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British Columbia Hydro and Power Authority

Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Decision
and Order G-91-23

April 21, 2023

Before:
D. M. Morton, Panel Chair
A. K. Fung, KC, Commissioner
R. I. Mason, Commissioner
A. Pape-Salmon, Commissioner

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Executive summary

On August 31, 2021, the British Columbia Hydro and Power Authority (BC Hydro or the Authority) filed its Revenue Requirements Application (RRA) with the British Columbia Utilities Commission (BCUC), for fiscal (F) years 2023 to 2025 (Test Period) (Application).

The Application contains several requests, including requests for approval to:[1]

- Increase general rates by 0.62 percent, effective April 1, 2022, by 0.97 percent, effective April 1, 2023 and by 2.18 percent, effective April 1, 2024;
- Set the Deferral Account Rate Rider (DARR) at (2.0) percent, effective April 1, 2022, at (1.0) percent, effective April 1, 2023, and at (0.5) percent, effective April 1, 2024; and
- Set the F2023, F2024, and F2025 Open Access Transmission Tariff (OATT) rates as set out in Table 9-4 of the Application.

The regulatory process included several rounds of BCUC and Intervener information requests[2] (IR) and three rounds of Panel IRs. Intervener evidence was filed by several parties, followed by a round of IRs and rebuttal evidence. The regulatory process also included an oral hearing and a Streamlined Review Process (SRP), and final and reply arguments and submissions.

The SRP reviewed certain items in the Application that may be impacted by certain regulations enacted by the Lieutenant Governor in Council, including the Direction to the BCUC Respecting Residential and Commercial Customer Account Credits (Account Credits Direction).[3] The BCUC issued Order G-341-22 pursuant to the Account Credits Direction, which enabled BC Hydro to, among other things, transfer $320 million from the Trade Income Deferral Account (TIDA) to the customer credit regulatory account. Subsequently, as part of the proceeding to review the Application, BC Hydro applied to the BCUC to reinstate the $320 million regulatory liability in the TIDA.

The current regulatory timetable for this proceeding includes responses to Panel IRs on the topic of BC Hydro's finance charges, and further process to be determined on both the finance charges and the separate topic of BC Hydro's request to reinstate the $320 million regulatory liability in the TIDA. Since the review of these two topics is currently ongoing, the Panel does not make determinations on them in this Decision. Any determinations with respect to these two topics will be made by the Panel in due course after the issuance of this Decision.

The BCUC approved BC Hydro's requested rate increases, the DARR, and the OATT rates for F2023 and F2024 on an interim basis by Order G-47-22 and G-60-23, respectively.

In this Decision, the Panel approves, among other things, the requested rates, subject to the adjustments resulting from the corrections identified by BC Hydro in the proceeding, the determinations and directives contained in the Decision, and any future determinations and directives made by the Panel with respect to BC Hydro's request to reinstate the $320 million regulatory liability in the TIDA and BC Hydro's finance charges. Since any future Panel determinations and directives on these two topics may impact the Test Period rates, the Panel directs that the requested general rate increases, OATT rates, and DARR for F2023 and F2024 approved by the BCUC on an interim basis by Order G-47-44 and Order G-60-23, respectively, remain unchanged until further order of the Panel.

[1] Exhibit B-2, pp. 1-49 – 1-50.
[2] Two rounds of IRs, an additional round of IRs on DSM (DSM IR no. 3), and a round of IRs related to the topics that were within the scope of the SRP (SRP IR no. 3)
[3] OIC 571, B.C. Reg. 224/2022.

The adjustments arising from the determinations and directives contained in the Decision include:

1. The removal of the $2.1 million in forecast labour costs for incremental FTEs associated with Connecting Customers in delivering the Electrification Plan from the revenue requirement, and instead the recording of up to a maximum of $2.1 million of actual operating labour costs for F2023 to F2025 in a new regulatory account.
2. The removal of 783 gigawatt hours (GWh) of forecast load in F2025 and the related forecast loads in F2023 and F2024 associated with the Electrification Plan. The Panel also directs BC Hydro to remove the cost of energy forecast to serve these loads from the Test Period revenue requirements.
3. An update of the fiscal 2023 to fiscal 2025 revenue requirements with respect to the Island Generation application.
4. The removal of $3.9 million from BC Hydro's original Mandatory Reliability Standards operating budget over the Test Period related to the implementation of the new Planning Coordinator function.
5. Adjustments to the average service life for depreciation purposes for the following:
    a. Account C25203, "Tower, Lattice / Aesthetic" should be increased from 65 to 75 years, and not remain unchanged as proposed by Concentric.
    b. Account C52106, "Transformer, Power, Comp Pool" should remain at 45 years, and not reduced to 40 years as proposed by Concentric.
    c. Account C55401, "Buswork & Station Conductor" should remain at 60 years, rather than reduced to 55 years as proposed by Concentric.
    d. Account C41002, "Governor System, Turbine" should remain at 50 years, and not increase to 55 years as proposed by Concentric.
6. The denial of BC Hydro's request regarding the recovery of interest charges with respect to the Mandatory Reliability Standards Costs Regulatory Account. Instead, the Panel authorizes BC Hydro to recover the actual interest charged to the account for amounts related to any completed fiscal years over the next test period, subject to BCUC review and approval of these amounts.
7. With respect to BC Hydro's EV Costs Regulatory Account, the denial of BC Hydro's request to recover the forecast March 31, 2022 balance of the EV Costs Regulatory Account over the Test Period, and various related directions.
8. The recovery of the actual (instead of the forecast) F2022 ending balance of the Fiscal 2022 Depreciation Study Impact Regulatory Account, based on the depreciation rates approved by the BCUC in this Decision, over the Test Period.
9. With respect to the recovery mechanism for the Trade Income forecast and the cost of energy variance accounts, commencing in F2025:
    a. The recovery of the Test Period Trade Income forecast from a rate rider rather than through the general revenue requirement (i.e. a Trade Income Rate Rider or TIRR).
    b. The recovery or the repayment of the TIDA balance from/to customers via the TIRR, instead of the DARR, over a 3-year amortization period, and limit the amortization of a deficit in the TIDA balance to the amount of forecast Trade Income that year. As a result, the TIRR rate rider will not be less than zero.
    c. Setting the TIRR annually at the beginning of each fiscal year based on the most recently available actual results.

d. Setting the DARR annually, using BC Hydro's proposed DARR table mechanism, at the beginning of each fiscal year, based on the most recently available actual net COE Variance Account balances without the TIDA balance. For example, commencing April 1, 2024, set the DARR based on the actual ending fiscal 2023 balances, with the same process to follow for each subsequent fiscal year; and
e. Filing for approval of the TIRR and the DARR annually in filings separate from its RRA filings.

The Panel directs BC Hydro to, among other things, provide certain reporting or analysis with respect to its Electrification Plan, industrial load forecast, energy studies models, cost of energy variances, vegetation management strategy, cybersecurity costs, capital assets, Non-Integrated Area (NIA) customer satisfaction index on reliability, historical asset retirement data, group accounting, demand side management (DSM), and UNDRIP implementation plan. The reporting or analysis is to be provided through various filings, including compliance filings or in BC Hydro's next RRA.

The Panel approves, among other things, the positive salvage percentages as set out in BC Hydro's depreciation study, BC Hydro's use of the traditional method of accounting for net salvage, the net salvage rates proposed by BC Hydro for use in the next test period, and the exclusion of specified asset classes from net salvage.

The Panel directs BC Hydro to establish a new regulatory account to capture certain variances related to the Site C capital costs and costs deferred to the Site C Regulatory Account resulting from any future BCUC prudency review of the Site C project.

The Panel also directs BC Hydro to file a cost of capital application, effective April 1, 2025, by no later than April 1, 2024, and to file its long-term resource plan for the NIA by March 31, 2024.

During the SRP, the Association of Major Power Customers of British Columbia (AMPC) proposed the BCUC direct BC Hydro to establish a new temporary deferral account, transfer available funds from the TIDA to the deferral account, and to refund these funds to customers that were excluded from the credits in the Account Credits Direction. The Panel rejects AMPC's request.

The Panel accepts BC Hydro's DSM expenditures schedule for F2023 to F2025 and its revised DSM expenditures schedule for fiscal 2022.

1.0 Introduction

1.1 The Application and Approvals Sought

On August 31, 2021, the British Columbia Hydro and Power Authority (BC Hydro or the Authority) filed its Revenue Requirements Application (RRA) with the British Columbia Utilities Commission (BCUC), for the fiscal (F) years 2023 to 2025 (Test Period) (Application).

BC Hydro outlined its original approvals sought in Section 1.4 of the Application. The Application originally requested that the general and OATT rates remain interim at the conclusion of the proceeding, pending the BCUC issuing final determinations on certain items in other proceedings. Specifically, BC Hydro requested:[4]

- The general and OATT rates for the Test Period remain interim pending the BCUC's approval of a demand-side management (DSM) schedule for F2023, F2024, and F2025 in another proceeding;
- The general rates for F2024 and F2025 remain interim pending the BCUC's final determination on BC Hydro's allowed net income for those years in another proceeding; and
- The general and OATT rates for F2025 remain interim pending the outcome of the BCUC's future assessment of the recoverable amount of Site C project costs.

Subsequent to filing the Application and pursuant to the BCUC's request,[5] BC Hydro filed expenditure schedules with respect to DSM and consequently sought additional approvals concerning those expenditure schedules and withdrew its original request to keep rates interim regarding its DSM expenditures.[6]

Subsequently, following an amendment to Direction No. 8 to the BCUC regarding BC Hydro's allowed net income, BC Hydro also withdrew its request to keep rates interim regarding its allowed net income for F2024 and F2025.[7] The amendment to Direction No. 8 to the BCUC is discussed in section 2.4.1 below.

The final approvals sought are listed in the table below, along with the references to sections of this Decision where the Panel addresses and makes determinations on the various requests.

Table 1: Approvals Sought

Approval Sought	Location in this Decision
Permanent approval of: • a general rate increase of 0.62 percent, effective April 1, 2022, and 0.97 percent, effective April 1, 2023; and • the F2023 and F2024 OATT rates as set out in Table 9-4 of the Application.[8]	Section 3.0
Interim and, after the BCUC's future assessment of the recoverable amount of Site C project costs, permanent approval of: • a general rate increase of 2.18 percent, effective April 1, 2024 for F2025; and • the F2025 OATT rates as set out in Table 9-4 of the Application.[9]	Section 5.3

[4] Exhibit B-2, pp. 1-51 – 1-55.
[5] Exhibit A-3.
[6] Exhibit B-10, Section 1.
[7] Exhibit B-17.
[8] OATT rates corrected on January 19, 2022 in Exhibit B-2-6, Table 9-4.
[9] OATT rates corrected on January 19, 2022 Exhibit B-2-6, Table 9-4.

Permanent approval to set the DARR at (2.0) percent, effective April 1, 2022, (1.0) percent, effective April 1, 2023, and (0.5) percent, effective April 1, 2024.	Section 4.11.1
Approval of changes to its regulatory accounts as set out in Chapter 7, Section 7.3 of the Application.	Section 4.8
Approval to implement for ratemaking purposes: • the updated useful lives and positive salvage rates and changes in asset classes, effective F2022, as set out in Chapter 8, Section 8.3 of the Application; and • net salvage rates beginning in the next test period, using a phased-in approach, as set out in Chapter 8, Section 8.4 of the Application.	Sections 4.6 and 4.7
Pursuant to section 44.2 of the *Utilities Commission Act (*UCA), acceptance of: • its F2023 to F2025 DSM expenditure schedule of $295.7 million; and • a revised F2022 DSM expenditure schedule of $85.4 million.	Section 4.9

1.2 The Applicant

BC Hydro is a Crown corporation established under the *Hydro and Power Authority Act* and its owner and sole shareholder is the Government of British Columbia (B.C.).[10] The organization is one of the largest energy suppliers in Canada, generating and delivering electricity to 95 percent of B.C.'s population and serving more than 4 million people.[11]

BC Hydro's stated mission is to safely provide customers with reliable, affordable and clean electricity throughout B.C. BC Hydro states that it has a responsibility to its customers to keep bill increases as low as possible while making investments for a resilient system and to provide reliable service.[12]

1.3 Regulatory Process and Participants

On September 7, 2021, the BCUC established an initial regulatory timetable for the review of the Application, and several additional regulatory timetables were subsequently established. The regulatory process included two rounds of information requests (IR) and an additional round of IRs on DSM (DSM IR no. 3). Intervener Evidence was also filed by several parties, covering the topics of BC Hydro's Non-Integrated Area (NIA), depreciation and asset service lives, net salvage, asset management, vegetation management, Electrification Plan spending, DSM spending, and Site C cost impacts, followed by a round of IRs and rebuttal evidence. The regulatory process also included an oral hearing and a Streamlined Review Process (SRP).

Since BC Hydro filed its DSM expenditure schedules subsequent to its IR no. 1 responses, the additional round of Irs (i.e. DSM IR no. 3) results in the F2023 to F2025 DSM schedule and the revised F2022 DSM expenditure schedule being subject to the same number of rounds of Irs as the rest of the Application.

An oral hearing was held on September 20 to 23, 2022 on the topics of depreciation and net salvage, United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) and the steps to advance reconciliation, the DARR and cost of energy forecasts, the expected asset lives used in asset management planning and strategy,

[10] Exhibit B-2, p. 1-1.
[11] Exhibit B-2-1, Appendix C, BC Hydro Service Plan, p. 5.
[12] Exhibit B-2, p. 1-1.

and vegetation management. The oral hearing also included BC Hydro's rebuttal evidence with respect to the intervener evidence that was filed during the proceeding.

During the final arguments portion of the proceeding, the Lieutenant Governor in Council enacted the Direction to the BCUC Respecting Residential and Commercial Customer Account Credits (Account Credits Direction)[13] and the Direction to the BCUC Respecting Cryptocurrency Mining Projects (Cryptocurrency Direction).[14] After consideration of these new Directions, the BCUC reopened the evidentiary record and established an amended regulatory timetable that included one round of Panel Irs, BCUC and Intervener Irs (SRP IR no. 3), and an SRP to review certain items in the Application that may be impacted by these government directions. The scope of the SRP was set out as follows:[15]

i. The impact of the Account Credits Direction on the Application, including but not limited to the Cost of Energy Variance Accounts, the DARR, and the forecasts related to the specified costs defined in the Account Credits Direction (Specified Costs); and

ii. The cost of energy forecasts, load forecasts, and Trade Income forecasts, as impacted by the F2022 actual results and the Cryptocurrency Direction.

Following the SRP, the BCUC established a further amended regulatory timetable that included written intervener final arguments on the topics within the scope of the SRP, arguments on Association of Major Power Customers of British Columbia (AMPC)'s proposal raised at the SRP, AMPC's reply to interveners regarding its proposal, and BC Hydro's reply argument.[16] BC Hydro's final argument on the topics within the scope of the SRP were provided orally at this review process.

Following the filing of intervener's final arguments and BC Hydro's reply argument on the SRP topics and AMPC's proposal, the BCUC invited parties' submissions on an alternative approach to setting the DARR.[17]

Subsequently, the Panel reopened the evidentiary record a second time to accommodate two rounds of Panel IRs (i.e. Panel IR no. 2 and no. 3) on the topic of BC Hydro's finance charges.[18] During this time, BC Hydro filed a request, as part of this proceeding, to reinstate a $320 million regulatory liability in the Trade Income Deferral Account (TIDA).[19] The reinstatement of the regulatory liability would have the effect of offsetting the transfer from the TIDA to the customer credit regulatory account that occurred pursuant to the Account Credits Direction. The Account Credits Direction is discussed in Section 2.4.3 of this Decision. The Panel invited, and received, parties' submissions on BC Hydro's request to reinstate the $320 million regulatory liability in the TIDA.[20] The current regulatory timetable for this proceeding includes responses to Panel IRs regarding BC Hydro's finance charges and further process to be determined on both the finance charges and the separate topic of BC Hydro's request to reinstate the liability in the TIDA.[21] Since the review of these two topics is currently ongoing, the Panel does not make determinations on them in this Decision. Any determinations with respect to these two topics will be made by the Panel in due course after the issuance of this Decision.

<u>Interim Rates</u>

[13] OIC 571, B.C. Reg. 224/2022.
[14] OIC 692, B.C. Reg. 281/2022.
[15] Exhibit A-41, Order G-386-22.
[16] Exhibit A-44, Order G-10-23.
[17] Exhibit A-46.
[18] Exhibit A-48, Order G-66-23; Exhibit A-49; Exhibit A-51, Order G-90-23; Exhibit A-52.
[19] Exhibit B-54.
[20] Exhibit A-50, Order G-74-23.
[21] Exhibit A-51, Order G-90-23.

By order dated February 22, 2022, the BCUC approved on an interim basis the requested rate increase of 0.62 percent, the requested DARR of (2.0) percent, and the requested F2023 OATT rates, effective April 1, 2022.[22] By order dated March 21, 2023, the BCUC approved on an interim basis the requested rate increase of 0.97 percent, the requested DARR of (1.0) percent, and the requested F2024 OATT rates, effective April 1, 2023.[23]

Participants and Parties

There were 15 registered interveners and five interested parties to this proceeding. The following parties registered as interveners:

- BC Sustainable Energy Association (BCSEA);
- Movement of United Professionals (MoveUP);
- FortisBC Energy Inc. and FortisBC Inc. (FortisBC);
- Clean Energy B.C. (CEBC);
- Kwadacha Nation and Tsay Keh Dene Nation, together the Zone II Ratepayers Group (Zone II RPG);
- Capital Power Corporation (Capital Power);
- Association of Major Power Customers of British Columbia (AMPC);
- Residential Customer Intervener Association (RCIA);
- Commercial Energy Consumers Association of British Columbia (CEC);
- Nuu-chah-nulth Tribal Council (NTC);
- British Columbia Old Age Pensioners’ Organization et al. (BCOAPO);
- Zone 1B Ratepayers Group (Z1BRG);
- Richard McCandless (McCandless);
- Canadian Manufacturers and Exporters (CM&E); and
- Edlira Gjoshe (Gjoshe).[24]

The BCUC also received three letters of comment from members of the public and one letter of comment from the Minister of Energy, Mines and Low Carbon Innovation.[25]

1.4 Previous BCUC Directives

The BCUC provided directives to BC Hydro in the BCUC’s Decision on BC Hydro’s F2020 to F2021 RRA and in the BCUC’s Decision on BC Hydro’s F2022 RRA which impact the current Application.

BC Hydro states that it has considered recent BCUC directives and BCUC and intervener feedback when drafting the Application. Of the 68 directives in the BCUC’s Decision on BC Hydro’s F2020 to F2021 RRA (F2020 to F2021 RRA Decision), BC Hydro states that 16 of them are addressed in the Application, while the other directives have either already been addressed, rescinded, or will be addressed in a future filing. Of the 27 directives in the

[22] Exhibit A-14, Order G-47-22.
[23] Exhibit A-47, Order G-60-23.
[24] On September 11, 2022, Gjoshe withdrew her intervener status in Exhibit C15-3.
[25] Exhibits E-1 to E-4.

BCUC's Decision on BC Hydro's F2022 RRA (F2022 RRA Decision), BC Hydro states that 16 of them are addressed in the Application, while the other directives have either already been addressed or will be addressed in a future filing. In Table 1-1 of the Application, BC Hydro provides a summary of the directives addressed in the Application.[26]

1.5 The BCUC's Review of BC Hydro's Performance Based Regulation Report

During the proceeding, the BCUC issued its Decision on BC Hydro's Performance Based Regulation (PBR) Report. This decision directed BC Hydro to file a proposal for its next RRA that includes the following items by December 31, 2023:[27]

1. A test period of at least 5 years;
2. A proposed formula for as much as possible of the utility's controllable operations and maintenance (O&M) and capital expenditures, incorporating cost inflation and productivity indices;
3. A proposal for which, if any, of the years F2022–F2025 should be used as the base year;
4. Proposals for specific exclusions from the formula or index approach, if appropriate (including "Y factors" and "Z factors");
5. Consideration of whether a different approach is required for growth capital as compared to sustainment capital;
6. A proposal for the criteria and reasons, if any, to abandon the PBR approach during the test period ("Off-Ramps"); and
7. An assessment of whether annual reviews of BC Hydro's performance and rates during the test period are appropriate and what they should encompass and exclude.

1.6 Decision Framework

The remaining sections of the Decision are organized into 4 sections. First, Section 2.0 outlines the legal and legislative framework relevant to the Application. Second, Section 3.0 provides an overview of the rate changes requested in the Application and the Panel's determination. Third, Section 4.0 discusses the key issues in the Application, as well as the topics discussed at the SRP. Finally, Section 5.0 discusses some of the other issues raised during the proceeding that do not fall within the general organization of the Application.

2.0 Legal and Legislative Framework

The BCUC's legislative authority is set out in various legislation pertaining to BC Hydro, including the UCA, the *Hydro and Power Authority Act*, and the *Clean Energy Act* (CEA) including relevant regulations and directions. Although some regulations and directions continue to have an impact on this Application, others that may have been relevant to the F2022 RRA have no impact on BC Hydro's current Test Period.

2.1 The Utilities Commission Act

The UCA, in particular sections 59 to 61, provides the regulatory framework for BCUC's review of BC Hydro's revenue requirements. These sections, generally speaking, reflect what is commonly known as the "Regulatory Compact" which provides for a utility to recover its prudently incurred costs and be given the opportunity to earn a fair return on its invested capital, in return for providing safe and reliable service at rates that are not unreasonable, not unjust and not unduly discriminatory or unduly preferential. A utility has an obligation to

[26] Exhibit B-2, pp. 1-9 – 1-11, Table 1-1, p. 1-12.
[27] BCUC Review of BC Hydro's PBR Report, Decision and Order G-388-21, p. 58.

supply service to premises located within certain distances of its supply line, unless otherwise directed by the BCUC.

In addition to these rate setting sections, the BCUC reviews the following under the UCA:

- BC Hydro's depreciation rates under section 56;
- BC Hydro's capital projects and expenditures under section 44.2 for the acceptance of a capital expenditure and / or section 45 to determine whether the project requires a Certificate of Public Convenience and Necessity (CPCN);
- BC Hydro's Electricity Purchase Agreements (EPAs) under section 71; and
- BC Hydro's DSM expenditure schedules under section 44.2 to determine whether they should be accepted.

2.2 The Hydro and Power Authority Act

The *Hydro and Power Authority Act* mandates BC Hydro to generate, manufacture, conserve, supply, acquire and dispose of power and related products, and to supply and acquire related services. BC Hydro explains that it 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 and that the Minister of Finance is the fiscal agent of BC Hydro. The *Hydro and Power Authority Act* also sets out certain provisions of the UCA that are not applicable to BC Hydro.[28]

2.3 The Clean Energy Act

BC Hydro states that sections 7, 8, and 18 of the *Clean Energ*y *Act* (CEA) continue to have direct relevance for its RRAs. These sections pertain to certain BC Hydro projects, programs, contracts and expenditures that are exempt from BCUC review under sections 45 to 47 and 71 of the UCA; and the allowances for BC Hydro to collect sufficient revenue to recover costs incurred for these exempt items and to recover the costs incurred for implementing prescribed undertakings.[29]

Prescribed undertakings are projects, programs, contracts or expenditures prescribed for the purpose of reducing greenhouse gas emissions in B.C., as defined in the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR). The GGRR sets out various classes of prescribed undertakings, including low carbon electrification infrastructure projects, low carbon electrification programs and expenditures, and electric vehicle (EV) charging stations.[30]

Section 2 of the CEA sets out B.C.'s energy objectives, which is relevant in the BCUC's review of BC Hydro's demand-side management expenditure schedules.

2.4 Relevant Regulations and Directions

In the Application, BC Hydro provides a table summarizing the regulations and directions in effect or that have been amended that impact its revenue requirements in the Test Period, which include:[31]

- Direction to the BCUC Respecting the Customer Crisis Fund Program;
- Direction to the BCUC Respecting Industrial Electrification;

[28] Exhibit B-2, p. 2-2.
[29] Exhibit B-2, p. 2-4.
[30] Exhibit B-2, p. 2-4.
[31] Exhibit B-2, Table 2-1, pp. 2-5 – 2-15.

- Direction No. 8 to the BCUC;
- Direction to the BCUC Respecting COVID-19 Relief;
- Direction to the BCUC Respecting the Biomass Energy Program;
- Greenhouse Gas Reduction (Clean Energy) Regulation;
- Direction No. 4 to the BCUC;
- Direction to the BCUC Respecting Mining Customers;
- Direction to the BCUC Respecting the Authority's TMP [Thermo-Mechanical Pulp] Program;
- Direction to the BCUC Respecting the Iskut Extension Project;
- Direction to the BCUC Respecting Undertaking Costs;
- Electricity Self-Sufficiency Regulation;
- Remote Communities Regulation;
- Shore Power Regulation;
- Special Direction – BC Hydro No. 2 Regulation;
- Special Direction No. 10 to the BCUC; and
- Transmission Upgrade Exemption Regulation.

Details of the above regulations and directions and how they impact BC Hydro's Test Period revenue requirements can be found in Table 2-1 of the Application.

In addition to the regulations and directions above, the Demand-Side Measures Regulation is relevant in the review of BC Hydro's demand-side management expenditure schedule that was filed as part of this proceeding.

During this proceeding, the Government of B.C. enacted and amended several directions that impact the Application, which are further described in the sub sections below. The overall effect of the various regulations and directions is that they circumscribe the statutory authority the BCUC would have otherwise had over these matters under the UCA.

2.4.1 Amendment to Direction No. 8 to the BCUC

On March 7, 2022, Direction No. 8 to the BCUC was amended to require the BCUC to set rates for BC Hydro that reflect an allowed net income of $712 million for each year of the Test Period.[32] Prior to this amendment, the requirement did not include fiscal years 2024 and 2025.

2.4.2 Direction to the BCUC Respecting Load Attraction and Low-Carbon Electrification

On June 27, 2022, the Direction to the BCUC Respecting Load Attraction and Low-Carbon Electrification (Electrification Plan Direction) was enacted by Order In Council (OIC) 355, which prescribes the requirements for the recovery of certain costs for the Load Attraction and Low Carbon Electrification (LCE) programs in BC Hydro's

[32] OIC 123, B.C. Reg. 56/2022; Exhibit B-17.

Electrification Plan.[33] BC Hydro's Electrification Plan is discussed in Section 4.1 of this Decision. BC Hydro states that since the Electrification Plan Direction was issued under section 3 of the UCA, the requirements of this regulation supersede any potentially conflicting provisions of the UCA, the CEA or the GGRR.[34]

With respect to the Load Attraction programs, section 3 of the Electrification Plan Direction requires the BCUC to allow BC Hydro to establish a regulatory account (Load Attraction Costs Regulatory Account) and to defer up to $52 million in costs incurred from April 1, 2022 to March 31, 2027 to provide its Load Attraction programs plus interest at BC Hydro's weighted average cost of debt. The BCUC must also allow BC Hydro to recover in its rates each year the interest on the regulatory account balance and the deferred load attraction amounts based on a 20-year amortization period.

With respect to the LCE programs, section 4 of the Electrification Plan Direction requires the BCUC to allow BC Hydro to defer to BC Hydro's DSM Regulatory Account up to $193.7 million in costs incurred from April 1, 2022 to March 31, 2027 to provide programs that BC Hydro considers as LCE actions under section 4 of the GGRR (LCE Program). The BCUC must also allow BC Hydro to recover these costs in its rates over a 15-year amortization period through its DSM Regulatory Account. The LCE Program does not include EV charging expenditures, except for those that relate to commercial fleet and mobile diesel electrification.

Section 5 of the Electrification Plan Direction requires the BCUC to allow BC Hydro to recover in its rates over a period determined by BC Hydro, the capital costs incurred "to provide service to persons who receive incentives or other funding, or are otherwise encouraged to apply for service," under BC Hydro's Load Attraction programs and the LCE Program.

Section 6 of the Electrification Plan Direction requires the BCUC to allow the apportionment of the above costs to be recovered or refunded by BC Hydro in either of the following ways:

(a) so that the charges under the specified rate schedules are all increased or decreased, as the case may be, by the same percentage; or

(b) so that, for each specified rate schedule, the increase or decrease in charges under the schedule will generate substantially the same revenue under the schedule as the apportionment described in paragraph (a).

2.4.3 Direction to the BCUC Respecting Residential and Commercial Customer Account Credits

On November 18, 2022, the Account Credits Direction was enacted by OIC 571.[35] The Account Credits Direction requires the BCUC to issue various final orders to BC Hydro and other regulated utilities to enable, among other things, BC Hydro to:

- Provide account credits to its commercial and residential customers and to establish a customer credit regulatory account to defer the amounts of customer account credits issued.
- Establish an inflationary pressures regulatory account to defer Specified Costs, which are defined as the variances between the Test Period forecast costs in the Application and the actual costs in relation to the following:
    - labour costs as set out in line 20 in Schedule 5 of Appendix A to the Application, other than the operating cost portion of current service pension costs;

[33] OIC 355, B.C. Reg. 156/2022.
[34] BC Hydro Final Argument, p. 194.
[35] OIC 571, B.C. Reg. 224/2022.

- vegetation management costs as set out in Table 5-27 of the Application, other than labour costs related to vegetation management; and
- fuel costs as set out in lines 5 and 6 on page 5E-44 of chapter 5E of the Application, other than the portion of fuel costs allocated to capital overhead.

- Transfer amounts from the Trade Income Deferral Account of $320 million to the customer credit regulatory account, $6 million to the Customer Crisis Fund (CCF) Regulatory Account, and $74 million to the inflationary pressures regulatory account.

On November 28, 2022, the BCUC issued Order G-341-22 pursuant to the Account Credits Direction.

OIC 571 also amended the Direction to the BCUC Respecting the CCF Program to allow BC Hydro to defer up to $11 million to the CCF Regulatory Account for costs incurred to administer the CCF program and for grants provided to residential customers under the CCF program. Prior to the amendment, BC Hydro was allowed to defer up to $5 million to the CCF Regulatory Account.

2.4.4 Direction to the BCUC Respecting Cryptocurrency Mining Projects

On December 21, 2022, the Province enacted the Cryptocurrency Direction by OIC 692.[36] The Cryptocurrency Direction requires the BCUC to relieve BC Hydro from its obligation to supply service to certain cryptocurrency projects for an 18-month period starting from the date the BCUC issues its final orders pursuant to this Direction. On December 28, 2022, the BCUC issued Order G-390-22A pursuant to the Cryptocurrency Direction.

3.0 Overall Determination on Rates

In the Application, BC Hydro requests approval for the following rate changes:

- Increase general rates by 0.62 percent, effective April 1, 2022, by 0.97 percent, effective April 1, 2023 and by 2.18 percent, effective April 1, 2024;
- Set the DARR at (2.0) percent, effective April 1, 2022, at (1.0) percent, effective April 1, 2023, and at (0.5) percent, effective April 1, 2024; and
- Set the F2023, F2024, and F2025 OATT rates as set out in Table 9-4 of the Application.

The general rate increases and the DARR rates set out above would result in a net bill decrease of 1.4 percent on April 1, 2022, followed by net bill increases of 2.0 percent on April 1, 2023 and 2.7 percent on April 1, 2024.[37]

During the proceeding, BC Hydro identified various corrections to the Application and to the evidence filed in the proceeding.[38]

For the reasons laid out in Sections 4.0 and 5.0 of this Decision, the Panel finds BC Hydro's forecast revenue requirements for the Test Period to be reasonable, except for certain components of the revenue requirements as identified and discussed in the remainder of this Decision.

