 2022 baseline forecast amounts. The variances deferred to these accounts will be determined from these baseline forecasts.

[223] As discussed in Chapter 7, section 7.8.7 of the Previous Application, the balance in the Real Property Sales Regulatory Account is expected to self-clear based on forecast gains and losses experienced over fiscal 2020 to fiscal 2024. On this basis, BC Hydro considers this account to be one for which a recovery mechanism will not be required.

Table 7-4 Fiscal 2022 Baseline Forecast Amounts for Regulatory Accounts

	($ million)	Schedule Reference	F2022 Plan
			1
	Heritage Deferral Account		
1	COE Subject to Deferral to HDA	4.0 L80	392.7
	Non-Heritage Deferral Account		
2	COE Subject to Deferral to NHDA	4.0 L97	1,186.2
3	External OATT	15.0 L4	11.1
4	NTL Supplemental Charge Revenue	15.0 L9	2.4
5	Load Variance	14.0 L40	5,195.8
6	Biomass Energy Program Variance - COE	4.0 L98	102.4
7	Biomass Energy Program Variance - Revenue	14.0 L41	15.9
8	Trade Income	1.0 L18	190.1
	Other Regulatory Accounts		
9	Non-Current PEB - Pension	8.0 L17	(52.0)
10	Current PEB - Operating Cost	N/A	113.1
11	Storm Restoration Costs	N/A	21.5
12	Total Finance Charges	8.0 L32-L16-L17	505.3
13	Amortization of Capital Additions	13.0 L35	26.6
14	Net Gain on Property Sales	5.01 L10	0.0
15	Dismantling Cost	5.01 L12	45.5

7.5 Impacts of COVID-19 on BC Hydro's Regulatory Accounts

Although the full impacts of the COVID-19 pandemic are not yet known, the COVID-19 pandemic has impacted, and is expected to continue to impact, several regulatory accounts as follows:

- Differences between actual and forecast revenues in fiscal 2021 caused by lower customer load, as well as any related impacts to cost of energy are deferred to the Cost of Energy Variance Accounts. For further information on the impacts of the COVID-19 pandemic to customer load, refer to Chapter 3;

- Lower revenues in fiscal 2021 due to BC Hydro’s COVID-19 pandemic relief measures for residential and commercial customers are deferred to the Customer Crisis Fund Regulatory Account and the Mining Customer Payment Plan Regulatory Account, respectively. The total amount deferred related to these programs was $46 million;
- The timing of capital additions has been impacted due to project schedule changes as a result of the COVID-19 pandemic in fiscal 2021 which could impact the Amortization of Capital Additions Regulatory Account. For further information, refer to Chapter 6, section 6.2.3.1;
- Interest rate fluctuations will lead to:
  - Higher or lower fair values of BC Hydro’s interest rate hedges on future debt issuances, which are deferred to the Debt Management Regulatory Account;
  - Higher or lower finance charges, which are deferred to the Total Finance Charges Regulatory Account; and
  - Higher or lower pension costs due to volatile discount rates which will impact BC Hydro’s PEB Current Pension Costs Regulatory Account and Non-Current Pension Costs Regulatory Account.

BC Hydro Fiscal 2022

Revenue Requirements Application

Chapter 8

Other Revenue Requirements Items

Table of Contents

List of Tables

8.1 Introduction

This chapter describes other revenue requirements items, including amortization expense, return on equity, finance charges, taxes, miscellaneous and inter-segment revenues, subsidiary net income, the allocation of BC Hydro's business support costs, provisions and other, and International Financial Reporting Standards (**IFRS**).

8.2 Amortization Expense

BC Hydro's forecast amortization expense is shown in Appendix A, Schedule 7.0, and includes:

- The amortization of property, plant and equipment (capital assets) in service;
- Amortization related to agreements that are recognized as leases in accordance with IFRS 16, *Leases*;
- Amortization of the following regulatory accounts:
  - DSM Regulatory Account;
  - Pre-1996 Contributions in Aid of Construction Regulatory Account; and
  - Amortization of Capital Additions Regulatory Account.

Amortization expense is summarized in Table 8-1 below.

Table 8-1 Amortization Expense

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	Amortization of Capital Assets	7.0 L5	885.4	885.8	904.5	903.1	929.4
2	IPP Leases	7.0 L12+L14	88.9	89.3	90.1	89.9	90.6
3	Other Leases	7.0 L13	3.4	2.6	3.4	3.7	3.7
4	Total Gross Amortization	7.0 L17	977.8	977.7	998.0	996.6	1,023.7
5	Transfer to NHDA	7.0 L18	0.0	(0.4)	0.0	0.2	0.0
6	Regulatory Account Transfers	7.0 L22	(0.2)	0.4	(0.5)	1.1	0.0
7	Total Transfer to Deferral & Regulatory		(0.2)	0.1	(0.5)	1.3	0.0
	Regulatory Account Recoveries						
8	DSM Amortization	7.0 L26	103.3	103.3	107.4	106.5	108.0
9	Pre-1996 CIAC Amortization	7.0 L32	5.1	5.1	5.1	5.1	5.1
10	Capital Additions Regulatory Account	7.0 L34	9.7	9.7	9.4	9.4	(2.1)
11	Regulatory Account Recoveries	7.0 L35	118.1	118.1	121.9	121.0	111.1
12	Total Current Amortization	7.0 L36	1,095.7	1,095.9	1,119.4	1,119.0	1,134.7

As shown in the table above, total planned amortization expense in fiscal 2022 is $1.135 billion, approximately $15 million higher than the fiscal 2021 RRA Plan. The increase is primarily due to higher planned amortization of capital assets, which is driven by capital additions, as described in Chapter 6.

Capital assets are amortized over the expected useful lives of the assets using the straight-line method, under which amortization expense is recognized evenly over the expected useful life of an asset. Asset class depreciation rates used in the Application are the same as those previously approved by the BCUC, except for certain property, plant and equipment at the Burrard synchronous condense facility, which is discussed in section 8.2.1 below. In the Application, BC Hydro is also seeking approval of the depreciation rate for the infrastructure rights asset class for fiscal 2022 as discussed in section 8.2.2 below.

In the proceeding on the Previous Application, BC Hydro committed to conduct a depreciation study[224] which is expected to be completed in fiscal 2022. As directed by the BCUC, this will include a net salvage study and a review of the expected

224 Refer to page 2 of Exhibit B-43 of the Previous Application.

useful life of infrastructure rights.[225] For further information please refer to section 8.2.2 below and Chapter 7, sections 7.2.2 and 7.2.3.

8.2.1 Burrard Synchronous Condense Facility Depreciation Rates

In its Decision on the Previous Application, the BCUC approved the depreciation rates related to certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2020 and fiscal 2021.

In the Application, BC Hydro is seeking approval for the depreciation rates of certain property, plant and equipment at the Burrard synchronous condense facility for fiscal 2022. Table 8-2 below provides the depreciation rates for the Burrard synchronous condense facility for fiscal 2022 for which BC Hydro is seeking BCUC approval.

Table 8-2 Burrard Synchronous Condense Facility Depreciation Rates

	Class of Property, Plant and Equipment		F2022 Depreciation Rate (%/year)
1	C12002	Road, Paved/Gravel	25.0
2	C12203	Bridge, Concrete	25.0
3	C12401	Drainage System, Yard	25.0
4	C21901	Roofs	25.0
5	C22001	Plant, Concrete or Steel	25.0
6	C22002	Commercial, Concrete or Steel	25.0
7	C22005	Building, Composite Pool	25.0
8	C22009	Buildings - HVAC Systems & Components	25.0
9	C22101	Office Trailer/Mobile Home	25.0
10	C23801	Cranes	25.0
11	C25101	Structure, Support, Steel	25.0
12	C25301	Foundations	25.0
13	C25401	Ducts & Trenches	25.0
14	C30102	Insulation, Boiler	25.0

225 BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directives 36, 40 and 57.

Class of Property, Plant and Equipment		F2022 Depreciation Rate (%/year)
C30501	Piping, High Pressure	25.0
C30607	Asbestos Abatement	25.0
C30802	Water Deluge System, Ammonia	25.0
C31001	Water Intake/Discharge Struct	25.0
C31002	Protection, Cathodic	25.0
C34004	Turbine, Composite Pool	25.0
C34005	Coils, Stator	25.0
C34006	Rotor, Generator	25.0
C34007	Generator, Composite Pool	25.0
C34009	Cooling System, Hydrogen	25.0
C42004	Major Maintenance - Rewedging	25.3
C42102	Exciter, Static	25.0
C48003	Generator, Composite Pool	25.0
C48004	Generator, Diesel	25.0
C49001	Pump	25.0
C49002	Motor	25.0
C51001	Condensor, Synchronous, Rotary	25.0
C52105	Transformer, Station Service	25.0
C52504	Transformer, Voltage, Encaps.	25.0
C54101	Breaker, Air/Magnetic	25.0
C55401	Buswork & Station Conductor	25.0
C55501	Grounding Systems	25.0
C56001	Insulators	25.0
C59001	Power Supply, Uninterruptible	25.0
C59101	Regulator, Feeder Circuit	25.0
C59201	Charger System, Battery	25.0
C61001	Fencing	25.0
C62001	Fire Protection System	25.0
C65001	Panels/Cubicles, P & C	25.0
C67003	Containment Facility, Concrete	25.0
C67005	Oil Spill Containment	25.0
C68204	Distributed Control System	25.0
C68301	Radio, Microwave, Analog	25.0
C70104	Instrumentation - Digital	25.0
C75104	Compressor, Air	25.0

	Class of Property, Plant and Equipment		F2022 Depreciation Rate (%/year)
50	C75201	Tanks, Steel, Air/Fuel	25.0
51	C75301	Water Supply System	25.0
52	C82504	Loader / Backhoe	25.0
53	C82550	Tools/Work Equipment, Misc	25.1
54	C82551	Tools/Work Equipment, Misc	25.0
55	C82603	Manufacturing/Test Equipment	25.0

The depreciation rates shown in Table 8-2 above, for a given fiscal year, are applied against the net book value of the asset at the beginning of that fiscal year. The methodology used to determine the depreciation rates for fiscal 2022 is consistent with the methodology underlying the depreciation rates approved in the Previous Application. The 25.0 per cent rate shown indicates that BC Hydro expects that the remaining useful life of these assets is four years (i.e., the assets will reach the end of their useful lives at the end of fiscal 2025).

8.2.2 Infrastructure Rights Depreciation Rate for Fiscal 2022

In its Decision on the Previous Application, the BCUC approved the requested depreciation rates for the infrastructure rights asset class for the fiscal 2020 to fiscal 2021 test period only. The BCUC directed BC Hydro to review the expected useful life of infrastructure rights in its upcoming depreciation study and to identify any differences from the requested 35-year useful life in the Revenue Requirements Application immediately following the completion of the depreciation study.[226] As BC Hydro will file the depreciation study with the Fiscal 2023 Revenue Requirements Application, BC Hydro is seeking approval to amortize the assets within the infrastructure rights asset class over a 35-year useful life in fiscal 2022, consistent with the treatment approved for fiscal 2020 and fiscal 2021.

226 BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 57.

8.3 Return on Equity

BC Hydro's return on equity is no longer prescribed by Direction No. 8. BC Hydro plans to file a cost of capital application in fiscal 2022 to recommend an appropriate return on equity. Until a return on equity is set, BC Hydro continues to forecast its return on equity to collect sufficient revenue to achieve an annual rate of return on deemed equity to yield a distributable surplus of $712 million for fiscal 2022 based on 30 per cent deemed equity, as prescribed by section 3 of Direction No. 8 for fiscal 2020 and fiscal 2021.

The calculation of BC Hydro's return on equity for the Test Period is set out in Appendix A, Schedule 9.

BC Hydro's dividend payment to the Province is prescribed by Heritage Special Directive No. HC1. In accordance with Order in Council No. 095 issued on March 5, 2014, for fiscal 2018 and subsequent years, the payment to the Province was reduced by $100 million per year based on the payment in the immediately preceding fiscal year until it reached zero and will remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.

There was no dividend payment to the Province for fiscal 2020. As shown on Appendix A, Schedule 9, line 4, BC Hydro's forecast dividend payment to the Province is zero in each of fiscal 2021 and fiscal 2022 as BC Hydro's forecast debt to equity ratio is 80:20 in fiscal 2021 and 79:21 in fiscal 2022. BC Hydro's debt to equity ratio is shown on Appendix A, Schedule 9, lines 19 and 20.

8.4 Finance Charges

BC Hydro's approach to finance charges is consistent with the Previous Application.

Finance charges are primarily comprised of interest charges on BC Hydro's debt. In addition, finance charges include interest related to leases recognized as lease obligations under IFRS 16, *Leases* and non-current pension costs. Total finance charges are calculated net of sinking fund income, finance charges capitalized to unfinished construction (interest during construction) and interest applied to regulatory accounts.

BC Hydro's long-term debt is comprised of bonds and revolving borrowings obtained under agreement with the Government of B.C. BC Hydro's debt is either held or guaranteed by the Government of B.C.

BC Hydro uses financial instruments, principally interest rate and foreign currency swaps, to manage interest rate and foreign exchange risks related to existing debt and forecast future debt issuances.

In accordance with BCUC Order No. G-42-16, mark-to-market gains and losses related to interest rate hedges of future debt are captured in the Debt Management Regulatory Account and are amortized over the term of the associated long-term debt issuances beginning in the test period subsequent to that in which the associated debt is issued, as shown on Appendix A, Schedule 2.2. Further information regarding the Debt Management Regulatory Account is provided in Appendix U, section 7.8.13 and in the Fiscal 2020 Debt Management Regulatory Account Annual Status Report (Appendix V).

To forecast finance charges, BC Hydro uses a number of external market inputs and economic forecasts related to short and long-term interest rates and foreign exchange rates. This is consistent with the approach in the Previous Application.

Finance charges for debt are forecast as follows:

- For existing debt, BC Hydro forecasts finance charges based on the actual cost of the debt;
- For debt that will be issued in the future that is unhedged, BC Hydro forecasts finance charges based on economic forecasts that are developed and provided by the Treasury Board of the Government of B.C. The most recent economic forecasts available at the time the finance charges forecast was prepared for the Application were as of July 2020 as shown in Table 8-3 below; and
- For debt that will be issued in the future and has already been hedged, BC Hydro forecasts finance charges based on the current market forward rates at the time the forecast is prepared. Mark-to-market gains or losses on the hedges are recorded in the Debt Management Regulatory Account.

Table 8-3 below shows the forecast interest rates for unhedged debt and the forecast foreign exchange rate for fiscal 2022 provided by the Treasury Board of the Government of B.C.

Table 8-3 Forecast Interest Rates for Unhedged Debt and Forecast Foreign Exchange Rate

	F2022 Plan
Canadian Short-term Interest Rate (%)	0.39
U.S. Short-term Interest Rate (%)	0.48
Canadian Long-term Interest Rate (%) – 10-year	1.91
U.S. Long-term Interest Rate (%)	1.97
US$/C$ Exchange Rate	0.7517

Source: Treasury Board Forecast, July 2020.

Forecast finance charges are shown on Appendix A, Schedule 8.0 and are summarized in Table 8-4 below.

Table 8-4 Finance Charges

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	Total Gross Finance Charges	8.0 L1	874.9	1,656.8	743.3	951.5	555.6
2	Total Finance Charge Reg. Acct Additions	8.0 L21	0.0	(0.9)	0.0	76.6	0.0
3	Other Regulatory Account Additions	8.0 L3-L8+L22	(119.8)	(803.1)	(18.6)	(201.8)	(11.9)
4	Interest on Regulatory Accounts	8.0 L25	(17.7)	(16.7)	(26.0)	(22.3)	(24.3)
5	Regulatory Account Recoveries	8.0 L31	(1.7)	(100.3)	(2.8)	(108.3)	(65.2)
6	Total Current Finance Charges	8.0 L32	735.8	735.8	696.0	695.6	454.2

As shown in the table above, total current finance charges are forecast to decrease from $696 million in the fiscal 2021 RRA Plan to $454 million in fiscal 2022, primarily due to lower planned gross finance charges driven by lower interest rates.

8.5 Taxes

Taxes include school taxes and grants-in-lieu of general taxes.

Consistent with the Previous Application:

- The *Hydro and Power Authority Act* exempts BC Hydro from all property taxes other than those levied in respect of schools. School taxes are based on the assessed value of taxable assets as prepared by B.C. Assessment and tax rates that are established by the Province of British Columbia.
- The *Hydro and Power Authority Act* authorizes BC Hydro to pay grants-in-lieu of general municipal, regional district and local improvement taxes. Order in Council No. 266/2016 and Order in Council No. 533/2017 set out the formula used to calculate the grant payments.

Forecast school taxes and grants-in-lieu are shown on Appendix A, Schedule 6.0 and are summarized in the table below.

Table 8-5 Taxes

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	Grants in Lieu	6.0 L15	110.8	111.3	114.8	115.7	118.0
2	School Taxes	6.0 L16	138.3	137.5	146.8	138.3	145.0
3	Other	6.0 L17+L18+L20	0.6	0.9	0.6	0.8	0.8
4	Total Gross Taxes	6.0 L21	249.8	249.7	262.2	254.8	263.8
5	Transfer to NHDA	6.0 L22	0.0	0.0	0.0	0.0	0.0
6	Total Current Taxes	6.0 L23	249.8	249.7	262.2	254.8	263.8

As shown in the table above, total planned taxes for fiscal 2022 are relatively consistent with those in the fiscal 2021 RRA Plan.

8.6 Miscellaneous Revenues

Consistent with the Previous Application, miscellaneous revenues include revenues from amortization of contributions in aid of construction, lease and other revenues related to BC Hydro’s purchase of the remaining two-thirds interest in the Waneta Dam from Teck Metals Ltd., external transmission revenues under the Open Access Transmission Tariff (**OATT**), meter/transformer rentals and power factor surcharges, late payment charges, building rentals, interconnections, Customer Crisis Fund rate rider revenues, and other revenues.

Forecast miscellaneous revenues for the Test Period are shown on Appendix A, Schedule 15.0 and are summarized in Table 8-6 below.

Table 8-6 Miscellaneous Revenues

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	Total Gross Miscellaneous Revenue	15.0 L39	240.6	247.3	247.0	243.7	255.4
2	Transfers to NHDA	15.0 L40	(3.1)	(1.3)	(3.5)	(3.5)	(15.5)
3	Transfers to Regulatory Accounts	15.0 L41	0.0	0.0	0.0	0.0	0.0
4	Total Current Miscellaneous Revenue	15.0 L42	237.5	246.0	243.6	240.2	239.9

As shown in the table above, total planned miscellaneous revenues for fiscal 2022 are relatively consistent with the fiscal 2021 RRA Plan.

8.7 Inter-Segment Revenues

Consistent with the Previous Application, Inter-Segment revenues include the following allocations:

- The allocation of business support costs to Powerex as discussed in section 8.9;
- The allocation of point-to-point transmission costs to Powerex under the 2020 Transfer Pricing Agreement between BC Hydro and Powerex; and
- The allocation of point-to-point transmission costs to BC Hydro under the 2020 Transfer Pricing Agreement between BC Hydro and Powerex.

Forecast Inter-Segment revenues for the Test Period are shown on Appendix A, Schedule 3.0 and are provided in Table 8-7 below.

Table 8-7 Inter-Segment Revenues

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	Powerex - Corporate Allocation	3.0 L57	(2.9)	(2.9)	(2.9)	(2.9)	(2.9)
2	Mark to Market Losses (Gains)	3.0 L58	(1.4)	0.8	0.0	(9.3)	0.0
3	Powerex PTP Charges	3.0 L59	(41.5)	(49.8)	(34.0)	(21.3)	(34.4)
4	BC Hydro PTP Charges	3.0 L60	(19.1)	(20.1)	(35.0)	(63.8)	(46.3)
5	Total Current Inter-Segment Revenues	3.0 L61	(64.9)	(72.0)	(71.9)	(97.4)	(83.5)

As shown in the table above, total planned Inter-Segment revenues for fiscal 2022 are forecast to increase by approximately $12 million compared to the fiscal 2021 RRA Plan due to higher planned point-to-point charges. The increase in point-to-point transmission charges is due to the increase in the point-to-point transmission service rate under the OATT and higher transmission reservations.

8.8 Subsidiary Net Income

Subsidiary net income includes Trade Income[227] for Powerex Corp. (**Powerex**) and the net income of Powertech Labs (**Powertech**).

The inclusion of subsidiary net income in BC Hydro's revenue requirements reduces the overall revenue requirements.

BC Hydro's approach to forecasting Trade Income is unchanged from the Previous Application. In the Test Period, Trade Income is forecast at $190.1 million in fiscal 2022 (net of BC Hydro's allocation of business support costs as described in section 8.9), and is calculated based on an average of actual Trade Income over the last five years (i.e., fiscal years 2016 through 2020).

Forecast subsidiary net income for the Test Period is shown on Appendix A, Schedule 3.0 and is provided in Table 8-8 below.

Table 8-8 Subsidiary Net Income

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	Powerex Trade Income	1.0 L18	(176.3)	(189.2)	(176.3)	(176.2)	(190.1)
2	Powertech Net Income	1.0 L19	(3.4)	(3.4)	(3.7)	0.0	(2.0)
3	Total Gross Subsidiary Net Income	1.0 L20	(179.7)	(192.7)	(179.9)	(176.2)	(192.1)
4	Deferral Account Additions	2.1 L17	0.0	68.7	0.0	0.0	0.0
5	Deferral Account Recoveries	2.1 L19	(159.5)	(164.2)	(109.8)	(109.8)	0.0
6	Total Current Subsidiary Net Income	3.0 L65+L66	(339.2)	(288.2)	(289.7)	(286.0)	(192.1)

As shown in the table above, total gross subsidiary net income (i.e., line 3 above) is forecast to increase by approximately $12 million in fiscal 2022 compared to the fiscal 2021 RRA Plan primarily due to an increase in the five-year average that is used to forecast Trade Income. As the DARR is proposed to be set at 0 per cent for fiscal 2022, deferral account recoveries are zero for fiscal 2022 (i.e., line 5 above), resulting in a decrease in total current subsidiary net income (i.e., line 6 above).

227 Trade Income is the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of BC Hydro's subsidiaries except Powerex, less the amount that BC Hydro's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero.

Variances between forecast and actual Trade Income are deferred to the Trade Income Deferral Account in accordance with BCUC Order No. G-96-04. However, if actual Trade Income in a given fiscal year is less than zero (i.e., a net loss), the transfer to the Trade Income Deferral Account would be the difference between the forecast Trade Income and zero. This means that a net loss in Trade Income would be borne by the Government of B.C. as BC Hydro's shareholder and therefore ratepayers do not bear the risk of losses in Trade Income.

In its Decision on the Previous Application, the BCUC directed that no actual Powerex net income be captured in the Trade Income Deferral Account absent further review and approval by the BCUC.[228] On December 1, 2020, BC Hydro filed a reconsideration application in response to this directive.[229] In the reconsideration application, BC Hydro requests that the BCUC rescind and vary its directive so that BC Hydro can continue to record variances between forecast and actual Trade Income in the Trade Income Deferral Account and make a proposal for the disposition of any balance in the account from the fiscal 2020 to fiscal 2021 test period in this application.[230] For further information on BC Hydro's proposal, refer to Chapter 7, section 7.2.1.1.

8.9 Allocation of Business Support Costs

Consistent with the Previous Application, for the purpose of determining the Transmission Revenue Requirement (as described in Chapter 9), BC Hydro's business support costs are allocated to generation, transmission, distribution, and customer care functions.

228 BCUC Decision and Order No. G-247-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), Directive 17.

229 Application to Reconsider and Vary Directives Relating to Powerex Net Income in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Decision (December 1, 2020).

230 Application to Reconsider and Vary Directives Relating to Powerex Net Income in the Fiscal 2020 to Fiscal 2021 Revenue Requirements Decision (December 1, 2020), page 6.

Business support costs are expenditures that are required to support BC Hydro’s Plan, Build, and Operate work functions. These are the costs related to BC Hydro’s Support work function (e.g., finance, technology, human resources, communications, regulatory, safety, legal, etc.) and reside in several business groups across the company.

The forecast allocation of business support costs is shown on Appendix A, Schedule 3.1 and are summarized in the table below.

Table 8-9 Allocation of Business Support Costs

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	Business Support Costs		(714.7)	(728.3)	(742.8)	(740.0)	(855.4)
2	Allocation to functional groups:						
3	Generation	3.1 L50	187.8	191.7	198.5	197.3	228.8
4	Transmission	3.1 L51	203.3	207.2	209.9	207.0	248.6
5	Distribution	3.1 L52	247.7	251.9	255.3	257.2	308.2
6	Customer Care	3.1 L53	73.0	74.6	76.2	75.7	66.9
7	Total Allocated Costs	3.1 L54	711.8	725.4	739.9	737.1	852.5
8	Powerex	3.1 L15	2.9	2.9	2.9	2.9	2.9
9	Allocation of Business Support Costs		714.7	728.3	742.8	740.0	855.4
10	Business Support Costs Fully Allocated		0.0	0.0	0.0	0.0	0.0

As shown in the table above, business support costs are forecast to increase by approximately $113 million in fiscal 2022 compared to the fiscal 2021 RRA Plan. The forecast increase is primarily due to: (i) an increase in fiscal 2022 operating costs related to reliability investments, uncontrollable cost increases and other cost pressures as described in Chapter 5; (ii) IFRS ineligible capital overhead costs that are being phased into operating costs over a ten-year period (the final year being fiscal 2022); and (iii) an increase in the amortization of the Non-Current Pension Costs Regulatory Account. BC Hydro has allocated $2.9 million of business support costs to Powerex for fiscal 2022, in accordance with Directive 9 of the BCUC’s Decision on our Fiscal 2009 to Fiscal 2010 Revenue Requirements Application.

8.10 Provisions and Other

"Provisions and Other" includes gains and losses on capital assets, dismantling costs, provision expenses and other costs that are not within the scope of other Nature View[231] expense items on BC Hydro's financial statements.

Gains and losses on capital assets include mass asset retirements and capital asset write-offs.

Forecast provisions and other are shown on Appendix A, Schedule 5.01 and are also summarized in the table below.

Table 8-10 Provisions and Other

	($ million)	Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	Total Gross Provisions & Other	5.01 L43	116.4	176.8	95.4	197.9	101.4
2	Deferral Account Additions	5.01 L34	0.0	0.0	0.0	0.0	0.0
3	Regulatory Account Transfers	5.01 L42	0.0	(48.0)	0.0	(102.2)	0.0
	Regulatory Account Recoveries						
4	Remediation, Dismantling and Other	5.01 L17:L24	46.3	46.3	43.3	43.3	63.9
5	Total Current Provisions & Other	5.01 L26	162.6	175.0	138.7	138.9	165.3

As shown in the table above, provisions and other are forecast to increase by approximately $27 million compared to the fiscal 2021 RRA Plan primarily due to higher regulatory account recoveries in the Remediation Regulatory Account and in the Project Write-off Costs Regulatory Account. These increases in recoveries were partially offset by lower regulatory account recoveries in the Dismantling Cost Regulatory Account. In addition, the refund of the credit balance in the Rock Bay Remediation Regulatory Account was completed in fiscal 2021.