Therefore, the Panel approves the requested rates, subject to the adjustments resulting from the corrections identified by BC Hydro in the proceeding, the determinations and directives contained in this Decision, and

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[36] OIC 692, B.C. Reg. 281/2022.
[37] Exhibit B-2, p. 1-50.
[38] Exhibits B-2-1-3; B-2-1-2, B-2-6; B-2-2-1; B-2-7; B-2-2-2; B-10-1; B-10-2; B-49; B-49-1; B-30-1; B-31-1; B-7-4; B-20-3; B-7-3; B-8-4; B-8-2; B-8-5; B-20-4; B-19-2; B-20-2.

any future determinations and directives made by the Panel with respect to the following two topics as noted in Section 1.3 of this Decision:

- **BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA; and**
- **BC Hydro's finance charges.**

Since any future Panel determinations and directives on the two topics above may impact the Test Period rates, **the Panel directs that the requested general rate increases, OATT rates, and DARR for F2023 and F2024 approved by the BCUC on an interim basis by Order G-47-22 and Order G-60-23, respectively, remain unchanged until further order of the Panel.**

BC Hydro is directed to re-calculate its revenue requirements in a compliance filing based on the corrections it identified in the proceeding, the Panel's determinations in this Decision, and any future Panel determinations and directives issued in the proceeding (Compliance Filing). The Compliance Filing is to be filed with the BCUC within 30 days of the issuance of an order approving the Test Period rates on a permanent basis. BC Hydro is directed to include in its Compliance Filing, a revised Appendix A to the Application and updated rate schedules, reflecting the corrections identified by BC Hydro in the proceeding, the BCUC's Decision and accompanying Order, and the future order approving Test Period rates on a permanent basis.

The Panel notes that Direction No. 8, as currently amended, requires the BCUC to set rates for BC Hydro that reflect an allowed net income of $712 million for each year of the Test Period. **Considering that Direction No. 8 only prescribes BC Hydro's net income up to and including F2025, the Panel directs BC Hydro to file a cost of capital application, effective April 1, 2025, by no later than April 1, 2024.**

4.0 Revenue Requirement – Key Issues

This section includes analysis and Panel determinations of exceptions to the overall finding of reasonableness of the revenue requirement in Section 3.0 of this Decision.

4.1 Electrification Plan

This section pertains to BC Hydro's Electrification Plan that it submitted on September 28, 2021 following the original Application.[39] BC Hydro's load forecast and cost of energy as they relate to the Electrification Plan are discussed in Section 4.2.3 and Section 4.3 of the Decision, respectively.

BC Hydro states the Electrification Plan supports its Five-Year Strategy and describes the three primary actions BC Hydro will take to work with customers: increase low carbon electrification (LCE), attract additional load (Load Attraction) and connect customers more efficiently (Connecting Customers). BC Hydro submits these actions will reduce rate increases for customers, lower greenhouse gas (GHG) emissions and provide economic benefits to B.C.[40]

The LCE component[41] of the Electrification Plan includes programs to help customers in the building, transportation and industrial sectors to electrify, while the Load Attraction component focuses on attracting new industrial customers to the BC Hydro system.[42] The Connecting Customers component supports both LCE and Load Attraction customers through improved connection processes, and upgrading existing services to support increased load on both the transmission and distribution systems.[43]

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[39] Exhibit B-2-3-1, Chapter 10; Appendix U
[40] Exhibit B-2-3-1, p. 10-1
[41] Exhibit B-2-3-1, Table 10-4, p. 10-15
[42] Exhibit B-2-3-1, p. 10-22
[43] Exhibit B-2-3-1, pp. 10-28 to 10-32

In the Application, BC Hydro refers to all actions that encourage the use of electricity for the purposes of reducing GHG emissions in B.C. as LCE, which includes prescribed undertakings under both section 4 and section 5 of the GGRR. However, BC Hydro refers to LCE actions under section 4 of the GGRR as the LCE Program, and LCE actions under section 5 of the GGRR as EV Charging Stations. This Decision uses the same terms to refer to BC Hydro's LCE actions.[44]

BC Hydro provides the following table of outcomes over the Test Period if the Electrification Plan is fully realized:[45]

Table 2: Summary of Electrification Plan Outcomes over Test Period[46]

	F2023 Plan	F2024 Plan	F2025 Plan	Total
Annual Revenue ($ million)	$20.2	$84.0	$152.1	$256.3
Capital Additions ($ million)	$17.8	$36.3	$91.0	$145.1
Deferred Expenditures excluding expenditures for electrification already in December 2020 load forecast ($ million)	$44.3	$59.2	$59.4	$162.9
Operating Costs ($ million)	$1.2	$2.1	$2.8	$6.1
Annual Rate Impact (%)[517]	-0.41	0.18	-0.73	
Cumulative Incremental Rate Impact[518](%)	-0.26	-0.08	-0.82	
Cumulative New Electric Energy Sales (GWh/year)	313	1,314	2,231	
Cumulative New Electricity Demand (MW)	63	234	390	
Cumulative GHG Emission Reductions (tonnes CO2e/year)	20,576	310,807	583,096	

The Electrification Plan sets out the actions BC Hydro intends to take to reduce GHG emissions, in the context of the emission reduction targets set by the BC Government in the *Climate Change Accountability Act*.[47]

BC Hydro states the Electrification Plan reduces rate increases because domestic sales generate more revenue than exporting surplus electricity and the incremental revenue generated by the Electrification Plan exceeds the associated costs.[48] BC Hydro also states that 21 percent of the forecasted load in the Electrification Plan is required to recover both the fixed and incremental variable costs in the Electrification Plan (i.e., achieve an NPV of $0).[49]

On June 27, 2022, the Electrification Plan Direction was enacted, as discussed in Section 2.4.2 of this Decision, which prescribes the requirements for the recovery of costs for the Load Attraction programs and the LCE Program, and prohibits the BCUC from disallowing recovery of the capital costs incurred by BC Hydro for customers who connect under the Load Attraction and the LCE Program.[50] The requirements of the Electrification Plan Direction supersede any potentially overlapping provisions of the UCA, the CEA and the GGRR; however, the requirements of the CEA and the GGRR continue to apply where there is no overlap.[51] For the purposes of this Decision, LCE Program refers to those LCE actions that are referenced in the Electrification

[44] Exhibit B-2-3-1, Footnote 515, p. 10-1
[45] Exhibit B-2-3-1, Table 10-1, p. 10-2.
[46] Exhibit B-2-3-1, Table 10-1, p. 10-2.
[47] Exhibit B-2-3-1, p. 10-6.
[48] Exhibit B-2-3-1, p. 10-4.
[49] Exhibit B-7, BCUC IR 122.1.1.
[50] OIC 355, B.C. Reg. 156/2022.
[51] BC Hydro Final Argument, p. 194

Plan Direction, and excludes EV station costs covered by section 5 of the GGRR. The LCE Program includes commercial fleet and mobile diesel electrification, as outlined in the Application.[52]

The Electrification Plan programs, incremental full-time equivalents (FTE)s, planned expenditures and revenues, and other details are presented in the Application.[53] A summary of the individual expenditures contained within BC Hydro's 5 year Electrification Plan, including the Test Period, is provided below.

Table 3: Expenditures over the Five year Electrification Plan ($ million)[54]

<table>
<tr><th>Electrification Plan Component</th><th>F2022</th><th>F2023</th><th>F2024</th><th>F2025</th><th>F2026</th><th>Total</th><th>Regulations</th><th>Cost Treatment</th></tr>
<tr><td>LCE Program</td><td>9.2</td><td>39.9</td><td>49.5</td><td>50.6</td><td>44.5</td><td>193.7</td><td>Electrification Plan Direction[55]</td><td>DSM Regulatory Account</td></tr>
<tr><td>Load Attraction</td><td>-</td><td>8.7</td><td>9.7</td><td>8.8</td><td>24.9</td><td>52.0</td><td>Electrification Plan Direction[56]</td><td>Load Attraction Costs Regulatory Account (new)</td></tr>
<tr><td>Connecting Customers – Operating Costs</td><td>-</td><td>0.9</td><td>1.8</td><td>2.4</td><td>2.4</td><td>7.5</td><td>Not covered by GGRR or the Electrification Plan Direction</td><td>Operating costs</td></tr>
<tr><td>EV Charging Stations Maintenance</td><td>-</td><td>0.2</td><td>0.3</td><td>0.4</td><td>0.5</td><td>1.5</td><td>GGRR[57]</td><td>Operating costs</td></tr>
<tr><td>EV Charging Stations Incremental Capital</td><td>-</td><td>2.0</td><td>2.0</td><td>2.1</td><td>2.1</td><td>8.2</td><td>GGRR[58]</td><td>Capital cost</td></tr>
<tr><td>Total</td><td>9.2</td><td>51.7</td><td>63.3</td><td>64.3</td><td>74.4</td><td>262.9</td><td></td><td></td></tr>
<tr><td colspan="9">The incremental transmission and distribution costs for the Connecting Customers component are not included in the above totals. BC Hydro states these will instead be approved through the individual capital projects triggered by specific interconnection requests, and the costs will be presented for each test period.[59] The amounts for F2022 and the test period are shown below.[60]</td></tr>
<tr><td>Connecting Customers – Estimated Capital Expenditures</td><td>6.5</td><td>26.7</td><td>60.2</td><td>53.3</td><td>-</td><td>146.6</td><td>Electrification Plan Direction[61]</td><td>Capital cost</td></tr>
<tr><td>Grand Total</td><td>15.7</td><td>78.3</td><td>123.5</td><td>117.6</td><td>74.4</td><td>409.5</td><td></td><td></td></tr>
</table>

[52] Exhibit B-2-3-1, Appendix U, Attachment 3, pp. 10-24.
[53] See Exhibit B-2-3-1, Chapter 10 and Appendices U, V and W for more details.
[54] BC Hydro Final Argument, pp. 191-–192; Table prepared based on information in Exhibit B-2-3-1, Table U-3 and Exhibit B-7, BCUC IR 119.2.
[55] OIC 355, BC Reg. 156/2022, S 4.1.
[56] OIC 355, BC Reg. 156/2022 , S 3.2.
[57] Section 5(2) of the GGRR sets out the criteria that qualify an EV charging station as a prescribed undertaking for the purposes of section 18 of the CEA. Section 18(2) requires the BCUC to set rates that allow public utilities, such as BC Hydro, to collect sufficient revenue to recover the costs incurred for implementing prescribed undertakings.
[58] Section 5(2) of the GGRR sets out the criteria that qualify an EV charging station as a prescribed undertaking for the purposes of section 18 of the CEA. Section 18(2) requires the BCUC to set rates that allow public utilities, such as BC Hydro, to collect sufficient revenue to recover the costs incurred for implementing prescribed undertakings.
[59] Exhibit B-2-3-1, Appendix U, p. 42
[60] Exhibit B-7, BCUC IR 119.2.
[61] OIC 355, B.C. Reg. 156/2022, S 5.

The related regulations and Directions are listed beside each component, namely the Electrification Plan Direction[62] and the GGRR.[63]

The table above shows forecast expenditures over the 5-year period of the Electrification Plan, which includes expenditures in F2022[64] and anticipated expenditures in F2026 that are outside of the Test Period of this RRA. Finally, the table lists the cost treatment which includes the following:

- LCE Program expenditures are to be allocated to the DSM Regulatory Account, with an amortization period of 15 years.
- The creation of a new Load Attraction Costs Regulatory Account to which the BCUC must allow BC Hydro to defer certain amounts, to be amortized over a 20-year period.
- Operating costs within the RRA Test Period, allocated to both the Connecting Customers program and EV Charging Station maintenance.
- Capital cost treatment of the capital expenditures and additions required to provide service to connect customers under the LCE Program and Load Attraction programs, and additional EV Charging Stations.

Over the Test Period, BC Hydro estimates the LCE Program expenditures, as covered by the Electrification Plan Direction, to amount to $39.9 million, $49.5 million and $50.6 million for F2023, F2024 and F2025 respectively, or a total of $140 million.

Load Attraction expenditures, as covered by the Electrification Plan Direction, are estimated at $8.7 million, $9.7 million and $8.8 million for F2023, F2024 and F2025 respectively, or a total of $27.2 million over the Test Period.

The capital and operating expenditures for the Connecting Customers component of the Electrification Plan over the Test Period are outlined in the following table.

Table 4: Electrification Plan - Connecting Customers ($ million)[65]

	F2023 Plan	F2024 Plan	F2025 Plan	Total
Capital Expenditures - Transmission and Distribution system improvements and interconnection costs (refer to section 10.4.2.4 above)	26.7	60.1	53.3	140.1
Amortization of Capital Expenditures for system improvements and interconnections	0.2	0.6	1.8	2.6
Operating Costs (non-capitalizable portion)	0.9	1.8	2.4	5.1

Section 5 of the Electrification Plan Direction prohibits the BCUC from disallowing the recovery of capital expenditures incurred "to provide service to persons who receive incentives or other funding, or are otherwise encouraged to apply for service, under the load-attraction program or the low-carbon electrification program."[66]

BC Hydro states that the incremental transmission and distribution capital costs for the Connecting Customers component will be approved through the individual capital projects triggered by specific interconnection

[62] OIC 355, B.C. Reg. 156/2022.
[63] Greenhouse Gas Reduction Regulation, Prescribed undertaking – Electrification, Section 4.
[64] $15.5 million was approved in the the F2022 RRA Decision, BCUC Order G-187-21.
[65] Exhibit B-2-3-1, Table 10-18, p. 10-59.
[66] Exhibit A-33, Decision accompanying Order G-248-22, p. 2.

requests.[67] The estimated Connecting Customers capital expenditures covered by the Electrification Plan Direction totals $140.1 million over the Test Period, as shown in Table 4 above.

Further, BC Hydro states that the only portion of the Electrification Plan expenditures not covered by either the Electrification Plan Direction or the GGRR, is the operating expenditures associated with Connecting Customers.[68] The Connecting Customers-related operating costs are intended to allow BC Hydro to respond to the increased volume of requests associated with both increased LCE and connecting new load.[69] The Test Period costs shown in Table 4 above, are discussed in more detail below.

With respect to the $5.1 million of operating costs for Connecting Customers over the Test Period, which are not covered by either the Electrification Plan Direction or the GGRR, BC Hydro has included $2.1 million[70] for 6 incremental FTEs required to primarily deliver the Electrification Plan.[71] The full-time equivalent (FTE) costs are associated with the early phases (non-capitalizable) of interconnection projects, additional operating cost for contract resources, as well as the residual non-billable portion of costs for FTEs' management, administrative and training time.[72] The process that was undertaken and the factors that were considered in determining additional FTE requirements for Connecting Customers to deliver the Electrification Plan are as follows:[73]

- Consideration of the nature (i.e., transmission, large distribution, and small distribution), and customer segments (i.e. residential, commercial, industrial, transportation), and the timing of the forecasted electrical load associated with the activities in the Electrification Plan;
- Forecasted volumes of customers for the different electrification programs combined with assumptions from the business units on the anticipated timing, scope and complexity of the connections;
- Baseline assumptions for resource productivity and efficiencies to calculate the net resource requirements;
- Utilize existing category management and procurement strategies for design, engineering and project management work where possible; and,
- Consideration of project phases (i.e., project definition, project implementation) and associated timelines for transmission and large distribution, FTEs requirements are focused on early study and investigative stages due to high uncertainty on the projects proceeding to later stages.

By the end of calendar 2025, BC Hydro's EV fast-charging network is forecast to include 325 stations at 145 sites. This includes an estimated 50 new eligible charging stations deployed per year during the Test Period.[74] The requirements for EV stations to qualify as a prescribed undertaking are outlined in section 5(2) of the GGRR, and BC Hydro provides details in the Application of how each station meets the GGRR requirements where a charging station's details are known.[75]

BC Hydro's Electrification Plan expenditures related to EV Charging Stations over the Test Period are outlined in the following table:[76]

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[67] Exhibit B-2-3-1, Appendix U, p. 42.
[68] Exhibit B-35, p. 2.
[69] Exhibit B-2-3-1, p. 10-28.
[70] Exhibit B-7, BCUC IR 61.2.
[71] Exhibit B-19, BCUC IR 177.3.
[72] Exhibit B-7, BCUC IR 61.5.
[73] Exhibit B-7, BCUC IR 61.3.
[74] Exhibit B-2-3-1, p. 10-52.
[75] Exhibit B-2-3-1, p, 10-53, updated in Exhibit B-7, BCUC IR 135.1, Attachment 1 and Exhibit B-19, BCUC IR 223.1, Attachment 1, Appendix W F2023-F2026 Plan
[76] Exhibit B-2-3-1, Table 10-8, p. 10-39; p. 10-43.

Table 5: EV Station expenditures over the Test Period ($millions)[77]

	F2023	F2024	F2025
Operating and maintenance - Incremental electrification	0.2	0.3	0.4
Capital expenditures – incremental electrification	2.0	2.0	2.1

BC Hydro forecasts one incremental FTE to support public EV charging, which is included in the operating costs.[78]

Positions of the parties

BC Hydro submits that the estimated capital expenditure of $140.1 million for the Connecting Customers component of the Electrification Plan over the Test Period is covered by the Electrification Plan Direction which states: "The commission must not disallow for any reasons the recovery in rates… of the capital costs incurred by the authority to provide service to person…". BC Hydro further states the only portion of the Electrification Plan expenditures not covered by the Electrification Plan Direction or the GGRR is $5.1 million over the Test Period, representing the operating expenditures associated with the Connecting Customers component of the Electrification Plan between F2023 to F2025.[79]

BC Hydro submits the investments under Connecting Customers will "improve BC Hydro's ability to study interconnection requirements and provide more accurate interconnection cost estimates in a timely manner for the increased volume and complexity of this work going forward, as required by section 39 of the UCA."[80]

No interveners take issue with BC Hydro's planned operating costs for Connecting Customers under the Electrification Plan with several accepting the need for these costs to support the LCE Program and Load Attraction customers.[81] The interveners didn't comment on the associated capital expenditures in final submissions.

FortisBC and BCOAPO note Order G-248-22 and the accompanying reasons, which clarified that the $5.1 million in operating costs related to Connecting Customers during the Test Period are not within the scope of the Electrification Plan Direction and clarified that the BCUC could not disallow the capital costs of $140.1 million pursuant to section 5 of the Direction.[82]

AMPC submits the BCUC should direct BC Hydro to provide regular updates on its Connecting Customers program, including benchmarking that measures and reports on queue wait times by connection size, and tracking improvements on key connection delays.[83]

With respect to the portion of the Electrification Plan that is subject to the Electrification Plan Direction, FortisBC submits that, "notwithstanding the Direction, the BCUC should perform a rigorous review of BC Hydro's Electrification Plan and make such determinations and findings as necessary to provide transparency to ratepayers and future guidance to BC Hydro regarding electrification issues." FortisBC encourages the BCUC to make clear in its decision that BCUC approval of the Electrification Plan expenditures in the Test Period does not indicate that these expenditures are cost-effective in the long-term or represent an endorsement of the merits

[77] Exhibit B-2-3-1, Table 10-14, p. 10-56 ; Table 10-15, p. 10-57.
[78] Exhibit B-2-3-1, p. 10-34.
[79] Exhibit B-35, pp. 1–2
[80] BC Hydro Final Argument, pp. 198–199
[81] Exhibit C1-11, BCSEA, p. 1; BCSEA Final Argument, pp. 61-62; BCOAPO Final Argument, p. 35; AMPC Final Argument, p. 4-4.
[82] FortisBC Final Argument, p. 3; BCOAPO Final Argument, p. 48,
[83] AMPC Final Argument, p. 8-2.

of the Electrification Plan, or for on-going proceedings such as the Integrated Resource Plan (IRP). Accordingly, FortisBC encourages the BCUC to note all of these caveats in its Decision.[84]

In addition to the Connecting Customers portion discussed above, FortisBC submits that the Electrification Plan Direction does not prescribe or determine issues such as the incremental Cost of Energy of $162 million, or the capital cost component of incremental transmission and distribution costs.[85]

AMPC submits the BCUC should not hesitate to make recommendations with respect to BC Hydro's electrification spending, because the Electrification Plan Direction is time-limited and BC Hydro will again have to justify its electrification spending, potentially in the next RRA.[86]

BC Hydro submits in reply that "FortisBC and AMPC are encouraging the BCUC to depart from its role as an independent, quasi-judicial tribunal and express opinion about the Government's electrification policies with the aim to influence future legislative decisions regarding electrification. It goes without saying that the BCUC should exercise prudence in considering these FortisBC and AMPC requests." BC Hydro cites the Supreme Court of Canada's statement in *Moore* v. *British Columbia (Ministry of Education)*, 2012 SCC 61 at para 64: "[t]he Tribunal, with great respect, is an adjudicator of the particular claim that is before it, not a Royal Commission."[87]

NTC questions whether BC Hydro is doing enough in the Application, including the Electrification Plan, to achieve the BC Government's GHG emission reduction targets.[88] NTC submits that "[i]n the proper course of events, the BCUC should expect to rely upon an approved IRP to form the basis for any shorter-term applications, such as an RRA."[89] Accordingly, NTC "recommends that the 3rd year of the proposed Test Period be only approved on an interim basis," and submits BC Hydro should be directed to return for further approval after the IRP has been completed and the Electrification Plan has been enhanced to achieve Government GHG emissions reduction goals.[90]

In response, BC Hydro agrees that it plays a large role in achieving GHG emission reduction targets, but that the legislated targets apply to the entire province and not only to BC Hydro. BC Hydro also submits that the Electrification Plan Direction clearly prescribes for the specified time periods up to $193.7 million for the LCE Program and up to $52 million for Load-Attraction programs and associated capital costs to provide service to customers participating in or taking service as a result of the Load Attraction programs and the LCE Program. Additional programs and expenditures, beyond those already included in BC Hydro's Electrification Plan, would not be within the scope of the Electrification Plan Direction.[91]

While acknowledging the Electrification Plan Direction, several interveners made suggestions regarding reporting or tracking of performance metrics. With respect to Load Attraction, NTC recommends that the BCUC should follow-up with BC Hydro and require regular updates on progress.[92]

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84 FortisBC Final Argument, pp. 11; 17.
85 FortisBC Final Argument, pp. 2–3.
86 AMPC Final Argument, p. 5.
87 BC Hydro Reply Argument, p. 169.
88 NTC Final Argument, pp. 22–25.
89 NTC Final Argument, p. 28.
90 NTC Final Argument, pp. 28–29.
91 BC Hydro Reply Argument, p. 171.
92 NTC Final Argument, p. 32.

The CEC recommends that the BCUC require more thorough analysis of electrification initiatives in the next BC Hydro RRA.[93] In reply, BC Hydro submits that the current analysis is thorough, and notes that the CEC does not identify any additional metrics for reporting.[94]

AMPC submits the Electrification Plan does not provide any measurable targets against which BC Hydro's expenditures can be assessed, such as on an emissions-reduction basis, and submits the BCUC should direct BC Hydro in future RRAs to report on the following four aspects of the Electrification Plan: [95]

(a) Actual spending, carbon emission reduction, and load increase results of these initial, protected plan year expenditures, and the actual revenue requirement impacts.

(b) Forecast plans and plan alternatives for test years, detailing individual measure incentive levels, expected payback periods, customer uptake profiles, and gaps in availability of electrification programming that may exist for certain customers. This would assist in determining whether future electrification plans are the most cost-effective, prudent option.

(c) Clear delineation between government and BC Hydro plans, and explanation of why BC Hydro is funding a program instead of government (or other third parties) through more relevant revenue streams, such as carbon tax revenue. This is required to be able to benchmark and report on actual results attributable to ratepayer-funded activities.

(d) Short-term rate impact analysis and longer-term cost/benefit tests being used by other jurisdictions to assess electrification, including a modified TRC and UCT. BC Hydro should also continue to include NPV and sensitivity analysis of its Electrification Plan.

AMPC also recommends that BC Hydro be encouraged to prioritise its Electrification Plan expenditures on time-sensitive opportunities, such as when a new customer locates in BC, when an existing customer alters or expands operations, or purchases replacement assets.[96]

BCSEA supports[97] the use of performance measures, noting the quantitative targets for performance measures included in the Five-Year Strategy including:

- Load growth supporting CleanBC (gigawatt hours (GWh));
- New connected commercial and industrial load (megawatt (MW))
- GHG emissions reduction – due to electrification and BC Hydro's own operations
- Customer interconnection studies completed on time.[98]

BCSEA also notes BC Hydro's statement that a performance review will include the added electrical load, new customer connections, emission reductions, cost effectiveness, and adherence to the budget.[99]

BC Hydro dismisses the need for additional reporting or metrics and points to the BC Hydro Service Plan,[100] noting several performance targets related to growing load,[101] as noted above by BCSEA.

[93] CEC Final Argument, p. 9.
[94] BC Hydro Reply Argument, p. 170.
[95] AMPC Final Argument, pp. 4-3–4-4.
[96] AMPC Final Argument, p. 4-2.
[97] BCSEA Final Argument, p. 64.
[98] Exhibit B-2-1, Appendix D, p. 21.
[99] BCSEA Final Argument, p. 66.
[100] See Exhibit B-2-1, Appendix D, p. 10.
[101] BC Hydro Reply Argument, p. 170.

Panel Determination

The Panel provides its determinations in three parts, starting with those expenditures in the Test Period that are mandated by the Electrification Plan Direction, followed by consideration of expenditures in the Electrification Plan that are not covered by the Electrification Plan Direction, and finally determinations on additional positions of the parties.

Part 1 – Expenditures mandated by the Electrification Plan Direction

The Panel finds that the expenditures in the following table are mandated by the Electrification Plan Direction.

Table 6: Test Period expenditures mandated by the Electrification Plan Direction

Expenditure ($ million)				
Component	**2023**	**2024**	**2025**	**Total**
LCE Program[102]	39.9	49.5	50.6	140.0
Load Attraction	8.7	9.7	8.8	27.2
Connecting Customers – Estimated Capital Expenditures	26.7	60.2	53.3	140.1
Total	75.3	119.4	112.7	

The regulatory account treatment of the expenditures related to the LCE Program and Load Attraction, as set out in the Electrification Plan Direction, is discussed in Section 4.8.4 of the Decision.

The accompanying reasons to Order G-248-22 stated that the only Test Period capital and operating Electrification Plan expenditures not covered by the Electrification Plan Direction or the GGRR are the $5.1 million in operating expenditures related to Connecting Customers. Due to the Electrification Plan Direction, the Panel must allow the recovery of the capital and operating Electrification Plan expenditures, other than the $5.1 million in operating expenditures related to Connecting Customers, from ratepayers. The Panel makes no findings as to the reasonableness of the expenditures covered under the Electrification Plan Direction.

Part 2 – Expenditures not mandated by the Electrification Plan Direction

The Panel now turns its attention to those Electrification Plan expenditures not prescribed in the Electrification Plan Direction, as summarized in the table below.

Table 7: Test Period Electrification Plan expenditures not mandated by the Electrication Plan Direction

Expenditure ($ million)	F2023	F2024	F2025	Total
Connecting Customers – Operating Costs	0.9	1.8	2.4	5.1
EV Charging Stations Operating and maintenance - Incremental electrification	0.2	0.3	0.4	0.9
EV Charging Stations Capital expenditures – incremental electrification	2.0	2.0	2.1	6.1

The first expenditure is the $5.1 million of operating costs for non-capitalizable phases of interconnection projects undertaken pursuant to the Electrification Plan, which includes $2.1 million in forecast labour costs for incremental FTEs associated with customer connections. The Panel finds there is insufficient evidence to support the $2.1 million of forecast labour costs for early phases of interconnection projects given the high degree of

[102] Low Carbon Electrification actions prescribed under S4 of the GGRR, excluding EV Charging Station expenditures covered under S5 of the GGRR.

uncertainty regarding the number of actual customers connected, the associated connection capital expenses and the resulting loads. The Panel acknowledges that interveners support approval of this expense. However, given the singular role of these expenditures for Connecting Customers, the reasonableness of these operating costs depends on the extent to which new customer connections actually occur. In BC Hydro's submission, the actual capital budget for the Connecting Customers initiative is uncertain, despite estimating $140.1 million over the Test Period.

The Panel directs BC Hydro to deduct from its revenue requirement the $2.1 million in forecast labour costs for incremental FTEs associated with Connecting Customers in delivering the Electrification Plan. The Panel directs BC Hydro to record its actual operating labour costs associated with Connecting Customers pursuant to the Electrification Plan in a new regulatory account, accruing interest at BC Hydro's current weighted average cost of debt, to a maximum of $2.1 million for the period F2023 to F2025, with the amortization and disposition of this account to be decided by a future BCUC panel.

The Panel acknowledges that any actual operating labour costs incurred to connect customers over and above the $2.1 million forecast amount will form part of the Specified Costs relating to labour, and may therefore be recorded at BC Hydro's discretion in the inflationary pressures regulatory account established pursuant to the Account Credits Direction.

The second and third rows of the table above relate to electrification of transportation, except the commercial fleet and mobile diesel electrification. The Panel accepts the EV station capital costs of $2.0 million, $2.0 million and $2.1 million and operating costs of $0.2 million, $0.3 million and $0.4 million, both sets of numbers in F2023, F2024 and F2025 respectively, as prescribed undertakings pursuant to section 5 of the GGRR. The Panel notes that the plan for the roll-out of the charging stations and sites in the NIA remains uncertain, and encourages BC Hydro to work with NIA communities to implement these stations, recognising the challenges of doing so while ensuring that GHG emissions do not increase.

Part 3 – Panel responses to positions of the parties on other issues

The Panel agrees with AMPC on the value of detailed reporting on results of the Electrification Plan in the next RRA. The Panel is not persuaded by BC Hydro's reply that such reporting is unnecessary due to the performance metrics in the Service Plan. The Service Plan focuses only on the load growth supporting CleanBC, newly connected commercial and industrial load and the GHG emission reductions from electrification, and does not report on expenditures, cost-effectiveness and impact on rates as AMPC have requested.

The Panel considers that the magnitude of the Electrification Plan expenditures, along with the submission of incremental load growth leading to reduced rate increases, necessitates reporting on the performance of the Electrification Plan, not just the energy and GHG emission impacts as per the Service Plan. Furthermore, the programs established under the Electrification Plan may be of benefit to ratepayers beyond the effective dates of the Electrification Plan Direction, at which time a history of such performance metrics would be of benefit in reviewing the associated costs in accordance with regulatory requirements under the UCA.

For the foregoing reasons, **the Panel directs BC Hydro to report on the following aspects of the Electrification Plan in its next RRA**:

- **A count of completed customer interconnection studies by rate schedule and the extent to which the subject customers of those completed studies actually connected new electrical loads.**
- **The actual expenditures, the electricity load increase, and the carbon emission reduction results, for each year of the Test Period and for each component of the Electrification Plan. This must include a clear delineation between government and BC Hydro expenditures and results where dual funding sources are combined. The results should be informed by measurement and verification studies for a sample of the projects, where possible.**

- **Forecast expenditures, electricity load increase and carbon emission reduction results, as a point of comparison against actuals in the previous bullet.**
- **Revenue versus cost impact analysis within this Test Period, as a basis for informing cost-effectiveness assessments for programming that may extend past the duration of the Electrification Plan Direction (i.e., in F2027 and beyond).**
- **Forecast and actual revenue requirement and rate impacts of the Electrification Plan.**

The Panel rejects the submission from NTC to approve the third year of the Test Period's rates on an interim basis until such time as the review of the IRP has been completed and the Electrification Plan has been enhanced to achieve government GHG emission reduction goals. Unlike an expenditure application under section 44.2(5.1)(b) of the UCA the BCUC is not required to consider the filed IRP for its Decision on this RRA.

4.2 Load Forecast

BC Hydro's December 2020 Reference load forecast (December 2020 Load Forecast) combined with its additional loads associated with BC Hydro's 5-year Electrification Plan (Electrification Plan Load) is used in calculating the revenue forecast for F2023, F2024 and F2025.[103] The load forecast for revenue purposes is, in turn, used in the calculation of the Test Period revenue requirements. [104] The table below presents the load forecast used for revenue purposes over the Test Period.

Table 8: Forecast load for revenue purposes[105]

	F2023 Plan	F2024 Plan	F2025 Plan
Domestic Energy Sales (GWh)			
Residential	19,676	19,913	20,038
Light Industrial and Commercial	18,785	18,730	18,642
Large Industrial	13,183	14,042	14,982
Irrigation	80	81	81
Street Lighting	215	210	209
New Westminster & Tongass	506	512	516
Fortis	618	615	637
Seattle City Light	310	310	310
Liquefied Natural Gas	0	0	0
Other	3	6	10
Subtotal	53,377	54,419	55,426
Electrification Plan			
Residential	(22)	(12)	1
Light Industrial and Commercial	(31)	42	135
Large Industrial	367	1,284	2,095
Subtotal	313	1,314	2,231
Total	53,691	55,733	57,657

BC Hydro states it prepared the December 2020 Load Forecast as a comprehensive 20-year load forecast to support both its RRA and the BC Hydro 2021 IRP. BC Hydro states the methodologies used to develop the

103 Exhibit B-2, pp. 3-1, 3-5, 3-47
104 Exhibit B-2, p. 3-47.
105 Exhibit B-2-1, Appendix A, Schedule 14 – extract.

December 2020 Load Forecast are substantially the same as those used to develop BC Hydro's previous comprehensive load forecast except for adjustments related to the COVID-19 pandemic.[106]

The December 2020 Load Forecast is also one of the inputs to BC Hydro's Energy Studies models which are used to forecast its cost of energy across a five-fiscal-year time horizon. BC Hydro's Non-Heritage Deferral account (NHDA) captures, among other things, the variances between revenues received for actual versus planned customer load, referred to as the Domestic Revenue Variance. BC Hydro recovers the balances in the NHDA using the DARR.[107]

The December 2020 Load Forecast and Electrification Plan Load Forecast are two distinct products developed using different methodologies and serving different purposes and costs, and revenues as a result of the Electrification Plan will depend on actual customer commitments.[108] Additional loads included in the Electrification Plan Load Forecast are considered estimates based on the potential loads that in BC Hydro's view could be achieved. In all cases, actual outcomes will depend on customer participation and actions.[109]

The following subsections review the previous BCUC directions and recommendations relating to BC Hydro's load forecast and outline the load associated with the December 2020 Load Forecast separately, before discussing the additional load related to the Electrification Plan.

4.2.1 Previous BCUC Directions and Recommendations

The BCUC's Decision on BC Hydro's F2020-F2021 RRA provided three directions pertaining to the load forecast to be included in the Application. The BCUC directed BC Hydro to provide:

- an analysis of i) any difference in elasticity between nominal versus real changes in price in the short-term and ii) any difference in elasticity between a price increase versus a price decrease.[110]
- a replication of the Test Period large industrial load forecast using the probability-weighting approach used in the May 2016 load forecast, and a report on how the performance of the Test Period large industrial load forecast compares under the probability weighted approach versus the binary approach.[111]
- An investigation and report of the source of any load forecast variances for the F2020-F2021 Test Period, and where possible, clearly distinguish the extent of any variance that is attributable to and independent from the COVID-19 pandemic, respectively.[112]

The BCUC's Decision to BC Hydro's F2022 RRA provided one directive pertaining to the load forecast to be included in the Application. The BCUC directed BC Hydro to provide historical or estimated actuals related to EV energy consumption over the five previous load forecasts (i.e. F2017 to F2021).[113]

A summary of the information contained in the Application in response to these directives is provided below.

<u>Price Elasticity</u>

[106] Exhibit B-1, p. 3-1.
[107] Exhibit B-19, BCUC IR 152.3.1.
[108] BC Hydro Final Argument, p. 14.
[109] Exhibit B-7, BCUC IR 120.7.
[110] BC Hydro F2020 to F2021 RRA, Decision to Order G-246-20, p. 13.
[111] BC Hydro F2020 to F2021 RRA, Decision to Order G-246-20, p. 18.
[112] BC Hydro F2020 to F2021 RRA, Decision to Order G-246-20, p. 21.
[113] BC Hydro F2022 RRA, Decision to Order G-187-21, p. 13.

BC Hydro engaged two North American utility experts from The Brattle Group to address this directive and filed the resultant report with the Application.[114] BC Hydro states its load forecast methodology uses a price elasticity value of (0.10) applied to real rate changes for all sectors and the same elasticity value for rate increases and decreases. The Brattle Group confirmed this approach is consistent with industry standards.[115]

Large Industrial Load Forecast

In the October 2018 load forecast, used in BC Hydro's F2020-F2021 RRA, BC Hydro modified the large industrial forecast methodology to provide a binary assessment of the likelihood an existing customer would operate or new customer would start operating in the first three years of the forecast period.[116] In this methodology, BC Hydro used the same risk assessment used in the probability-weighted approach to make a binary determination to reflect the fact that operational shutdowns or start ups are binary in nature.[117]

BC Hydro's comparative analysis shows that in most sub-sectors the binary methodology yields results closer to actuals than the probability-weighted method.[118] However, for F2020 the binary forecast model was lower than actuals by 11 percent, the probability-weighted forecast by 8 percent. For F2021 the binary forecast was lower than actuals by 16 percent, the probability-weighted forecast by 17 percent.[119]

The industrial load forecast in the Test Period is discussed further in Section 4.2.2.1 below.

F2020 to F2021 Load Variances

BC Hydro provided the following table showing its F2020 load variances:[120]

Table 9: F2020 Domestic Energy Accrued Sales Variance

		Schedule	F2020			
	(GWh)	Reference	Decision	Actual	Difference	% Diff
			1	2	3	4
1	Residential	14.0 L1	17,751	17,993	242	1%
2	Light Industrial and Commercial	14.0 L2	18,631	18,692	60	0%
3	Large Industrial	14.0 L3+L9	13,533	13,398	(135)	-1%
4	Other	14.0 L4:L8+L10	2,042	1,848	(194)	-10%
5	Total	14.0 L16	51,958	51,931	(27)	0%

Table Notes:

1. Actual sales are accrued sales.

BC Hydro states the F2020 load variance was 27 gigawatt hours (GWh), which is negligible. Further, BC Hydro explains, any variance that might be attributed to the COVID-19 pandemic is also negligible as the pandemic began to impact B.C. in March 2020, at the end of the fiscal year.[121]

BC Hydro provided its F2021 load variance in the following table:[122]

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114 Exhibit B-2-1, Appendix CC.
115 Exhibit B-2, p. 3-6.
116 The first three years of the December 2020 load forecast period are F2021, F2022, F2023; Exhibit B-7, BCUC IR 10.1.
117 Exhibit B-2, p. 3-8.
118 Exhibit B-2, p. 3-8.
119 Exhibit B-2, Table 3-2, Table 3-3, p. 3-9.
120 Exhibit B-2, Table 3-5, p. 3-13.
121 Exhibit B-2, p. 3-13.
122 Exhibit B-2, Table 3-6, p. 3-14.

Table 10: F2021 Domestic Energy Sales Variances

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

BC Hydro states the variance of (801) GWh, compared to its F2021 forecast of 51,940 GWh can be attributed to the COVID-19 pandemic.[123]

Historical EV Load

BC Hydro provided the historical consumption actuals for light duty EV loads for the five prior fiscal years in the following table:[124]

Table 11: Estimated Actual Light Duty EV Load

Fiscal Year	Estimated Light Duty EV Load (GWh)
F2017	17
F2018	30
F2019	59
F2020	106
F2021	145

4.2.2 Load Forecast for the Test Period: December 2020 Load Forecast

BC Hydro states the forecast loads for F2023 to F2025 from the December 2020 Load Forecast use established forecasting methodologies and include a variety of actions to support government policy under the CleanBC plan, along with adjustments for the COVID-19 pandemic's estimated impact on the provincial economy. BC Hydro states an independent audit[125] in 2017 concluded BC Hydro's load forecasting methodologies are robust and compare well to industry best practices.[126] The additional load associated with the Electrification Plan was developed using a different methodology, and is addressed in Section 4.2.3 below.

BC Hydro provides its load forecast growth (excluding the Electrification Plan load) over the Test Period as follows:[127]

[123] Exhibit B-2, pp. 3-13 – 3-15.
[124] Exhibit B-2, Table 3-7, p. 3-18.
[125] According to Appendix P of the F2020-F2021 RRA, BC Hydro's internal audit team was supplemented with a subject matter expert from GDS Associates Inc.
[126] Exhibit B-2, p. 3-21.
[127] Exhibit B-2, Table 3-1, p. 3-4.

Table 12: Test Period Growth Total Domestic Sales

Sector or Sub-Sector	F2022 Decision per COVID-19 Scenario A (GWh)	F2025 Forecast per December 2020 Load Forecast (GWh)	Test Period Growth (F2025 Forecast - F2022 Decision) (GWh)
Residential	18,836	20,033	1,197
Commercial	14,366	13,820	(546)
Light Industrial	4,546	4,825	279
Large Industrial			
Forestry	5,000	4,714	(286)
Mining	3,987	4,072	85
Oil & Gas and LNG	2,806	5,042	2,236
Other	1,189	1,154	(35)
Other Loads	1,701	1,753	52
Total Test Period Growth	**52,431**	**55,413**	**2,982**

Table Notes:

1. Forecast values are billed sales and include all adjustments for rate impacts, Volt-ampere reactive and VVO energy savings, and DSM savings.

While the historic load growth has been relatively flat, the Load Forecast is showing growth of approximately 3,000 GWh during the Test Period, relative to the F2022 RRA Decision. This growth is driven primarily by growth in the large industrial sector due to oil and gas and Liquified Natural Gas (LNG) projects coming into service and growth in the residential sector which is primarily due to light duty EVs.[128]

BC Hydro states the December 2020 Load Forecast accounts for developments related to the COVID-19 pandemic and a number of electrification activities that are distinct from the Electrification Plan.[129] BC Hydro clarifies that 147 GWh of load associated with the Electrification Plan in each year of the Test Period was already included in the December 2020 Reference Load Forecast shown above. This is because the December 2020 Load Forecast included forecast electrification load from CleanBC projects administered by BC Hydro (building retrofits and EV chargers) and BC Hydro-funded Low Carbon Electrification projects (transportation and industry).[130] This overlap is shown in more detail in Table 14 in Section 4.2.3 below.

Regarding the impacts of the COVID-19 pandemic, BC Hydro states the forecast accounts for developments related to the COVID-19 pandemic and assumes a gradual economic recovery beginning in F2021 with a full economic recovery and return to pre-pandemic load growth levels in all major sectors by the beginning of the Test Period.[131]

Several assumptions and contributing factors for the Reference Load Forecast were tested throughout the proceeding, including:

- the forecast load growth, driven primarily by the large industrial sector and the anticipated growth of light duty EVs in the residential sector;[132]
- the assumption that aggregate load is expected to return to pre-pandemic growth rates by the start of the Test Period;[133] and

[128] Exhibit B-2, p. 3-4.
[129] Exhibit B-2, p. 3-4.
[130] Exhibit B-2-3-1 p. 10-41.
[131] Exhibit B-2, p. 3-27.
[132] Exhibit B-2, p. 3-4; Exhibit B-7, BCUC IR 5.4; 8.1; 8.2.
[133] Exhibit B-2, p. 3-27.

- the impact of extreme weather events experienced in summer 2021, which occurred after the Load Forecast was developed.[134]

BC Hydro's load forecasting methodology included the preparation of high and low uncertainty bands to account for sources of forecasting uncertainty. BC Hydro clarifies that these are used in planning to ensure sufficient resources are available to meet load scenarios other than the reference load forecast over a 20-year time horizon, but are not used in revenue requirements calculations.[135] In addition to comparing the December 2020 Reference Case to these bands, BC Hydro provided a qualitative assessment of the load forecast sensitivity to certain key load variables referenced in Appendix F of the Application (namely economic growth, cryptocurrency/data centre and cannabis loads, large industrial sector growth due to projects and the speed of low carbon electrification).[136]

During the proceeding, BC Hydro provided a comparison of F2022 actual and forecast loads, summarized in the table below.

Table 13: F2022 Actual and Forecast Loads[137]

	F2022			
GWh	**Forecast per the Application**	**Actual**	**Variance**	**% Variance**
Residential	**19,778**	**19,440**	**(338)**	**-2%**
Light Industrial and Commercial	**18,256**	**19,029**	**773**	**4%**
Large Industrial	**12,424**	**13,312**	**888**	**7%**
Other Sales	**1,438**	**1,361**	**(76)**	**-5%**
Total	**51,896**	**53,142**	**1,247**	**2%**

Table Notes:

1. **Forecast values show accrued sales and include BC Hydro's Electrification Plan.**
2. **Actual values are not temperature normalized.**

The variance between BC Hydro's actual and forecast F2022 load was 2 percent, which is within industry standard range and BC Hydro expects its variances will remain within industry standard range over the Test Period. The primary drivers of the variance were the COVID-19 pandemic restrictions being lifted sooner than forecast and the forestry sub-sector closures occurring later than forecast. BC Hydro explains that these drivers have limited impact on the Test Period load. This is because the magnitude of COVID-19 adjustments to the load forecast diminished after F2022 and a number of forestry customers have now closed or announced future curtailments and the Test Period load forecast already reflects closures in this sub-sector.[138]

Positions of the Parties

With respect to the updated load figures for F2022, BC Hydro submits that the evidence does not show that an update to the forecasts is required. The F2022 load forecast results are reasonable and will have limited impact on the Test Period.[139]

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[134] Exhibit B-7, BCUC IR 24.1.
[135] Exhibit B-2, p. 3-41.
[136] Exhibit B-7, BCUC IR 8.1.
[137] Exhibit B-49-1, Panel IR 1.5a. Other Sales "Other Sales" includes Irrigation, Street Lighting, New Westminster & Tongass, Fortis, and other sales which contribute to the Load Variance Regulatory Account.
[138] Exhibit B-49, Panel IR 1.5.b.
[139] 2023-01-16 SRP Transcript Volume 6, p. 1494, lines 14 to 22; p. 1497, line 23 to p. 1502, line 2.

MoveUP, BCSEA, the CEC, and Zone II RPG support not updating the load forecast to reflect the F2022 actual results and the Cryptocurrency Direction.[140]

The CEC comments that it does not find the Itron benchmarking study[141] a useful comparator for BC Hydro's load forecast because the study uses actuals, which are not temperature adjusted.[142] In reply to the latter comment from the CEC, BC Hydro points out that its F2022 temperature normalized actual load is only 2 percent higher than forecast, which is the same variance as non-temperature normalized results.[143]

BCSEA and BCOAPO either support or accept the load forecast and revenue forecast for the Test Period.[144]

The CEC recommends that BC Hydro provide feedback in future load forecasts on the magnitude of any uncertainties that the load forecast methodology change concerning extrapolation based on the Conference Board of Canada (CBoC) economic forecast for the Metro Vancouver area may have introduced to BC Hydro's December 2020 Load Forecast.[145]

BC Hydro submits that the cost and resource requirements for such an assessment are unwarranted, given the methodology change was a one-time response to the change in available input data that is not expected to be used again in future forecasts.[146]

The CEC supports BC Hydro's initiative to engage a third-party consultant to review the overall methodology for developing load forecast uncertainty bands, including the use of Monte Carlo simulation modelling and its willingness to consider the results in future load forecasts.[147]

In addition to changes to the industrial forecast addressed in the following section, the CEC recommends the following adjustments to the load forecast:[148]

- Adjust the residential load forecast to use the actual, temperature normalized amount for F2021 (10,252 kWh/account) as the base residential use-per-account, rather than the higher 10,516 forecast for F2021;
- Adjust the light industrial load forecast by negative 50 GWh of annual billed sales forecast for the Test Period to address concerns surrounding sustainability of some cannabis loads;
- Adjust the EV load forecast to incorporate BC Hydro's Low EV forecast instead of the average of Low and High, resulting in negative 345 GWh of annual billed sales for the test period; and
- Adjust each of the residential, commercial and light industrial, industrial and EV load forecasts "arising from updating rates impact calculations to use the rates sought in the Application, resulting in an aggregate negative 0.5% adjustment" to the domestic load forecast in the Test Period.

In Reply to the CEC's recommended adjustments, BC Hydro submits that while there is inherent uncertainty in load forecasting, the CEC's approach of downwards adjustment while overlooking the possibility of counteracting upward pressures on load is not appropriate. BC Hydro submits year to date actuals for F2022 were tracking two percent higher than the December 2020 Load Forecast.[149] BC Hydro's reply to each of the

[140] MoveUP SRP Final Argument, p. 1; BCSEA SRP Final Argument, pp. 1–2; Zone II RPG SRP Final Argument, p. 2.
[141] Exhibit B-49, BCUC Panel IR 1.5.b.
[142] CEC SRP Final Argument, pp. 3 – 4.
[143] BC Hydro SRP Reply Argument, p. 4.
[144] BCSEA Final Argument, p. 11; BCOAPO Final Argument, p. 10.
[145] CEC Final Argument, p. 19.
[146] BC Hydro Reply Argument, p. 9.
[147] CEC Final Argument, p. 23.
[148] CEC Final Argument, p. 3.
[149] BC Hydro Reply Argument, p. 8.

CEC's recommended load forecast adjustments is addressed below, and BC Hydro submits each of the elements is reasonable and should be accepted without modification, and the forecast should not be adjusted.[150]

BC Hydro notes the underlying issue with respect to the higher than actual F2021 use-per account for the residential sector is the COVID-19 adjustment, not the statistically adjusted end-use (SAE) model. Calibrating the statistically adjusted end-use models using 10,252 kWh/account in F2021, as suggested by the CEC, and applying the same COVID-19 adjustment to SAE model outputs would likely have a net positive impact on the residential load forecast, not a negative effect, as intended by the CEC.[151]

With regard to cannabis loads in the light industrial sector, BC Hydro notes there is no substantive basis, rooted in evidence on the record, for the CEC's proposed 25 percent downward adjustment, and submits that the F2022 YTD commercial and light industrial load indicated that commercial and light industrial year-to-date temperature normalized load was three percent higher than forecast.[152]

BC Hydro also responds to the CEC's EV forecast adjustments, noting that the CEC offers no evidence on the potential implications of hydrogen-based light duty vehicles or COVID-19 related inflationary and supply chain uncertainties over the Test Period. For the light-duty EV sector, BC Hydro believes it is possible that future EV sales will exceed government legislated targets (i.e., those set out in the *Zero-Emission Vehicles Act*), although the pace and magnitude associated with this growth is uncertain, and submits given the uncertainty related to the growth trajectory, BC Hydro's averaging approach is reasonable.[153]

Panel Determination

We focus on the December 2020 Load Forecast prior to including the additional load growth from the Electrification Plan, as they rely on distinctive methodologies, serving different purposes.

The Panel confirms that the related directives from the two previous RRA decisions have been met, namely the analysis on price elasticity, a comparison of large industrial load forecast methodologies, an investigation of load variances for the F2020 and F2021 test years and the estimated light-duty EV energy consumption for the past five years. Further discussion on large industrial load forecast methodologies is included in Section 4.2.2.1 below.

The Panel finds the December 2020 Load Forecast to be reasonable. We rely on three key sources of evidence to support this determination. First, the methodology is established and continues to evolve between successive revenue requirements applications toward an improved correlation between forecast and actual consumption, in particular for the large industrial sector. Second, the recent evaluation of previously forecast, approved and actual loads for F2020, F2021 and F2022 shows a reasonable margin of error, all within 2 percent. Third, BC Hydro demonstrated due diligence through a qualitative assessment of the load forecast sensitivity to certain key load variables and consideration of uncertainty bands for each sector and industrial sub-sectors after applying a number of macro-scale variables.

The Panel notes the overlapping customer load growth in both the load forecast and the Electrification Plan that BC Hydro submits has been removed to avoid duplication with respect to LCE programs. These specifically relate to electrification in support of reduced greenhouse gas emissions in British Columbia. The Panel acknowledges BC Hydro's efforts to differentiate between two distinctive buckets of forecast load , but notes the different vintage of data considered for the December 2020 Load Forecast versus the Electrification Plan forecast, as well as different methodologies. **The Panel directs BC Hydro to integrate all future electrification forecasts into its normal load forecasting efforts with its established and evolving methodology as a means of reducing the**

[150] BC Hydro Reply Argument, pp. 10–16.
[151] BC Hydro Reply Argument, pp. 10–11.
[152] BC Hydro Reply Argument, pp. 11–12.
[153] BC Hydro Reply Argument, p. 15.

possibility of duplication. This serves to improve the confidence in the load growth figures, as challenged by the CEC.

The Panel acknowledges uncertainties of referencing the more recent Lower Mainland CBOC economic forecast for province-wide conditions, rather than using regional forecasts which is the normal practice for load forecasting. The Panel rejects the CEC's related request for BC Hydro to provide feedback in future load forecasts on the magnitude of any related uncertainties, as this was a one-time response to the change in available input data and is not expected to be used again in future forecasts.

The Panel also rejects the CEC's submission to reduce the load forecast. The Panel has endorsed the December 2020 Load Forecast in its entirety and it is not appropriate for the BCUC to make adjustments with respect to a complex methodology. For example, the CEC request to adjust the residential use per customer using a F2021 reference would be inappropriate, as the effect of the COVID-19 pandemic on this value would have a short-term duration.

4.2.2.1 Industrial Load Forecast within the December 2020 Load Forecast

As explained in Section 4.2.1 above and as directed in the Order G-246-20, BC Hydro provides an analysis comparing the performance of the binary and probability weighted analysis for the large industrial sector, as directed by the F2022 RRA Decision. BC Hydro states, for most sub-sectors, the binary methodology yields results that are closer to actuals than the probability-weighted methodology.

The industrial load in the December 2020 Load Forecast was developed using a binary approach for the first 3 years of the load forecast (F2021-F2023) and a probability weighted approach for the remaining years.[154]

BC Hydro acknowledges that its industrial load has been over-forecast in the past, and the industrial load continues to be the source of the largest variance between actuals and forecast.[155] BC Hydro plans to continue monitoring both binary and probability-weighted methods in future and plans to continue to monitor variances for trends.[156]

BC Hydro provided F2022 load actuals, indicating that load was higher than forecast. BC Hydro stated that actual large industrial sales were 888 GWh (or 7 percent) higher than forecast. The main contributor to this variance is closures or curtailments for pulp and paper customers in the December 2020 Load Forecast which materialised later than forecast.[157] The remaining positive variances are largely attributed to customer-specific variances in the Forestry sub-sector, Oil and Gas sub-sector, and the Other sub-sector, due mainly to more favourable market conditions relative to forecast. These positive variances are partially offset by small negative variances from customers in the Mining sub-sector due mainly to supply chain disruptions and later than forecasted production ramp up.[158]

BC Hydro confirmed in the SRP that the above-referenced closures or curtailments for pulp and paper customers materialized between F2022 and F2023, and that BC Hydro does not expect the restart of pulp and paper related activities during the Test Period at facilities for which a public announcement of indefinite curtailment has been made.[159]

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[154] Exhibit B-2, p. 3-36; Exhibit B-7, BCUC IR 7.1, 10.1.
[155] Exhibit B-7, BCUC IR 8.4.
[156] Exhibit B-19, BCUC IR 155.1, 155.2.
[157] Exhibit B-49, BCUC Panel IR 1.5.a.
[158] Exhibit B-19, BCUC IR 152.6.
[159] Exhibit B-51, CEC SRP IR 80.2

Positions of the Parties

BC Hydro submits it has incorporated lessons from past over-forecasting in the industrial sector, and made minor changes to its industrial load forecasting approach in the Test Period. These include the development of stricter criteria for incorporating customer loads, such as stricter criteria in considering cryptocurrency and cannabis (which is in the Light Industrial sector) loads; and incorporation of estimated DSM persistence drop-off after F2025 to capture the potential that customers will replace energy efficient measures with measures of similar efficiency when they reach end of life. [160]

BCSEA considers the changes in the industrial load forecast methodology to a binary approach for the first 3 years and a probability weighted approach for the remaining years, to be reasonable.[161]

BCOAPO speaks to the DSM persistence drop-off, but notes it would have a minimal impact on the large industrial load forecast.[162]

The CEC recommends an adjustment to the industrial load forecast resulting in a negative 700 GWh of annual billed sales forecast for the Test Period, representing a 5 percent downward adjustment consistent with the underperformance of BC Hydro's various forecast vintages for F2020.[163]

In response to the CEC, BC Hydro submits that the CEC's assessment is flawed, and the large industrial forecast is reasonable and should not be adjusted as the CEC recommends. BC Hydro notes the CEC has not isolated the impact of the change in methodology relative to other major factors influencing the large industrial load forecast (e.g., new customer service requests, changing market conditions, etc.). Instead, the CEC has compared the performance of different vintages of forecasts, which were subject to differing conditions.[164]

BC Hydro observes that, while the CEC is advocating for a reduction in the industrial load-forecast, F2022 large industrial year-to-date temperature normalized load was 717 GWh or 8 percent higher than forecast using the CEC's methodology.[165]

McCandless states the load forecast does not include the loss of sales associated with the closure of the Power River pump and paper mill nor the closure of the Crofton paper mill. These losses would suggest that the December 2020 Load Forecast is optimistic for the industrial sector.[166]

In reply, BC Hydro states that since it avoids disclosing customer-specific information to protect commercially sensitive information, BC Hydro did not specifically describe how the two mills were forecast over the Test Period. However, the December 2020 Load Forecast does in fact forecast a downturn in the pulp and paper segment of the forestry sub-sector. BC Hydro submits its pulp and paper segment sales projection remains appropriate for rate setting purposes.[167]

Panel Determination

The Panel recognizes the difficulty of forecasting industrial loads, and considers the approach used by BC Hydro to be reasonable for the Test Period. **The Panel directs BC Hydro to continue producing both the binary and probability-weighted methods for forecasting industrial loads and to report on the results including a comprehensive load forecast in the next RRA.**

[160] BC Hydro Final Argument, pp. 16–17.
[161] BCSEA Final Argument, p. 11.
[162] BCOAPO Final Argument, p. 14.
[163] CEC Final Argument, pp. 3, 33
[164] BC Hydro Reply Argument, p. 13.
[165] BC Hydro Reply Argument, p. 14.
[166] McCandless Final Argument, p. 5
[167] BC Hydro Reply Argument, pp. 5–6

The Panel is not persuaded by the CEC's recommendation to adjust the industrial load forecast down by 5 percent consistent with the underperformance of BC Hydro's various forecast vintages for F2020, and agrees with BC Hydro that the CEC has not isolated the impact of the change in methodology relative to other major factors influencing the large industrial load forecast, including changing market conditions.

While the results of the industrial load forecasting to date have been higher than actuals in most cases to date, the Panel acknowledges the work BC Hydro has put into establishing a reasonable methodology for this sector, and is therefore reluctant to order changes to the load forecast which are not based on a consistent methodology, and which have not been tested in this proceeding.

4.2.3 Additional load related to the Electrification Plan

As stated earlier, the load forecast used to calculate the Test Period rates consists of both the December 2020 Load Forecast and the additional load forecast due to the Electrification Plan.[168] In addition to the 3,313 GWh load growth included in the December 2020 Reference Load Forecast, BC Hydro anticipates an additional 2,231 GWh of load from the Electrification Plan, as shown in Figure 1 below.[169] BC Hydro states Electrification Plan loads were not developed using load forecast methodologies.[170] The December 2020 Load Forecast and Electrification Plan are two distinct products developed using different methodologies and serving different purposes and costs, and revenues as a result of the Electrification Plan will depend on actual customer commitments.[171]

Figure 1: Electrification Related Loads in Load Forecast and Electrification Plan[172]

BC Hydro provided the following table presenting the forecast Test Period volumes of the Electrification Plan load by rate category, program and sector, showing the forecast additional load from LCE and Load Attraction actions if the Electrification Plan is fully realized. The negative amounts are due to the removal of LCE load already included in the December 2020 load forecast, and total 147GWh of load in each year of the Test

[168] Exhibit B-2, pp. 3-5, 3-47.
[169] Exhibit B-2-3-1, p. 10-42, Figure 10-3.
[170] Exhibit B-19, BCUC IR 152.2.
[171] BC Hydro Final Argument, p. 14.
[172] Exhibit B-2, Figure 10-3, p. 10-42.

Period.[173] This is because the December 2020 Load Forecast included forecast electrification load from CleanBC projects administered by BC Hydro (building retrofits and EV chargers) and BC Hydro-funded LCE projects (transportation and industry).[174]

Table 14: Forecast Test Period Volumes of Electrification Load[175]

Rate Category	Program	Parent Program	Sector	F2023	F2024	F2025
Residential	Low Carbon Electrification (LCE)	BC Hydro	Buildings	3	5	6
		CleanBC	Buildings	(25)	(17)	(5)
			Transportation	(0)	(0)	(0)
Residential Total				(22)	(12)	1
Light Industrial & Commercial	Low Carbon Electrification (LCE)	BC Hydro	Buildings	-	5	21
			Industry	(33)	(23)	6
			Transportation	12	43	59
		CleanBC	Buildings	(9)	18	50
			Transportation	(1)	(1)	(1)
Light Industrial & Commercial Total				(31)	42	135
Large Industrial	Load Attraction	BC Hydro	Load Attraction	261	804	1,303
	Low Carbon Electrification (LCE)	BC Hydro	Industry	106	480	792
Large Industrial Total				367	1,284	2,095
Grand Total				313	1,314	2,231

BC Hydro states the additional load from the Electrification Plan depends on customer uptake. BC Hydro determined the scale and timing of proxy projects "based on market knowledge, informed through discussions with customers in the different sub-sectors."[176]

BC Hydro states that if BC Hydro's Electrification Plan is fully realized, it will result in incremental revenue during the Test Period of $256.3M by adding an incremental annual load of 2,231 GWh by F2025,[177] and result in customer rates being an estimated 0.82 percent lower by the end of the Test Period compared to what they would be if there were no Electrification Plan.[178]

LCE Program Loads

Regarding the incremental large industrial load resulting from the LCE Program, BC Hydro states that the methodology used two primary considerations:

1. Large industrial projects already identified in the December 2020 Load Forecast.
2. Information on potential low carbon electrification customer projects (proxy projects) collected from a range of sources, including: BC Hydro Program Managers, completed low carbon electrification studies,

[173] Exhibit B-2, p. 10-41, Exhibit B-7, BCUC 23.1.
[174] Exhibit B-2-3-1 p. 10-41.
[175] Exhibit B-7, BCUC IR 120.11.
[176] Exhibit B-7, BCUC IR 121.3.
[177] Exhibit B-2, p. 10-40.
[178] Exhibit B-10, p. 10-4.

BC Hydro Key Account Managers, and Customer Energy Managers. The sales funnel only includes customers who are still actively in discussions with BC Hydro.[179]

Referring back to the large industrial load growth in the December 2020 Load Forecast, load growth over the Test Period is forecast in the Oil and Gas and LNG sector, growing by 2,646 GWh between F2022 and F2025.[180] BC Hydro states most of the Test Period growth is attributed to expected LNG terminal load coming into service and new upstream natural gas production and processing facilities, some of which will be supplying natural gas feedstock to LNG facilities.[181]

BC Hydro states that to "avoid double-counting of industrial customers, in the case of anticipated electrification projects among large industrial customers resulting from the Low Carbon Electrification Program that were included in both the December 2020 Load Forecast and the Electrification Plan, the December 2020 Load Forecast includes the project's binary or probability-weighted load while the Electrification Plan includes any remaining balance of the project's load."[182] BC Hydro explains that the subset of projects includes three projects and the associated incremental portion of load included in the Electrification Plan is 512 GWh.[183]

Regarding progress as of February 2022 in attracting the LCE loads, BC Hydro states:

> For Low Carbon Electrification, we currently have projects totaling approximately 444 GWh of Industrial load that are in the process of formalizing funding agreements through our Large Custom Program. This equates to approximately 48 per cent of the incremental load target for industry for Low Carbon Electrification and approximately 39 per cent of the incremental load target for Low Carbon Electrification overall.[184]

<u>Load Attraction Loads</u>

BC Hydro explains the Load Attraction portion of the Electrification Plan load is entirely large industrial load and is based on proxy projects. BC Hydro determined the scale and timing of the proxy projects based on its market knowledge, informed through discussions with customers in the different sub-sectors, cross-checked against the sales funnel to provide a level of assurance that the estimated incremental load was achievable. The sales funnel is an inventory of customers who have inquired about connecting to BC Hydro's grid (or increasing their electrical load in relation to potential low carbon electrification opportunities) and are still active in discussions with BC Hydro.[185] The table below lists the Electrification Plan Load Attraction loads in GWh by sub-sector for the Test Period.[186]

[179] Exhibit B-7, BCUC IR 120.10.
[180] Exhibit B-2, Table 3-15, p. 3-37.
[181] Exhibit B-2, p. 3-38.
[182] Exhibit B-2-3-1, p. 10-41.
[183] Exhibit B-19, BCUC IR 201.1.
[184] Exhibit B-19, BCUC IR 210.3.
[185] Exhibit B-7, BCUC IR 121.3.
[186] Exhibit B-7, BCUC IR 130.1.