[231] Under the Nature View presentation, costs are classified by their nature (i.e., labour, materials, services, energy purchases, water rentals, amortization, etc.), rather than by their function.

8.11 International Financial Reporting Standards (IFRS)

BC Hydro prepares its financial statements in accordance with IFRS including IFRS 14, *Regulatory Deferral Accounts*, and has prepared this application in accordance with IFRS in effect at the time the forecast for this application was prepared.

In the Application, there were no new accounting standards adopted by BC Hydro or significant changes to accounting standards that would impact the Test Period.

BC Hydro
Power smart

BC Hydro Fiscal 2022
Revenue Requirements Application

Chapter 9

Transmission Revenue Requirement

Table of Contents

List of Figures

List of Tables

9.1 Introduction

This chapter describes how BC Hydro's proposed Open Access Transmission Tariff (**OATT**) rates are determined to recover BC Hydro's Transmission Revenue Requirement (**TRR**), consistent with past BCUC Orders. The OATT commercializes BC Hydro's transmission capacity and facilitates participation in the electric industry by entities that may not own their own transmission systems. The OATT contains BCUC-approved terms and conditions through which OATT customers are provided with access to BC Hydro's transmission sytem on a comparable basis to that of electric utilities throughout the Western Interconnection. The OATT rates are the prices for transmission services purchased from BC Hydro and are applicable to all usage of the transmission system, including usage by BC Hydro itself and by external OATT customers. OATT customers are able to reserve transmission capacity on the transmission system, which they can use to schedule their energy requirements. The OATT considers only the commercialization of transmission capacity and BC Hydro does not sell energy through the OATT except for some ancillary services.

The rates charged under the OATT are for Network Integration Transmission Service (**NITS**), Point-To-Point (**PTP**) Transmission Service and Ancillary Services, as set out in Appendix Y and summarized in Table 9-4. BC Hydro and Powerex are the main users of the transmission system and therefore account for approximately 99 per cent of the revenue collected through the OATT (forecast to be $1,067.5 million for fiscal 2022). Other transmission customers account for only approximately 1 per cent of the revenue (forecast to be $11.1 million forecast for fiscal 2022). The OATT therefore recovers a small fraction of the TRR from external customers. This amount is forecast to be lower in fiscal 2022 than in previous revenue requirements applications since a long-term contract of 50 MW is ending on January 1, 2021 and there is uncertainty whether this capacity will purchased by another cutomer. Accordingly, this 50 MW is not included in the forecast for fiscal 2022.

The rates charged under the OATT are designed to collect the TRR, which is the sum of all costs associated with the assets used to provide transmission service under the OATT, and for which OATT customers are responsible according to the principle of cost causation. The cost causation methodology used by BC Hydro to calculate the TRR in the Application is consistent with the method used by both BC Hydro and the British Columbia Transmission Corporation (**BCTC**) in previous revenue requirement applications, which has been consistently applied and approved by the BCUC.

This chapter is organized around the following key points:

- Section 9.2 describes how the TRR is determined through the direct assignment or allocation of transmission-related costs to the transmission function, based on cost causation principles and consistent with past practice;
- Section 9.3 describes how the OATT rates are calculated consistent with past practice and past BCUC Orders; and
- Section 9.4 explains why a comprehensive review of the OATT rate design would not add value at this time.

9.2 Transmission Revenue Requirements are Calculated using a Cost Causation Allocation Methodology Consistent with Past Practice

BC Hydro's TRR is comprised of the current costs associated with BC Hydro's transmission lines and high-voltage station equipment used to provide transmission service pursuant to the OATT (**OATT-Related Assets**), which excludes both generation related transmission assets and substation distribution assets. The methodology used to derive the TRR is based on cost causation and is consistent with the methodology used in the past by BC Hydro and BCTC.

Figure 9-1 illustrates the allocation and direct assignment of costs to establish the proposed OATT rates for fiscal 2022.

Figure 9-1 Fiscal 2022 Transmission Revenue Requirement Components ($ million) with References to Appendix A Financial Schedules

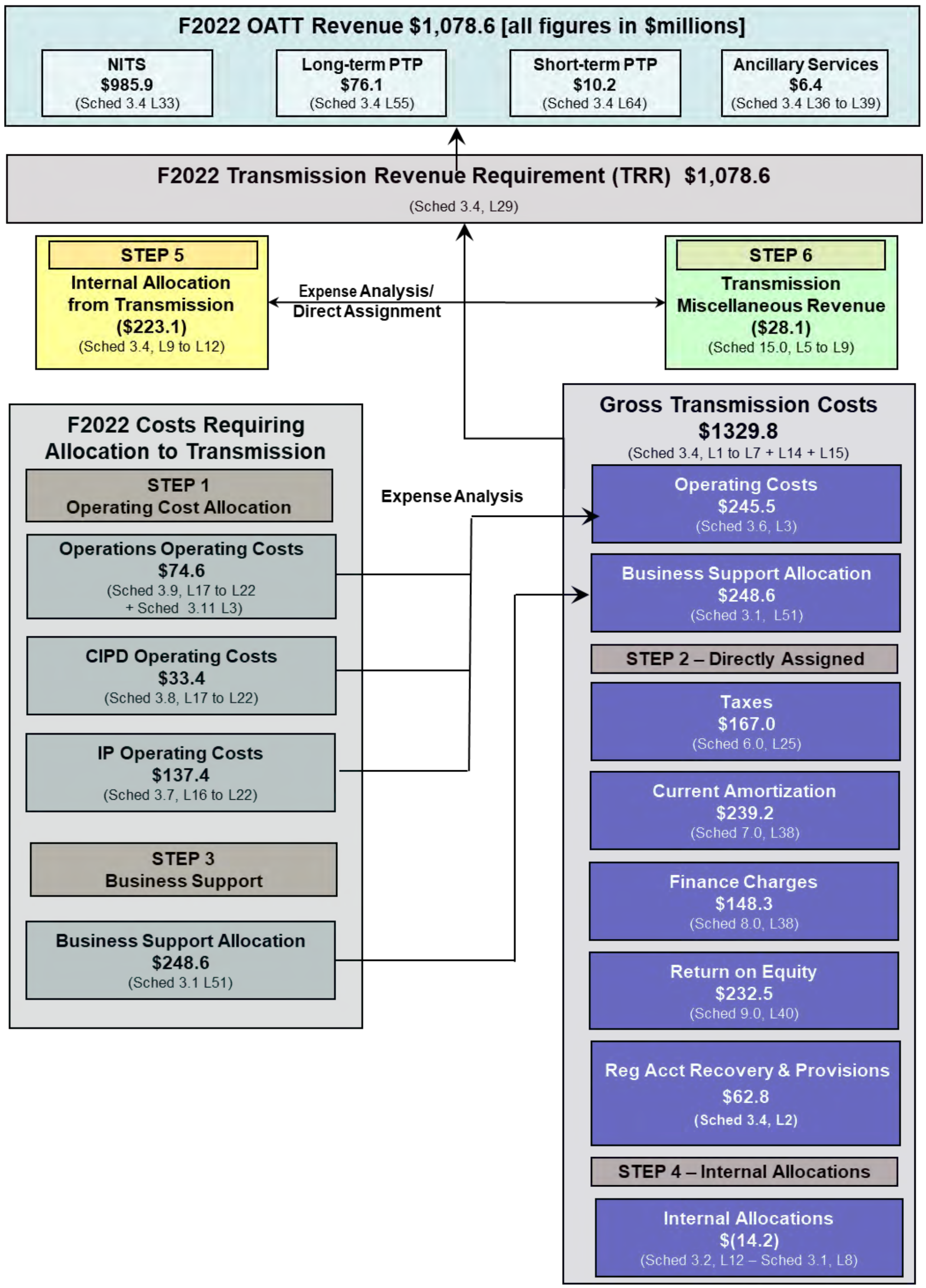


Table 9-1 below sets out the cost components that make up the TRR from fiscal 2020 through fiscal 2022. The fiscal 2020 and fiscal 2021 approved amounts represent the approved amounts from the Previous Application, as reflected in the OATT rate schedules included in BC Hydro's Compliance Filing to the Previous Application.

Table 9-1 Transmission Revenue Requirement

		F2020 RRA ($ million)	F2020 Actual ($ million)	F2021 RRA ($ million)	F2021 Forecast ($ million)	F2022 Plan ($ million)
		1	2	3	4	5
1	Operating Cost	219.4	206.4	220.5	226.2	245.5
2	Provisions and Other	33.8	48.7	37.3	37.8	62.8
3	Taxes	157.6	158.4	163.7	163.1	167.0
4	Amortization	233.5	234.4	236.1	233.9	239.2
5	Finance Charges	243.9	243.0	227.6	226.8	148.3
6	Allowed Net Income	236.1	232.8	232.9	225.2	232.5
7	Business Support Cost	203.3	207.2	210.0	207.0	248.6
8	Internal Allocations to Transmission					
9	Generation Ancillary Services	2.8	2.1	2.8	2.8	2.5
10	Transmission Capitalized Overhead	(16.1)	(16.1)	(16.3)	(15.6)	(16.6)
11	Gross Transmission Costs	1,314.4	13116.8	1,314.7	1,307.2	1,329.8
12	Less Internal Allocations from Transmission					
13	Generation Related Transmission Assets	(43.3)	(43.3)	(43.3)	(43.3)	(43.3)
14	Generation Real Time Dispatch	(2.4)	(2.4)	(2.4)	(2.4)	(3.1)
15	Distribution Real Time Dispatch	(20.6)	(20.8)	(21.0)	(20.9)	(26.3)
16	Substation Distribution Assets	(125.6)	(127.0)	(127.4)	(145.8)	(150.4)
17	Less Miscellaneous Revenues					
18	FortisBC Inc. General Wheeling Agreement	(5.2)	(5.2)	(5.3)	(5.3)	(5.3)
19	Secondary Revenues	(6.0)	(7.1)	(6.2)	(6.9)	(7.1)
20	Interconnections	(2.2)	(6.4)	(2.2)	(4.6)	(2.3)
21	Amortization of Contributions	(14.6)	(14.6)	(15.0)	(14.8)	(11.0)
22	NTL Supplemental Charges	(2.3)	(2.3)	(2.3)	(2.4)	(2.4)
23	Subtotal	(222.1)	(229.1)	(225.0)	(246.2)	(251.2)
24	Transmission Revenue Requirement	1,092.3	1,087.7	1,089.6	1,061.0	1,078.6

As shown in Table 9-1, the TRR decreases by 1 per cent from fiscal 2021 RRA to the fiscal 2022 plan.

The allocation or direct assignment of the components of the TRR is discussed in the six steps discussed below. These have also been shown on Figure 9-1 above.

9.2.1 Step One: Direct Assignment and Allocation of Operating Costs and Provisions to Gross Transmission

Consistent with past practice, the first step in the cost allocation methodology to derive the TRR is to directly assign or allocate current operating costs and provisions to the transmission function based on cost causation. The result of this step is shown in line 1 of Table 9-1 above.

9.2.1.1 Identification of Business Groups and Functional Activities

First, BC Hydro identifies the business groups currently carrying out transmission functions, which are as follows:

1. Integrated Planning Business Group;
2. Capital Infrastructure Project Delivery Business Group;
3. Operations Business Group; and
4. Finance, Technology, Supply Chain Business Group.

BC Hydro then determines the relevant functional activity of each Key Business Unit (**KBU**) within the Business Groups. The functional activities performed by the relevant Business Groups are shown in Table 9-2 below. A summary of key changes to BC Hydro's Organizational Structure since the Previous Application is provided in Chapter 5, section 5.3.

Table 9-2 KBU Functional Activities

1	**Generation Function:**	
	(i)	Generation Real-time Dispatch
	(ii)	Generation Related Transmission Assets
	(iii)	Generation Other
2	**Transmission Function:**	
	(i)	Scheduling, System Control and Dispatch Service (OATT Rate Schedule 03)
	(ii)	Transmission Other
3	**Distribution Function:**	
	(i)	Substation Distribution Assets
	(ii)	Distribution Real-time Dispatch
	(iii)	Distribution Other

9.2.1.2 Methodologies for Allocating Costs to Functional Activities

Where possible, costs are directly assigned to one of the functional activities shown in Table 9-2 above. Where direct assignment is not possible, costs are allocated to the functional activities, using one or more of the following parameters to develop allocation factors:

(i) Planned expenditures for maintenance and/or capital programs that are representative of the work a KBU expects to undertake during the Test Period;

(ii) Historical expenditures for work performed by a KBU;

(iii) Work performed by Full-Time Equivalents (**FTEs**) within a KBU;

(iv) Manager and financial analyst interviews; and

(v) Direct allocation of certain specific activity costs.

In most cases, functionalization at the Director and Vice President levels is based on a roll-up of the overall allocation of the Departments or KBUs for which they are responsible.

Functionalization for provisions and other is based on an analysis of related current and historical capital programs.

Table 9-3 below summarizes the allocation approach used for each KBU or Department in the Integrated Planning, Capital Infrastructure Project Delivery, Operations, and Finance, Technology, Supply Chain Business Groups.