Table 15: Load Attraction Load in the Electrification Plan (GWh/year)

	F2023	F2024	F2025
Cryptocurrency	223	410	410
Data Centres	-	223	223
Hydrogen	37	74	74
Mining	-	97	596
Total	261	804	1,303

BC Hydro has not attributed the loads to specific Load Attraction programs in order to maintain the flexibility to tailor support from the two programs to the needs of specific customers.

BC Hydro states that as of February 2022: "For Load Attraction, we currently have projects totalling approximately 800 GWh that are advancing through the interconnection process. This equates to approximately 43 per cent of the incremental load target for the Load Attraction component of the Electrification Plan of 1,866 GWh" in F2026. [187]

BC Hydro provided the following table showing the cryptocurrency load included in the revenue forecast for each of F2022 and F2023 through to F2025.[188]

Table 16: **Cryptocurrency loads considered in the Revenue Forecast**

Fiscal Year	December 2020 Reference Load Forecast - before adjustments for rates & DSM (GWh/yr) A	BC Hydro's Electrification Plan (GWh/yr) B	Total Load Considered in Revenue Forecast (GWh/yr) C = A + B
F2022	60	0	60
F2023	108	223	331
F2024	108	410	518
F2025	48	410	458

According to BC Hydro, two cryptocurrency customers were considered in the Load Forecast and one in the Electrification Plan. The load forecast methodology for cryptocurrency customers was described as follows:

> As emerging industries, the forecast is developed with consideration of customer-requested loads that are deemed highly probable based on their advanced stage of progress in BC Hydro's interconnection process. <u>The December 2020 Load Forecast for cryptocurrency and data centres is lower than previous forecasts due to a number of project cancellations and updated load requests</u>. The cryptocurrency and data centres load are forecast to increase to about 100 GWh through F2024 before returning to F2021 levels by F2025. Given the segment's continued uncertainty and volatility, the forecast assumes these facilities are not long lived.[189] [emphasis added]

BC Hydro states "(t)he Electrification Plan cryptocurrency estimate was developed based on market intelligence collected by our Business and Economic Development department. The energy forecast was based on a generic

[187] Exhibit B-19, BCUC IR 210.3.
[188] Exhibit B-51, CEC SRP IR 82.1.
[189] Exhibit B-2, p. 3-39.

project that reflected expected projects at the time the plan was developed. Subsequently, cryptocurrency projects similar to this generic project and not affected by OIC 692 were energized."[190]

In December 2022, the Province issued the Cryptocurrency Direction, releasing BC Hydro from the need to connect any further cryptocurrency loads. BC Hydro states the Cryptocurrency Direction does not affect the cryptocurrency load included in the Test Period forecast, with the exception of one customer accounting for 48 GWh of load in each year of the Test Period.[191] However, BC Hydro states the exclusion of this load would not have a material impact on the Test Period rates and bills because it represents approximately 0.1 percent of the forecast domestic sales in each year of the Test Period. The rest of the expected load has either already materialized, or is expected to materialize in the Test Period.[192]

Positions of the Parties

BC Hydro submits that, based on its opportunity tracking and initial results, it is reasonable to set rates for the Test Period that incorporate all the forecast costs and revenues associated with the Electrification Plan.[193] BC Hydro notes that any variances will be deferred for future recovery from, or refund to, ratepayers.[194]

BCOAPO does not have substantial concerns regarding forecast load associated with BC Hydro's Electrification Plan.[195]

The CEC is sceptical that all of the electrification anticipated by the Electrification Plan will materialize, and the economic backdrop does not inspire confidence in the load growth rates presumed in the combined load forecast for revenue purposes.[196]

McCandless submits this is the first time that BC Hydro has used a load plan/budget to justify its RRA that includes additional load that does not match the forecast developed through established methodologies. [197] McCandless submits the Panel should not include the aspirational load growth of 313 GWh for F2023, 1,314 GWh for F2024 and 2,231 GWh for F2025 as these forecasts were not developed using the standard methodology.[198]

NTC recommends the BCUC require BC Hydro to provide regular updates on progress in attracting new large loads.[199]

In reply, BC Hydro states McCandless incorrectly implies the difference in forecasting approach for the Electrification Plan sales is a shortcoming. Similar to energy and capacity savings from demand-side measures, incremental load resulting from Electrification Plan programs is forecast separately from the load forecast and included as an adjustment to the load forecast. BC Hydro submits the incremental load resulting from the Electrification Program results from BC Hydro's efforts, which needs to be accounted for in the load forecast. BC Hydro submits it has had success advancing large low-carbon electrification projects to the point where potential customers are making a positive investment decision in the mining and upstream natural gas production and pipelines sub-sectors, which are some of the most significant portions of large industrial low-carbon loads included in the Electrification Plan. BC Hydro submits revenue requirements and rates would be

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[190] Exhibit B-51, CEC SRP IR 82.2.
[191] Exhibit B-49, Panel IR 1.6.
[192] Exhibit B-51, BCSEA IR 103.1.
[193] BC Hydro Final Argument, p. 14.
[194] BC Hydro Final Argument, pp. 1415.
[195] BCOAPO Final Argument, p. 14.
[196] CEC Final Argument, p. 108.
[197] McCandless Final Argument, p. 2.
[198] McCandless Final Argument, p. 5.
[199] NTC Final Argument, p. 32.

higher if the incremental cost and revenues of the Electrification Plan were excluded. To the extent that actual revenue is different from the Revenue Forecast for the Test Period (which includes both revenue from the December 2020 Load Forecast plus revenue from BC Hydro's Electrification Plan), this variance will be deferred for future recovery from, or refund to, ratepayers.[200]

Panel Determination

The Electrification Plan load forecast uses a different methodology than the December 2020 Load Forecast, despite having some overlapping new loads for large industrial customers in the oil and gas sector. The Panel is satisfied with BC Hydro's efforts to avoid duplication, but finds that there is insufficient evidence to persuade the Panel of the credibility of the Electrification Plan load forecast. Based on the available evidence, the methodologies are significantly different insofar as the December 2020 Load Forecast relies on diverse and large data sets such as historic actuals by sector, external studies (e.g., CBoC economic forecasts) and sensitivity analysis of demand (uncertainty bands) due to macro-scale variables. In contrast, the Electrification Plan load forecast is based on LCE pilot projects in previous test years and for load attraction is largely based on "proxy projects". In conclusion the Panel is not persuaded that the forecast Electrification Plan load will materialize to the extent submitted in the Application.

Although the Electrification Plan Direction requires the BCUC to allow the recovery of certain expenditures in rates, it does not compel the BCUC to approve the Electrification Plan load forecast for revenue purposes. The Panel now considers each component of the Electrification Plan load forecasts for reasonableness.

The Panel finds that the LCE residential, commercial and light industrial sector load estimates are reasonable. This is equivalent to a net load increase of 136 GWh over and above the December 2020 Load Forecast. This is supported by historic LCE initiatives that overlap with the December 2020 Load Forecast that was developed with a credible methodology. This is evidenced by the downward adjustments for CleanBC related initiatives in the Electrification Plan load forecast in those sectors.

The Panel finds that the LCE Oil & Gas estimate of 512 GWh of load growth by F2025 is reasonable, given that this is based on the credible methodology within the December 2020 Load Forecast. Furthermore, this estimate is backed by evidence that, as of February 2022, specific projects equivalent to 444 GWh of industrial load are in the process of finalizing funding agreements through the Large Customer Program.

In a similar vein, the Panel finds the 800 GWh of Load Attraction load that is advancing through the interconnection process to be reasonable.

The Panel is not satisfied that the methodology backing the remaining large industrial load growth included in the Electrification Plan is credible, namely the asserted 2,095 GWh by F2025 less the total of 1,312 GWh (the sum of 512 GWh + 800 GWh) noted in the paragraphs above. The balance of 783 GWh[201] of asserted Electrification Plan load growth (which represents 37 percent of estimated additional large industrial load by F2025) is not based on a credible methodology that is backed by empirical data and thus, should not be included for revenue purposes. Therefore, **the Panel directs BC Hydro to remove 783 GWh of forecast load in F2025 and to remove the related forecast loads in F2023 and F2024. The Panel also directs BC Hydro to remove the cost of energy forecast to serve these loads from the Test Period revenue requirements.**

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[200] BC Hydro Reply Argument, pp. 6–7

[201] This figure is the forecast large industrial load growth in the Application of 2,095 GWh, less the 1,312 GWh (512 + 800) deemed reasonable in the previous paragraphs.

4.3 Cost of Energy

BC Hydro's forecast Cost of Energy for the Test Period is $1,781.6 million in F2023, $1,943.3 million in F2024 and $2,001.4 million in F2025, per the table below. These costs of energy reflect only variable costs. Fixed costs, such as amortization and financing costs are not included. Neither are O&M costs:[202]

Table 17: Cost of Energy (Integrated System and Non-Integrated Areas)

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
Heritage Energy	4.0 L43	273.4	350.6	386.2	353.5	367.2	359.1
Non-Heritage Energy	4.0 L51	1,438.5	1,511.5	1,461.1	1,508.2	1,528.7	1,543.0
Market Energy	4.0 L58	(189.4)	(191.9)	(183.7)	(83.7)	(23.2)	11.6
Total		1,522.5	1,670.1	1,663.7	1,778.0	1,872.7	1,913.7
Cost of Energy for Electrification Plan	4.0 L44 + L45 + L59	-	-	-	3.6	70.7	87.7
Total	4.0 L61	1,522.5	1,670.1	1,663.7	1,781.6	1,943.3	2,001.4

BC Hydro notes that customers will only pay the actual costs of energy and not the planned costs. This is because the BCUC has approved Cost of Energy Variance Accounts to capture any variances between the planned and actual energy costs for recovery or repayment to customers. Variances between planned and actual costs of energy are deferred to either the Heritage Deferral Account, the Non-Heritage Deferral Account, or the Biomass Energy Program Variance Regulatory Account.[203]

BC Hydro states, by F2025, its total Cost of Energy is planned to increase by $331.3 million compared to the F2022 Decision amounts, primarily due to the following items: [204]

- $87.7 million in costs related to the Electrification Plan, if fully realized;
- $31.5 million of planned increases to Non-Heritage Energy, primarily related to Independent Power Producers (IPP)s and Long-Term Commitments; and
- $203.5 million of planned increases to Market Energy primarily due to reduced revenue from System Exports as a result of higher forecast load.

The Electrification Plan is forecast to require an increase in BC Hydro's forecast Cost of Energy of $162 million over the Test Period. A further breakdown of the Electrification Plan cost of energy is presented in Tables 19 and 22 below of the Decision.

The following sections address the Panel's determinations with respect to BC Hydro's forecast Cost of Energy during the Test Period, BC Hydro's monthly energy studies, the variance treatment of Cost of Energy, and BC Hydro's fully allocated Cost of Energy.

4.3.1 Cost of Energy Components

BC Hydro's cost of energy consists of Heritage Energy, Non-Heritage Energy, and Market Energy. The following table compares BC Hydro's approved versus actual costs of energy for each of the three components for F2020 through F2022:

[202] Exhibit B-2, Table 4-2, p. 4-8.
[203] Exhibit B-2, pp. 4-8 – 4-9.
[204] Exhibit B-2, p. 4-8.

Table 18: BC Hydro's Cost of Energy in F2020 to F2022[205]

	F2020 Decision	F2020 Actual	F2021	F2021 Actual	F2022 Decision	F2022 Actual
Heritage Energy ($ million)	351.2	358.8	317.7	273.3	350.6	391.3
Non-Heritage Energy ($ million)	1,332.4	1,353.1	1,447.2	1,438.5	1,511.5	1,566.1
Market Energy ($ million)	184.4	99.0	(98.4)	(189.4)	(191.9)	(200.7)
Total	**1,867.9**	**1,810.9**	**1,666.5**	**1,522.4**	**1,670.1**	**1,756.7**
Total Domestic Sales (GWh)	51,958	51,931	51,940	51,139	52,448	53,452
Weighted Cost ($/MWh)	35.95	34.87	32.08	29.77	31.84	32.87

Heritage Energy

Heritage Energy costs are generally related to the operation of heritage assets listed in Schedule 1 of the *Clean Energy Act*.[206] The following table provides a breakdown of some components of the incremental cost of Heritage Energy. The fully allocated cost is provided in Section 4.3.4 below.

Table 19: BC Hydro's Cost of Heritage Energy[207]

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
Water Rentals	4.0 L38	333.2	375.4	385.0	389.0	384.9	385.7
Natural Gas for Thermal Generation	4.0 L39	6.5	11.8	8.2	9.7	10.7	10.7
Domestic Transmission - Other	4.0 L40	25.5	25.5	24.6	25.1	25.7	26.2
Columbia River Treaty Related Agreements	4.0 L41	(49.9)	(19.0)	10.0	(26.3)	(9.4)	(19.5)
Remissions and Other	4.0 L42	(42.0)	(43.2)	(41.5)	(44.0)	(44.7)	(44.0)
Total	4.0 L43	273.4	350.6	386.2	353.5	367.2	359.1
Cost of Energy for Electrification Plan	4.0 L44 + L45	-	-	-	2.5	(6.5)	(2.1)
Total	4.0 L46	273.4	350.6	386.2	356.0	360.7	357.0

BC Hydro forecasts the costs of Heritage Energy in the above table to remain relatively consistent during the Test Period compared to the F2022 Decision amounts. Some fluctuations in costs are stated to be associated with the Columbia River Treaty agreements - coordination agreements related to the operation of the Columbia River Treaty reservoirs in Canada. These agreements generate revenue during water releases and incur costs during storage. Both revenues and costs depend on the market price at the time of the release and storage.[208] BC Hydro further states that the Electrification Plan is forecast to result in $6.1 million lower Heritage Cost of Energy from the F2023 to F2025 Plan, driven mostly by the timing of hydro generation.[209]

[205] Prepared by the BCUC from information in Exhibit B-2-1, Appendix A, Schedule 4.0, Lines 25, 38 to 61; Exhibit B-51, BCOAPO SRP IR 210.1, 210.2.
[206] Exhibit B-2, p. 4-9.
[207] Exhibit B-2, Table 4-3, p. 4-9.
[208] Exhibit B-2, pp. 4-13 - 4-14.
[209] Exhibit B-2, p. 4-9.

Water rental fees are the largest contributor to Heritage Cost of Energy. BC Hydro states that these are fees paid to the Government of B.C. on the generation output (GWh) and capacity (MW) of hydroelectric heritage assets. They also include water rental fees paid on reservoir storage as well as miscellaneous water licences. The water rental fees across the Test Period are relatively consistent and similar to the F2022 forecast amount.[210]

Non-Heritage Energy

Non-Heritage Energy costs include costs associated with Electricity Purchase Agreements (EPA) for the integrated system and the non-integrated area communities.[211] The following table provides a breakdown of the components of the cost of Non-Heritage Energy.

Table 20: Cost of Non-Heritage Energy[212]

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
IPPs and Long-Term Commitments	4.0 L47	1,404.0	1,475.7	1,426.9	1,471.9	1,490.5	1,504.3
Non-Integrated Area	4.0 L48	26.0	27.4	26.5	28.4	30.0	30.4
Gas & Other Transportation	4.0 L49	5.3	4.9	4.3	4.4	4.5	4.5
Water Rentals (Waneta 2/3)	4.0 L50	3.2	3.5	3.4	3.5	3.7	3.8
Total	4.0 L51	1,438.5	1,511.5	1,461.1	1,508.2	1,528.7	1,543.0

BC Hydro states that the forecast costs of Non-Heritage Energy over the Test Period are primarily associated with existing EPAs, and because the terms of these agreements are already set, the planned costs for these EPAs are largely prescribed. BC Hydro is not acquiring new resources from IPPs during the Test Period. BC Hydro states that there are 16 potential EPA renewals in relation to the integrated system during the Test Period and the forecast Cost of Energy for the Test Period assumes that any potential EPA renewals will be at market-based prices.[213] Although BC Hydro is in a surplus situation, it intends to continue using existing clean or renewable IPP resources, provided that the EPAs can be renewed at cost-effective prices.[214] BC Hydro states that it does not expect any impact on regional or system reliability because of its approach to IPP renewals during the Test Period.[215]

On July 29, 2022, BC Hydro filed an application with the BCUC pursuant to section 71 of the UCA for a short-term renewal of the EPA for the Island Generation facility on Vancouver Island (Island Generation Application).[216] The RRA does not include costs related to the Island Generation EPA.[217] During the oral hearing, BC Hydro presented two options to recover the costs from ratepayers:[218]

i. if the Island Generation Application is approved by the BCUC prior to the conclusion of the current proceeding, the BCUC in its decision to the current proceeding could order BC Hydro to update its forecast for the costs related to the Island Generation EPA in a compliance filing; or

ii. allow the existing Cost of Energy Variance Accounts to capture the Test Period actual costs related to the Island Generation EPA for future recovery from ratepayers.

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[210] Exhibit B-2, pp. 4-9 - 4-12.
[211] Exhibit B-2, p. 4-15.
[212] Exhibit B-2, Table 4-6, p. 4-15.
[213] Exhibit B-2, pp. 4-16 – 4-17.
[214] Exhibit B-7, BCUC IR 32.3.
[215] Exhibit B-7, BCUC IR 32.4.
[216] Exhibit A2-10.
[217] 2022-09-21 Oral Hearing Transcript Volume 3 PM, pp. 823 - 828
[218] 2022-09-21 Oral Hearing Transcript Volume 3 PM, p. 824 line 25 to p. 826 line 11.

The first option would result in the inclusion of the costs in the current Test Period revenue requirement and allow BC Hydro to start recovering the costs in its F2023 rates. However, BC Hydro states that the second option would be administratively simpler, but it would delay the recovery of the Test Period costs by three years.[219] BC Hydro also confirmed that the currently expected rate impacts related to the Island Generation EPA are essentially the same as in the Island Generation Application.[220]

Subsequent to the oral hearing, the BCUC completed its review of the Island Generation Application and accepted the Island Generation EPA for filing pursuant to section 71 of the UCA.[221]

Non-Integrated Areas

BC Hydro provides service to 14 non-integrated areas (NIAs), which are served by local generating facilities, primarily diesel, and distribution networks. Generating capacity in these areas is provided by a combination of BC Hydro owned diesel generating stations, as well as four hydro IPP facilities and one biomass IPP facility, and one BC Hydro owned hydro facility in the Bella Coola region.[222] The following table provides a breakdown of the Cost of Energy in the NIAs.

Table 21: Non-Integrated Areas Generation Costs[223]

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
NIA - BC Hydro Diesel Generating Stations		14.3	17.6	16.4	17.2	17.7	17.8
NIA - IPPs		11.7	9.9	10.1	11.1	12.3	12.5
Total	4.0 L48	26.0	27.4	26.5	28.4	30.0	30.4

For the NIAs, the variability in costs for BC Hydro's diesel generating stations are primarily driven by fluctuations in fuel costs, load variability and IPP deliveries.[224]

BC Hydro states that, in support of CleanBC and BC Hydro's clean energy commitment, it actively looks for opportunities to displace diesel generation with clean or renewable resources in NIA communities. IPPs may displace a portion of diesel generation, but diesel generation facilities must be in place for reliability purposes.[225] BC Hydro has undertaken several initiatives other than IPP generation to reduce supply costs while maintaining reliability. These initiatives include demand-side management, connection of remote communities to the integrated BC Hydro grid, BC Hydro's Net Metering program and ongoing work related to community-owned clean generation in the NIAs.[226]

Market Energy

The cost of Market Energy reflects the imports and exports resulting from BC Hydro's energy transactions with Powerex.[227] The following table provides a breakdown of the cost of Market Energy.

[219] 2022-09-21 Oral Hearing Transcript Volume 3 PM, p. 824, line 25 to p. 826, line 11.
[220] 2022-09-21 Oral Hearing Transcript Volume 3 PM, p. 827, lines 15 to 23.
[221] BC Hydro EPA Renewal for the Island Generation Facility, Decision and Order G-325-22.
[222] Exhibit B-2, p. 4-20.
[223] Exhibit B-2, Table 4-8, p. 4-20.
[224] Exhibit B-2, p. 4-20.
[225] Exhibit B-2, p. 4-21.
[226] Exhibit B-7, BCUC IR 33.6.
[227] Exhibit B-2, p. 4-22.

Table 22: Cost of Market Energy[228]

($ million)	Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
System Imports	4.0 L54	26.9	77.1	69.0	125.6	149.2	157.9
System Exports	4.0 L55	(227.9)	(296.5)	(266.5)	(223.3)	(186.7)	(160.9)
Net System Imports / (Exports)		(201.0)	(219.4)	(197.4)	(97.7)	(37.5)	(3.0)
Domestic Transmission – Export	4.0 L57	11.6	27.5	13.8	14.1	14.3	14.6
Total	4.0 L58	(189.4)	(191.9)	(183.7)	(83.7)	(23.2)	11.6
Cost of Energy for Electrification Plan	4.0 L59	-	-	-	1.1	77.1	89.8
Total	4.0 L60	(189.4)	(191.9)	(183.7)	(82.6)	53.9	101.4

BC Hydro states that the Cost of Market Energy is planned to increase by $293 million by the end of the Test Period compared to the F2022 Decision amounts, primarily due to higher forecast load. This includes $89.8 million due to increased load from the Electrification Plan, if fully realized. Load is expected to increase during the Test Period because of increased sales to the oil and gas sector, increased load associated with EVs and BC Hydro's Electrification Plan, if fully realized. Net System Exports are decreasing from $219.4 million in the F2022 Decision to $3.0 million in F2025 due to higher forecast load.[229]

Positions of the Parties

BC Hydro submits that its forecast Cost of Energy is reasonable for the purpose of setting rates in the Test Period.[230] It further submits that the total planned Cost of Energy is increasing over the Test Period primarily due to higher forecast load. With respect to the components of the Cost of Energy, BC Hydro argues that the total planned Cost of Heritage Energy is relatively consistent compared to F2022 RRA Decision amounts, with some fluctuations in costs associated with the Columbia River Treaty related agreements. BC Hydro also submits that Non-Heritage Energy costs are driven primarily by predetermined factors in existing contracts and that it proactively manages its energy costs from IPPs as opportunities arise. With respect to the cost of Market Energy, BC Hydro submits that the planned increase by $293.3 million by the end of the Test Period is primarily due to higher forecast load, resulting in less surplus to export. BC Hydro asserts that its approach to meeting load using existing resources will be the same regardless of whether the Electrification Plan load materializes, and that the Cost of Energy Variance Accounts ensure that customers pay the actual Cost of Energy.[231]

BCSEA, BCOAPO and the CEC submit that BC Hydro's forecast Cost of Energy for the Test Period is reasonable.[232] Zone II RPG generally supports the NIA Cost of Energy included in the Application.[233] However, Zone II RPG is concerned that BC Hydro's NIA generation costs do not accurately reflect the rising cost of diesel fuel and the trial use of more costly low-carbon diesel during the Test Period. It submits that diesel fuel costs are a significant contributor to the total cost of diesel generation. However, there are no diesel reduction projects for the NIA included in the Cost of Energy.[234]

With respect to the Island Generation Application, BC Hydro recommends a compliance filing to update the F2023 to F2025 revenue requirements to avoid deferring multiple years of costs for recovery later.[235]

[228] Exhibit B-2, Table 4-9, p. 4-22.
[229] Exhibit B-2, pp. 4-22 - 4-23.
[230] BC Hydro Final Argument, p. 18.
[231] BC Hydro Final Argument, pp. 23–26, 28.
[232] BCSEA Final Argument, p. 14, BCOAPO Final Argument pp. 15–17, CEC Final Argument, pp. 46–52.
[233] Zone II RPG Final Argument, p. 1.
[234] Zone II RPG Final Argument, p. 22.
[235] BC Hydro Final Argument, pp. 25–26.

BCSEA and BCOAPO agree with BC Hydro that a compliance filing approach is preferred over a deferral approach.[236] However, the CEC submits that the allocation of the Island Generation EPA costs variances to regulatory accounts provides for more consistency with BC Hydro's typical deferral account treatment of Cost of Energy variances.[237]

Panel Determination

For the reasons set out below, the Panel finds the F2023 to F2025 Cost of Energy to be reasonable for the purpose of setting rates for F2023 to F2025 inclusive, with the exception of certain cost of energy related to loads that BC Hydro has been directed to remove from its Test Period revenue requirements in Section 4.2.3 of this Decision. In making this finding of reasonableness we rely considerably on the output of BC Hydro's Energy Studies Models and BC Hydro's assessment of that output.

Much of BC Hydro's long-term planning and many of its medium-term operational decisions are based the Energy Studies models, which are discussed in Section 4.3.2 of the Decision. With the exception of the concern noted in that section, the Panel is generally satisfied that the models are optimizing Consolidated Net Revenue from Operations (CNRO). Therefore, that portion of rates driven by the forecast Cost of Energy is just and reasonable.

The Island Generation Application

With respect to the Island Generation Application, we accept BC Hydro's recommendation of a compliance filing to update the F2023 to F2025 revenue requirements to avoid deferring multiple years of costs for recovery later. **Therefore, the Panel directs BC Hydro to update, in its Compliance Filing, the F2023 to F2025 revenue requirements with the costs related to the Island Generation EPA.**

Load Forecast Variance

The forecast Cost of Energy is based on the amount of energy needed to serve load, and the load as set out in the load forecast. Therefore, the Panel's finding that the Cost of Energy in the Application is reasonable for the purpose of setting rates for the Test Period is also subject to the accuracy of the load forecast and we have expressed certain concerns around the load forecast for the Electrification Plan in Section 4.2.3 of this Decision. While BC Hydro's revenue decoupling mechanism ensures that ratepayers will not pay more in the current Test Period if more energy is required to meet BC Hydro's load, that incremental cost will be borne by ratepayers in future test periods.

The Panel notes that in the F2020 to F2021 RRA Decision, BC Hydro was directed to defer the variances between actual and forecast Cost of Energy arising from differences between actual and forecast domestic customer load to the Load Forecast Variance Account instead of the NHDA, on an ongoing basis. This approach provides for revenue decoupling, which was considered by the BCUC at some length in its recent review of BC Hydro's PBR Report.[238] In summary, revenue decoupling removes utilities' disincentive to pursue measures to provide for the more efficient use of electricity. Generally, revenue decoupling makes utilities indifferent to changes in load. This could be either to support reductions in load, such as DSM, or increases in load, such as fuel switching from less clean alternatives.

Incremental Cost of Energy for the Electrification Plan

[236] BCSEA Final Argument, p. 13, BCOAPO Final Argument p. 16.
[237] CEC Final Argument, p. 49.
[238] BCUC Review of BC Hydro Performance Based Regulation Report, Decision and Order G-388-21, , pp. 32 – 33; pp. 54 - 55.

BC Hydro asserts that as a result of the forecast costs associated with the Electrification Plan, ratepayers "will face lower Heritage Energy costs."[239] However, they will face commensurate increases to the cost of Market Energy associated with the Electrification Plan.

The decrease in Heritage Energy costs arising from the Electrification Plan is the result of changes to the dispatch choices the model makes under the Electrification Plan load forecast. Less generation is exported under the Electrification Plan scenario, so the net cost of Market Energy increases substantially. The increase in Market Energy costs of $168 million more than offsets the decreases of Heritage Energy costs of $6.1 million.

The load forecast related to the Electrification Plan is discussed in Section 4.2.3 of this Decision. In that section, the Panel directed BC Hydro to remove the Cost of Energy forecast associated with 783 GWh of forecast load in F2025 and the related forecast load in F2023 and F2024.

4.3.2 Monthly Energy Studies

BC Hydro's Monthly Energy Studies optimize the operational management of generation within BC Hydro's integrated system. They are used to inform operational dispatch decisions and forecast the Cost of Energy for financial reporting purposes. In the Application, BC Hydro provides a description of its Monthly Energy Studies components, processes, methodology, key inputs, and outputs. BC Hydro states that the methodology to conduct the Energy Studies has not changed from the one used in the two previous RRAs and that the objective function remains to maximize the expected CNRO.[240]

<u>System Optimization Objective, Inputs and Outputs</u>

BC Hydro's system optimization objective is to maximize the expected CNRO.[241] Key inputs of the Monthly Energy Studies are inflow forecasts, load forecasts, market forward prices, IPP forecasts, generation unit availability forecasts and operational constraints. The key outputs of the Monthly Energy Studies are forecasts of the operation of the generating system and major storage reservoirs, forecast of price signals to be used as decision support and forecasts of imports and exports.[242]

The 2020 Transfer Price Agreement (TPA) between BC Hydro and Powerex governs electricity and natural gas transactions between both entities.[243] The 2020 TPA accounting model does not impact the optimization of forecasted dispatch. It is only used to calculate the forecast value of imports and exports post-optimization.[244] BC Hydro states that it does not operate its system in a manner to maximize stand-alone payments to BC Hydro under the 2020 TPA, as doing so would reduce the total value of the system and the total value that accrues to BC Hydro's ratepayers.[245]

BC Hydro states that it uses an ensemble of the previous 49 years of historic weather, inflow and generation data as an input to the Energy Studies models. It also states that the variability in the historic record used is an order of magnitude larger than the impact of any climate change on the mean forecast over the time horizon of an energy study. As the data ensemble already contains the most recent historic observations, the effects of climate change are implicitly included to the extent that climate change has influenced observed data.[246] BC Hydro states that it has analyzed trends in historic inflows to each of its basins and has determined that the

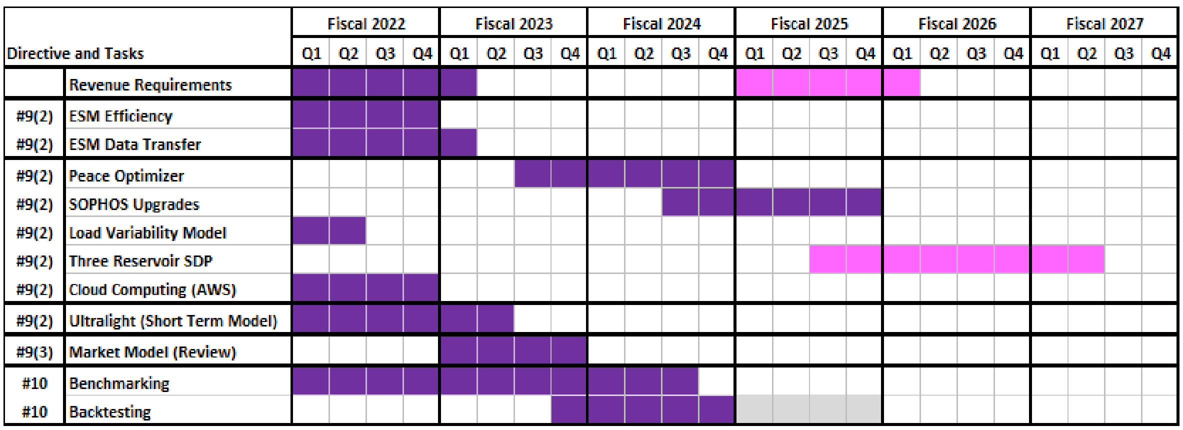
[239] Exhibit B-2, p. 4-9.
[240] Exhibit B-2-1, Appendix DD, p.1.
[241] Exhibit B-2-1, Appendix DD, p. 6.
[242] Exhibit B-2-1, Appendix DD, pp. 2–3.
[243] Exhibit B-2, p. 4-6.
[244] Exhibit B-7, BCUC IR 27.1.
[245] Exhibit B-19, BCUC IR 158.1.
[246] Exhibit B-2-1, Appendix DD, pp. 5–6.

effect of climate change on the seasonality of inflows to its reservoirs is not significant. BC Hydro also states that it is increasing its capabilities to detect and respond to changes in both weather (short-term) and climate (long-term).[247]

Development of Energy Studies Models

Directive 4 in the BCUC's F2022 RRA Decision directed BC Hydro to provide an update on the timeline for improvements to the models in the Energy Studies and explain any changes in the timeline. Specifically, the BCUC noted that it was concerned about the length of time it would take to complete benchmarking and backtesting. In the Application, BC Hydro provided an updated schedule whereby the schedule for backtesting was advanced by one year. BC Hydro states that under the revised schedule there is less ability for the team to respond to any new issues that may arise and that further compression of the schedule for benchmarking is not feasible without impacting other scheduled tasks.[248] BC Hydro provides the table below, illustrating the revised schedule:[249]

Table 23: Monthly Energy Studies Models Tasks (Update to Table 1 in the April 2021 Compliance Filing)



BC Hydro states that with respect to the Energy Studies model it will be developing processes to implement benchmarking and backtesting and report on the results.[250] In response to IRs, BC Hydro described the nature and scope of the backtesting and benchmarking it will perform.[251] BC Hydro states that benchmarking and backtesting have been performed on several components of the Energy Studies process in order to calibrate sub-models and continue to be part of the model development process. It continually works to ensure confidence in the model results through a comprehensive review process.[252]

Energy Studies Process

BC Hydro states that the key inputs of the Monthly Energy Studies are: [253]

- Forecasts of the operation of the generating system and major storage reservoirs;

[247] Exhibit B-19, BCUC IR 159.1.
[248] Exhibit B-2-1, Appendix DD, pp. 20–21.
[249] Exhibit B-2-1, Table DD-1, Appendix DD, p. 21.
[250] Exhibit B-2-1, Appendix DD, p. 20.
[251] Exhibit B-7, BCUC IRs 29.1, 29.2.
[252] Exhibit B-7, BCUC IR 29.3.
[253] Exhibit B-2-1, Appendix DD, p. 3.