Table 9-3 Allocation of Costs to Functional Activities

KBU/Department	Basis of Allocation to Functional Activities
Integrated Planning Business Group	
Engineering Design	Direct assignment, capital programs and manager interviews
Engineering Services	Direct assignment, capital programs and manager interviews
Energy Planning and Analytics	Direct assignment and manager interviews
Dam Safety	Direct assignment to generation function
Line Asset Planning	Direct assignment, maintenance and capital programs, and manager interviews
Stations Asset Planning	Direct assignment, maintenance and capital programs, and manager interviews
Interconnections and Shared Assets	Direct assignment and manager interviews
Business Unit Support	Direct assignment roll-up of overall allocation
Capital Infrastructure Project Delivery Business Group	
Project Delivery	Capital programs managed by the Project Delivery KBU and manager interviews
Indigenous Relations	Activity analysis and manager interviews
Environment	Direct assignment and manager interviews
Properties	Direct assignment and manager interviews
Business Unit Support	Direct assignment roll-up of overall allocation
Operations Business Group	
Line Field Operations	Direct assignment, maintenance and capital programs, specific activity analysis and manager interviews
Stations Field Operations	Direct assignment, maintenance and capital programs, specific activity analysis, and manager interviews
T&D System Operations	Direct assignment, specific activity analysis, and manager interviews
Generation System Operations	Direct assignment to generation function
Program and Contract Management	Specific activity analysis, maintenance and capital programs, and manager interviews
Distribution Design and Customer Connections	Direct assignment to distribution function
Construction Services	Maintenance and capital programs, specific activity analysis, and manager interviews
Business Support	Direct assignment roll-up of overall allocation

KBU/Department	Basis of Allocation to Functional Activities
Finance, Technology, Supply Chain Business Group	
Materials Management	Manager interviews
Fleet Services	Manager interviews

9.2.1.3 Resulting Portion of Business Groups Assigned to Gross Transmission Operating Costs

As a result of the above analysis, operating costs and provisions were assigned to gross transmission, as shown in line 1 of Table 9-1 and line 1 of Appendix A, Schedule 3.4, as follows:

- 39 per cent of the Integrated Planning Business Group operating costs;
- 28 per cent of the Capital Infrastructure Project Delivery Business Group operating costs;
- 30 per cent of the Operations Business Group operating costs;
- 25 per cent of the Materials Management operating costs; and
- 30 per cent of the Fleet Services operating costs.

Portions of the total costs allocated to gross transmission from the Integrated Planning, Capital Infrastructure Project Delivery and Operations Business Groups are subsequently allocated to generation and distribution, as discussed in section 9.2.5 below.

As shown on lines 1 and 2 of Table 9-1, the current operating costs and provisions allocation to gross transmission have increased by 20 per cent from fiscal 2021 RRA to fiscal 2022 plan. Operating costs are discussed in Chapter 5.

9.2.2 Step Two: Costs Directly Assigned to Gross Transmission

The second step in the cost allocation method is to directly assign taxes, amortization, finance charges and return on equity to gross transmission. As noted below, the portion of these cost that are related to Generation Related Transmission

Assets and Substation Distribution Assets must then be removed through a further allocation process.

9.2.2.1 Provisions and Other

Provisions and regulatory account recoveries are summarized on Schedule 5.01 of Appendix A. The Provisions and Other that are directly assigned to the gross transmission function are shown on line 2 of Appendix A, Schedule 3.4. There has been a 68 per cent increase in the amount of Provisions and Other assigned to Gross Transmsision, largely due to an increase in PCB Remediation regulatory account recoveries. Provisions and Other are discussed in Chapter 8, section 8.10. These costs include Provisions and Other related to Generation Related Transmission Assets and to Substation Distribution Assets. To derive the Provisions and Other specific to the OATT Related Assets, they are further allocated through direct assignment. These allocations of Provisions and Other are included in the internal allocations to Generation Related Transmission Assets and to Substation Distribution Assets on line 9 and line 12 of Appendix A, Schedule 3.4, as discussed in section 9.2.5 below.

9.2.2.2 Taxes

The taxes that are directly assigned to the gross transmission function are shown on line 3 of Appendix A, Schedule 3.4. Taxes that are directly assigned to the gross transmission function also include taxes related to Generation Related Transmission Assets and to Substation Distribution Assets. To derive the taxes specific to the OATT Related Assets, taxes are further allocated through direct assignment and asset analysis. These taxes are included in the internal allocations to Generation Related Transmission Assets and to Substation Distribution Assets on line 9 and line 12 of Appendix A, Schedule 3.4. As shown on line 3 of Table 9-1 and on line 25 of Appendix A Schedule 6.0, there has been a 2 per cent increase in the Taxes allocated to gross transmission from fiscal 2021 RRA to fiscal 2022 plan. Taxes are discussed in Chapter 8, section 8.5.

9.2.2.3 Amortization, Finance Charges and Return on Equity

Amortization, finance charges and return on equity are directly assigned to gross transmission and are shown on lines 4, 5 and 6, respectively, of Appendix A, Schedule 3.4. Amortization, Finance Charges and Return On Equity are discussed in Chapter 8, sections 8.2, 8.4 and 8.3, respectively.

The amortization assigned to gross transmission includes amortization related to Generation Related Transmission Assets, Substation Distribution Assets, and OATT Related Assets, and 5 per cent of demand-side management amortization.[232]. The remaining gross transmission amortization has been allocated to the functional activities using allocation factors derived from asset analysis. As shown on line 4 of Table 9-1 and on line 38 of Appendix A Schedule 7.0, there has been a 1.3 per cent increase in the current amortization cost allocation to gross transmission from fiscal 2021 RRA to fiscal 2022 plan.

The Finance Charges and Return On Equity assigned to gross transmission are allocated to the functional activities shown in Table 9-2 above based on the average rate base for each fiscal year. As shown on line 5 of Table 9-1 and on line 38 of Appendix A Schedule 8.0, there has been a 34.8 per cent decrease in the current Finance Charges allocated to gross transmission from fiscal 2021 RRA to fiscal 2022 plan. As shown on line 6 of Table 9-1 and on line 40 of Appendix A Schedule 9.0, there has been a 0.1 per cent decrease in the Return on Equity allocated to gross transmission from fiscal 2021 RRA to fiscal 2022 plan.

9.2.3 Step Three: Business Support Cost Allocation

The third step is to allocate business support costs. Business support costs are allocated to the generation, transmission and distribution functional activities shown

[232] By Order No. G-47-16, issued on March 31, 2016, the BCUC approved a Cost of Service Study and Rate Class Segmentation Negotiated Settlement Agreement, as part of BC Hydro's 2015 Rate Design Application. In section 8 on page 11 of the Negotiated Settlement Agreement appended to Order No. G-47-16, the negotiating parties agreed it was appropriate to functionalize 5 per cent of DSM costs to transmission, subject to BC Hydro revisiting the functionalization between generation, transmission and distribution in its fiscal 2019 Cost of Service Study.

in Table 9-2 above, using allocation factors derived from activity analysis. The current business support costs assigned to gross transmission are shown on line 7 of Appendix A, Schedule 3.4. As shown on line 7 of Table 9-1 and on line 51 of Appendix A, Schedule 3.1, there has been a 18.4 per cent increase in the current business support cost allocation to gross transmission from fiscal 2021 RRA to fiscal 2022 plan. Business support costs are discussed in Chapter 8, section 8.9.

9.2.4 Step Four: Internal Allocations to Transmission

The fourth step is to allocate other internal costs attributable to transmission. The following costs are also assigned to transmission:

1. Generation operating costs relating to the generation ancillary services that BC Hydro provides to OATT customers, as shown on line 9 of Table 9-1 and on line 14 of Appendix A, Schedule 3.4; and
2. Capitalized Overhead, as shown on and line 10 of Table 9-1 and on line 8 of Appendix A, Schedule 3.1.

These costs are functionalized directly to transmission and are not allocated further through the internal allocations from gross transmission, discussed in section 9.2.5 below.

9.2.5 Step Five: Internal Allocations from Gross Transmission

The fifth step is to make internal allocations from gross transmission, as it is necessary to remove transmission-related costs that are not related to providing service under the OATT and therefore do not belong in the TRR. These allocations are shown on lines 12 to 16 of Table 9-1 and on lines 9 to 12 of Appendix A, Schedule 3.4, and are described below.

9.2.5.1 Generation Related Transmission Asset Allocation

First, BC Hydro's transmission assets related to the generation function are not used to provide service under the OATT and therefore must be removed to calculate the TRR.

By Letter No. L-92-07, the BCUC accepted that a fixed charge of $43.3 million was appropriate for Generation Related Transmission Asset costs, and that re-evaluations of Generation Related Transmission Asset costs were not required.

The $43.3 million internal allocation of Generation Related Transmission Asset costs from the transmission function to the generation function is shown on line 13 of Table 9-1 and on line 9 of Appendix A, Schedule 3.4.

9.2.5.2 Generation Real Time Dispatch

Second, generation real time dispatch costs are not used to provide service under the OATT and therefore must be removed to calculate the TRR.

Generation real time dispatch activities performed by the T&D System Operations KBU include generation control, water conveyance, alarm monitoring, notification and reporting services, data services and Supervisory Control and Data Acquisition system services. These control centre activities support the operation of the generation and transmission systems. Manager interviews were conducted to derive the allocation of the total cost for this activity.

The overall determination of the Real Time Dispatch revenue requirement is required to establish the Scheduling and Dispatch rate for OATT Rate Schedule 03. These costs are assumed to be transmission costs for the purpose of determining the Scheduling and Dispatch rate. A portion is then allocated to generation, representing Generation Real Time Dispatch. The internal allocation of generation real time dispatch costs from the transmission function to generation is shown on line 14 of Table 9-1 of and on line 10 of Appendix A, Schedule 3.4.

9.2.5.3 Distribution Real Time Dispatch

Third, distribution real time dispatch functions are not used to provide service under the OATT and therefore the costs must be removed to calculate the TRR.

Distribution real time dispatch supports the operation of the distribution system, and includes activities performed by the control centre within the T&D System Operations KBU. This activity supports the operation of the distribution system from inside the substation fence, downstream of the high-side of the step down transformer, outside the substation fence, and also supports restoration of the distribution system outages. The cost for distribution real time dispatch includes costs for the restoration centre and an allocation of business support costs assigned to gross transmission and to the T&D System Operations KBU. Manager interviews were conducted to derive the allocation of the total cost for this activity.

Distribution real time dispatch costs are assumed to be transmission costs for the purpose of determining the Scheduling and Dispatch rate. A portion is then allocated to distribution, representing Distribution Real Time Dispatch. The internal allocation of distribution real time dispatch costs from the transmission function to distribution is shown on line 15 of Table 9-1 and on line 11 of Appendix A, Schedule 3.4.

9.2.5.4 Substation Distribution Assets Allocation

Fourth, Substation Distribution Assets are also not used to provide service under the OATT and therefore must be removed to calculate the TRR.

All substation assets, including distribution specific substation assets, are recorded as transmission property. Substations with both transmission and distribution functions include assets common to both functions, such as buildings and fences as well as heating, ventilation and air conditioning equipment.

The Substation Distribution Assets allocation is necessary to transfer the distribution-related portion of the substation costs, including an allocation of common assets, to the distribution function. To determine an appropriate share of gross transmission costs to allocate to Substation Distribution Assets, allocation factors are determined using asset analysis, maintenance, capital expenditures, manager interviews and direct assignment. The costs allocated to the Substation Distribution Asset functional activity include operating costs, capital related expenses, taxes and business support costs.

The internal allocation of Substation Distribution Asset costs from gross transmission to distribution is shown on line 16 of Table 9-1 and on line 12 of Appendix A, Schedule 3.4.

9.2.6 Step Six: Transmission Miscellaneous Revenue Allocated to the TRR

Miscellaneous revenues directly attributed to the OATT-Related Assets are directly assigned to the TRR, and serve as an offset to TRR costs.

The miscellaneous revenue functionalized to transmission is shown on lines 18 to 23 of Table 9-1 and on line 8 of Appendix A, Schedule 3.4.

Miscellaneous revenue continues to be directly assigned to the transmission function, as shown on lines 4 to 9 of Appendix A, Schedule 15.0.

9.2.6.1 FortisBC Inc. General Wheeling Agreement

Wheeling is the transportation of electricity from one utility's service area to another's. Wheeling revenue is collected from FortisBC Inc. in accordance with the General Wheeling Agreement. The charges for the wheeling of electricity from the Point of Supply to the Creston, Okanagan and Princeton Points of Interconnection are set out in BC Hydro’s Rate Schedule 3817. In accordance with the General Wheeling Agreement, the forecast of wheeling revenue for the Test Period reflects annual rate increases equal to the forecast increases in the Consumer Price Index and expected increases in volumes, based on the nomination provided by FortisBC Inc.

The forecast of wheeling revenue from FortisBC Inc. is shown on line 18 of Table 9-1 and on line 5 of Appendix A, Schedule 15.0.

9.2.6.2 Secondary Revenue

Secondary revenue is revenue received from other parties for the non-electric use of transmission assets, such as facility and digital communications site rentals.

The forecast of secondary revenue is shown on line 19 of Table 9-1 and on line 6 of Appendix A, Schedule 15.0.

9.2.6.3 Interconnection Revenue

Interconnection revenue consists of payments for engineering studies done by BC Hydro for generator and load interconnection customers connecting to the transmission system. Under the OATT, BC Hydro conducts engineering studies for customers requesting service, and the customers pay for the engineering studies.

The forecast of transmission interconnection revenue is shown on line 20 of Table 9-1 and on line 7 of Appendix A, Schedule 15.0.

9.2.6.4 Amortization of Contributions

Amortization of Contributions revenue relates to contributions from external parties toward the construction of capital assets.

The forecast of Amortization of Contributions revenue is shown on line 21 of Table 9-1 and on line 8 of Appendix A, Schedule 15.0.

9.2.6.5 Northwest Transmission Line Supplemental Charge

The costs to construct the Northwest Transmission Line are recovered from customers taking service on the line, in accordance with Electric Tariff Supplement No. 37. As the capitalized costs of the Northwest Transmission Line are a component of the gross transmission costs, they are offset by the amortized contributions from customers connected to the line.

The forecast Northwest Transmission Line Supplemental Charge revenue is shown on line 22 of Table 9-1 and on line 9 of Appendix A, Schedule 15.0.

9.3 OATT Rates are Set to Recover Transmission Revenue Requirements Consistent with Past Orders

9.3.1 Proposed OATT Rates

BC Hydro's calculation of its proposed OATT rates is consistent with the cost causation rate design of the OATT rates as originally approved by BCUC through Order No. G-43-98, and subsequently confirmed or altered through multiple OATT proceedings, including the comprehensive applications and regulatory processes resulting in Orders Nos. G-58-05, G-127-06 and G-102-09.

Table 9-4 summarizes the proposed OATT rates.

Table 9-4 Proposed OATT Rates Fiscal 2022

	Rate Schedule	Rate Class	Reference	F2022 Plan
1	Attachment H	NITS Revenue Requirement ($)	Schedule 3.4 L33	985,900,800
2	RS 00	NITS Monthly Rate ($)	Schedule 3.4 L34	82,158,400
3	RS 01	Long Term Firm Point-to-Point		
4		Yearly - $/MW of Reserved Capacity per year	Schedule 3.4 L42	78,862
5		Short Term Firm and Non-Firm Maximum Price for Delivery		
6		Monthly - $/MW of Reserved Capacity per month	Schedule 3.4 L43	6,571.79
7		Weekly - $/MW of Reserved Capacity per week	Schedule 3.4 L44	1,516.57
8		Daily - $/MW of Reserved Capacity per day	Schedule 3.4 L45	216.06
9		Hourly - $/MW of Reserved Capacity per hour	Schedule 3.4 L46	9.00
10	RS 03	Scheduling, System Control and Dispatch Service ($)		
11		per MW of Reserved Capacity per hour	Schedule 3.4 L49	0.155

The NITS rate increases by 2.2 per cent from fiscal 2021 RRA to fiscal 2022 plan, due to the TRR remaining essentially constant but the recovery through PTP transmission service sales decreasing. There is a 3.3 per cent decrease in the long-term PTP rate between fiscal 2021 RRA and fiscal 2022 plan. This is due to a stable TRR and a 2.4 per cent increase in the maximum capacity supply billing determinant, which is the denominator for calculating the PTP rate, as discussed below. The Scheduling and Dispatch Ancillary Services fee increases by 11.5 per cent as a result of a reduction to the volume of scheduling in the fiscal 2022 plan.

9.3.2 Calculation of OATT Rates

Once the TRR is known, BC Hydro's OATT rates can be calculated in the following steps:

- The revenue from Ancillary Services under the OATT is forecast based on forecast volumes of NITS and PTP transmission service;
- The PTP transmission service rate is calculated based on the TRR minus the Ancillary Service revenue divided by the Maximum Supply Capacity;
- The PTP revenue forecast is calculated based on the PTP rate and forecast volumes of PTP transmission service; and
- The monthly NITS rate is calculated based on the TRR minus Ancillary Services and PTP revenue, divided by 12 months.

Each of the above steps is described in the subsections below.

9.3.3 Calculation of Ancillary Services Revenue

Ancillary Services are needed with transmission service to maintain the reliability of the interconnected transmission system. Of the Ancillary services, only the Scheduling, System Control and Dispatch Rate is updated along with the TRR and is designed to recover the cost of provision of these scheduling services for the forecast transmission service to be sold under the OATT during the test period.

9.3.3.1 Calculation of the Scheduling, System Control and Dispatch Rate

Scheduling, System Control and Dispatch services include:

- Pre-scheduling, Settlements and Billing - transactional processing through market operation and business systems to ensure accurate transmission schedules are confirmed for customers, followed by timely invoicing, accounting and performance reporting;
- Revenue Reporting and Forecasting - providing monthly and annual revenue reports for OATT services and provision of the historical information and forecasts for future years, as required for determination of revenue requirements and rate setting; and
- Real-Time Scheduling - managing the transmission reservations and energy schedules in real-time. Interchange Operators coordinate with Bonneville Power Administration and the Alberta Electric System Operator at least every hour to match schedules and reach a net interchange schedule which is incorporated into the Automatic Generation Control system to maintain energy balance.

The Scheduling, System Control and Dispatch rate is a volume-driven rate, calculated as the total cost for Scheduling, System Control and Dispatch, divided by the total forecasted volumes for NITS, long-term PTP and short-term PTP services.

The derivation of the Scheduling, System Control and Dispatch rate is shown in Table 9-5 below. As shown, the scheduling fee on line 8 is calculated by dividing the cost to provide this service on line 7 by the forecast total volume on line 6.

1 **Table 9-5 Calculation of Scheduling, System Control and Dispatch Rate**

		Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	**PTP Volumes (MWh)**						
2	Long-Term PTP	Schedule 3.4 L52	9,881,280	10,120,632	9,881,280	9,286,728	8,453,400
3	Short Term PTP	Schedule 3.4 L61	9,939,991	4,017,483	10,324,607	4,347,966	4,087,966
4	**Total PTP Volumes**		19,821,271	14,138,115	20,205,887	13,634,694	12,541,366
5	NITS and Secondary Transmission		9,566,902	12,954,763	9,566,902	12,954,763	12,954,763
6	**Total Volumes**	**Schedule 3.4 L48**	29,388,173	27,092,878	29,772,789	26,589,457	25,496,129
7	**Scheduling, Control and Dispatch Cost ($ million)**	Schedule 3.4 L47	4.1	3.6	4.1	4.0	4.0
8	**Scheduling Fee[233] ($/MWh)**	**(L47/L48) =Schedule 3.4 L49**	0.138	0.133	0.139	0.152	0.155

233 Scheduling, System Control and Dispatch rate.

9.3.3.2 Other Ancillary Services

BC Hydro provides ancillary generation services for OATT customers. Other ancillary services include energy imbalance service, loss compensation service, spinning and supplemental operating reserve services, and reactive power service. The rates for these services are not tied to the cost of providing transmission services and do not change with the TRR.

BC Hydro forecasts the amount to be recovered from these services based on its forecast of the transmission service usage for the test period and an estimate of the ancillary services that are likely to be attracted by this usage. BC Hydro self supplies all ancillary services that are attracted by transmission service used by internal customers.Accordingly, the amount of internal ancillary services is shown as zero on line 36 of Appendix A, Schedule 3.4. The revenue from the sale of these service to external customers is shown as external ancillary services on line 37 of Appendix A, Schedule 3.4.

9.3.4 Calculation of the PTP Transmission Service Rate

As described in part two of the OATT, PTP service is the reservation of capacity and transmission of energy, on a firm or non-firm basis, from point A to point B, on the transmission system.

The PTP Service rate is designed to recover the cost of the TRR if PTP transmission service were used to transfer the maximum capacity supply on the system. In theory, if there were no NITS customer, the PTP charge would recover the TRR, less ancillary service revenue. Specifically, based on the approved rate design, the PTP Transmission Service rate is calculated as follows:

$$\text{PTP Rate} = \frac{\text{(TRR - Ancillary Services Revenue)}}{\text{(Maximum Capacity Supply)}}$$

The billing determinant for the long-term PTP Transmission Service rate is BC Hydro’s Maximum Capacity Supply, which is BC Hydro’s total dependable capacity including planned resources. The Ancilliary Services revenue calculated in section 9.3.3 must be excluded from this calculation in order to avoid double-counting.

The derivation of the PTP Transmission Service rate is shown in Table 9-6 below.

1 **Table 9-6 Calculation of the PTP Transmission Service Rate**

		Reference	F2020 RRA ($ million)	F2020 Actual ($ million)	F2021 RRA ($ million)	F2021 Forecast ($ million)	F2022 Plan ($ million)
			1	2	3	4	5
1	TRR	Schedule 3.4 L29	1,092.3	1,087.7	1,089.6	1,061.0	1,078.6
2	Less Ancillary Services	Schedule 3.4 L36 to L39	(6.9)	(5.7)	(7.0)	(6.9)	(6.4)
3	Net TRR	Schedule 3.4 L40	1,085.4	1,082.0	1,082.7	1,054.1	1,072.2
4	Maximum Capacity Supply (MW)	Schedule 3.4 L.41	13,279	13,279	13,279	13,279	13,596
5	Annual Billing Determinants (MW month)	L4 x 12 months	159,348	159,348	159,348	159,348	163,152
6	PTP Rate ($/MW Month)	L3 X 1,000,000/L5 = Schedule 3.4 L43	6,811.71	6,540.80	6,794.28	6,615.27	6,571.79

9.3.5 Calculation of the PTP Revenue Forecast

The BC Hydro derives the long-term PTP revenue from the forecast long-term PTP volumes and the proposed long-term PTP rates. The forecasts of long-term PTP volumes are based on committed long-term transmission contracts.

The short-term PTP (including non-firm PTP) revenue forecast reflects the discounting of short-term PTP rates on export and wheel-through transactions pursuant to Schedule 01 of the OATT. The applicable rates are $3.00/MWh during High (Heavy) Load Hours and $1.00/MWh during Low (Light) Load Hours, Sundays and North American Electricity Reliability Corporation (**NERC**) holidays. The forecast of external short-term PTP volumes are based on fiscal 2020 actual volumes. The internal short-term PTP volumes are based on the Energy Studies model, which is discussed further in Chapter 4, section 4.3.

Table 9-7 summarizes the forecast PTP revenue and volumes.

1 **Table 9-7 Summary of Forecast PTP Revenue and Volumes**

		Schedule Reference	F2020 RRA	F2020 Actual	F2021 RRA	F2021 Forecast	F2022 Plan
			1	2	3	4	5
1	**PTP Revenue ($ million)**						
2	Long Term PTP	Schedule 3.4 L55	92.2	90.7	92.0	84.1	76.1
3	Short-Term PTP	Schedule 3.4 L64	24.8	11.5	25.8	10.9	10.2
4	**Total PTP Revenue**	**Schedule 3.4 L70**	117.0	102.2	117.8	95.0	86.3
5	**PTP Volumes (MWh)**						
6	Long-Term PTP	Schedule 3.4 L52	9,881,280	10,120,632	9,881,280	9,286,728	8,453,400
7	Short Term PTP	Schedule 3.4 L61	9,939,991	4,017,483	10,324,607	4,347,966	4,087,966
8	**Total PTP Volumes**		19,821,271	14,138,115	20,205,887	13,634,694	12,541,366
9	**PTP Average Price ($/MWh)**						
10	Long Term PTP	Schedule 3.4 L58	9.33	8.96	9.31	9.06	9.00
11	Short Term PTP	Schedule 3.4 L67	2.50	2.87	2.50	2.50	2.50

9.3.6 Calculation of the NITS Rate

Once the Ancillary Services and PTP revenues have been calculated, the NITS rate is determined as the residual TRR. As BC Hydro is the only NITS customer, the entire NITS rate, plus PTP and ancillary services used by BC Hydro, are ultimately recovered through BC Hydro's bundled service rates. Revenues from PTP services paid by Powerex reduce the revenue requirement to be recovered from the BC Hydro NITS service. Only the revenues from PTP and ancillary services used by parties other than BC Hydro and Powerex reduce the revenue requirement to be recovered through bundled service rates. Only approximately 1 per cent of the total TRR collected under the OATT is collected from customers other than BC Hydro and Powerex.

As described in part three of the OATT, NITS is a flexible transmission service which allows the NITS customer to integrate, economically dispatch and regulate its designated generation resources to serve its designated loads, as well as deliver energy from non-designated generation resources on an as-available basis. This flexible use of the network to integrate resources and loads is different than PTP service, which is the reservation and transmission of capacity for the transmission of energy on a firm or non-firm basis from point A to point B.

The NITS charge is designed to recover the TRR, less any revenues from PTP and Ancillary services, as illustrated in the following equation:

$$\text{Monthly NITS Charge} = \frac{\text{TRR} - (\text{PTP Revenue} + \text{Ancillary Services Revenue})}{12 \text{ months}}$$

The derivation of the monthly NITS charge is shown in Table 9-8 below.