- Forecasts of price signals to be used as decision support for system hydro and thermal plant operations relative to markets; and
- Forecasts of imports and exports

BC Hydro states that the key outputs are: [254]

- Inflow Forecasts;
- Load Forecasts;
- Market Forward Prices;
- IPP Forecasts;
- Generation Unit Availability Forecasts; and
- Operational Constraints.

BC Hydro's evidence also shows that:[255]

> [t]he Energy Studies are produced every month. The results are reviewed weekly by the Generation System Operations (GSO) Key Business Unit, discussed with Powerex, compared to other models, and tracked against actuals. The results are reviewed every month by the Executive Vice President of Operations. BC Hydro maintains the integrity of the Monthly Energy Studies process using a proprietary tool, the Energy Studies Manager. The Energy Studies Manager helps to manage process flow and the thousands of datasets that make up model inputs, outputs and parameters. Each month the progress of the Monthly Energy Study is tracked through the Energy Studies Manager as team members update input data and run models. This tool also archives all the relevant historic and forecast data at each step in the process.

According to BC Hydro, the resolution of the models is, at a minimum, monthly but many model components execute with a finer granularity (as short as eight hours).[256]

Positions of the Parties

BC Hydro submits that the Monthly Energy Studies methodology used in the Application to inform Cost of Energy forecasts is consistent with previous applications. It further submits that it is advancing improvements to the Energy Studies models.[257] The objective function in the Energy Studies is to maximize expected CNRO and BC Hydro argues that doing so does not result in an opportunity cost, nor does it consider Powerex's market-based position, as price risk is implicitly recognized in BC Hydro's system optimization objective.[258] BC Hydro submits that price and volume terms of the 2020 TPA are not used as constraints in the Monthly Energy Studies models since operating the system in a manner to maximize stand-alone payments under the 2020 TPA would reduce the total value of the system and the value that accrues to ratepayers.[259]

With respect to the current probability distribution derived from the historic record, BC Hydro submits that it is still appropriate for use in the Energy Studies. The effects of observed historic extreme weather and climate change are already captured in the model due to the inclusion of recent historic years of weather and inflow observations. Further, BC Hydro has determined that the effect of climate change on the seasonality of inflows

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[254] Exhibit B-2-1, Appendix DD, p. 3.
[255] Exhibit B-2-1, Appendix DD, p. 3.
[256] Exhibit B-2-1, Appendix DD, p. 8.
[257] BC Hydro Final Argument, p. 18.
[258] BC Hydro Final Argument, p. 19.
[259] BC Hydro Final Argument, pp. 22–23.

to BC Hydro's reservoirs is not significant. It is however increasing its capabilities to detect and respond to both changes in weather and climate.[260]

BC Hydro submits that it maintains confidence in the forecasts by incorporating feedback from the benchmarking of new models or major upgrades, backtesting and through ongoing reviews with System Optimization and Operations Planning Engineers, Generation Resource Coordinators, as well as Powerex.[261] BC Hydro further submits that it already conducts benchmarking for specific models within the Energy Studies; however, for optimization models, direct alternatives do not exist. BC Hydro will therefore continue with its planned improvements to the Energy Studies models as provided in Appendix DD to the Application.[262]

BCSEA submits that it accepts that the methodology to conduct the Energy Studies has not changed from the previous application, and that BC Hydro is advancing improvements to the Energy Studies models. BCESA also submits that it accepts that the 2020 TPA does not constrain or otherwise affect BC Hydro's Energy Studies optimization process.[263] No other intervener commented on the Energy Studies.

Panel Determination

The Panel is satisfied with the BC Hydro evidence that the application of the Monthly Energy Studies methodology with its objective function to maximize the expected CNRO, continues to be appropriate for ratemaking purposes.

Below we make determinations on areas where further improvements may be possible.

Monthly Energy Studies

We acknowledge that BC Hydro uses the Energy Studies Manager decision support tool when making short term operational decisions and we understand the following improvements are planned from F2022 to F2027:[264]

- Increase Automation of the Energy Studies Manager: Efficiency Improvements; and
- Improve Data Transfer management in the Energy Studies Manager.

BC Hydro is directed to include the impact of these improvements on its short term decision making in the next RRA.

Effects of Climate Change and Weather Variability

BC Hydro provided detailed information regarding the effects of climate change on its use of historic weather and inflow data in the 49-year ensemble. The Panel accepts BC Hydro's explanation; but we remain concerned that such a large data set may not reflect the growing near-term effects on operations due to climate change and extreme weather events.

We note BC Hydro's explanation below:

> The variability in the historic record is an order of magnitude larger than the impact of any climate change on the mean forecast over the time horizon of an Energy Study. Nonetheless, since the ensembles always contain the most recent historic observations,

[260] BC Hydro Final Argument, pp. 19–20.
[261] BC Hydro Final Argument, p. 20.
[262] BC Hydro Final Argument, p. 21.
[263] BCSEA Final Argument, p. 12.
[264] Exhibit B-2-1, Appendix DD, p. 19.

effects of climate change are implicitly included to the extent that climate change has influenced observed data.[265]

It is not unreasonable that variability in the weather record is larger – and likely significantly so – than the impact of any climate change on the mean, even a mean that may be changing. That is a natural consequence of the way a mean is calculated and the larger the dataset the less influence any single data point will have on the mean of that dataset.

However, the Panel's primary concern isn't the effect of climate change on the mean – it is the effect of climate change on both the intensity and frequency of extreme events. Extremes can increase on both sides of the mean and have no effect on the mean. Many planning and design criteria and decisions, including capacity forecasts and planning for infrastructure resiliency, are not based on the mean, but on extremes that are reasonably expected to occur.

We agree that due to the multi-year nature of BC Hydro's large reservoirs, short-term variability can be managed. However, in the case of multiple years of extreme weather events, it is not clear how BC Hydro's system would fare. We commend BC Hydro on its commitment to increasing its capabilities to detect and respond to both changes in weather and climate. **However, due to the Panel's concerns, BC Hydro is directed in its next RRA to provide a progress report on its commitment to increase its capabilities to understand and model increases in the intensity and frequency of extreme weather events, and report on any consequent modifications to the Energy Studies models.**

Backtesting of Models

In response to Directive 4 of the F2022 Decision, BC Hydro provided a revised schedule, whereby it has advanced backtesting and benchmarking of the Energy Studies models. We appreciate BC Hydro's effort in prioritizing this effort and remain cognizant of the resultant loss in schedule and resource flexibility. We are satisfied with the plans presented by BC Hydro for backtesting, benchmarking, and future model improvements.

Other Cost of Energy Variances

BC Hydro's energy models provide long-term planning and medium-term operational forecasts based on the maximization of CNRO. However, as BC Hydro's evidence shows, the short-term (within a month) operational landscape may differ. Monthly runs of the Energy Studies provide outputs based on CNRO and those outputs drive operational decisions that are made by management.
Some decisions that are, at least to some extent, within management control include:

- Renewal costs of IPPs and Long-Term Commitments (non heritage energy);
- The decision of when to import and when to use domestic generation resources;
- Maintenance schedule of generation assets that will affect when units are available and also the life of the asset;
- Long term planning decisions that affect generation availability and costs; and
- Generation technology and fuel choices in the NIAs.

BC Hydro stated that "other than a small number of new Indigenous Nations energy projects and expected EPA renewals, BC Hydro is not acquiring new resources from IPPs during the Test Period. BC Hydro is not seeking

[265] Exhibit B-2-1, Appendix DD, pp. 5–6.

approval of any EPA renewals in this Application and will be filing separate applications, pursuant to section 71 of the *Utilities Commission Act*, seeking acceptance of energy supply contracts”. [266]

It also stated that “[t]he planned costs of [IPP EPAs] over the Test Period are primarily associated with existing EPAs, and because the terms of these agreements are already set, the planned costs for these EPAs are largely prescribed. During the Test Period, for each EPA, there may be a number of factors which may cause the planned costs to either increase or decrease, such as a change in operation as may be allowed under the EPA and price escalation as defined in the EPA”.[267]

Although BC Hydro is currently in a surplus situation, we are concerned that the Electrification Plan, if fully realized, may reduce that surplus faster than anticipated and we encourage BC Hydro to continue renewing EPAs at market-based prices as necessary to ensure an adequate supply of reasonable-cost energy. We also recommend that BC Hydro avoid “take or pay” contracts where possible. Taking these steps would result in a more uniform approach to energy imported into the BC Hydro system and avoiding paying for energy that is not needed, thereby providing ratepayers with just and reasonable rates.

Further, we understand that there are limited options for firm supply resources in the NIAs and that diesel is still the primary fuel source for those facilities. We encourage BC Hydro to continue to pursue exploring clean energy options that may offer a source of reliable and cost-effective electricity and reduce greenhouse gas emissions in alignment with government policy.

We appreciate BC Hydro’s responses with respect to the 2020 TPA and how it is applied in the Energy Studies methodology. However, with respect to the first three bullets above which are within management’s control, there is still a lack of clarity as to why BC Hydro uses forecast market prices alone and not in tandem with the financial provisions of the 2020 TPA to optimize CNRO and whether there is material value in doing so. We agree with BC Hydro’s position that it should not attempt to maximize stand-alone payments as it could reduce the value of the entire system, but we are concerned that a market forecast alone may not adequately reflect any opportunities to import or export. **Therefore, we direct BC Hydro, in its next RRA filing, to report on the materiality and effects on CNRO of including 2020 TPA price and volume terms in the Energy Studies models.**

4.3.3 Deferral Account Treatment of Cost of Energy

<u>Heritage Energy Deferral Account</u>

In 2003, by OIC 1123, the BC Government issued Heritage Special Direction No. HC2 to the BCUC (HC2).[268] HC2 set out the Heritage Payment Obligation (HPO) to BC Hydro Generation for the electricity provided to BC Hydro Distribution.

HC2 also set out the following calculation of the HPO:

a. adding those of the following costs incurred by BC Hydro Generation in the year that the BCUC orders may be included in the heritage payment obligation:

   i. cost of energy such as the cost of water rentals and energy purchases, including purchases of gas and electricity, required to supply heritage electricity;

   ii. operating costs such as the costs of operating and maintaining the heritage resources, including an allocation of corporate costs;

[266] Exhibit B-2, p. 4-16.
[267] Exhibit B-2, p. 4-16.
[268] OIC 1123, B.C. Reg. 158/2005, Special Direction No. HC2.

iii. all costs of owning the heritage resources, including, without limitation, depreciation, interest, finance charges and other asset related expenses;

iv. all costs or payments related to generation-related transmission access required by the heritage resources, and

b. subtracting from the sum obtained under paragraph (a) any revenues BC Hydro Generation receives from other services provided from the heritage resources, including, without limitation,

i. revenues related to Skagit Valley Treaty obligations,

ii. revenues from provision of ancillary services to the transmission operator in respect of third party use of the transmission system, and

iii. revenues from the sale of surplus hydro electricity under section 5 of the Transfer Pricing Agreement.

OIC 1123 also defines "heritage deferral account" as "an account established under section 7 (a) of this Special Direction". Section 7 states:

Deferral accounts

7 When regulating and setting rates for the authority, the commission:

(a) must allow the authority to establish one or more accounts to reflect and record variances between

(i) the heritage payment obligation and the authority's forecast of the heritage payment obligation, and

(ii) the trade income and the authority's forecast of trade income,

(b) may allow the authority to establish one or more other deferral accounts for other purposes, and

(c) must set or regulate the authority's rates in such a way as to allow the deferral accounts to be cleared from time to time and within a reasonable period of time.

In December 2003, BC Hydro applied to the BCUC[269] to, among other things, establish both the Heritage Deferral Account (HDA) and the NHDA. In that proceeding, BC Hydro stated:

> The components of the HDA, as proposed by BC Hydro, result from BC Hydro's conviction that it should assume financial responsibility for all controllable risks but create deferral accounts for non-controllable risks. This logic applies equally to non-heritage payment obligations.[270]

BC Hydro also proposed certain cost characteristics to be used to assess whether or not a risk is a controllable or non-controllable risk.[271] Regarding these cost characteristics, BC Hydro stated that it used "controllable vs. non controllable costs" in a broad sense intended to capture a variety of characteristics including:[272]

• BC Hydro's ability to directly influence the cost category;

[269] BC Hydro 2004/05 and 2005/06 Revenue Requirements Application and An Application by British Columbia Transmission Corporation for Approval of an Application for Deferral Accounts.

[270] BC Hydro 2004/05 and 2005/06 Revenue Requirements Application and An Application by British Columbia Transmission Corporation for Approval of an Application for Deferral Accounts proceeding, Exhibit B1-200, Final and Reply Argument, p. 63.

[271] BC Hydro 2004/05 and 2005/06 Revenue Requirements And British Columbia Transmission Corporation – Deferral Accounts, Decision to Order G-96-04, p. 28.

[272] BC Hydro 2004/05 and 2005/06 Revenue Requirements Application and An Application by British Columbia Transmission Corporation for Approval of an Application for Deferral Accounts proceeding, Exhibit B1-11, BCUC IR 221.1.

- The volatility of the costs category;
- The materiality of the cost category to the revenue requirement; and
- The frequency of major exceptions within the cost category.

BC Hydro went on to explain that: [273]

> Weather related variations in load were not included because while weather itself is outside BC Hydro's control, the impact of weather on energy sales is generally offset by changes in the cost of energy thus reducing the materiality of this influence on costs.
>
> BC Hydro is committed to managing normal business and operational risks on an economic basis and mitigates the chance of catastrophic losses to tolerable risk levels. In referring to cost variances from forecast, the term "controllable risk" was used loosely to infer that the probability and cost consequence of the risk of variation from forecast is within a tolerable level given that prudent cost and risk management is in place.

In section 7(a), Direction No. 7 required the BCUC to allow BC Hydro "to continue to defer to the heritage deferral account the variances between the actual and forecast heritage payment obligation". However, Direction No. 7 was repealed by B.C. Reg. 24/2019 (Direction No. 8), effective February 14, 2019. Direction No. 8 makes no reference to the HDA.

BC Hydro has continued to defer expenses to the HDA in the same cost categories.

Non-Heritage Energy Deferral Account

BC Hydro states that currently the NHDA captures variances between the forecast and actual cost of Non-Heritage Energy which includes:

- IPPs and Long-Term Commitments as described in Chapter 4, Section 4.6.1,
- Non-Integrated Areas in Chapter 4, Section 4.6.2,
- Gas and other transportation costs in Chapter 4, Section 4.6.3,
- System Exports which consists of sales of electricity to Powerex by BC Hydro, and System Imports which consists of purchases of electricity by BC Hydro from Powerex and thermal generation run for Powerex as described in Chapter 4, Section 4.7.1, and
- Variances between forecast and actual costs for items approved by BCUC Order G-96-04 and subsequent orders. [274]

When the NHDA was originally approved, along with the HDA, in Order G-96-04 only the following inclusions in the NHDA were applied for and all were approved except for item four below:

1. cost of energy – all variances in non-HPO energy costs except those arising from changes in customer load;
2. significant unplanned major maintenance costs greater than $1 million related to single event equipment or infrastructure failure or caused by weather related events;

[273] Ibid..
[274] Exhibit B-2-1, Appendix R, p. 15.

3. significant unplanned major capital expenditures having an incremental annual impact on the Income Statement greater than $1 million related to single event equipment or infrastructure failure;
4. distribution emergency restoration costs – all variances in emergency restoration expenditures; and
5. all Founding Partner Benefits and Customer Information System Credits under the Accenture Business Services of British Columbia Contract.

With regard to item four, the BCUC stated:

> The Commission Panel approves all elements of the NHDA, except the distribution emergency restoration costs element, item 4, because it can be forecast with some confidence, unlike unplanned major capital expenditures and unplanned major maintenance expenditures, and because of risk/reward considerations. Given the denial of item 4 of the NHDA, item 3 of the NHDA is to be as set forth in Final Argument. The Commission Panel approves BC Hydro's forecast of the NHDA non-HPO cost of energy for F2005 and F2006.

Subsequent to the initial approval of the NHDA as described above, the following changes have also been approved:

- Order G-16-09 approved the deferral of energy costs arising from load variances to the NHDA. This includes variances related to both Heritage Energy and Non-Heritage Energy. In the 2004 RRA, which established the NHDA, BC Hydro stated that it believed that the variability in non-HPO energy costs arising from changes in customer load was acceptable and not high enough to warrant a deferral account. BC Hydro estimated that changes in customer load were expected to fall within a range of $20 million on an annual basis.[275]
- Subsequent Orders G-77-12A and G-48-14 approved BC Hydro to continue deferring load variance costs to the NHDA pursuant to directives to the BCUC in Directions Nos. 3 and 7.
- Order G-48-14 approved the deferral of Burrard decommissioning costs to the NHDA pursuant to Direction No. 7.
- Order G-16-11 approved the deferral of variances between forecast and actual transmission service revenue and non-capital emergency transmission maintenance expenditures over $1 million to the NHDA.
- Order G-68-17 approved the deferral of variances between forecast and actual Northwest Transmission Line Supplemental Charge revenues to the NHDA.
- Order G-130-18 approved the deferral of the F2019 lease revenues arising from the Waneta 2017 Transaction and the revenue associated with capital expenditures made by Teck with respect to Teck's two-third interest in Waneta during the lease term to the NHDA. The order also approved the variance between forecast and actual water rentals in a given year arising from the Waneta 2017 transaction be excluded from the water rental variances that are currently deferred to the NHDA during the lease term.
- Section 7 (c) (i) of Direction No. 7 required the BCUC to allow BC Hydro to continue to defer to the non-heritage deferral account the variances between actual and forecast cost of energy arising from differences between actual and forecast domestic customer load. On February 14, 2019, with the issuance of Direction No. 8, Direction No. 7 was rescinded. As a result, BCUC Order G-256-20 directed load variances be captured in a new Load Forecast Variance Account instead of the NHDA. This order

[275] BC Hydro and Power Authority 2004/05 To 2005/06 Revenue Requirements Application and British Columbia Transmission Corporation Application for Deferral Accounts, Decision to Order G-96-04, p. 38.

also directed BC Hydro to move all balances related to load forecast variance from the Non-Heritage Deferral Account to the Load Forecast Variance Account.

Positions of Parties

Parties did not provide a position on the HDA and NHDA.

Panel Determination

Controllable Variances

Even if the load forecast is 100 percent accurate, the actual cost of energy could differ from the forecast. BC Hydro notes that “customers will only pay the actual costs of energy and not the planned costs”. The Panel agrees, because much of the variance between BC Hydro’s forecast and actual cost of energy is subject to variance account treatment.

However, paying the actual cost of energy may not necessarily result in a rate that is just and reasonable. In order for it to be just and reasonable, the variance should be outside of management’s control. For controllable costs, ratepayers should only pay the forecast cost.
When establishing the HDA and the NHDA, in Order and accompanying decision G-95-04, the BCUC considered the criteria for inclusion of costs for variance treatment. In that decision, the BCUC stated: [276]

> The Commission Panel accepts BC Hydro’s proposed criteria for determining the appropriateness of deferral accounts; however, the Commission Panel concludes that risk/reward considerations are also relevant criteria. In some cases, costs may not be controllable but because of risk/reward considerations the risk of variances from forecasts may be more appropriately borne by the shareholder.

The BCUC further stated:

> For costs that are controllable, the Commission Panel recognizes that customers, especially in the long-term, can reasonably be expected to benefit by the shareholder(s) assuming the risk, in part, because holding the utility management accountable for variances around forecasts provides an incentive to control those costs that would otherwise be reduced with the creation of a deferral account.

However, the BCUC accepted “significant unplanned major maintenance costs greater than $1 million as appropriate for deferral account treatment in the HDA and NHDA because of forecasting difficulties of this type of non-recurring event. However, BC Hydro will be expected to mitigate the costs of unplanned major maintenance.” It also accepted “significant unplanned major capital expenditures greater than $1 million as appropriate for deferral account treatment in the HDA and NHDA because of forecasting difficulties of this type of non-recurring event."[277]

This Panel agrees with the BCUC’s approach in that proceeding. Generally speaking, where management has control over expenditures within a test period, no variance account treatment should apply.

In Section 4.3.2 above, we discuss short-term operational decisions made by management that could give rise to unit cost variances between forecast and actual. In such cases, there is a possibility that CNRO would no longer

[276] BC Hydro 2004/05 and 2005/06 Revenue Requirements Application and An Application by British Columbia Transmission Corporation for Approval of an Application for Deferral Accounts, Decision to Order No. G-96-04, pp. 29–30.
[277]Ibid., p. 40.

be maximized. In some cases, variances may be driven by randomly occurring events such as extreme weather events, unexpected market price fluctuations and unplanned equipment downtime.

Based on the historical cost of energy shown in Table 18 above, the Panel has calculated the following variances between actual and forecast cost of energy per MWh. The results show that the variances have been negative (i.e. actuals less than forecast) for 2 out of the last 3 years with no trend discernable to the Panel.

Table 24: Variances Between Actual and Forecast Cost of Energy

2020	2021	2022
-3.0%	-7.2%	+3.2%

From the evidence of historical variances available to the Panel, it is not possible to discern what portion, if any, of the cost of energy is controllable, the extent to which those variances are controllable and whether there is a trend of positive or negative variances over time.

Therefore, the Panel directs BC Hydro to file, in its next RRA, an analysis of the variance in cost of energy for the past five years, including the controllability of the circumstances leading to those variances and whether all the items deferred to the Cost of Energy variance accounts should continue to receive variance account treatment and if so under what circumstances.

4.3.4 The Fully Allocated Cost of Energy

The Cost of Energy filed in the Application represents only those costs whereby variances are recorded in BC Hydro's Cost of Energy Variance Accounts and does not represent the fully allocated costs comprising O&M costs.[278] In response to BCUC IRs, BC Hydro supplied an estimate of fully allocated costs by category and component below, which provides for a comparison of the total costs to generate or purchase electricity:[279]

Table 25: Fully Allocated Cost of Energy

Cost of energy - Fully Allocated Costs	Schedule Reference	F2023 Plan	F2024 Plan	F2025 Plan
Fully allocated costs by Major Cost Category ($ million):				
Heritage Energy	A	1,753.6	1,759.9	2,034.5
Non Heritage Energy	B	1,558.8	1,574.3	1,584.3
Market Energy	C	(82.2)	54.3	101.8
Total	D	**3,230.3**	**3,388.5**	**3,720.7**
Sources of Supply (GWh):				
Heritage Energy	E	45,598	45,738	45,617
Non Heritage Energy	F	16,069	16,114	16,118
Market Energy	G	(2,494)	(535)	1,644
Total	H	**59,172**	**61,317**	**63,380**
Cost of energy per MWh ($/MWh):				
Heritage Energy	I = (A * 1000 / ABS(E))	$ 38.46	$ 38.48	$ 44.60
Non Heritage Energy	J = (B * 1000 / ABS(F))	$ 97.01	$ 97.70	$ 98.29
Market Energy	K = (C * 1000 / ABS(G))	$ (32.96)	$ 101.63	$ 61.94
Total	L = (D * 1000 / ABS(H))	**$ 54.59**	**$ 55.26**	**$ 58.70**

Table 26: Fully Allocated Cost of Energy by Component

[278] Exhibit B-7, BCUC IR 30.2.
[279] Exhibit B-19, BCUC IR 163.1.

Cost of energy - Fully Allocated Costs by Component: $ million	Schedule Reference	F2023 Plan	F2024 Plan	F2025 Plan
Heritage energy:				
Cost of energy		356.0	360.7	357.0
OM&A expenses		429.8	434.7	450.9
Depreciation & Amortization		307.4	314.2	345.0
Taxes		51.3	53.2	53.7
Finance charges		241.4	232.6	376.6
Allowed Net Income (Return on Equity)		314.5	311.7	401.0
Miscellaneous Revenues		(15.1)	(15.0)	(15.0)
Revenue Offsets & Other		68.2	67.8	65.4
Total Heritage Energy		**1,753.6**	**1,759.9**	**2,034.5**
Non-Heritage Energy:				
Cost of energy		1,611.0	1,628.2	1,641.9
OM&A expenses		21.5	21.9	22.5
Depreciation & Amortization		6.0	6.4	6.7
Taxes		0.8	0.0	0.0
Finance charges		2.4	2.4	2.5
Allowed Net Income (Return on Equity)		7.1	7.3	4.6
Miscellaneous Revenues		(90.1)	(92.0)	(94.0)
Revenue Offsets & Other		0.0	0.0	0.0
Total Non-Heritage Energy		**1,558.8**	**1,574.3**	**1,584.3**
Market Energy:				
Cost of energy		(82.6)	53.9	101.4
OM&A expenses		0.4	0.4	0.4
Depreciation & Amortization		0.0	0.0	0.0
Taxes		0.0	0.0	0.0
Finance charges		0.0	0.0	0.0
Allowed Net Income (Return on Equity)		0.0	0.0	0.0
Miscellaneous Revenues		0.0	0.0	0.0
Revenue Offsets & Other		0.0	0.0	0.0
Total Market Energy		**(82.2)**	**54.3**	**101.8**
Total		**3,230.3**	**3,388.5**	**3,720.7**

The previous two tables illustrate an increase in total Heritage Energy expense from $1.76 billion in F2024 to $2.03 billion in F2025, an increase of $274.6M. This is, in part, due to an increased F2025 allocation of allowed net income of $401.0 million up from $311.7 million in F2024, $144 million increase in finance charges and approximately $28 million[280] in amortization expense of some Site C assets in operation starting that same year.

Positions of the Parties

BC Hydro submits that it has explained in its responses to information requests that fully allocated Cost of Energy costs are unnecessary to assess whether the Cost of Energy is reasonable for the Test Period. It submits that the costs included in the Application are presented by cost components that best enable the BCUC to consider whether the costs are reasonable.[281]

BCSEA agrees with BC Hydro that fully allocated costs are not necessary to assess the Cost of Energy.[282]

No other parties commented on the fully allocated Cost of Energy.

[280] Exhibit B-2-1, Appendix A, Schedule 13.0, Line 40.
[281] BC Hydro Final Argument, p. 27.
[282] BCSEA Final Argument, p. 4.

Panel Discussion

We appreciate the time and effort required to produce the fully allocated Cost of Energy and have found the estimate provided by BC Hydro to be helpful. In this regard, we note that although the term Cost of Energy is used in the RRA for certain expenditures, these expenditures represent only a portion of the total costs of energy, generally the short run variable costs associated with the production and purchase of energy. This narrower view of the cost of energy is adequate for the RRA and we agree with BC Hydro that the fully allocated costs are unnecessary to evaluate the reasonableness of Cost of Energy for the Test Period. However, as BC Hydro is moving to a future where it may have to somehow acquire significant quantities of electricity there is value in understanding the full cost of electricity in its long term planning. BC Hydro's own historic fully embedded costs, especially with the addition of new Site C generation, may help to inform estimates of its long term marginal costs of electricity.

4.4 Operating Costs

BC Hydro is requesting recovery of $1.3205 billion, $1.3403 billion and $1.3602 billion in operating costs in rates for F2023, F2024 and F2025, respectively. Compared to the F2022 RRA Decision amounts, BC Hydro's proposed operating costs for recovery in rates over the Test Period are as follows:[283]

Table 27: Operating Costs for Recovery in Rates ($millions)

F2022	F2023		F2024		F2025	
RRA Decision	**Plan**	**Change**	**Plan**	**Change**	**Plan**	**Change**
1,352.3	1,320.5	(31.8)	1,340.3	19.8	1,360.2	19.9

BC Hydro separates its operating costs into different categories and refers to the operating costs included in the revenue requirement and to be recovered in rates over the Test Period as "current operating costs" (also referred to as operating costs in this Decision). Current operating costs include:[284]

- base operating costs, which are costs for personnel, materials and external services that are incurred in the day-to-day operations, and are net of recoveries, capitalized costs and reclassification adjustments;
- operating costs that BC Hydro does not have direct control over, such as capital overhead that can no longer be capitalized under International Financial Reporting Standards (IFRS), and costs related to the 2017 Waneta Transaction and Customer Crisis Fund. These costs together with base operating costs are referred to as net operating costs by BC Hydro; and
- operating costs incurred in prior periods to be recovered in the current period based on each regulatory account's established recovery mechanism.

According to BC Hydro, base operating costs are the relevant measure for the assessment of its efforts to control operating costs because they are limited to the normal day to day operations.[285]

Compared to the F2022 RRA Decision amounts where base operating costs were $905.1 million[286], BC Hydro's base operating costs are increasing by $21.5 million (or 2.4 percent) for F2023, a further $20.4 million (or 2.2

[283] Exhibit B-2, Appendix A, Schedule 5.0, lines 45, 55 and 85; annual changes calculated by BCUC Staff: (F2023 Plan – F2022 RRA Decision = $1,320.5 million - $1,352.3 million = ($31.8 million)).
[284] Exhibit B-2, Section 5.5.4 pp. 5-38 and 5-40, Table 5-7; Section 5.5.4, p. 5-39.
[285] Exhibit B-2, Section 5.1, p. 5-1, Footnote 157; Section 5.5.4 pp. 5-38 and 5-40, Table 5-7; Section 5.5.4, p. 5-39.
[286] Exhibit B-2, Section 5.1, Figure 5-1, p. 5-2.

percent) for F2024, and a further $31.7 million (or 3.4 percent) for F2025, for a total net increase of $73.6 million in the Test Period (or 2.6 percent on average per year).[287]

BC Hydro has identified the following six drivers contributing to the change in base operating costs over the Test Period, and notes that more than three-quarters (81.3 percent) of the increase is associated with what it labels as “uncontrollable” costs and reliability investments:[288]

- Uncontrollable cost increases of $33.6 million (or 45.7 percent of the Test Period net increase), which include: (i) Labour costs ($39.8 million[289]) partially offset by a reduction in current service pension costs[290] ($(15.0) million[291]) due to an increase in the discount rate in F2023; (ii) BCUC and Canada Energy Regulator Cost Recovery Levies ($0.6 million[292]); (iii) Insurance costs ($1.9 million[293]); (iv) BC Hydro’s obligation to fulfill Water Use Plan order review requirements under the Provincial Water Use Planning Guidelines ($2.2 million); and (v) Support costs for software licensing and outsourced application and infrastructure ($4.1 million).
- Reliability investments of $26.2 million (or 35.6 percent of the Test Period net increase), which include: (i) Costs to strengthen its Mandatory Reliability Standards (MRS) program and implement and sustain new standards and functions (3.0 million[294]); (ii) Costs for vegetation management to support reliability, compliance, access and employee and public safety ($16.7 million[295]); and (iii) Costs to enhance cybersecurity programs ($6.5 million[296]).
- Site C operating costs of $11.0 million (or 15 percent of the Test Period net increase) associated with the partial operations expected in the Test Period. The Site C Generation Station is expected to transition to partial operations by December 2024 in anticipation of the in-service of the first generating unit, with the expectation of full operations by the end of F2026.
- Strategic Initiatives of $5.9 million (or 8 percent of the Test Period increase), which include: (i) Increased costs to support the implementation of the Electrification Plan ($2.9 million[297]); (ii) Increased costs to support and develop a strategy to pursue new renewable generation opportunities to reduce diesel use in remote communities ($1.0 million[298]); and (iii) Increased costs to support the development and implementation of BC Hydro’s UNDRIP plan ($2.0 million[299]).
- Third-party billable work of $1.3 million (or 1.8 percent of the Test Period net increase) associated with the increase in work volumes offset by an increase in miscellaneous revenues.
- Net cost savings of $(4.5) million (or a 6.1 percent decrease over the Test Period) which consists of cost increases of $8.4 million (or 11.4 percent of the Test Period net cost increase) offset by cost savings and reductions of $12.9 million (or (17.5) percent of the Test Period net cost increase), as follows:[300]

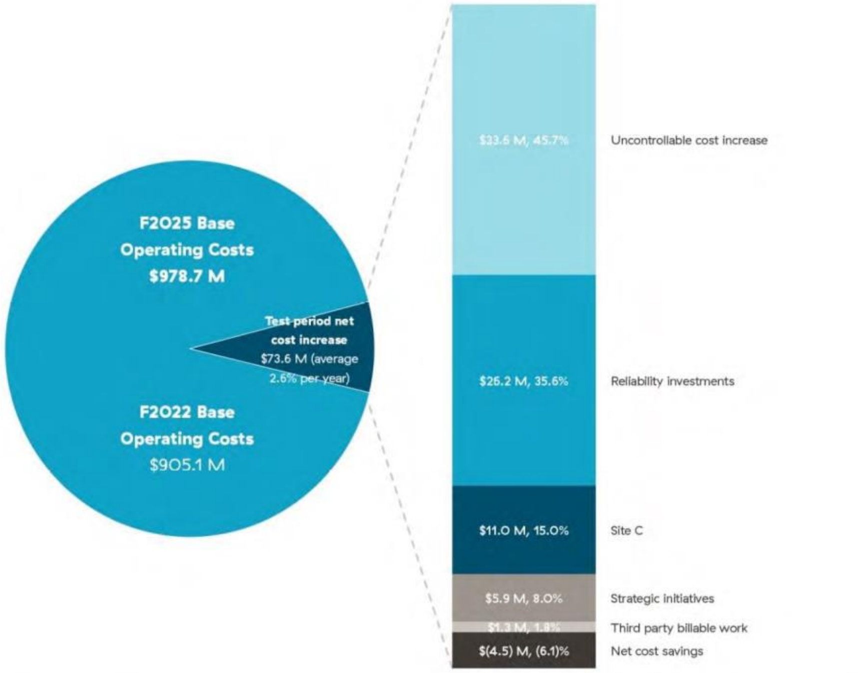
[287] Exhibit B-2, Section 5.1, p. 5-1.
[288] Exhibit B-2, Section 5.1, pp. 5-1, 5-4; Section 5.5, p. 5-13 – 5-14.
[289] Exhibit B-2, Section 5.5.3.1, p. 5-27.
[290] Current Service Costs are for future pension benefits earned by employees in the current year and are determined by BC Hydro’s external 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 (Exhibit B-2, Section 5.5.1, p. 5-15, Footnote 166).
[291] Exhibit B-2, Section 5.5.3.1, p. 5-27.
[292] Exhibit B-2, Section 5.5.3.1, p. 5-28.
[293] Exhibit B-2, Section 5.5.3.1, p. 5-28.
[294] Exhibit B-2, Section 5.5.3, Table 5-6, p. 5-24.
[295] Exhibit B-2, Section 5.5.3, Table 5-6, p. 5-24.
[296] Exhibit B-2, Section 5.5.3, Table 5-6, p. 5-24.
[297] Exhibit B-2, Section 5.5.3, Table 5-6, p. 5-25.
[298] Exhibit B-2, Section 5.5.3, Table 5-6, p. 5-25.
[299] Exhibit B-2, Section 5.5.3, Table 5-6, p. 5-25.
[300] Exhibit B-2, Section 5.5.3.6, pp. 5-33 – 5-34.

- The cost increases over the Test Period include the following: (i) $2.6 million for apprentice and trainee funding; (ii) $3.5 million to ensure adequate resources and support are in place for the Operations Business Group to deliver its workplan; (iii) $0.4 million for routine trouble work primarily caused by vegetation growth; (iv) $0.2 million to address regulatory, legislative and other compliance obligations; and (v) $1.8 million related to electric vehicle charging infrastructure.[301]
- The offsetting cost savings and reductions over the Test Period include the following: (i) $3.3 million in reduced employee training as BC Hydro completed the catch up of technical and leadership training requirements for IBEW employees in F2022[302] and reverts to funding levels prior to F2022; (ii) $2.3 million for reduced storm restoration operating costs as a result of the five-year rolling average budget including the below average storm related damage in F2021; (iii) $2.2 million in reduced operating costs from the benefits realized from the supply chain applications which include headcount reduction, reduced costs from contract and supplier management, reduced inventory obsolescence and improved excess project material visibility; (iv) $2.1 million in reduced travel and related requirements due to the increased use of technology solutions during the pandemic; (v) $2.0 million reduction due to the transition to BC Hydro's Safety Framework that supports targeted investments in its safety programs; (vi) $0.7 million reduction due to an increase in costs eligible for capitalization; and (vii) $0.3 million in reduced overtime costs for trades training instructors that support field workers on site and classroom courses as a result of scheduling efficiencies.[303]

The following figure illustrates the overall increase in base operating costs over the Test Period and the six drivers of the change in base operating costs. The circle shows the overall increase in base operating costs over the Test Period relative to F2022 RRA Decision base operating costs. The column breaks down the change in base operating costs over the Test Period by key driver, and the table summarizes the annual incremental increase in base operating costs over the Test Period.

[301] Exhibit B-2, Section 5.5.3, Table 5-6, p. 5-26; Section 5.5.3.6, pp. 5-34 – 5-35.
[302] In the F2022 test period BC Hydro included an increase of $3.3 million (3.5 additional training days on average) for the International Brotherhood of Electrical Worker (IBEW) employees to catch up on training where they had fallen behind. The training focused on both safety leadership training as well as the procedures to ensure that the IBEW employees had the skills to commission, maintain, operate and decommission equipment. Technical training included helicopter, switching, and equal potential grounding and bonding/blocking in addition to training on critical protection and control and telecommunications equipment (Exhibit B-2, Section 5.5.3.6, pp. 5-35–5-36; 2022 RRA, Exhibit B-1, Section 5.9, p. 5-87).
[303] Exhibit B-2, Section 5.5.3.6, pp. 5-35 – 5-38.

Figure 2: Summary of Test Period Base Operating Costs Increases – F2025 Compared to F2022 RRA Decision[304]



Base Operating Costs—$ million[1]	Starting point	Current fiscal year	$ increase	% increase	Average % increase per year
F2023	905.1	926.6	21.5	2.4%	
F2024	926.6	947.0	20.4	2.2%	
F2025	947.0	978.7	31.7	3.4%	
Test period total	**905.1**	**978.7**	**73.6**	**8.1%**	**2.6%**
[1] Appendix A, Schedule 5.0, line 14	a	b	c=b−a	d=c/a	

May not add due to rounding

A significant component of BC Hydro's base operating costs is the power system maintenance costs.[305] The budget for this component is forecast to increase from an F2022 RRA Decision amount of $267.2 million to $281.6 million in F2023, $287.2 million in F2024, and $294.1 million in F2025. BC Hydro notes that the increase is primarily driven by vegetation management and an increase in stations asset maintenance to maintain the additional assets as the result of Site C Project. Both of these contributors are reflected above as key drivers for increases in base operating costs over the Test Period.[306] Power system maintenance work is necessary for assets to achieve the assets' expected performance throughout their lifecycle and ongoing maintenance is necessary to support improvements to vegetation management.[307] BC Hydro participates in benchmarking studies for its maintenance costs and performance for its substation, transmission and distribution operations and also for its generation facilities.[308] The benchmarking results show that BC Hydro's maintenance cost performance is either consistent with or lower than its utility peers. Specifically, BC Hydro's reports the following results from two independent expert consulting groups that provide maintenance benchmarking services:[309]

[304] Exhibit B-2, Section 5.1, Figures 5-1, p. 5-2.
[305] Exhibit B-2, Section 5.15.1, p. 5-176.
[306] Exhibit B-2, Section 5.15, p. 5-175; Section 5.15.2, p. 5-178.
[307] Exhibit B-2, Section 5.1, p. 5-5.
[308] Exhibit B-2, Section 5.15.3, p. 183.
[309] Exhibit B-2, Section 5.15.3.1, p. 5-183. The consulting groups are First Quartile (transmission and distribution); and Guidehouse (generation).

- Transmission distribution line operations and maintenance costs were below the average of the approximately 20 peer utilities included in these categories;[310]
- Operations and maintenance costs for its transmission and distribution stations were below average and only slightly above the first (i.e., best) quartile of the peer group;[311] and
- Ninety-two (92) percent of BC Hydro's 24 generation stations sampled were performing as expected or better than expected in maintenance and operations costs, where "better" represents lower costs than expected.[312]

BC Hydro notes that the benchmarking studies it completes represent one point of data in comparing the organization's performance to peers, and on their own are not used to make specific management decisions or draw definitive conclusions.[313] However, it adds where performance is different than the industry peers, additional review may be undertaken to understand the reasons.[314]

Panel Determination

The Panel has reviewed the evidence with respect to all of BC Hydro's operating costs forecasts in this proceeding, including the reasons BC Hydro provided for the changes in costs as compared to the 2022 RRA Decision amounts. Consistent with the BCUC's practice in previous BC Hydro RRAs, the Panel does not examine each element of BC Hydro's operating costs in minutiae. Instead, the Panel examines the reasonableness of the changes in operating expenditures along with BC Hydro's explanation for those changes, when compared against those approved by the BCUC in the F2022 RRA Decision. In addition, the Panel will review specific operating cost issues which have been identified by the BCUC and interveners to determine whether any adjustments to the proposed expenditures are warranted.

The Panel is satisfied that BC Hydro continues to benchmark its operating costs and performance in specified areas including its substation, transmission and distribution operations against a peer group of electric utilities. The Panel agrees with BC Hydro that benchmarking results are not determinative, but they can be a useful indicator of areas of possible concern where costs deviate significantly from the benchmark. Based on the results of its benchmarking studies, BC Hydro performs reasonably well in the noted categories and the Panel does not have concerns with respect to the forecast spending over the Test Period in these areas.

Subject to the specific adjustment made regarding the operating costs related to Connecting Customers under the Electrification Plan in Section 4.1 above, the Panel finds BC Hydro's forecast operating costs of $1.3205 billion, $1.3403 billion and $1.3602 billion to be recovered in F2023, F2024 and F2025 rates, respectively, are reasonable.

In the subsections below, the Panel reviews the issues arising and concerns raised with respect to the following matters:

- The Account Credits Direction which requires the BCUC to issue final orders to allow BC Hydro to establish an inflationary pressures regulatory account to defer the Specified Costs;[315]
- Labour costs, which are the largest contributor of the increase in uncontrollable costs and primarily include salary and benefit increases. Labour cost increases associated with incremental FTEs over the

[310] Exhibit B-2, Section 5.15.3.2, pp. 5-184–5-186.
[311] Exhibit B-2, Section 5.15.3.3, pp. 5-186–5-187.
[312] Exhibit B-2, Section 5.15.3.4, pp. 5-187–5-188.
[313] Exhibit B-2, Section 5.15.3, p. 183; Exhibit B-7, BCUC IR 52.5.
[314] Exhibit B-2, Section 5.15.3, p. 183.
[315] Exhibit B-49, Panel IR 1.7.

Test Period are separately included and discussed in the operating cost for the specific projects, investments or initiatives to which they relate, as applicable, in various subsections below;

- Reliability investments which include MRS, vegetation management and cybersecurity;
- Site C Clean Energy Project (Site C Project) operating costs; and
- The statistical benchmarking and performance metrics that monitor BC Hydro's effectiveness of managing base operating costs.

We reviewed issues related to BC Hydro's Electrification Plan and the associated operating costs earlier in Section 4.1 of this Decision.

Issues related to BC Hydro's strategic initiatives involving UNDRIP and the diesel reduction strategy in the NIA including the associated operating costs are discussed further in Section 5.4 of this Decision. The Panel considered that the issues raised with respect to these initiatives were important and distinct enough to warrant a discussion separately from their impact on BC Hydro's operating costs.

4.4.1 Inflationary Pressures Regulatory Account

As mentioned in Section 2.4.3 of this Decision, the BCUC issued Order G-341-22 pursuant to the Account Credits Direction,[316] which enabled BC Hydro to, among other things, establish an inflationary pressures regulatory account to defer the Specified Costs, which are defined as the variances between the Test Period forecast costs in the Application and the actual costs in relation to the following three items:

- Labour costs as set out in line 20 in Schedule 5 of Appendix A to the Application, other than the operating cost portion of current service pension costs;
- Vegetation management costs as set out in Table 5-27 of the Application, other than labour costs related to vegetation management; and
- Fuel costs as set out in lines 5 and 6 on page 5E-44 of chapter 5E of the Application, other than the portion of fuel costs allocated to capital overhead.

The forecast labour, vegetation management, and fuel costs for F2023, F2024 and F2025 as captured in the definition of the Specified Costs are included in BC Hydro's base operating costs.[317]

BC Hydro states that the full impact, including the magnitude and duration of "the current extraordinary inflationary environment" is not yet known, but provides an estimate of the base operating costs included in the definition of the Specified Costs in the Account Credits Direction.[318] Table 28 below provides BC Hydro's point-in-time estimate of the inflationary pressures for the specified base operating costs to be incurred for each year of the Test Period, the respective forecast operating costs included in the Application, and the estimated variance for F2023 to F2025.[319]

Table 28: F2023 to F2025 Estimated Variance[320]

[316] OIC 571,B.C. Reg. 224/2022, Direction to the BCUC Respecting Residential and Commercial Customer Account Credits..
[317] Exhibit B-50, BCUC IR SRP 3.274.4.
[318] Exhibit B-48, BCUC IR D2.iv; Exhibit B-49, Panel IR 1.7.
[319] Exhibit B-50, BCUC IR 1.7; Exhibit B-50, BCUC IR SRP 247.3.
[320] Exhibit B-50, BCUC IR 1.7.

	Estimate[321]			RRA[322]			Variance
	F2023 ($ millions)	F2024 ($ millions)	F2025 ($ millions)	F2023 ($ millions)	F2024 ($ millions)	F2025 ($ millions)	Total ($ millions)
Labour Costs	572	618	644	565	582	601	(85)
Vegetation Management Costs	71	84	88	69	73	77	(25)
Fuel Costs	8	8	8	5	5	5	(10)
Total	651	711	741	639	660	684	(120)

BC Hydro estimates spending $120 million more during the Test Period with respect to the Specified Costs categories and provides the following factors and assumptions supporting each of the point-in-time estimates:

1. Labour Costs

   BC Hydro states that the operating cost estimate for labour over the Test Period uses the following assumptions for salary increases for its employees and adds that these assumptions are consistent with the collective bargaining mandate established by the Public Sector Employers' Council:[323]

   - April 1, 2022: $0.25/hour plus 3.24 percent;
   - April 1, 2023: 6.75 percent. BC Hydro notes that the actual wage increase will be 5.5 percent to 6.75 percent depending on the change in the BC consumer price index (CPI) from March 1, 2022, to February 28, 2023, and adds that the average BC CPI rate of change for the period March 1, 2022, to November 30, 2022, was 7.41 percent; and
   - April 1, 2024: 3 percent. BC Hydro notes that the actual wage increase will be 2 percent to 3 percent depending on BC CPI from March 1, 2023, to February 29, 2024, and given the current rate of inflation, it assumed the maximum increase of 3 percent.

   BC Hydro noted that at the time of responding to information requests on the Account Credits Direction in December 2022, it has not yet concluded collective bargaining with its unions. It adds that the above increases are higher than the 2.0 percent per year increase included in the Application, as its filing was prior to the Public Sector Employers' Council establishing the collective bargaining mandate in the current inflationary environment.[324] We review the forecast salary increase over the Test Period in Section 4.4.2 below.

2. Vegetation Management Costs

   BC Hydro states that the operating cost estimate for vegetation management is derived by applying an average inflation rate determined through price increases finalized with contractors because of requests received related to labour, fuel, equipment, and travel and accommodation increases.[325]

   Specifically, in F2023, BC Hydro calculated $11 million in inflationary cost pressures based on contractor negotiations, using a bottom-up approach. BC Hydro applied this to F2024 and F2025 for a total of $33 million over the Test Period. However, for the point-in-time estimate presented in the above table, BC Hydro adjusted the annual estimated inflationary cost pressure down by $3 million, to account for the timing of revised contract prices coming into effect and reduced work volume on the distribution system for a

[321] Estimated "actual costs" incurred, as defined on page 3 of the Direction to the BCUC Respecting Residential and Commercial Customer Account Credits, B.C. Reg. 224/2022 (OIC 571).
[322] Forecast costs in the F2023 - F2025 Revenue Requirement Application, as defined on page 3 of Direction to the BCUC Respecting Residential and Commercial Customer Account Credits, OIC No. 571, B.C. Reg. 224/2022.
[323] Exhibit B-49, BCUC IR 1.7.
[324] Exhibit B-49, BCUC IR 1.7.
[325] Exhibit B-49, BCUC IR 1.7.

resulting total of $25 million over the Test Period. BC Hydro expects the inflation estimates for F2024 and F2025 will be revised as an outcome of the contract pricing negotiations that will occur each year.[326]

3. Fuel Costs

   BC Hydro estimates an increase of $3 million in annual fuel costs for each year of the Test Period[327] based on the published nominal fuel price of motor gasoline and diesel fuel forecast in the United States Energy Information Administration's Annual Energy Outlook report (Energy Outlook Report).[328] Despite the estimated inflationary increase in fuel costs from F2022 to F2023, BC Hydro notes that the Energy Outlook Report shows no expected percent change in the combined fuel price for motor gasoline and diesel fuel over the Test Period.[329]

In addition to the Specified Costs the Account Credits Direction also enables BC Hydro to transfer $74 million (credit) from the TIDA to the inflationary pressures regulatory account.[330] The additional $120 million BC Hydro estimates spending during the Test Period with respect to the Specified Costs categories exceeds the $74 million transferred to inflationary pressures regulatory account.[331] Based on BC Hydro's current projections, it expects to exhaust the entire $74 million by the end of F2024 or early in F2025. BC Hydro indicates that it may apply to the BCUC for a recovery mechanism for any remaining balance at that time.[332]

BC Hydro states that an alternative approach to address the additional $120 million in the Specified Costs is that the BCUC could direct BC Hydro to file an evidentiary update to the Application to include the additional forecast costs or the BCUC could direct BC Hydro to include the additional forecast costs in the Test Period via a compliance filing. However, if the BCUC determines to include these costs in the Test Period, then BC Hydro considers that the adjustment should be limited to $46 million (i.e. the difference between the $120 million and the $74 million credit that was transferred from the TIDA. However, in BC Hydro's view, these costs should not be included in the Test Period forecast due to the uncertainty of the estimates.[333]

If each of the cost categories were updated in the Test Period based on the estimated cost increases shown in Table 29, it would result in total annual bill increases of 0.2 percent, 0.7 percent, and 0.1 percent in F2023, F2024, and F2025, respectively, compared to the bill increases applied for in the Application.[334]

During the SRP, BC Hydro clarified that the Account Credits Direction does not limit the amounts being transferred to the inflationary pressures regulatory account to only variances due to inflation. BC Hydro also clarifies that it has the discretion to defer the variances since the Account Credits Direction uses the words "may defer." Further, BC Hydro states that the BCUC has full jurisdiction to review from a prudency perspective all of the amounts deferred to the regulatory account rather than only the amount in excess of the $74 million credit transfer from the TIDA.[335]

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[326] Exhibit B-50, BCUC IR SRP 3.246.2.
[327] Exhibit B-50, BCUC IR SRP 3.247.5.
[328] Exhibit B-49, BCUC IR 1.7; Exhibit B-50, BCUC IR SRP 3.247.5. BC Hydro notes that information from the Energy Outlook Report for calendar 2022, 2023 and 2024 was used as a proxy for BC Hydro's F2023, F2024 and F2025 (Exhibit B-50, BCUC IR SRP 3.247.5).
[329] Exhibit B-50, BCUC IR SRP 3.247.5.
[330] OIC 571, B.C. Reg. 224/2022 , Direction to the BCUC Respecting Residential and Commercial Customer Account Credits.
[331] Exhibit B-49, Panel IR 1.7.
[332] Exhibit B-48, p. 4.
[333] Exhibit B-51, BCSEA IR 101.1; 2023-01-16 SRP Transcript Volume 6, p. 1345, line 20 to p. 1347, line 20.
[334] Exhibit B-50, BCUC IR 247.6.
[335] 2023-01-16 SRP Transcript Volume 6, p. 1388, line 12 to p. 1391, line 12.

Positions of the Parties

In BC Hydro's view, the inflationary pressures on vegetation, labour and fuel are best addressed through the inflationary pressures regulatory account. BC Hydro submits that the $120 million increase in these cost items due to inflationary pressures is a point-in-time estimate based on current assumptions regarding the impact of inflation. The impact of the inflationary environment is uncertain despite these estimates being provided. While the BCUC can take the inflationary environment into consideration when it deliberates on the Application, in BC Hydro's view, there is no need to update the forecast for these cost items. BC Hydro suggests that the BCUC would not wish to increase the forecast by the $74 million that has already been transferred to the inflationary pressures regulatory account as it is now available to offset the impact of any inflationary pressures that may occur during the Test Period. Further, it would be preferrable not to increase the forecast for any potential impacts beyond the $74 million because it would result in rate increases based on an estimate of costs that may or may not materialize.[336]

MoveUP, BCSEA, the CEC, Zone II RPG, AMPC, RCIA, and BCOAPO all support not updating the labour, fuel, and vegetation management cost forecasts related to the Specified Costs.[337]

AMPC submits that since the inflationary pressures regulatory account has been established, the BCUC should evaluate BC Hydro's Test Period forecast spending without considering the effects of inflation.[338]

In reply to AMPC, BC Hydro submits that it would be "an error for the BCUC to ignore relevant evidence such as the current extraordinary inflationary environment and the effect of that environment on BC Hydro's costs." BC Hydro argues that the BCUC must consider the relevant evidence and the scope of the inflationary pressures regulatory account. BC Hydro submits that if the BCUC considers that BC Hydro's vegetation management, labour, and fuel costs are likely to exceed the forecast in the Application due to inflationary pressures, then rather than approve a forecast greater than applied for, it would be reasonable to rely on the inflationary pressures regulatory account to address the potential for variances from forecast due to inflation.[339]

RCIA recommends not updating BC Hydro's Test Period forecasts. Rather, it submits that labour, vegetation management, and fuel costs forecasts should continue to be included in the revenue requirement based on reasonableness and that the recovery of these cost items, to the extent forecast updates have been introduced through the inflationary pressures regulatory account, should be limited to the $74 million directed to be transferred from the TIDA into the inflationary pressures regulatory account, such that any amounts in excess should not be recoverable from ratepayers. RCIA also submits that "the BCUC should deny BC Hydro continued use of the inflationary pressures account beyond the present test period."[340]

In reply, BC Hydro submits that RCIA's recommendation to deny the recovery of any balance above the $74 million transferred must be rejected because it contradicts the clear wording of the Account Credits Direction and BCUC Order G-341-22. BC Hydro argues that RCIA's recommendation would effectively deny BC Hydro's ability to defer the Specified Costs. Further, BC Hydro argues that there is no evidence or rational basis for the BCUC to pre-emptively deny recovery because it is currently not known what amounts BC Hydro will defer to the inflationary pressures regulatory account. With respect to RCIA's submission regarding the closing of the inflationary pressures regulatory account, BC Hydro submits that this should be addressed in the ordinary course once any balance in the account has been cleared.[341]

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336 2023-01-23 SRP Transcript Volume 6, p. 1502, line 3 to p. 1504, line 4.
337 MoveUP SRP Final Argument, p. 1; BCSEA SRP Final Argument, pp. 1–2; CEC SRP Final Argument, pp. 3 – 4; Zone II RPG SRP Final Argument, p. 2; AMPC SRP Final Argument, p. 3; BCOAPO SRP Final Argument, pp. 8, 12; SRP Final Argument, pp. 5, 7.
338 AMPC SRP Final Argument, pp. 3, 17 – 18.
339 BC Hydro SRP Reply Argument, pp. 20 – 21.
340 RCIA SRP Final Argument, pp. 5, 7.
341 BC Hydro SRP Reply Argument, pp. 19 – 20.

BCOAPO submits that labour, vegetation management and fuel costs that are included as the Specified Costs do not need to be updated because of the establishment of an inflationary pressures regulatory account and the transfer of $74 million that offsets the variances captured in the regulatory account. It also submits that the recovery of any outstanding balance in this regulatory account should be addressed as part of BC Hydro's next RRA, which would allow for a "full testing" of the requested amounts.[342]

In reply to BCOAPO, BC Hydro notes that its next RRA-related filing will be its PBR Plan in December 2023, which would be too early to review the balance in the inflationary pressures regulatory account. BC Hydro submits that at the appropriate time, it will apply to recover the balance in the regulatory account and there is no need to identify the exact timing or filing at this time.[343]

Panel Discussion

The Accounts Credit Direction removes the BCUC's discretion to review the amounts that BC Hydro may choose to defer on account of the Specified Costs into the inflationary pressures regulatory account during the Test Period. Similarly, the BCUC must allow BC Hydro to transfer $74 million from the TIDA into the inflationary pressures deferral account to offset the balance in the latter account. While BC Hydro has provided a point in time estimate of the projected variances between the amounts forecast for those costs during the Test Period and anticipated actuals, those variances are based on current forecasts of inflation that are subject to considerable uncertainty.

Notwithstanding, the Panel agrees with BC Hydro that there is no need to update the current forecasts for the Specified Costs, which are simply part of many categories of costs forming the entirety of BC Hydro's revenue requirement for the Test Period. There is no justification for the Panel to single out the Specified Costs as requiring updated forecasts when it has not done so in respect of other forecasts which may well have changed materially since the filing of the Application. The Panel is mindful as well that reforecasting the Specified Costs for the Test Period would entail increasing rates to capture the recovery of the estimated $120 million shortfall, which may or may not materialize. Lastly, the Panel notes that even if the actual Specified Costs for the Test Period exceed the forecasts and BC Hydro opts to defer all of the variances to the inflationary pressures regulatory account, the BCUC retains the discretion to determine whether any or all of the balance in that account is recoverable from ratepayers. Nothing in the Account Credits Direction precludes the BCUC from doing so.

As for RCIA's submission that BC Hydro's recovery of the balance in the inflationary pressures regulatory account should be limited to the $74 million directed to be transferred from the TIDA into the former, such that any amounts in excess should not be recoverable from ratepayers and that the BCUC should deny BC Hydro continued use of the inflationary pressures regulatory account beyond the Test Period, we reject that recommendation. We agree with BC Hydro that RCIA's recommendation would effectively deny BC Hydro's ability to defer Specified Costs and would therefore be contrary to the wording and intent of the Account Credits Direction. Furthermore, we agree with BC Hydro that there is no evidence or rational basis for the BCUC to pre-emptively deny recovery because it is currently not known what, if any, amounts BC Hydro will defer to the inflationary pressures regulatory account. With respect to RCIA's submission regarding the timing of the closing of the inflationary pressures regulatory account, we find that this should be addressed in the ordinary course once any balance in the account has been cleared.[344]

As for BCOAPO's submission that the recovery of any outstanding balance in the inflationary pressures regulatory account should be addressed as part of BC Hydro's next RRA, which would allow for a "full testing" of the requested amounts, we share BC Hydro's concern that with the anticipated filing of its PBR Plan in

[342] BCOAPO SRP Final Argument, pp. 8, 12.
[343] BC Hydro SRP Reply Argument, p. 19.
[344] BC Hydro SRP Reply Argument, pp. 19 – 20.

December 2023, that may be too early to review the balance in the inflationary pressures regulatory account. We therefore accept BC Hydro's proposal to apply to recover the balance in the regulatory account at an appropriate time. We find there is no need to identify the exact timing of that filing at this juncture and in any event, as we have already noted above, the account should only be closed once any balance therein has been cleared.

4.4.2 Operating Labour Costs

Salary and benefit cost increases account for $39.8 million of the operating labour costs over the Test Period.[345] The following table provides the annual operating labour cost increases broken down by their key components:

Table 29: Annual Increase in Operating Labour Costs Broken Down by Component[346]

	F2022 RRA Decision to F2023 Plan ($ millions)	F2023 Plan to F2024 Plan ($ millions)	F2024 Plan to F2025 Plan ($ millions)
Salaries (e.g., regular time, overtime, union gainshare, holdback pay)	8.6	9.9	10.1
Employer Health Tax, CPP and EI	1.1	1.5	2.0
Extended Health and Dental	0.4	1.1	2.2
Other Benefits	0.6	1.0	1.4
Labour Costs	**10.7**	**13.4**	**15.7**

The key driver of the increase in operating labour costs is salaries. BC Hydro forecasts salaries to increase by 2.0 percent for both union as well and management and professional staff in each year of the Test Period.[347] The 2.0 percent annual salary increase was determined in alignment with 2021 forecasted median market salary increases,[348] as well as BC Hydro's five-year strategic goal to control its costs and is within the range of the Public Sector Employers' Council guidelines.[349] BC Hydro adds that according to the CBoC's Compensation Planning Outlook 2021 report, the forecast median market salary increase for 2021 was 2.1 percent.[350] However, it notes that in September 2021, the CBoC released a Compensation Planning Outlook report for 2022 which forecast salary increases to be higher in 2023, at 2.4 percent on average as the economy recovers from COVID-19. As a result, BC Hydro states its forecast salary increase of 2.0 percent in F2023 will be lower than the forecast market salary increase of 2.4 percent and salaries will not keep pace with forecast market salary increases.[351]

BC Hydro considers management and professional compensation increases to be a priority and a non-controllable cost given how BC Hydro's employee compensation compares to that of the median market and that the increase is essentially a cost-of-living increase. BC Hydro adds that there were no salary increases for management and professional staff in F2022.[352]

Positions of the Parties

Interveners either support or do not oppose BC Hydro's forecast labour costs. However, the CEC and AMPC raised concerns with BC Hydro's characterization of labour costs increases as uncontrollable.

345 Exhibit B-2, Section 5.5.3.1, p. 5-27.
346 Exhibit B-7, BCUC IR 39.9.
347 Exhibit B-2, Section 5.5.3.1, p. 5-25; Section 5.12, p. 5-156.
348 Exhibit B-2, Section 5.5.3.1, p. 5-25; Section 5.12, p. 5-156.
349 Exhibit B-7, BCUC IR 39.4.
350 Exhibit B-2, Section 5.5.3.1, p. 5-28; Exhibit B-7, BCUC IR 39.4.
351 Exhibit B-7, BCUC IRs 39.4 and 39.5.
352 Exhibit B-2, Section 5.5.3.1, p. 5-28.

The CEC maintains that “managing labour costs is a direct management responsibility and that these are not uncontrollable costs.” It adds that the BCUC “should not endorse such language” being used by a utility with respect to its management of costs.[353]

AMPC states that BC Hydro “controls the ability to manage overall labour costs including levels of FTEs and prioritization of activities undertaken” and BC Hydro does not explain why reductions in the controllable aspects of labour costs have not been considered.[354]

In reply, BC Hydro submits that the characterization of labour costs as uncontrollable is fair in the context of this proceeding, noting that labour cost increases are driven primarily by increases in employee salaries and benefits. It adds that a government agency, the Public Sector Employers’ Council, sets the compensation guidelines for public sector employees.[355]

Panel Discussion

On balance, the Panel is satisfied with BC Hydro’s forecast increase in salaries and benefits and the methodology it used to arrive at the forecast increase which is consistent with that used in prior RRAs.