1 **Table 9-8 Calculation of Monthly NITS Charge**

		Reference	F2020 RRA ($ million)	F2020 Actuals ($ million)	F2021 RRA ($ million)	F2021 Forecast ($ million)	F2022 Plan ($ million)
			1	2	3	4	5
1	**TRR**	Schedule 3.4 L29	1,092.3	1087.7	1,089.6	1,061.0	1,078.6
2	**Less PTP and Ancillary Services Revenue:**						
3	PTP Revenue	Schedule 3.4 L70	(117.0)	(102.2)	(117.8)	(95.0)	(86.3)
4	Ancillary Service	Schedule 3.4 L36 to L39	(6.9)	(5.7)	(7.0)	(6.9)	(6.4)
5	**Total PTP and Ancillary Services Revenue**	L3+L4	(123.9)	(107.9)	(124.8)	(101.9)	(92.7)
6	**NITS Revenue Requirement**	Schedule 3.4 L33	968.4	928.2	964.8	959.1	985.9
7	**Monthly NITS Charge**	Schedule 3.4 L34	80.7	77.4	80.4	79.9	82.2

9.4 A Comprehensive Review of OATT Rate Design Would Not Add Value at this Time

In its Decision on the Previous Application, the panel recommended a comprehensive review of the OATT rate design:

> The Panel agrees with BC Hydro that the OATT rate design is complex, and that changes to it should be made only after consideration of such relevant factors as BC Hydro's compliance with FERC orders.
>
> However, the Panel is concerned that the complexity of the OATT rate design is preventing the examination of important matters which have arisen since the OATT (previously, the Wholesale Transmission Services) rate design principles were reviewed in 1998. The BCUC's recommendation in the FortisBC COSA and RDA proceeding that rate harmonization be reviewed is a good example. While no one transmission service issue on its own might justify the effort to examine the entire rate design, the danger is that the benefits that might come from such an examination will never be realized. There has been no comprehensive review of the OATT since its introduction in 1998.
>
> For these reasons, the Panel recommends that the BCUC initiate a proceeding to review the OATT rate design in a comprehensive manner, including addressing the rate harmonization issue raised in the FortisBC COSA and RDA proceeding.[234]

BC Hydro does not support the initiation of a proceeding to review OATT rate design in a comprehensive manner, for the following four reasons:

- First, the OATT rate design has been comprehensively reviewed by the BCUC two times since its introduction in 1998. The first comprehensive review was in 2004/2005 when BCTC filed for approval of its OATT, resulting in BCUC Order No. G-58-05. This proceeding was extensive, including 21 registered interveners, multiple rounds of IRs, an eight-day oral hearing, and written and

[234] BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), pages 158-159.

oral argument. The second comprehensive review was in 2008 as part of BCTC's application to amend the OATT, which resulted in Order No. G-103-09. BCTC's application, filed in 2008, was based on the changes to the OATT that FERC had approved in its Order 890. Order 890 itself was a comprehensive review of the OATT undertaken by FERC which was extensively litigated in the U.S., including four rehearing orders (Order 890-A through Order 890-D). Since Order 890, FERC has not engaged in a comprehensive review of the OATT, but has amended the OATT from time to time to address issues that arise. BC Hydro has followed with applications to the BCUC to amend the OATT as required;

- Second, BC Hydro has relatively few external OATT customers and there is relatively little customer interest in the OATT. The portion of the total TRR that BC Hydro expects to recover from customers other than Powerex and BC Hydro itself is only $11.1 million per year, as shown on schedule 15, line 4 of Appendix A. The remainder of the $1,079 million TRR, as shown on schedule 3.4, line 29 of Appendix A, is recovered through BC Hydro's electric tariff rates. Further, no customer has ever taken advantage of some OATT services, such as the rate harmonization provisions of Schedule 01;
- Third, BC Hydro has limited flexibility to amend the OATT as it must maintain comparability with FERC's *pro forma* OATT to demonstrate that it is complying with FERC's reciprocity requirement. This is necessary in order to obtain the trade benefits for all customers associated with Powerex's participation in U.S. markets at market based rates. BC Hydro must maintain the OATT to be comparable to the wholesale transmission provisions of FERC jurisdictional entities in the U.S. This limits the flexibility we have to address a range of potential changes to the OATT. Likewise, OATT rate design cannot address additional matters that appear to be of interest to stakeholders and the BCUC, such as retail access and distribution wheeling. The OATT is neutral to these

matters,as they are set by Government of B.C. policy and cannot be addressed through OATT rate design; and

- Finally, a comprehensive OATT rate design proceeding would require significant resources, including specialized consultants familiar with OATT rate design, which would increase regulatory costs.

Given the above factors, BC Hydro does not consider that the benefits of a comprehensive OATT rate design application would outweigh the costs. Rather, we submit that the OATT should be maintained and modernized as needed to respond to specific customer needs and FERC developments. BC Hydro plans to file an OATT application with regard to FERC Order No. 845/842 (generator interconnection) in 2021. Any further interest in OATT amendments or review could be explored through that proceeding.

BC Hydro Fiscal 2022

Revenue Requirements Application

Chapter 10

Demand Side Management

Table of Contents

List of Tables

10.1 Introduction

In this chapter, BC Hydro sets out the information and analysis in support of our proposed fiscal 2022 demand-side measures expenditure schedule, and our low carbon electrification (**LCE**) expenditures that are prescribed undertakings under the *Clean Energy Act*. We are requesting that the BCUC accept the demand-side measures expenditure schedule under section 44.2 of the *Utilities Commission Act*. We are also forecasting LCE expenditures in fiscal 2022 for recovery through the DSM Regulatory Account.

Demand side management (**DSM**) refers to the broad concept of helping customers manage their electricity use. This includes traditional DSM, which encourages customers to reduce and/or shift the timing of their electricity consumption, as well as LCE, which encourages customers to switch from higher carbon sources of energy to electricity. Traditional DSM has been a valuable component of BC Hydro's energy resource plan for several decades. BC Hydro has more recently begun to focus on LCE initiatives as well. DSM initiatives provide BC Hydro with the opportunity to engage and enhance relationships with customers, save customers money on their utility bills, support BC Hydro's affordability mandate, and support multiple *Clean Energy Act* energy objectives. DSM also contributes to broader environmental benefits and creates jobs and economic benefits for the province.

Our proposed demand-side measures expenditure schedule for fiscal 2022 continues to provide broad customer access to conservation and energy management opportunities, while managing the overall level of expenditures to limit forecast rate increases as BC Hydro continues to be in an energy surplus position.[235] In its next Integrated Resource Plan (**IRP**), BC Hydro will explore future levels of DSM beyond fiscal 2022.[236]

235 BC Hydro refers to this approach as its "moderation approach" to DSM.
236 This is in accordance with Directive 46 of the BCUC's Decision on the Previous Application.

In addition to the proposed demand side measures expenditure schedule, BC Hydro is forecasting expenditures on LCE undertakings in fiscal 2022. The LCE undertakings described in this chapter reflect undertakings that fall within one or more classes defined in sections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the Greenhouse Gas Reduction (Clean Energy) Regulation (B.C. Reg. 102/2012) (**GGRR**), and represent a continuation of the activities that were described in the Previous Application and expenditures which were accepted by the BCUC as prescribed undertakings. BC Hydro expects that its LCE activities in fiscal 2022 and beyond will be informed by a broader electrification plan. BC Hydro is currently developing the electrification plan and will be consulting stakeholders on the plan in 2021.

Our demand-side measures expenditure schedule and LCE expenditures are shown in Table 10-1 below.

Table 10-1 Fiscal 2022 Demand-Side Measures Expenditure Schedule and Low-Carbon Electrification Expenditures

	Expenditure ($ million)
Demand-Side Measures (for section 44.2 acceptance)	82.2
Low-Carbon Electrification	15.5
Total	**97.7**

Descriptions of our traditional DSM programs and initiatives, and detailed data tables showing demand-side measures expenditures, savings and cost-effectiveness are provided in Appendix M. Details on our LCE undertakings are provided in Appendix N.

The remainder of this chapter is organized around the following key points:

- Section 10.2 reviews the outcomes of the fiscal 2020 to fiscal 2021 traditional DSM initiatives and LCE undertakings and BC Hydro's response to Directives from the BCUC's Decision on the Previous Application;

- Section 10.3 presents an overview of BC Hydro's forecasted expenditures, and energy and capacity impacts over the Test Period. It explains that we have made minor updates to adjust Industrial sector program expenditures and to continue Capacity-Focused DSM activity, but overall BC Hydro's expenditures during the Test Period reflect a similar level of activity as the Previous Application; and
- Section 10.4 explains that BC Hydro is complying with the regulatory and legislative frameworks applicable to BC Hydro's traditional DSM and LCE expenditures, including cost-effectiveness.

10.2 Fiscal 2020 and F2021 DSM Results and Response to BCUC Directives

10.2.1 Results and Achievements from Fiscal 2020 to Fiscal 2021

Table 10-2 and Table 10-3 below provide the actual fiscal 2020 and forecast fiscal 2021 energy impacts, capacity impacts and associated expenditures compared to plan values. The plan values represent the planned amounts described in BC Hydro's Previous Application,[237] and accepted by the BCUC[238]. The forecast amounts for fiscal 2021 represent a year-end forecast, as of August 2020.

Table 10-2 Traditional DSM Incremental Savings and Expenditures

	New Incremental Energy Savings (GWh/year)		New Incremental Associated Capacity Savings (MW)		Expenditures ($ million)	
	RRA	Actual/ Forecast	RRA	Actual/ Forecast	RRA	Actual/ Forecast
F2020	700	722	128	128	90.8	78.5
F2021	753	747	136	133	89.1	82.4

237 Plan values for Traditional DSM reflect adjustments made in the Evidentiary Update to the Previous Application to remove expenditures for the Thermo-Mechanical Pulp (**TMP**) program, as described in Exhibit B-11, page 4 of that proceeding. Traditional DSM energy and associated capacity savings excluding TMP can be seen in the bottom row of Table A-4 and Table A-5 of Appendix A to Appendix X of the Previous Application.

238 Refer to Directive 51 of the BCUC's Decision on the Previous Application.

Table 10-3 Low-Carbon Electrification Incremental Load and Expenditures

	New Incremental Load (GWh/year)		New Incremental Associated Capacity Load (MW)		Expenditures ($ million)	
	RRA[239]	Actual/ Forecast	RRA[6]	Actual/ Forecast	RRA[6]	Actual/ Forecast
F2020	214	213	29	29	17.8	16.9
F2021	61	65	9	9	7.7	7.6

As shown in the tables above, energy and capacity impacts were approximately on-plan for both traditional DSM and LCE, while expenditures were below plan for traditional DSM and approximately on-plan for LCE. As discussed further in the subsections below, expenditures for traditional DSM were below plan primarily due to lower than planned participation in industrial incentive projects as well as lower than planned expenditures on capacity-focused DSM. A full reporting of the historical energy impacts and expenditures for fiscal 2020 is provided in Appendix W for traditional DSM and Appendix X for the low-carbon electrification undertakings. BC Hydro will report on actual energy impacts and expenditures for fiscal 2021 in its Report on Demand-Side Management Activities for fiscal 2021, which we expect to file in July 2021.

10.2.1.1 Participation in Industrial Incentive Projects has been Lower Than Planned

DSM expenditures were below plan in fiscal 2020 and are forecast to be below plan in fiscal 2021, primarily due to spending below plan in our Industrial sector programs. While the mining, forestry, and pulp and paper sectors represent a significant portion of industrial load and have previously been frequent participants in our incentive offers, the economic uncertainty in these industries has resulted in fewer incentive projects coming through the program in recent years from these large customers. This reduction has been partially offset by an increasing number of

[239] RRA values for LCE reflect updates made in Exhibit B-31, Attachment 1 to BC Hydro’s response to BCUC Panel IR 2.18.2 of the Previous Application. Note that an annual view of LCE energy and capacity impacts was not provided in that IR response.

projects from other industries. However, the overall result has been a trend of spending below plan for the Industrial sector. Looking forward, we expect this trend to continue and we have reduced our fiscal 2022 Industrial sector expenditures accordingly.

While expenditures in the Industrial sector have been below plan, energy savings have been approximately on-plan as a result of strong participation in our Strategic Energy Management initiative, which enables energy savings at a lower cost.

10.2.1.2 Expenditures were Lower Than Planned for Capacity-Focused DSM

Capacity-focused DSM expenditures were below plan over the fiscal 2020 to fiscal 2021 period. Activities during this period involved a variety of pilot and trial initiatives, which were new to BC Hydro and therefore subject to a wider range of uncertainty in terms of cost and feasibility. BC Hydro spent less than plan due to some activities coming in with lower costs than expected, and other planned pilot activities not going ahead because they were either not feasible or not needed. Learnings from these pilots and trials have informed the specific activities and level of spend that we have planned for fiscal 2022. Further details on the fiscal 2022 activities planned for capacity-focused DSM are provided in section 10.3.2.3 below.

10.2.1.3 COVID-19 has Impacted Our Fiscal 2021 Performance

Directive 65 of the BCUC's Decision on the Previous Application requires BC Hydro to report in future Revenue Requirements Applications on the impact of the COVID-19 pandemic and BC Hydro's plans to manage the resulting impact.

In the initial months of the pandemic, there was a reduction in the number of participants in our traditional DSM programs as a result of a number of factors, including increased difficulty in accessing and implementing projects in customer's homes and businesses, financial hardship for some customers, and an overall reduction in load which reduces the overall conservation potential. However, many customers remained engaged and BC Hydro attempted to mitigate impacts by implementing activities virtually, where possible, developing and implementing safety protocols where site visits remained necessary, and introducing some time-limited changes to offers, such as increased incentives, to encourage participation. As a result, participation returned to close to planned levels for many programs after the initial months. The impact was also mitigated by the fact that the DSM Plan is operating at a moderated level and is only targeting a portion of the overall market. As a result, even though some areas of the market became harder to access, BC Hydro was still able to achieve participation levels that were close to plan. We expect overall traditional DSM expenditures to come in close to plan for fiscal 2021, with the exception of the Industrial sector, as discussed further in section 10.3.2.1 below.

For LCE, most of the activities planned for fiscal 2021 are to support the identification and investigation of LCE opportunities that will in turn lead to implementation in future years. In spite of the COVID-19 pandemic, we are seeing strong interest from customers and support from our trade alliance network in advancing study activities. Two implementation projects were planned to complete in fiscal 2021. It now appears likely that these projects could be delayed to fiscal 2022, as a result of the COVID-19 pandemic.

As the COVID-19 pandemic continues, there is uncertainty regarding future impacts on BC Hydro's DSM expenditures; however, we will continue to look for ways to mitigate any impacts that arise.

10.2.2 We have Addressed the BCUC's Recommendations and Comments on DSM

In its Decision on the Previous Application, the BCUC accepted BC Hydro's traditional DSM expenditures for fiscal 2020 and fiscal 2021 and approved the deferral of LCE expenditures to the DSM Regulatory Account. The BCUC also made several other determinations and directions, to which BC Hydro has responded or will respond in due course.

Directive 46 directed BC Hydro "to present options for the level of DSM in future years for BCUC review as part of BC Hydro's next IRP, using the results of the latest Conservation Potential Review and any other relevant analysis." BC Hydro will comply with this directive in its next IRP.