The Panel strongly disagrees, however, with BC Hydro that labour costs are uncontrollable costs, because the utility has ultimate control over such matters as the number of employees, salaries for its management and professional employees and overtime costs. The Panel notes that BC Hydro’s logic, if taken to the extreme, would suggest that all costs should be considered uncontrollable if one component of those costs (e.g., public sector employee wage increases in BC) is outside the utility’s control. BC Hydro’s argument does not address the constant changes and difficult cost cutting measures that other companies must take to reduce labour costs in the face of rising prices including increasing productivity, reducing FTEs, controlling overtime, and moving towards automation. BC Hydro should not expect to be insulated from those challenges simply because it is a regulated utility operating under a cost of service regime currently.

4.4.3 Mandatory Reliability Standards Costs

In the Application, BC Hydro originally proposed a total budget of $78.2 million for MRS operating costs for the Test Period.[356] The F2022 RRA Decision includes ongoing annual operating costs of $4.7 million which are carried over annually during the Test Period and thus totalling $14.1 million for the Test Period. Accordingly, the incremental budget increase for MRS operating costs during the Test Period is $64.1 million ($78.2 million minus $14.1 million) as proposed by BC Hydro.[357]

Included in BC Hydro’s original total Test Period budget for MRS costs of $78.2 million is $3.9 million for the implementation of the Planning Coordinator function. BC Hydro explains that following the BCUC’s adjournment of the proceeding to review the adoption of reliability standards applicable to the Planning Coordinator function (Planning Coordinator Assessment Report), it proposes to deduct the $3.9 million from its budget in a compliance filing following the determination of the Application, resulting in a reduced MRS budget of $74.3 million over the Test Period.[358] BC Hydro submits that any costs incurred as a result of new MRS adopted as an outcome of the Planning Coordinator Assessment Report proceeding would be eligible for deferral to the MRS

[353] CEC Final Argument, para. 40, p. 5; para. 458, p. 70.
[354] AMPC Final Argument, Section I(A), para. 18(c), p. 3.
[355] BC Hydro Reply Argument, Part 5, Section B, para. 72, p. 25.
[356] Exhibit B-2, Section 5.7, p. 5-49.
[357] Exhibit B-2, Section 5.7, pp. 5-48–5-49.
[358] Exhibit B-20, BCOAPO IR 120.1.

Costs Regulatory Account.[359] The treatment of the MRS Costs Regulatory Account is further discussed in Section 4.4.3 of this Decision.

The following table provides a summary of the revised planned MRS related operating cost budget of $74.3 million, including the planned increases and decreases to the budget for each year of the Test Period:

Table 30: F2023 to F2025 Proposed Revised MRS Operating Costs[360]

($ millions)	F2022 RRA	F2023 Increase	F2023 Plan	F2024 Increase	F2024 Decrease	F2024 Plan	F2025 Increase	F2025 Decrease	F2025 Plan
Strengthening Our MRS Program									
Implement Mitigation Plans	-	2.3	2.3	-	(1.8)	0.6	-	(0.3)	0.3
Investments in Program Sustainment	4.7	12.3	17.0	2.9	(3.3)	16.5	-	-	16.5
Program Assurance	-	1.1	1.1	0.8	-	1.9	-	(0.8)	1.1
Sub-Total Strengthen Our Program	4.7	15.7	20.4	3.6	(5.1)	19.0	-	(1.0)	18.0
New Standards									
Implement New Standards	-	0.7	0.7	-	(0.7)	-	-	-	-
Sustain New Standards	-	4.6	4.6	1.1	-	5.7	0.5	-	6.2
Sub-Total New Standards	-	5.2	5.2	1.1	(0.7)	5.7	0.5	-	6.2
Total	**4.7**	**20.9**	**25.6**	**4.7**	**(5.7)**	**24.6**	**0.5**	**(1.0)**	**24.1**

The main driver of the increase in the Test Period MRS operating costs is investments in program sustainment. BC Hydro states that over the last decade, its approach with MRS investments was discrete in nature with a capital project implementation mindset and it did not separately budget or track MRS sustainment. Instead, costs related to MRS sustainment were embedded within the work across the organization.[361] However, with the electric grid and MRS compliance becoming more complex, BC Hydro states that it has become necessary to transition to a more programmatic approach and specifically, one that reflects increased investment in the overall MRS program structure to better facilitate sustainment of the current and future MRS program.[362] BC Hydro states that the investments it is making in MRS over the Test Period reflect its continued commitment to strengthening the MRS program and that these investments are necessary and prudent to mature the MRS program and will continue to enable a strong compliance program going forward.[363]

As already noted, the F2022 RRA Decision approved $21.7 million for MRS operating costs including $4.7 million of ongoing costs.[364] BC Hydro explains that of its $21.7 million total investment in MRS in F2022, the remaining $17.0 million, approximately 80 percent, were one-time costs driven by mitigation activities and that while it continues to undertake some activities identified by the Western Electricity Coordinating Council, mitigation work has largely been completed in F2022.[365] In contrast, BC Hydro's funding for investments in program sustainment and sustaining new standards will represent more than 80 percent of the budget in F2023 and rises to approximately 95 percent of the budget in F2025.[366] BC Hydro states that the planned investment over the Test Period will shift the MRS program from a mitigation focus to a sustainment focus and that this approach is intended to systematically reduce the risk of non-compliance across the MRS program.[367]

[359] Exhibit B-20, BCOAPO IR 120.1.
[360] BC Hydro Final Argument, p. 39.
[361] Exhibit B-2, Section 5.7.4, p. 5-59.
[362] Exhibit B-2, Section 5.7.4, p. 5-59.
[363] Exhibit B-2, Section 5.7.4, pp. 5-59–5-60.
[364] Exhibit B-2, Section 5.7.6, p. 5-70.
[365] Exhibit B-2, Section 5.7.4.1, p. 5-60; Exhibit B-7, BCUC IR 72.2.
[366] Exhibit B-7, BCUC IR 72.2.
[367] Exhibit B-2, Section 5.7.4.2, pp. 5-61–5-62.

BC Hydro states that new standards adopted by the BCUC are also an additional cost driver in the Test Period.[368] BC Hydro explains that the primary new standard driving this cost is Critical Infrastructure Protection (CIP) version 7, which will require BC Hydro to expand CIP compliance to 18 generating stations, 115 transmission substations and thousands of additional cyber assets.[369] BC Hydro clarifies that the MRS planned spending includes costs related to CIP standards, but there is no overlap with the cybersecurity budget,[370] which is discussed in Section 4.4.5 (Cybersecurity Costs) of this Decision.

Positions of Parties

BCSEA submits that it takes no position regarding the costs in BC Hydro's MRS budget.[371]

The CEC recommends that the BCUC approve BC Hydro's MRS funding.[372]

BCOAPO states that given BC Hydro has proposed to remove the $3.9 million of spending over the Test Period related to the implementation of the new Planning Coordinator function, the $2.1 million allocated for the sustainment of the Planning Coordinator function should also be removed. BCOAPO requests that BC Hydro address this issue in its Reply Argument.[373]

In BC Hydro's Reply Argument, it submits that $3.9 million of spending relates to the implementation of the Planning Coordinator Assessment Report standards for the province-wide function.[374] In contrast, BC Hydro submits that the $2.1 million relates to sustainment activities for the Planning Coordinator function for BC Hydro's own Bulk Electric System (BES) assets for the standards currently in effect in BC, and that BC Hydro has been fulfilling that function since February 1, 2022. BC Hydro therefore contends that the $2.1 million is still required.[375]

Panel Determination

Apart from BCOAPO, interveners either take no position or support the inclusion of the revised MRS operating costs of $74.3 million in BC Hydro's revenue requirement for the Test Period. We agree with the latter group of interveners that the budgeted amount is reasonable. We accept BC Hydro's explanation that the increase in MRS costs over the previous test period relates primarily to increased funding for investments in program sustainment and implementing new standards, which will represent more than 80 percent of the budget in F2023, rising to approximately 95 percent of the budget in F2025.[376] This investment over the Test Period is intended to shift the MRS program from a mitigation focus to a sustainment focus in order to systematically reduce the risk of non-compliance across the MRS program.[377] An additional cost driver in the Test Period is increased costs relating to the implementation of the new CIP version 7 standards which were recently adopted by the BCUC. We find the increases to be reasonable for these reasons.

We reject BCOAPO's suggestion that because BC Hydro plans to remove $3.9 million from its original budget of MRS operating costs over the Test Period related to the implementation of the new Planning Coordinator function, it should similarly remove the $2.1 million allocated for the sustainment of the Planning Coordinator function. BC Hydro correctly removed the $3.9 million from its proposed MRS budget for the Test Period to

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[368] Exhibit B-2, Section 5.7.5, p. 5-63.
[369] Exhibit B-2, Section 5.7.5.2, p. 5-66.
[370] BC Hydro Final Argument, p. 42.
[371] BCSEA Final Argument, p. 15.
[372] CEC Final Argument, p. 61.
[373] BCOAPO Final Argument, pp. 25–26.
[374] BC Hydro Reply Argument, p. 26.
[375] BC Hydro Reply Argument, p. 26.
[376]Exhibit B-7, BCUC IR 72.2.
[377] Exhibit B-2, Section 5.7.4.2, pp.5-61–5-62.

reflect the fact that the proceeding dealing with the adoption and implementation of the standards relating to the Planning Coordinator function for the Province of BC has been adjourned pending a BCUC review in a separate but related BCUC proceeding which is ongoing. Thus, there is no certainty as to the timeframe within which BC Hydro would become the Planning Coordinator for the Province and if so, upon what terms. In the meantime, however, BC Hydro is still required to carry out its activities for the Planning Coordinator function for its own BES assets for the MRS standards currently in effect in BC, which it has been doing since February 1, 2022. Accordingly, the $2.1 million in sustainment costs for those activities is still required and appropriately forms part of BC Hydro's overall MRS operating costs for the Test Period.

The Panel directs BC Hydro, as part of its Compliance Filing, to deduct $3.9 million from its original budget of MRS operating costs over the Test Period related to the implementation of the new Planning Coordinator function.

4.4.4 Vegetation Management Costs

BC Hydro's vegetation management budget is based on its new Vegetation Management Strategy (VMS), which was filed as Appendix G to the Application.[378] BC Hydro's planned vegetation management expenditures for the Test Period include an $8.1 million incremental increase for F2023 over F2022 RRA Decision amounts, followed by increases of $4.0 million in F2024 and $4.8 million in F2025.[379] BC Hydro provides a breakdown of the annual vegetation management cost increases as follows:

Table 31: Summary of Test Period Vegetation Management Funding[380]

($ million)	F2022 Decision	LiDAR	Incremental Funding	F2023 Plan	Incremental Funding	F2024 Plan	Incremental Funding	F2025 Plan
Transmission Vegetation Maintenance	33.3	3.9	1.7	38.9	1.1	40.0	2.0	41.9
Distribution Vegetation Maintenance	36.1		3.9	40.1	3.3	43.3	3.6	46.9
Access Maintenance	1.0		2.7	3.7	0.2	3.9	-	3.9
Total Gross	**70.5**	**3.9**	**8.4**	**82.7**	**4.5**	**87.2**	**5.6**	**92.8**
Distribution Vegetation Recoveries (TELUS)	(6.9)		(0.3)	(7.2)	(0.5)	(7.7)	(0.8)	(8.5)
Total Net of Recoveries	**63.5**	**3.9**	**8.1**	**75.5**	**4.0**	**79.5**	**4.8**	**84.3**

In the F2022 RRA Decision, the BCUC directed BC Hydro to file its new VMS with its 2023 RRA. In the same decision, the BCUC approved an approximately 50 percent increase in vegetation management expenditures, with that Panel accepting that "the status quo over the previous twelve years has not been sustainable and has led to an environment of increased risk," and noting it supports "BC Hydro's commitment to reducing vegetation risk and improving reliability on its transmission and distribution systems."[381]

The F2022 RRA Decision recognized that the approved F2022 budget represented the maximum amount BC Hydro believed it could prudently manage at that time as it transitioned to its new VMS.[382] However, that Panel questioned whether BC Hydro was adequately supporting the distribution system's vegetation management and requested BC Hydro to elaborate on its long-term plan to address vegetation risk and reliability on the distribution system in its new VMS.[383]

<u>Vegetation Management Strategy Overview</u>

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[378] Exhibit B-2, p. 5-95.
[379] Exhibit B-2, p. 5-95; Appendix G (amounts presented include Standard Labour Rate changes of ($0.1) million in fiscal 2023, $0.1 million in fiscal 2024, and $0.2 million in fiscal 2025; Application, p. 5-95, Footnote 232).
[380] Exhibit B-2, p. 5-95, Table 5-27.
[381] BC Hydro Fiscal 2022 RRA,Decision and Order G-187-21, pp. 40, 41.
[382] BC Hydro Fiscal 2022 RRA, Decision and Order G-187-21, p. 41.
[383] BC Hydro Fiscal 2022 RRA, Decision and Order G-187-21, p. 41.

When developing the VMS strategy, BC Hydro set goals related to safety, reliability, compliance, access, and stewardship to define the desired outcomes from the delivery of vegetation management activities.[384] BC Hydro evaluated different clearing approaches on estimated costs, resource availability, system reliability impact, vegetation risk, compliance risk, delivery complexity, delivery risk, unit cost, and public impact, and selected a stable annual vegetation maintenance approach as the best option among those considered. [385]

Based on the overall goals and selected approach, BC Hydro set specific actionable objectives of the program and determined specific work volumes to achieve these objectives. The identified objectives are:[386]

- Plan and implement an effective vegetation management program across the province that ensures sustainable mitigation of the risk posed by regular annual growth, notable events (infestations, droughts, climate impacts, etc.) and storms;
- 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;
- Strengthen compliance assurance within vegetation program delivery and processes;
- Manage climate change impacts and risks (e.g., wildfires, storm resiliency, tree health from drought, flooding, disease and other impacts);
- Secure vegetation management resources and ensure supply;
- Maximize efficacy of vegetation investment (e.g., treatment longevity, vegetation and access inspections combined, etc.); and
- Optimize vegetation management delivery.

For the transmission system, BC Hydro identified a minimum work level based on maintaining an average system-wide maintenance cycle of five years, which is intended to address vegetation risks in advance of a potential problem. BC Hydro also notes that transmission maintenance volumes are expected to be increased during the Test Period in order to address the highest risk accumulation and support a shift to a stable approach in the years following.[387] Ground inspections will be conducted annually and be augmented by enhanced modelling through a Light Detection and Ranging (LiDAR) program which will cover at least 20 percent of the system each year.

Planned distribution clearing volumes were also calculated based on an average system-wide maintenance cycle of five years. BC Hydro states:[388]

> Over the Test Period, BC Hydro plans to increase annual pruning volumes on the distribution system by approximately 25 per cent compared to F2022 amounts. In addition, BC Hydro is planning to remove approximately 40,000 hazard trees in F2023 so that the documented inventory is fully cleared, and a stable, ongoing maintenance level can be established.

BC Hydro also plans to increase the frequency of its visual inspections on the distribution system to once every three years, moving towards the identified optimal level of once every two years by F2025. [389] BC Hydro states, "This frequency is intended to allow for proactive identification of 6 potential risks that would impact reliability

[384] Exhibit B-2, pp. 5-99 – 5-100.
[385] Exhibit B-2, p. 5-102.
[386] Exhibit B-2, p. 5-102.
[387] Exhibit B-2, p. 5-105.
[388] Exhibit B-2, p. 5-107.
[389] Exhibit B-2, p. 5-110.

and safety on the distribution system."[390] In access areas, facilities and properties, BC Hydro also plans to increase vegetation management in terms of inspection frequency and maintenance conducted, as access has become impaired in many locations.[391]

BC Hydro submits that it engaged an external consultant, Guidehouse, to review the VMS and BC Hydro's planned vegetation management capabilities and practices. Guidehouse concluded that BC Hydro's VMS was consistent with or slightly exceeded industry practices.[392] BC Hydro also submits its strategy is validated by a report from the CEA, which in BC Hydro's submission "demonstrated that BC Hydro's overall approach to vegetation management is consistent in terms of approach other Canadian utilities engage."[393]

Test Period Funding

BC Hydro's budget includes $0.9 million for an additional six vegetation coordinators and two vegetation specialists to support increased activity levels. BC Hydro submits that these resources are needed to deliver the vegetation management program effectively given the expected increase in work volumes.[394]

LiDAR accounts for a $3.9 million addition to the vegetation management budget beginning in F2023. BC Hydro submits that this amount was reclassified from an operating to a maintenance expense, consistent with other inspection expenditures.[395] As this amount was previously considered a planning operational cost, its inclusion in the vegetation management budget has no net impact on the overall O&M budget.[396]

The majority of the vegetation management budget is allocated to contractor costs to perform the work required in the field.[397] BC Hydro submits that it used the necessary amount of work indicated by its VMS and its contract rates for the units needed to calculate the vegetation management budget for the Test Period.[398] BC Hydro notes that its existing contracts cover the Test Period, affording a degree of certainty over rates, and submits that these contracts are competitively sourced and represent current market rates.[399]

BC Hydro submits that it "used actual historical work types (from completed work orders) and financial actuals to develop the model which in turn produced the Test Period budget."[400] BC Hydro also confirmed that pricing is based on specific unit types broken down by region, stating, "we actually break those units from F20 and '21 that we used historical numbers in the different regions and by different FERC [Federal Energy Regulatory Commission] class. So whether it's hot spotting or pruning or hazard trees. So all that, sort of, variability across the province is taken into account in terms of projecting it into the future."[401]

BC Hydro also provided a comparison of its planned expenditures for the Test Period with industry benchmarks, demonstrating that its planned spending aligns with the industry range and remains below industry averages.[402]

Performance Metrics

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390 Exhibit B-2, p. 5-110.
391 Exhibit B-2, p. 5-110.
392 Exhibit B-2, p. 5-117.
393 Exhibit B-2, p. 5-117.
394 Exhibit B-2, p. 5-111
395 Exhibit B-2, p. 5-95; Exhibit B-7, BCUC IR 51.1.
396 Exhibit B-2, p. 5-95; p.5-179, Table 5-45.
397 Exhibit B-2, p. 5-111.
398 Exhibit B-2, p. 5-110.
399 Exhibit B-2, p. 5-110; Exhibit B-19, BCUC IR 2.181.1.2.
400 Exhibit B-19, BCUC IR 187.1.
401 2022-09-22 Oral Hearing Transcript Volume 4 PM, p. 1137 lines 12 – 18.
402 Exhibit B-2, pp.5-113 – 5-116.

BC Hydro summarizes its performance metrics and targets to monitor and evaluate the outcomes resulting from the VMS in Table 5-31 of the Application, as reproduced below:[403]

Table 32: Vegetation Management Performance Metrics and Targets

	Inputs (i.e., Planned Investment)	**Outputs (i.e., Target)**	**Outcomes**
Transmission	\$38.9 million in F2023 \$40.0 million in F2024 \$41.9 million in F2025	6700-8600 hectares cleared / year 30,000-40,000 trees addressed / year 100 percent annual inspections 20 percent LiDAR / year	Compliance with required standards. Reliable and safe operation of the transmission system.
Distribution	\$40.1 million in F2023 \$43.3 million in F2024 \$46.9 million in F2025	3.1 to 3.3 million meters pruned each year by fiscal 2025; 26,000 to 30,000 hazard trees removed each year (higher level in F2023 for addressing inventory) Remaining trees in the distribution hazard tree inventory reduced to zero by the end of fiscal 2023	30 percent reduction in outages caused by vegetation by fiscal 2025
Access	\$3.7 million in F2023 \$3.9 million in F2024 \$3.9 million in F2025	All access areas, facilities and properties inspected by fiscal 2025. A priority based workplan developed with high priority items addressed in the same year.	Improved access to assets and easier movement of resources to maintenance areas Reduced risk of access impairment Properties and facilities in compliance with required regulations

BC Hydro expects that achieving these outputs will reduce outages caused by vegetation by approximately 30 percent by F2025, maintain compliance with required standards, including MRS, and promote ongoing safe and reliable operation of the transmission system.[404]

Positions of the Parties

BC Hydro submits that it has absorbed vegetation management cost increases in recent years through efficiency measures and reduced volumes, but this approach is no longer sustainable. Increased activity levels are required to mitigate growing reliability, safety, fire, and compliance risk. BC Hydro views that the planned incremental funding relative to the F2022 RRA Decision is required to address vegetation that has accumulated over successive years of reduced activity and implement a Stable Annual Vegetation Maintenance approach.[405]

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[403] Exhibit B-2, pp.5-118 – 5-119, Table 5-31.
[404] Exhibit B-2, pp. 5-119 – 5-120.
[405] BC Hydro Final Argument, p. 45.

AMPC and RCIA do not support the level of funding requested by BC Hydro and recommend that the BCUC set the Test Period vegetation management spending at the same level as approved for F2022, in real dollar terms.[406]

AMPC supports the implementation of a "stable annual vegetation maintenance" approach, similar to the approach proposed by BC Hydro. However, AMPC does not agree with the requested budget for vegetation management.[407] AMPC states that, "This "step change" is speculative and hence ultimately unsupported. Rather than prudent spending on necessary activities, it reflects an aspirational discretionary spending envelope, inconsistent with proper rate regulation. BC Hydro's myriad and consistently shifting justifications for this spending inhibit BCUC supervision."[408]

AMPC submits:[409]

> BC Hydro has failed to meet its onus to justify the requested vegetation management spending during the test period, and has failed to show that it has sought or achieved proper cost efficiencies and pacing of vegetation management activities. During the oral hearing BC Hydro's justifications consistently migrated and evolved and belie the rationales advanced in the Application. But on that front, in its Application:
>
> (i) BC Hydro has failed to demonstrate that it has achieved the cost efficiencies a "Stable Annual Vegetation Management" approach should provide;
>
> (ii) BC Hydro's bidding process for vegetation management contractors failed to prioritize cost control;
>
> (iii) The dramatic increase in BC Hydro's unit costs demonstrates a lack of cost control; and
>
> (iv) BC Hydro has failed to justify the vegetation management activity levels that it proposes for the Test Period and does not demonstrate prioritization of activity to control costs; […]

BC Hydro refutes the arguments put forth by AMPC regarding vegetation management spending. BC Hydro states that adopting the proposed budget by AMPC would be insufficient to meet the VMS objectives and result in poor outcomes.[410] BC Hydro submits it has provided significant evidence to justify the proposed VMS, and that the cost of work results from empirically calculated amounts of work and competitive bidding for the work.[411]

BC Hydro submits that AMPC's critique of BC Hydro's procurement process, "is overly simplistic, and fails to recognize that lowest bid does not guarantee the most cost-effective outcome."[412] BC Hydro points out that price is already heavily weighted in its procurement process, being weighted at 60 percent in its Transmission request for proposals (RFP). The Distribution RFP weighed "Overall annual and long-term cost to BC Hydro using BC Hydro's forecasted needs and Proposal pricing" at 25 percent, but also incorporated cost as a component in two other equally-weighted evaluation criteria.[413] BC Hydro states that increasing weighting on price would compromise weighting on other important factors such as compliance, reliability, safety, and fire risk.[414]

[406] AMPC Final Argument, p. 4; RCIA Final Argument, p. 79.
[407] AMPC Final Argument, p. 2-9.
[408] AMPC Final Argument, p. 2-2.
[409] AMPC Final Argument, p 2-4.
[410] BC Hydro Reply Argument, p.40.
[411] BC Hydro Final Argument, p. 39.
[412] BC Hydro Reply Argument, p.45.
[413] BC Hydro Reply Argument, pp.45 – 46.
[414] BC Hydro Reply Argument, p. 46.

RCIA submits that the evidentiary record demonstrates that the proposed increased spending in the Test Period is not justified by the historical vegetation growth and removal data,[415] and that BC Hydro has not demonstrated that the proposed increases in vegetation management spending will produce reliability improvement outcomes commensurate with the incremental costs.[416] RCIA submits that BC Hydro's strategy "represents a departure from its historical risk-based strategy of managing costs by not removing trees that do not require removal in the year they are identified, to a risk-insensitive strategy of removing all hazard trees in the year they are identified, regardless of their hazard ratings, the risk they pose, and/or the cost of removal."[417]

RCIA submits that, "If more spending for additional vegetation management activities does not noticeably improve service reliability at customer premises, customers will not want to pay those additional costs."[418] RCIA highlights BC Hydro submissions that customers care primarily about all-events outages as measured by System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), because customers typically do not know about the cause of an outage.[419] In RCIA's view, BC Hydro's evidence does not predict a significant improvement in reliability during extreme events, almost regardless of vegetation management spending.[420]

In reply to RCIA's submissions above. BC Hydro believes it has demonstrated the reliability, safety, and compliance benefits of its VMS approach, and BC Hydro has provided evidence to support its empirically calculated volumes of work and costs which result from competitive bidding.[421] BC Hydro submits that RCIA's emphasis of all-events outages treats the compliance, safety, and fire implications of vegetation contacts as an afterthought rather than integral objectives of a vegetation management program. [422] Even using RCIA's preferred reliability metrics of all-events SAIDI/SAIFI, BC Hydro submits there is still a reasonable correlation between vegetation management activities and improved reliability.[423]

RCIA also raised concerns that BC Hydro's metric for distribution forced outages that originated by vegetation should include a target based on hours rather than based on percentage terms. BC Hydro notes that the proposed measure is industry standard. However, BC Hydro states that it is willing to provide results in actual hours as part of the next RRA.[424]

BCSEA, MoveUP, and BCOAPO either support or do not object to BC Hydro's new VMS.[425] However, BCOAPO requests that the BCUC direct BC Hydro to report on the continued appropriateness of using a five-year cycle for distribution in its next RRA and to also report the number of hours of outage due to vegetation as a measure of success of the VMS to facilitate better evaluation going forward.[426]

In reply to BCOAPO's request to report on the continued appropriateness of a five-year cycle, BC Hydro does not believe there is any benefit in this type of reporting, given that the five-year approach has already been validated. BC Hydro submits that vegetation growth rates and asset health are unlikely to change in the three-year period before the next RRA.[427]

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[415] RCIA Final Argument, p. 11.
[416] RCIA Final Argument, p. 93.
[417] RCIA Final Argument, p. 92.
[418] Exhibit C8-9, p. 15.
[419] RCIA Final Argument, p. 88.
[420] RCIA Final Argument, p. 88.
[421] BC Hydro Reply Argument, p. 39.
[422] BC Hydro Final Argument, p. 57
[423] BC Hydro Final Argument, pp. 57–58
[424] BC Hydro Final Argument, p. 80.
[425] BCSEA Final Argument, p. 16; MoveUP Final Argument, p. 5; BCOAPO Final Argument, pp. 30 – 31.
[426] BCOAPO Final Argument, pp. 31, 33.
[427] BC Hydro Reply Argument, p. 29.

The CEC supports approval of the vegetation management budget. However, it recommends that the BCUC direct BC Hydro to tailor its Test Period VMS approach to allow for "first work priority" in areas with the highest vegetation related reliability hazards.[428] The CEC also submits that the BCUC should direct BC Hydro to develop local line reliability data in respect of priority lines.[429]

In reply to the CEC, BC Hydro submits that the focus of CEC's approach is too narrow to be effective and is similar to the hot-spotting / triage only approach that BC Hydro evaluated as an alternative and rejected.[430] BC Hydro evaluated this approach as least favorable of those considered in all but two categories, and less cost effective than the proposed VMS.[431] As a result, BC Hydro submits that BC Hydro's well-developed stable annual vegetation maintenance approach should be preferred to CEC's proposal.[432]

In MoveUp's submission, the proposals made by AMPC and RCIA to scale back BC Hydro's planned vegetation management activity, "are not only inequitable, but give excessive priority to minor short-term rate savings over keeping homes and businesses lit and heated as hostile weather conditions proliferate." MoveUp endorses BC Hydro's argument with respect to vegetation management and submits that AMPC's and RCIA's objections should be rejected.[433]

Similarly, BCSEA supports BC Hydro's new vegetation management strategy and agrees with BC Hydro's submissions on the evidence of RCIA and AMPC regarding vegetation management. In BCSEA's view, BC Hydro's vegetation management plans and expenditures are reasonable.[434]

Panel Determination

Having reviewed the totality of the evidence and submissions provided by the parties, the Panel must assess the reasonableness of BC Hydro's proposed expenditures on vegetation management activities contemplated in its VMS for the Test Period. The Panel notes that the proposed budget represents an increase of 18.9 percent (12.7 percent net of the LiDAR reclassification), 5.3 percent, and 6 percent respectively over the three years from F2023 to F2025.

Both RCIA and AMPC advocate for the BCUC to freeze BC Hydro's vegetation management spending program at F2022 real dollar levels. This amount is estimated to be $67.9 million in F2023, as compared to 75.5 million requested by BC Hydro.[435] Similar or greater differences would prevail for F2024 and F2025 depending on assumptions for inflation, as BC Hydro has requested an incremental 5.3 percent increase in F2024 and 6.0 percent increase in F2025.

In contrast, four interveners (MoveUP, BCSEA, the CEC and BCOAPO) support acceptance of the proposed vegetation management budget, with the proviso in the case of the CEC that BC Hydro tailor its management approach to maximize reliability and in the case of BCOAPO, for Hydro to adopt some reporting requirements.

No party advocates for a further increase in the vegetation management based on the updated 2022 forecast even though the latter suggests that there will be an increase of approximately 11 percent averaged over the entire Test Period. Accordingly, the Panel does not consider a further increase in the vegetation management budget to be appropriate or warranted.

[428] CEC Final Argument, pp. 4 – 5; 65 – 66.
[429] CEC Final Argument, p. 66.
[430] BC Hydro Reply Argument, pp. 28–29.
[431] BC Hydro Reply Argument, p. 29.
[432] BC Hydro Reply Argument, p. 29.
[433] MoveUp Final Argument, p. 5.
[434] BCSEA Final Argument, p.16.
[435] Based on 63.5M approved F2022 budget in Order G-187-21 and 6.9% inflation per the British Columbia Consumer Price Index for 2022.

In determining whether the vegetation management budget should be capped at the approved 2022 level in F2022 dollars or should be accepted as proposed by BC Hydro, we consider the following factors to be relevant:

- Freezing the vegetation management budget in real terms, as suggested by RCIA and AMPC, exposes BC Hydro to increased system reliability and safety risks when compared with the status quo;
- A reduction in the vegetation management budget on the transmission system may affect MRS compliance efforts given that MRS compliance is now built into BC Hydro's VMS;
- Accepting the proposed budget has a greater impact on rates than freezing the budget at its current level but would be consistent with the previous BCUC determinations and directions with respect to the need for greater investments in vegetation management; and
- Although this appears unlikely based on current forecasts, if BC Hydro is unable to spend all of the proposed budget within the Test Period, that underspending may be captured in the inflationary pressures regulatory account to offset any balance therein to the benefit of ratepayers in the future.

On balance and taking all these factors into account, we find that BC Hydro's proposed vegetation management budget for the Test Period is reasonable.

As for the request from the BCOAPO for BC Hydro to provide evaluation of its five-year cycle time in the next application, the Panel does not see the usefulness of requesting this information in the next RRA, as the vegetation management strategy has been reviewed in great detail in this proceeding including during the oral hearing. RCIA has requested that BC Hydro include results on the distribution forced outages due to vegetation in both percentage terms and actual hours in future RRAs, which BC Hydro has agreed it could provide. Accordingly, **the Panel directs BC Hydro to include results on the distribution forced outages due to vegetation in both percentage terms and actual hours in future RRAs.**

As for the CEC's recommendation that the BCUC direct BC Hydro to tailor its Test Period VMS approach to allow for "first work priority" in areas with the highest vegetation related reliability and that the BCUC direct BC Hydro to develop local line reliability data in respect of priority lines, the Panel sees no need for such directions at this time. The VMS appears to be well supported and to make such directions in the absence of any demonstrated need to do so borders on encroachment into the management of BC Hydro's operations, which is unwarranted.