Directive 47 directed BC Hydro to report on the progress of the Non-Integrated Area (**NIA**) program in future annual DSM reports, and in the fiscal 2023 Revenue Requirements Application, "including an assessment of whether that program has been effective in reducing barriers for Non-Integrated Area customers in accessing DSM offerings and thereby meeting the objective of Directive 23 from the 2017 to 2019 [Revenue Requirements Application]." BC Hydro's Fiscal 2020 Annual Report on DSM Activities, filed as Appendix W to the Application, contains a section on Non-Integrated Area activities, which was enhanced to include information on the progress of the NIA program in that year. We have also provided information on further progress of the NIA program during fiscal 2021 in the NIA program description in Appendix M, page 12. As directed, we will also report on the progress of the NIA program as part of the annual DSM report, and in the next Revenue Requirements Application.

Directive 49 directed BC Hydro "to report on the Low Carbon Electrification expenditures within the DSM Regulatory Account annually in its annual DSM report to the BCUC, clearly allocated to the applicable classes defined in section 4 (3) (a), (b), (c) or (d) of the GGRR, including a consolidated table with a break down between the Initial LCE and BC Hydro LCE projects and programs." In future annual DSM reports BC Hydro will report on the balance of LCE expenditures in the DSM Regulatory Account in the manner directed. For the Test Period, the balance of LCE expenditures in the DSM Regulatory Account is provided in Appendix A, Schedule 2.2.

In response to BC Hydro's request in the Previous Application, Directive 50 of the BCUC's Decision rescinded Directive 61 from Order G-96-04 on BC Hydro's

Fiscal 2005 to Fiscal 2006 Revenue Requirements Application. Directive 61 had directed BC Hydro to add a prorated amount of costs from supporting initiatives to the cost of each DSM program to assess cost-effectiveness. As this directive is rescinded, the cost-effectiveness of BC Hydro's DSM programs no longer includes an allocation of supporting initiatives costs. Supporting initiatives costs are assessed at the portfolio level, consistent with the Demand-Side Measures Regulation.

Directive 51 determined that BC Hydro may make inter-year and inter-program area transfers, as follows:

- BC Hydro may transfer unspent accepted DSM expenditures in a program area to the same program area in the following year of the Test Period, on the condition that BC Hydro provides information regarding unspent amounts as part of its annual DSM reports so that all amounts transferred within a program area are transparently accounted for from one test year to the next; and
- The Panel accepted the DSM expenditure schedule including transfers of up to 25 per cent of DSM expenditures from any one existing program area to any other existing program area.

BC Hydro confirms that over fiscal 2020 and fiscal 2021, no transfers between program areas were made or are anticipated to be made beyond the allowed levels. BC Hydro is also not anticipating any transfers from the previous test period to the current test period. Going forward, should BC Hydro determine that a transfer in excess the allowed levels is warranted, BC Hydro will seek acceptance from the BCUC of the transfer.

10.3 Planned DSM Expenditures, Energy and Capacity Impacts

This section outlines the forecast expenditures and energy and capacity impacts of BC Hydro's traditional DSM and LCE initiatives in fiscal 2022 and describes the changes relative to the Previous Application.

10.3.1 Forecast Expenditures and Energy and Capacity Impacts

The tables below provide the expenditures and the energy and capacity impacts of traditional DSM and LCE activities. Table 10-4 below provides a detailed breakdown of planned expenditures, Table 10-5 below provides a detailed breakdown of the energy impacts, and Table 10-6 below provides a detailed breakdown of capacity impacts. Further details are provided for traditional DSM in the data tables in Appendix M, pages 58 to 66, and for LCE in Appendix N, Tables N-1 and N-3.

Table 10-4 Fiscal 2021 and Fiscal 2022 Expenditure Summary ($ million)

	F2021 RRA	F2021 Forecast	F2022 Plan
Rate Structures	0.5	0.5	0.5
Programs			
Residential	19.7	19.8	21.0
Commercial	17.5	17.1	16.6
Industrial	26.9	21.6	20.8
Total Programs	64.1	58.5	58.4
Capacity-focused	4.3	3.6	2.9
Supporting Initiatives	20.2	19.9	20.5
Total Traditional DSM	**89.1**	**82.4**	**82.2**
Low-Carbon Electrification	7.7[240]	7.6	15.5
Total Expenditures	**96.8**	90.0	97.6

[240] Plan values for LCE reflect updates made in Exhibit B-31, Attachment 1 to BC Hydro's response to BCUC Panel IR 2.18.2 (Exhibit B-31) of the Previous Application.

Table 10-5 Fiscal 2021 and Fiscal 2022 Energy (GWh/year) Impact Summary

	F2021 RRA	F2021 Forecast	F2022 Plan
New Incremental Energy Savings (GWh/year)			
Codes and Standards	411	405	259[241]
Rate Structures	118	119	119
Programs			
Residential	36	39	41
Commercial	52	48	43
Industrial	136	136	127
Total Programs	224	222	210
Total New Incremental Energy Savings	753	747	588
New Incremental Load Growth (GWh/year)			
Low-Carbon Electrification	61	65	148

Table 10-6 Fiscal 2021 and Fiscal 2022 Associated Capacity (MW) Impact Summary

	F2021 RRA	F2021 Forecast	F2022 Plan
New Incremental Associated Capacity Savings (MW)			
Codes and Standards	88	88	51
Rate Structures	14	9	9
Programs			
Residential	10	11	11
Commercial	8	8	6
Industrial	16	16	15
Total Programs	34	35	33
Total New Incremental Energy Savings	136	133	93
New Incremental Associated Capacity Growth (MW)			
Low-Carbon Electrification	9	10	29

The BCUC's Decision on the Previous Application found the breakdown of DSM costs across customer classes to be reasonable for fiscal 2020 and fiscal 2021.[242]

[241] The magnitude of codes and standards savings can vary year over year, due to the timing of enactment of regulations, and stock turnover in the market place.

As shown in Table 10-7 below, BC Hydro's fiscal 2022 DSM expenditures reflect a similar allocation across customer classes.

Table 10-7 DSM Program Spend by Sector

	Residential (including low income) (%)	Commercial and light industrial (%)	Large Industrial (%)
BC Hydro percentage of DSM program spend by sector (excluding TMP program)			
F2020 to F2021 RRA	30	38	32
Fiscal 2022 Forecast	36	35	29
BC Hydro Allocation of DSM costs for cost recovery purposes			
Allocation of DSM costs	40	35	25

10.3.2 DSM and LCE Expenditures Reflect a Continuation of Similar Activities as Previous Application

DSM and LCE expenditures in fiscal 2022 generally reflect a continuation of the activities that were approved by the BCUC for fiscal 2020 and fiscal 2021. However, BC Hydro has adjusted its plans for fiscal 2022 to reflect historical results, the estimated impacts of the COVID-19 pandemic, new market information, and a continuation of activities within the area of capacity-focused DSM. These adjustments are discussed in the following subsections.

10.3.2.1 We Have Adjusted our Forecast to Reflect Historical Industrial Results

As described in section 10.2.1.1 above, the number incentive projects coming from large mining and pulp and paper customers has decreased in recent years. Although this has been partially offset by an increasing trend in projects from other industries, BC Hydro's spending in the industrial sector overall has been below plan for a number of years. Looking forward, our outlook of projects for fiscal 2022 suggests the trend will continue. Therefore, BC Hydro has reduced its planned industrial

[242] BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 147.

expenditures in fiscal 2022, compared to fiscal 2020 and fiscal 2021, to reflect this trend and to align with historical results.

10.3.2.2 We Expect to be Able to Mitigate Impacts of COVID-19

As described in section 10.2.1.3 above, in spite of challenges arising from the COVID-19 pandemic, many customers remained engaged and BC Hydro expects to be able to reach expenditure levels that are close to plan in fiscal 2021, with the exception of spending in the Industrial sector. Likewise, in fiscal 2022, we expect that impacts on participation from the COVID-19 pandemic can be mitigated by implementing activities virtually, where possible, and developing and implementing safety protocols where site visits remain necessary. With these mitigation activities, we expect that participation and expenditures will remain similar to previously planned levels. However, we recognize that the COVID-19 pandemic continues to evolve and there is uncertainty as to how it will impact our ability to implement our planned expenditures. We will continue to monitor the situation and will adapt if needed and where possible in fiscal 2022.

10.3.2.3 We Plan to Continue Capacity-Focused DSM Activities

Since fiscal 2017, BC Hydro has completed a wide variety of capacity-focused activities, which have provided information that inform the savings potential and cost effectiveness of different technologies and approaches. Additionally, BC Hydro has piloted a demand response management system to allow Transmission and Distribution Systems Operations to trigger control events on customer connected devices and lower demand on target areas of the grid as needed.

Capacity-focused DSM has the potential to be used to reduce or shift electricity consumption in order to optimize system capacity and reduce the amount of infrastructure and electricity that needs to be acquired in the future. The next IRP will assess the need for new capacity resources at the system-level and regional-level. We have incorporated the learnings from our capacity-focused pilots and trials into the DSM capacity resource options being developed for the IRP.

Capacity-focused DSM also has the potential to be used as a "Non-Wires Alternative" to alleviate constraints at the local substation or feeder level. This consists of geo-targeting our traditional energy efficiency programs to maximize the load reduction in the constrained area, along with technologies and offers that shift customer consumption. These initiatives are collectively known as demand response.

In fiscal 2021, work is continuing on Non-Wires Alternatives and BC Hydro will consider how Non-Wires Alternative solutions could be viable alternatives to capital projects in constrained substations or feeders.

While awaiting the completion of the IRP and additional work on Non-Wires Alternatives, BC Hydro plans to continue work on capacity-focused DSM in fiscal 2022. Expenditures in fiscal 2022 will be used to run Non-Wires Alternative programs at five substations, including a continuation of activities at the substations discussed in the Previous Application.[243] In fiscal 2022, we will also continue to pilot the use of the demand response management system, refine the management of the initiatives, conduct monitoring and tracking, and add new technologies and solutions as required for the specific local substations. Further information on capacity-focused DSM activities is provided in Appendix M.

10.3.2.4 We are Continuing with Similar Low Carbon Electrification Activities

BC Hydro's planned LCE activities for fiscal 2022 are similar to those described in the Previous Application and fall within one or more classes defined in sections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR, as described in Appendix N.

[243] Refer to BC Hydro's response to BCUC IR 1.183.1 (Exhibit B-5 of the Previous Application) and to BC Hydro's responses to BCSEA IR 1.39.1 and BCSEA IR 1.39.2 (Exhibit B-6 of the Previous Application).

Beginning in fiscal 2018, BC Hydro provided support to some initial low carbon LCE projects to assess and enable LCE opportunities among our customers. In fiscal 2022, we expect the last of these initial projects to be completed.

In fiscal 2019, BC Hydro became responsible for delivering the fuel switching component of CleanBC Better Buildings program on behalf of the Government of B.C., and in fiscal 2020, BC Hydro became responsible for administering the Government of B.C.'s CleanBC 'Go Electric' Electric Vehicle charger rebate program. In fiscal 2022, BC Hydro will continue to administer these offers, with costs borne by the Government of B.C., and not by BC Hydro's ratepayers.

In fiscal 2019, to complement government programs, BC Hydro developed a multi-year BC Hydro funded LCE program. The Previous Application described the LCE activities we planned to undertake up to fiscal 2021, with some lingering commitments beyond fiscal 2021 to reflect the time required for some of these projects to be implemented. LCE expenditures for fiscal 2022 reflect a continuation of the BC Hydro funded LCE programs for a further year.

Expenditures are higher in fiscal 2022 compared to fiscal 2021 due to the timing of larger projects in the natural gas and transportation sector, which are planned to be implemented in fiscal 2022.

More detail on our LCE expenditures, including how they fall within one or more classes defined in sections 4(3)(a), 4(3)(b), 4(3)(c), and 4(3)(d) of the GGRR, is provided in Appendix N.

10.4 DSM Expenditures Aligned with Legal and Regulatory Frameworks

10.4.1 BC Hydro's Traditional DSM Complies with the Framework under Section 44.2 of the *Utilities Commission Act*

BC Hydro is requesting BCUC acceptance of our proposed fiscal 2022 demand-side measures expenditure schedule under section 44.2 of the *Utilities Commission Act*.

Under section 44.2 of the *Utilities Commission Act*, the BCUC must accept an expenditure schedule if it considers that making the expenditures would be in the public interest. Otherwise, the BCUC must reject the schedule. Alternatively, the BCUC may accept or reject a part of the expenditure schedule. However, section 44.2 does not provide the BCUC with the authority to direct BC Hydro to file a DSM expenditure schedule, make additions to a DSM expenditure schedule, or change the design of a particular DSM program.

Section 44.2 sets out the factors that the BCUC must consider when deciding whether to accept a demand-side measures expenditure schedule filed by a public utility. Specifically, for BC Hydro the BCUC must consider:

- The interests of persons in British Columbia who receive or may receive service from BC Hydro;
- British Columbia's energy objectives as set out in section 2 of the *Clean Energy Act*;
- An applicable Integrated Resource Plan approved under section 4 of the *Clean Energy Act*; and
- The extent to which the demand-side measures are cost-effective within the meaning prescribed by the Demand-Side Measures Regulation.[244]

BC Hydro's traditional DSM supports each of these factors as discussed below.

10.4.1.1 Traditional DSM Is in the Interest of Persons who Receive or May Receive Service

The BCUC's Decision on the Previous Application found our proposed traditional DSM expenditures to be in the interests of persons in B.C. who receive or may receive service from BC Hydro.[245] DSM expenditures for fiscal 2022 reflect activities

[244] B.C. Reg. 326/2008 (Ministerial Order M271), B.C. Reg. 228/2011 (Ministerial Oder M335), B.C. Reg. 141/2014 (Ministerial Order M233) and B.C. Reg. 117/2017 (Ministerial Order M138).

[245] Refer to page 139 of Order No. G-246-20.

similar to those in the Previous Application, and continue to reflect a broad and cost effective range of traditional DSM initiatives that provide significant energy savings and capacity benefits and provide customers with the opportunity to save electricity and lower their bills, while reducing BC Hydro's revenue requirements. Therefore, BC Hydro's proposed DSM expenditures continue to be in the interest of persons who receive or may receive service.

10.4.1.2 Traditional DSM Supports Energy Objectives

A summary of how BC Hydro's proposed fiscal 2022 DSM expenditures continue to support the applicable energy objectives in the *Clean Energy Act* is provided in Table 10-8 below:

Table 10-8 DSM Plan Alignment with BC Energy Objectives

Energy Objective	DSM Plan
To achieve electricity self-sufficiency	The DSM Plan's energy and capacity savings have contributed to BC Hydro achieving and maintaining electricity self-sufficiency and will continue to do so going forward.
To take demand-side measures and to conserve energy	Fiscal 2022 expenditures will continue the objective of taking demand-side measures and conserving energy at a similar level to the Previous Application.
To use and foster the development of innovative technologies that support energy conservation	Both DSM programs and the Codes and Standards initiatives will use and foster the development of innovative technologies supporting energy conservation. Refer to Appendix M for more detail.
To ensure that BC Hydro's rates remain among the most competitive	The moderation strategy reduces rates relative to the DSM investment level for fiscal 2022 that was contemplated in the 2013 Integrated Resource Plan.
To reduce B.C. GHG emissions	The Non Integrated Areas Program is expected to reduce GHG emissions by reducing diesel generation.

Energy Objective	DSM Plan
To encourage communities to reduce GHG emissions and use energy efficiently	BC Hydro’s Codes and Standards initiatives provide support to communities (including Indigenous communities) to incorporate electricity efficiency into community energy planning and implement energy efficiency policies and projects.
To encourage economic development and the creation and retention of jobs	BC Hydro’s DSM efforts create significant economic activity and jobs within the province. Analysis undertaken for the Previous Application estimated the impact at 11,600 person years of employment over the ten years from fiscal 2020 to fiscal 2029.

10.4.1.3 Traditional DSM Continues Moderation Approach Consistent with the 2013 Integrated Resource Plan

In its Decision on the Previous Application, the BCUC found that alignment between the DSM expenditure schedule and the most recent IRP is a moot issue given the seven years that have elapsed since the 2013 IRP and that BC Hydro is in the process of developing its next IRP for BCUC review in 2021.[246] BC Hydro agrees.

Nevertheless, BC Hydro notes that the selected level of DSM expenditures continues a moderation approach, as was recommended in the 2013 IRP for fiscal 2014 to fiscal 2016. This moderation approach was subsequently continued for fiscal 2017 to fiscal 2019, and for fiscal 2020 to fiscal 2021, in response to an extended energy surplus and to limit forecast rate increases. The BCUC has accepted BC Hydro’s past expenditure schedules reflecting the moderation approach.[247] For fiscal 2022, BC Hydro has continued with the same approach, consistent with the Previous Application.

BC Hydro’s next IRP will examine different levels of DSM.[248]

---

[246] Refer to page 142 of Order No. G-246-20.

[247] BCUC Decision and Order No. G-47-18, BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (March 1, 2018), page 78 and BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 146.

[248] In accordance with Directive 46 of the BCUC’s Decision on the Previous Application.

10.4.1.4 Traditional DSM Meets Adequacy Requirements Under the Demand-Side Measures Regulations

Section 44.1 of the *Utilities Commission Act* requires BC Hydro's demand-side measures to meet the adequacy requirements set out in the Demand-Side Measures Regulation under the *Utilities Commission Act*. These adequacy requirements set out the measures that a DSM portfolio must include in order to be considered adequate. Table 10-9 below shows how BC Hydro's traditional DSM aligns with the adequacy requirements set out in the Demand-Side Measures Regulation.

Table 10-9 Traditional DSM Alignment with Adequacy Requirements in the Demand-Side Measures Regulation

Adequacy Requirements	DSM Plan
Demand-side measure for low income households	BC Hydro's Low Income Program, Non-Integrated Areas Program, and Social Housing Retrofit Support Offer (within the Leaders in Energy Management – Commercial Program) assist residents of low income households, low income housing providers, and Indigenous communities with reducing their energy consumption. Further information on these offers is provided on pages 3, 12 and 22 of Appendix M.
Demand-side measure for rental accommodations	BC Hydro offers a combination of programs that are available to rental accommodations. Renters with BC Hydro accounts participate in our Team Power Smart offer which helps to develop energy efficient behaviours. Renters also represent a significant portion of the participants in our Low Income program. Over the past two years, approximately 35 per cent of Energy Savings Kit participants have been renters and approximately 75 per cent of Energy Conservation Assistance Program participants have been renters. Renters also participate in our Retail program, purchasing products such as appliances and lighting technologies. These initiatives are contained within our residential sector initiatives, described on pages 2-19 of Appendix M.
An education program for schools	Our Public Awareness Supporting Initiative provides school education programs across the province to engage teachers and students. This initiative is described on page 54 of Appendix M.
An education program for post-secondary institutions	BC Hydro partners with post-secondary institutions and industry associations who develop and deliver new training and education programs. This partnership is delivered through our Commercial Energy Management activities, described on page 34 of Appendix M.

Adequacy Requirements	DSM Plan
Financial or other resources provided to support development of or compliance with standards	BC Hydro supports the development of and compliance with standards through its Codes and Standards initiatives, described on page 45 of Appendix M. The Demand-Side Measures Regulation requires expenditures in this area to be no less than an average of 1 per cent of a public utility's plan portfolio's expenditures per year or an average of $2 million per year. BC Hydro's DSM Plan meets this requirement. Annual expenditures of $5.4 million are planned to support governments, standards-making bodies, and regulatory bodies in the development and compliance of codes and standards.
Demand-side measures to support adoption of step codes by local government and first nations	BC Hydro supports the adoption of step codes through its Codes and Standards initiatives, described on page 46 of Appendix M.

10.4.1.5 BC Hydro's Traditional DSM is Cost-Effective

The Utility Cost and Total Resource Cost tests are standard cost tests used in the DSM industry to assess cost effectiveness. The results of cost-effectiveness tests are typically expressed in a benefit-cost ratio. A ratio of greater than 1.0 means that benefits exceed costs and that the DSM program or portfolio is cost effective under that particular test.

The results of the cost-effectiveness tests can also be expressed as a levelized cost of energy (dollar per MWh of energy saved). In calculating the costs for this metric, any non-energy benefits, such as capacity benefits, are subtracted from the DSM implementation costs to get a net cost, which is then expressed on a per MWh basis. For levelized costs, a lower result is better. A negative net levelized cost indicates that non-energy benefits exceed the DSM costs. A larger negative value is better than a smaller negative value or any positive value. The resulting levelized cost can be compared to a value such as the market price of electricity, or to the levelized cost of energy for new supply-side resources.

The Utility Cost Test indicates the impact of a DSM initiative or portfolio on the utility's revenue requirements. Consistent with the Previous Application, BC Hydro is using the export market price to value the energy savings resulting from activities in the Test Period. This approach ensures that even surplus energy resulting from

DSM would have a positive impact on BC Hydro's revenue requirements. BC Hydro applies this test as a screening filter to prioritize DSM investments and to inform BC Hydro's business decisions.

The Total Resource Cost Test is presented because the Demand-Side Measures Regulation stipulates that the BCUC is required to use this test for determinations of cost-effectiveness. The Demand-Side Measures Regulation requires that a long-run marginal cost (**LRMC**) of acquiring electricity from clean or renewable resources in British Columbia be used in the Total Resource Cost Test.[249] The Total Resource Cost Test can also be used to assess how a DSM initiative or portfolio compares to the cost of other supply side resource options.

For the purposes of assessing the Total Resource Cost Test under the Demand-Side Measures Regulation, BC Hydro used an avoided cost of $54 per MWh[250], based on the low end of the preliminary range of the cost of new wind resources presented in the Previous Application.[251] This approach was accepted by the BCUC in the Previous Application.[252] Internal decisions on demand-side measures are based on the Utility Cost Test at market price and not on the LRMC.

The cost-effectiveness of BC Hydro's DSM initiatives, as demonstrated by their benefit-cost ratios and levelized costs, is provided in Table 10-10 below.

[249] Specifically, section 4 (1.1(b)) of the Demand-Side Measures Regulation states that the avoided electricity cost respecting a demand-side measure is an amount that the Commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia.

[250] Includes BC Hydro's cost to integrate and deliver energy to the load centre (Lower Mainland).

[251] As discussed in the Previous Application, BC Hydro's current LRMC is outdated and an updated LRMC will be determined through the next IRP.

[252] BCUC Decision and Order No. G-246-20, BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application (October 2, 2020), page 144.

Table 10-10 Benefit-Cost Ratios and Net Levelized Costs ($/MWh)

	Benefit-Cost Ratios		Net Levelized Costs ($/MWh)	
	Utility Cost Test (Market Price at $33 per MWh)	Modified Total Resource Cost Test (LRMC at $54 per MWh)	Utility Cost ($)	Total Resource Cost ($)
Rate Structures	34.6	1.8	(11)	26
Programs	2.1	2.4	1	(18)
Total Portfolio[253]	1.4	1.6	19	14

As shown in Table 10-10 above:

- The net levelized utility cost of $19 per MWh is lower than the market price of $33 per MWh. This means that BC Hydro's DSM portfolio is cost-effective under the Utility Cost Test; and
- BC Hydro's DSM initiatives have a Total Resource Cost Test result of $14 per MWh. This means that BC Hydro's DSM portfolio is cost-effective under the Demand-Side Measures Regulation, even using the low end of the preliminary range of the cost of new wind resources ($54 per MWh).

Under the Demand-Side Measures Regulation, the cost-effectiveness of "specified demand-side measures" is determined by whether the portfolio as a whole is cost effective. Table 10-10 demonstrates that the portfolio as a whole is cost-effective. Accordingly, our specified demand-side measures are also determined to be cost-effective. Specified demand-side measures include the Public Awareness Supporting Initiative, sector Energy Management Activities, technology innovation activities, and codes and standards support.

10.4.2 Regulatory Framework for Low-Carbon Electrification

Section 4 of the GGRR defines a number of classes of electrification prescribed undertakings for the purposes of section 18 of the *Clean Energy Act*. Consistent with

[253] Consistent with the Previous Application, codes and standards savings and capacity-focused DSM expenditures are not included in the calculation of portfolio level cost-effectiveness and levelized costs.

the Previous Application, BC Hydro's LCE activities described in this chapter fall within one or more class of undertakings described in sections 4(3)(a), 4(3)(b), 4(3)(c) or 4(3)(d) of the GGRR, and expenditures for such activities have been accepted by the BCUC as prescribed undertakings. These activities include:

- Providing financial support to customers to assist them with the acquisition, installation and use of equipment that uses or affects the use of electricity instead of other sources of energy that produce more greenhouse gas emissions;
- Providing funding to conduct research and pilot projects respecting technology that may enable our customers to use electricity instead of other sources of energy that produce more greenhouse gas emissions;
- Providing funds to enable energy management and audit services to our customers or educating and training customers regarding the use of electricity instead of other sources of energy that produce more greenhouse gas emissions;
- Carrying out public awareness campaigns respecting use of electricity instead of other sources of energy that produce more greenhouse gas emissions; and
- Supporting standards making bodies in their development of standards respecting technologies that use electricity instead of other sources of energy that produce more greenhouse gas emissions.

In Appendix N, BC Hydro describes its LCE activities in more detail and explains how they fall within one or more class of prescribed undertakings under the GGRR.

Section 4(4) of the GGRR requires that, at the time BC Hydro decides to carry out undertakings defined in section 4(3)(a) and 4(3)(b) of the GGRR, BC Hydro must reasonably expect the undertakings to be cost-effective. To be cost-effective, the present value of the benefits of all these undertakings must exceed the present value of the costs of all of the undertakings. Benefits are defined to mean all revenues BC Hydro expects to earn as a result of these undertakings, less revenues that would have been earned from the sale of that electricity to export markets. Costs mean all the costs BC Hydro expects to incur to implement the undertakings, including development and administration costs. As shown in detail in Appendix N, the net present value of all of BC Hydro's LCE programs/projects prescribed under section 4(3)(a) and 4(3)(b) of the GGRR including BC Hydro's proposed LCE expenditures for fiscal 2022 is $118.8 million, which indicates that these undertakings are cost-effective within the meaning of the GGRR.

BC Hydro's LCE undertakings also support the B.C. Energy Objectives as outlined in Table 10-11 below.

Table 10-11 Low-Carbon Electrification Plan Alignment with B.C. Energy Objectives

Energy Objective	Low-Carbon Electrification Plan
To ensure that BC Hydro's rates remain among the most competitive	The incremental revenue from LCE undertakings reduces forecast rate increases.
To reduce B.C. GHG emissions	BC Hydro's planned low-carbon electrification undertakings up to and including fiscal 2022 are forecast to result in natural gas and other fossil fuel savings. These savings will reduce B.C. GHG emissions by approximately 330,000 tonnes of CO^2e/year.
To encourage the switching from one kind of energy source or use to another that decreases GHG emissions in B.C.	BC Hydro's planned LCE undertakings are focused on reducing GHG emissions.
To encourage economic development and the creation and retention of jobs	BC Hydro's planned LCE undertakings create economic activity and jobs within the province.

Section 18 of the *Clean Energy Act* requires the BCUC to allow BC Hydro to collect sufficient revenue to recover costs incurred for prescribed undertakings. Further, the Direction to the BCUC Respecting Undertaking Costs, issued under section 3 of the *Utilities Commission Act*, requires the BCUC to allow BC Hydro to defer the costs incurred for prescribed undertakings as defined under section 4 (3) (a), (b), (c) or (d) of the GGRR to the DSM Regulatory Account.