With respect to the performance metrics that BC Hydro proposes to monitor the effectiveness of the VMS, the Panel finds them to be reasonable in quantifying the outputs and outcomes of the vegetation management program relative to input costs. While BC Hydro' s intent is to monitor these metrics internally, the Panel considers that it would be useful for BC Hydro to provide information in the next RRA with respect to the performance of the VMS when measured against these metrics to assess the effectiveness of the new VMS. Accordingly, **the Panel directs BC Hydro to provide information in the next RRA with respect to the performance of the Vegetation Management Strategy when measured against the metrics set out in Table 5-31 of the Application.**

With respect to RCIA's submissions regarding the linkage between overall improvements in system reliability and increased spending on VMS, the Panel acknowledges the difficulty of establishing a direct correlation between the VMS and specific improvements in SAIDI and SAIFI. However, BC Hydro expects that achieving these improvements will reduce outages caused by vegetation by approximately 30 per cent by F2025. In our view this is a reasonable target for the VMS.

4.4.5 Cybersecurity Costs

In F2022, BC Hydro increased its investment in cybersecurity by $3.0 million, and indicated a need for further investment in future years.[436] BC Hydro states that it is planning to increase funding for cybersecurity by a further $6.5 million for the Test Period resulting in a total cybersecurity operating budget of $14.5 million by F2025.[437] The additional funding will be directed towards BC Hydro's expanding digital footprint, continuous improvement following industry best practices, and areas that have emerged as a result of the changing threat landscape.[438]

The table below shows the increase in the cybersecurity operating budget over the Test Period.[439]

Table 33: Increase in the Cybersecurity Operating Budget in the Test Period

	F2022 Decision	F2023 Increase	F2024 Increase	F2025 Increase	F2025 Plan
Operating budget ($ million)	$8.0	$4.2	$1.9	$0.4	$14.5
FTEs	25	4.5	9.5	0	39

BC Hydro states that continuous improvement in its cybersecurity practices is required to strengthen the security of its Information Technology and Operational Technology environments. Threat intelligence, risk assessments, maturity self-assessments, performance during incidents, audits and CIP compliance requirements all come into play in identifying areas for BC Hydro to improve its practices.[440]

BC Hydro further states that it is planning for the additional $6.5 million in funding including 14 FTEs in order to extend and expand its practices in the areas of cybersecurity training and awareness, vulnerability management, risk assessments, cybersecurity assurance, monitoring and detection as well as response and recovery.[441] BC Hydro identified these areas of focus using multiple assessments performed using the National Institute of Science and Technology Cybersecurity Risk Management Implementation Framework, the U.S. Department of Energy, Electricity Subsector Cybersecurity Capability Maturity Model and the Canadian Cyber Security Tool.[442] BC Hydro provides the allocation of FTEs and funds to the target cybersecurity practices in the table below.[443]

[436] Exhibit B-2, p. 5-120.
[437] Exhibit B-2, p. 5-120.
[438] Exhibit B-2, p. 5-120.
[439] Exhibit B-2, p. 5-121.
[440] Exhibit B-2, p. 5-130.
[441] Exhibit B-2, p. 5-133.
[442] Exhibit B-2, p. 5-133.
[443] Exhibit B-2, p. 5-137.

Table 34: Additional Resources Required for Cybersecurity Functions in the Test Period

Practices	F2023 incremental				F2024 incremental				F2025 incremental			
	FTE	Funding ($ million)			FTE	Funding ($ million)			FTE	Funding ($ million)		
		Labour	Other	Total		Labour	Other	Total		Labour	Other	Total
Enhance identity and access management	1.0	0.2		0.2				-				-
Enhance vulnerability management	2.0	0.3		0.3				-				-
Extend cybersecurity monitoring and detection	0.5	0.1	2.9	3.0	2.5	0.4	0.1	0.5			0.2	0.2
Enhanced training and awareness	1.0	0.1	0.3	0.4	2.0	0.4	0.1	0.5				-
Extend risk assessments and penetration testing			0.3	0.3	2.0	0.4		0.4			0.1	0.1
Enhance information protection and recovery plans				-	2.0	0.3		0.3				-
Enhance supply chain risk management				-	1.0	0.2		0.2		0.1*		0.1
Total	**4.5**	**0.7**	**3.5**	**4.2**	**9.5**	**1.7**	**0.2**	**1.9**	**-**	**0.1**	**0.3**	**0.4**

In the F2022 RRA Decision, the BCUC directed BC Hydro to undertake a Cyber Risk Assessment of all its cyber assets within three months, file it with the BCUC and notify the BCUC of any required actions in response to immediate or time-sensitive concerns (Directive 8).[444] The BCUC also directed BC Hydro to develop a company-wide Cyber Security Plan that encompasses BC Hydro, its subsidiaries and third parties that interface with BC Hydro and file the plan with the BCUC within one year (Directive 9).[445]

In response to these directives, on September 17, 2021, BC Hydro filed a confidential Cyber Threat and Risk Assessment (Risk Report) and on July 27, 2022, a confidential Cyber Security Plan (CSP). The CSP describes how BC Hydro has identified projects to extend existing or implement new cybersecurity capabilities to address the recommendations in the Risk Report. BC Hydro states in the CSP that the F2023-F2025 RRA includes capital and O&M funding to address the scope of cybersecurity projects identified in the CSP over the Test Period.[446]

Positions of Parties

BCOAPO, BCSEA, and the CEC support BC Hydro's proposed expenditures in this area during the Test Period.[447] AMPC, however, states that the increases in cybersecurity costs over the Test Period have limited justification and are also deserving of special BCUC scrutiny.[448]

In reply, BC Hydro submits that AMPC offers no specific justification for its assertion that the costs are deserving of special BCUC scrutiny. BC Hydro further reiterates that the areas in which BC Hydro is increasing investment correspond directly with the priority areas identified through threat intelligence and assessments.[449]

Panel Determination

The Panel finds that BC Hydro's budget for cybersecurity operating costs for the Test Period to be reasonable as presented. BC Hydro proposes to increase funding for cybersecurity by a further $6.5 million for the Test Period

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[444] BC Hydro Fiscal 2022 RRA, Order G-187-21, p. 33, "… the Panel, directs BC Hydro to undertake a Cyber Risk Assessment …."
[445] BC Hydro Fiscal 2022 RRA, Order G-187-21, p. 33, "… BC Hydro is directed to develop a company-wide, comprehensive Cyber Security Plan…."
[446] Confidential BC Hydro Cyber Security Plan, Attachment 1, p. 5.
[447] BCOAPO Final Argument, p. 34; BCSEA Final Argument, p. 17; CEC Final Argument, p. 5.
[448] AMPC Final Argument, p. 3.
[449] BC Hydro Reply Argument, p. 50.

resulting in a total cybersecurity operating budget of $14.5 million by F2025.[450] The additional funding will be directed towards the seven cybersecurity practices identified by BC Hydro, and as referenced in the CSP.[451]

The increase in funding is appropriate given the increasing threats associated with cybersecurity and the importance of maintaining the integrity and security of the BES. Contrary to AMPC's characterization, we find that BC Hydro has provided ample justification for the increased expenditures in order to carry out the following activities during the Test Period:

- Continuously improve its cybersecurity practices and strengthen the security of its Information Technology and Operational Technology environments; and
- Extend and expand its practices in the areas of cybersecurity training and awareness, vulnerability management, risk assessments, cybersecurity assurance, monitoring and detection as well as response and recovery.

In the face of ever-increasing incidents of cybersecurity breaches and given the visibility and prominence of BC Hydro's system, it would be unwise for the utility to refrain from taking appropriate steps to protect the system and its ratepayers from such threats.

However, in order to ensure proper alignment of cybersecurity costs and deployment of FTEs with the Cyber Security Plan (CSP), the Panel directs BC Hydro to file a report of actual cybersecurity costs incurred and FTEs deployed during the Test Period, with a detailed breakdown referencing the specific recommendations in its confidential Cyber Threat and Risk Assessment and the projects in the CSP where the costs were incurred, and FTEs deployed. BC Hydro must file this report with the BCUC, on a confidential basis if needed, within three months of the date of issuance of this Decision and thereafter, within three months of the end of each remaining fiscal year in the Test Period.

4.4.6 Site C Transitioning from Construction to Operating Phase

Assets in the Site C generating station are expected to transition from the construction phase to the operating phase starting in F2023 in advance of the generating units forecast to be placed in-service during F2025 and F2026.[452] During this transition period, incremental operating costs of $11.0 million and 26.8 FTEs are required to transition these assets to the operating phase.[453] The $11.0 million of operating costs is comprised of:[454]

- $5.2 million for additional FTEs (i.e., electricians, mechanics, field managers, etc.) to operate the assets, to manage the reservoir intake debris removal program, and to execute maintenance work; and
- $5.8 million for operating costs related to contract commitments in F2025, including the Peace River Regional District.

The following table summarizes the incremental operating costs, FTEs, and key schedule assumptions by fiscal year as the Site C Project transitions various assets from the construction phase to the operating phase.[455]

[450] Exhibit B-2, p. 5-120.
[451] Exhibit B-2, p. 5-137.
[452] Exhibit B-2, Section 5.5.3.3, pp. 5-30 – 5-31; 5.10, p. 5-141.
[453] Exhibit B-2, Section 5.5.3.3, pp. 5-30 – 5-31; 5.10, p. 5-141; Section 5.10.1, p. 5-141.
[454] Exhibit B-2, Section 5.5.3.3, pp. 5-30 – 5-31; 5.10, p. 5-141.
[455] Exhibit B-2, Section 5.10.1, p. 5-141.

Table 35: Site C Operating Phase F2023 to F2025 Plan Operating Costs and FTEs[456]

Fiscal Year	Incremental Operating Costs ($ million)	Incremental FTEs	Key Schedule Assumptions[457]
F2023 Plan	0.4	2.0	50 percent of the auxiliary assets[458] transitioned to the operating phase
F2024 Plan	0.8	1.5	Spillway and an additional 12.5 percent of the auxiliary assets transitioned to the operating phase
F2025 Plan	9.8	23.3	Two generating units and an additional 12.5 percent of the auxiliary assets transitioned to the operating phase
Total	**11.0**	**26.8**	

The Site C incremental operating costs for the Test Period are comprised of both operating and maintenance costs, as follows:

- Operating costs to fund the FTEs required to support and operate the Site C generating station and the site substation – Southbank. The staffing was determined by assessing resource requirements at other comparable BC Hydro generating stations and conducting interviews in the areas that will be impacted by the Site C operating phase.[459] The Peace Canyon Generating Station, located upstream from Site C was used as a basis to create this initial estimate of FTEs and associated operating costs.[460]
- Maintenance Costs to fund the maintenance work on the Site C generating station and the site substation – Southbank. A large portion of these costs were determined by assessing, and adjusting for differentiating factors, the historical maintenance expenditures from F2016 to F2020 incurred at the following comparable BC Hydro generating stations: Peace Canyon Generating Station, Seven Mile Generating Station, Kootenay Canal Generating Station and Mica Generating Station.[461]

BC Hydro states that the forecast operating costs are related to Site C transitioning to operations in the Test Period and do not contribute to the completion of the Site C Project. The operating costs are incurred for the purpose of operating Site C project auxiliary assets that have been completed and can operate independently, even though not all of the Site C Project assets are ready for their intended use of generating electricity. Examples of these auxiliary assets include station service equipment, battery banks, heating, ventilation, air conditioning (HVAC), and water treatment equipment.[462]

The costs to operate and maintain these auxiliary assets are not eligible for capitalization under IFRS because they are not being incurred to bring the Site C Project to the location and condition necessary for it to be capable of operating in the manner intended by management.[463] BC Hydro adds that operating costs should not be deferred to the Site C Regulatory Account, as this regulatory account was approved to defer Site C Project expenditures that otherwise have to be expensed and contribute to the overall development and completion of the Site C Project.[464] Although the operating costs are incurred while construction of the Site C Project is

[456] Exhibit B-2, Section 5.10.1, Table 5-34, p. 5-142.
[457] BC Hydro notes that the timing of the incremental costs and FTEs are based on key Site C Project schedule assumptions. In the case that the Site C Project is ahead or behind schedule, incremental costs may be incurred differently than planned.
[458] BC Hydro notes that examples of auxiliary assets are station service equipment, battery banks, heating, ventilation, air conditioning (HVAC), water treatment equipment, etc.
[459] Exhibit B-2, Section 10.1, p. 5-142.
[460] Exhibit B-2, BCUC IR 62.4.
[461] Exhibit B-2, Section 10.1, pp. 5-142 – 5-143; Exhibit B-7, BCUC IR 48.12.
[462] Exhibit B-7, BCUC IR 48.3, Exhibit B-8, BCOAPO IR 39.1.
[463] Exhibit B-8, RCIA IR 57.1; the referenced IFRS is International Accounting Standard (IAS) 16.
[464] Exhibit B-7, BCUC IR 48.2.

completing, they are attributable to using the assets, and they are not related to the remaining work on the Site C Project.[465]

BC Hydro states that it is on track to meet the project transition schedule[466] with the first generating unit planned to be in-service in December 2024.[467] Assets in the Site C generating station will finish transitioning from the construction phase to the operating phase after the Test Period, by the end of F2026.[468] The first 75 percent of the auxiliary assets are expected to transition to the operating phase through F2023 to F2025 in alignment with the Site C Project schedule and the remaining 25 percent are expected to transition in F2026 as the final four generating units are placed in-service.[469]

The estimated rate and bill impacts of the recovery of the forecast operating costs over the Test Period are 0.01 percent, 0.01 percent and 0.17 percent in F2023, F2024, and F2025, respectively.[470] BC Hydro notes that if there is a six-month delay in transitioning Site C generating station assets to the operating phase, the annual rate and bill impact to the Test Period would be a decrease to the rates requested in the Application by 0.01 percent, 0.01 percent, and 0.15 percent in F2023, F2024, and F2025, respectively.[471]

Positions of the Parties

Apart from AMPC and BCOAPO, interveners either support or do not oppose BC Hydro including the operating costs associated with transitioning certain assets of the Site C Project to the operating phase.

AMPC opposes the approach of BC Hydro including the operating costs associated with Site C Project in its revenue requirement and considers that BC Hydro is "prematurely attempting to recover Site C costs in advance of prudency review." AMPC submits that there is "weak evidence to support" the planned in-service date of December 2024 and notes that there are only four remaining months of F2025.[472] BC Hydro did not reply to the concerns raised by AMPC.

BCOAPO does not support BC Hydro's position and submits that BC Hydro should defer the operating costs to the Site C Regulatory Account. It states that the assets transitioning into the operating phase are "to allow the reservoir to be filled and protect the other Site C assets before and as they are brought into service"[473] and notes they "do not provide any service or direct benefit to customers until Site C's generating units are in-service and operational." Based on this BCOAPO submits that "deferring these costs to the Site C Regulatory Account is consistent with the benefits matching principle" and asks that the BCUC direct BC Hydro to record these operating costs in the Site C Regulatory Account.[474]

BC Hydro explains it is incurring operating costs in respect of auxiliary assets that "must be operated and maintained before the main components of Site C begin being used to produce power." It submits the costs "relate to operations and relate to a current year, not future years" and there is "no reason to treat these operating costs any differently from similar operating costs incurred in respect of other capital projects in BC Hydro's portfolio."[475]

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[465] Exhibit B-7, BCUC IR 48.2; Exhibit B-8, RCIA IR 57.1.
[466] Exhibit B-7, BCUC IR 48.8.
[467] Exhibit B-7, BCUC IR 48.9.
[468] Exhibit B-2, Section 5.10.5, p. 5-149.
[469] Exhibit B-7, BCUC IR 48.6.
[470] Exhibit B-19, BCUC IR 171.2.
[471] Exhibit B-7, BCUC IR 48.11.
[472] AMPC Final Argument, Chapter 6, para. 5–6, pp. 6-1–6-2.
[473] BCOAPO Final Argument, para. 125, p. 37.
[474] BCOAPO Final Argument, para. 126, p. 37.
[475] BC Hydro Reply Argument, Part 5, Section F, paragraph 145, p. 50.

Panel Determination

The Panel finds that BC Hydro's proposal to include the forecast $11.0 million of incremental operating costs related to Site C within the Test Period revenue requirement is reasonable.

The Panel does not accept AMPC's characterization that BC Hydro is "prematurely attempting to recover Site C costs in advance of prudency review." The Panel does not consider it reasonable that recovery of the Site C Project operating costs (as opposed to capital costs) would only occur after a prudency review is complete with respect to the total costs of the entire project. In any event, absent the establishment of interim rates or a deferral account, a prudency review would not affect the recoverability of any operating costs associated with any Site C assets that have already been recovered in rates in a prior test period. Furthermore, the Panel's acceptance of the inclusion of BC Hydro's forecast of incremental operating costs related to Site C within the Test Period revenue requirement does not preclude the BCUC from finding in a prudency review that these costs were nonetheless not prudently incurred.

We further reject BCOAPO's recommendation that the Site C Project operating costs be deferred to the Site C Regulatory Account, as the regulatory account was established to capture those expenditures related to the development and completion of the Site C Project that could not otherwise be capitalized under IFRS, whereas the operating costs in question are incurred for operating Site C Project auxiliary assets that are capable of independent operation. The Panel makes further determinations regarding Site C in Sections 4.8.2 and 5.3 of this Decision.

4.4.7 Statistical Benchmarking and Performance Metrics

In the decision accompanying the Review of the PBR Report Order G-388-21 (PBR Report Decision) dated December 21, 2021, issued approximately four months after BC Hydro filed its Application, the BCUC concluded that BC Hydro should adopt, among other items, the following improvements to its existing regulatory framework to incentivise BC Hydro to control costs, improve productivity and performance, while also improving regulatory efficiency:[476]

- Statistical benchmarking; and
- Information-only performance metrics.

BC Hydro states that its Application includes proposals to improve the existing regulatory regime by incorporating aspects of PBR in order to augment existing incentives to control costs, improve productivity and achieve superior performance.[477] BC Hydro notes that in the PBR Report proceeding, it identified three improvements to the existing regulatory framework that could be advanced as part of this Application which included: (i) regularly scheduled statistical cost benchmarking; and (ii) expanded use of information-only performance metrics.[478] Each of these topics is discussed separately below.

Statistical Benchmarking

With respect to statistical cost benchmarking, BC Hydro proposes terms of reference as part of the Application to guide future statistical benchmarking studies which would include, but are not limited to, the following:[479]

[476] BCUC Review of BC Hydro and Power Authority's PBRReport Decision, Section 5.0, pp. 58–59.
[477] Exhibit B-2, Section 1.3.8.1, p. 1-37.
[478] Exhibit B-2, Section 1.3.8.1, p. 1-38.
[479] Exhibit B-2, Section 1.3.8.3, Table 1-2, p. 1-40–1-41; Section 5.15.3.1, pp. 5-183 and 5-184; Exhibit B-8, BCOAPO IR 2.3; BC Hydro Final Argument, Part 2, Section D, paragraph 18, p. 10.

a. First Quartile Consulting benchmarking of the cost and performance of BC Hydro's transmission and distribution operations and vegetation costs against a peer panel of electric utilities. BC Hydro proposes to complete this study approximately every three years, with the next report being included as part of the RRA covering F2026.[480]

b. Cost and performance benchmarking of generation facilities as part of the Generation Knowledge Services report authored by Guidehouse. BC Hydro proposes to complete this study approximately every three years, with the next report being included as part of the RRA covering F2026.[481]

c. A LifeWorks (formerly Morneau Shepell) benchmarking study, comparing BC Hydro's total rewards offer relative to median market employee compensation rates. BC Hydro proposes to complete this study every five to six years, with the next report being provided as part of the next RRA.[482]

d. The Brattle Group Benchmarking Study and the Canadian Utility Comparison, designed to provide a high-level cost comparison between BC Hydro and utilities in both the United States and Canada.[483] BC Hydro proposes to complete this study every five to six years, with the next report being provided as part of the RRA covering F2026.[484]

e. A review of the operating costs of other Canadian integrated electric utilities to be completed approximately every five to six years with the next report being included as part of the next RRA.

BC Hydro states that the suite of benchmarking studies covers multiple areas of its business, which provides regularly produced, credible information that can be used, in conjunction with other relevant information, to evaluate its revenue requirements.[485] Additionally, BC Hydro notes that the proposed terms of reference for statistical cost benchmarking could be used to identify key areas where efficiencies could be targeted.[486]

BC Hydro notes that the benchmarking studies use actual costs as a point of comparison, which provide insight and comparability of actual performance as well as an objective comparison of its revenue requirement forecasts. It adds that each benchmarking study compares the cost and performance of BC Hydro's operations against a peer panel of electric utilities and other companies, and although perfect comparability is never possible in benchmarking studies, it can be addressed through the selection of the peer panel and through the evaluation of data comparability.[487]

BC Hydro's expert, Mr. Zarakas from The Brattle Group, notes in response to information requests that the statistical cost benchmarking studies BC Hydro proposed in its terms of reference are quite similar to the studies used by peer utilities.[488] However, he adds that although most energy utilities conduct statistical cost benchmarking studies to various degrees, the area of focus and/or level of detail may vary depending on the goals of the utility conducting the study. That is, some utilities compare their costs of overall operations to peers and/or to the industry overall, while other utilities may examine costs at a more detailed level.[489]

Information-Only Performance Metrics

[480] Exhibit B-2, Section 1.3.8.3, Table 1-2, p. 1-41.
[481] Exhibit B-2, Section 1.3.8.3, Table 1-2, p. 1-41.
[482] Exhibit B-2, Section 1.3.8.3, Table 1-2, p. 1-41.
[483] Exhibit B-19, BCUC IR 165.2.
[484] Exhibit B-2, Section 1.3.8.3, Table 1-2, p. 1-41.
[485] Exhibit B-19, BCUC IR 165.1.
[486] Exhibit B-7, BCUC IR 35.2.
[487] Exhibit B-19, BCUC IR 165.2.
[488] Exhibit B-19, BCUC IR 165.3.1.
[489] Exhibit B-19, BCUC IR 165.3.

As noted above, the PBR Report Decision concluded information-only performance metrics, could help incentivise BC Hydro to perform efficiently and effectively. Accordingly, BC Hydro provided information about the performance metrics it uses and proposes to use going forward, that could assist in the evaluation of its revenue requirements.[490]

BC Hydro has historically used a variety of performance metrics and targets[491] to monitor the performance of its operations at the business group level in the following areas: safety, financial compliance, people, and operational and service delivery.[492] BC Hydro's expectation to remain on track against financial metrics and targets is supported through a monthly review by the Executive Team of financial results and forecasts of cost pressures and savings. BC Hydro notes that staying on track with these targets requires a combination of cost control to manage cost pressures as well as seeking efficiencies to find offsetting savings.[493]

BC Hydro has also included new performance metrics[494] to monitor its effectiveness in areas where there is increased investment related to reliability and BC Hydro's strategic initiatives for the Test Period.[495] These new performance measures and targets are intended to provide a way to monitor the impact or outcome of incremental investments in the areas identified.[496]

Positions of the Parties

Apart from AMPC, the CEC, RCIA, and Zone II RPG, interveners either support or do not oppose BC Hydro's benchmarking and performance metrics. RCIA's concerns were centered on metrics for distribution forced outages that originate by vegetation and are discussed in Section 4.4.4 of this Decision, and Zone II RPG encouraged BC Hydro to consider affordability metrics, which is reviewed in Section 5.4 of this Decision.

AMPC recommends that the BCUC direct BC Hydro to prepare specific benchmarking measures to assess its achievement of cost efficiencies in vegetation management spending, as BC Hydro has not provided "specific and measurable benefits to assess cost efficiencies and vegetation management activity optimization, with the goal of reducing overall vegetation management expenditures."[497]

In reply, BC Hydro submits that there is an entire section of BC Hydro's VMS devoted to measuring performance and reporting.[498] BC Hydro notes that its operational reporting highlights work performance and output, and that "[c]ost and efficiency is monitored annually via benchmarking and periodically revised during market tenders as this is when unit cost adjustments generally occur."[499] Additionally, BC Hydro measures its performance against that of other utilities using Guidehouse and First Quartile reports, and MRS reporting adds a level of oversight to outcomes.[500]

The CEC raised concerns with respect to BC Hydro's benchmarking of operating and maintenance costs noting that most of the participants in the study for distribution, transmission line and station operations are from the United States[501] and that the peer group of participants may vary from year to year and the cost estimates are

[490] Exhibit B-2, Section 1.3.8.4, p. 1-42.
[491] Exhibit B-2, Appendix E.
[492] Exhibit B-2, Section 1.3.8.4, p. 1-42; Exhibit B-7, BCUC IR 53.5.
[493] Exhibit B-7, BCUC IR 53.5.
[494] Exhibit B-2, Section 5.6, pp. 5-45 to 5-47.
[495] Exhibit B-2, Section 5.6, p. 5-44.
[496] Exhibit B-7, BCUC IR 53.3.
[497] AMPC Final Argument, p.2-4.
[498] BC Hydro Reply Argument, p.48.
[499] BC Hydro Reply Argument, p.48.
[500] BC Hydro Reply Argument, p.49.
[501] CEC Final Argument, para. 491, p. 78.

subject to fluctuations in currency exchange rates.[502] The CEC adds that BC Hydro has confirmed that the usefulness of unit cost benchmarking results depends on the composition of peer panel and data availability of peer utilities. Based on this, the CEC submits that BC Hydro's benchmarking information is not very useful[503] and recommends the BCUC direct BC Hydro to:[504]

1. Refine its peer group selection for transmission, distribution and station operations benchmarking, to better reflect the realities of other jurisdictions with similar power system and focus on the cost strategies used in these other jurisdictions to improve performance; and
2. Develop and report in future RRAs on internal operating and maintenance cost metrics that track cost-effectiveness.

In reply, BC Hydro states that the data from the benchmarking studies is anonymized to encourage participation and as such refining the peer group selection, as suggested in the CEC's first point, would be impractical.[505] With respect to the CEC's second point, BC Hydro notes that the Application includes proposed terms of reference to guide future statistical cost benchmarking studies, which have been reviewed and endorsed by an independent benchmarking expert and that it already uses a variety of performance metrics and targets "to monitor the performance of our operations and our progress towards meeting certain objectives."[506]

Panel Discussion

With respect to the proposed terms of reference for the benchmarking studies and the performance only metrics, the Panel thanks BC Hydro for providing this information as part of this Application and looks forward to receiving similar information that is tailored to PBR as part of its next application.

With respect to both AMPC's and the CEC's concerns about the need to develop specific cost effectiveness metrics, the Panel anticipates that the issues related to cost effectiveness raised by each of the interveners will be addressed as part of the next RRA to be filed by December 31, 2023 which will include the PBR elements that were directed in the PBR Report Decision.[507] To the extent that the PBR framework is designed to incent the utility to reduce costs, the need for such specific cost effectiveness metrics may become less important if not altogether moot.

4.5 Capital Expenditures

BC Hydro sets out its proposed capital additions and capital expenditures during the Test Period in Chapter 6 of the Application, and states that the forecasts are derived from its capital plan (Capital Plan). BC Hydro states that its capital planning process remains substantially the same as that submitted in prior RRAs.[508]

In reviewing BC Hydro's forecast capital additions and forecast capital expenditures in the Test Period, we must determine whether the forecasted amounts are reasonable. In making this determination, we must also evaluate BC Hydro's asset management and capital investment planning strategy and assess BC Hydro's system performance and safety over time along with their impacts on BC Hydro's Capital Plan to gauge the sufficiency and reasonableness of that plan.

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[502] CEC Final Argument, para. 492, p. 78.
[503] CEC Final Argument, para. 495, p. 78.
[504] CEC Final Argument, paras. 47–48, pp. 5–6; paras. 496–497, p. 78.
[505] BC Hydro Reply Argument, Part 5, Section G, para. 147.
[506] BC Hydro Reply Argument, Part 5, Section G, paras. 148 and 149.
[507] BCUC Review of BC Hydro and Power Authority's PBR Report Decision, Section 5.0, p. 58.
[508] Exhibit B-2, p. 6-1.

BC Hydro states that it is not seeking approval of specific projects in this Application. Instead, it is seeking approval of the rates associated with the execution of those projects, which would include depreciation from projects included in the Capital Plan during the Test Period.[509]

In developing the Capital Plan, BC Hydro explains its capital investments have multiple drivers.[510] BC Hydro considers criteria such as asset health, the significance of the asset to the system, asset redundancy and other issues such as safety and environmental risks to manage the condition of Power System assets and determine the appropriate level of sustainment investments. BC Hydro states system performance indicators are monitored, and the Capital Plan is adjusted accordingly on an annual basis.[511] In addition, the Capital Plan supports the goals in BC Hydro's Five-Year Strategy including "Strengthening our Resiliency and Agility" and to "Control Our Costs".

The following sections will address the Panel's determinations with respect to BC Hydro's forecast capital additions and expenditures during the Test Period, BC Hydro's capital planning methodology and the 2018 capital filing guidelines (Guidelines), asset management planning and strategy, and system performance and risk management.

4.5.1 Forecast Capital Additions and Expenditures

BC Hydro states the forecast capital additions are the capital investments that affect rates during the Test Period and occur when the capital assets enter service. The following table sets out BC Hydro's actual capital additions for F2021, approved and forecast capital additions for F2022 and proposed capital additions for the Test Period:[512]

[509] 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 883, lines 8–17.
[510] Exhibit B-8, RCIA IR 74.1.
[511] Exhibit B-7, BCUC IR 84.4.
[512] Exhibit B-2, Table 6-2, p. 6-7.

Table 36: Actual and Planned Capital Additions (F2021 to F2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Generation						
Growth	0.6	-	-	-	-	-
Sustaining	102.0	272.4	393.2	443.2	223.2	249.3
Total Generation (Schedule 13, Line 18)	102.6	272.4	393.2	443.2	223.2	249.3
Site C Project (Schedule 13, Line 22)	220.9	-	-	-	-	13,977.3
Transmission						
Growth	155.7	168.1	202.7	11.4	143.7	133.2
Sustaining	132.8	272.6	287.1	246.3	292.2	409.2
Total Transmission (Schedule 13, Line 20)	288.5	440.7	489.8	257.7	436.0	542.4
Distribution						
Growth	346.2	301.7	404.8	307.3	362.6	333.7
Sustaining	189.8	201.2	221.8	235.2	191.1	197.5
Total Distribution (Schedule 13, Line 21)	536.0	502.9	626.6	542.6	553.7	531.1
Business Support						
Technology (Schedule 13, Line 23)	164.9	94.3	79.3	130.6	119.5	78.6
Properties (Schedule 13, Line 24)	70.9	59.8	38.5	32.7	65.9	25.7
Fleet / Other (Schedule 13, Line 25)	49.5	75.2	63.3	70.3	90.9	56.8
Total	1,433.4	1,445.2	1,690.7	1,477.0	1,489.1	15,461.3
Less: Contribution in Aid	(180.7)	(187.2)	(213.3)	(170.1)	(176.6)	(209.4)
TOTAL	1,252.7	1,258.0	1,477.5	1,306.9	1,312.5	15,251.9
Electrification						
Transmission Load Interconnections - Growth	-	-	0.3	9.4	18.9	51.7
Transmission Regional System Reinforcement - Growth	-	-	0.2	5.2	10.4	28.4
Total Transmission Electrification (Schedule 13, Line 27)	-	-	0.5	14.6	29.2	80.1
Distribution System Expansion and Improvement - Growth	-	-	0.2	1.6	5.0	8.9
Distribution Electric Vehicle Charging Infrastructure - Sustain	-	-	-	1.6	2.0	2.0
Total Distribution Electrification (Schedule 13, Line 28)	-	-	0.2	3.2	7.0	10.9
Total Electrification (Schedule 13, Line 29)	-	-	0.7	17.8	36.3	91.0
TOTAL	1,252.7	1,258.0	1,478.2	1,324.8	1,348.8	15,342.8

BC Hydro states, as in prior years, its existing 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 in subsequent test periods.[513]

BC Hydro states that 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 year. BC Hydro's proposed capital expenditures in the Test Period are included in the following table:[514]

[513] Exhibit B-2-1, Appendix R, pp. 17–18
[514] Exhibit B-2, Table 6-1, p. 6-6

Table 37: Actual and Planned Capital Expenditures (F2021 to F2025)

($ millions)	F2021	F2022		F2023	F2024	F2025
	Actual	Decision	Forecast	Plan	Plan	Plan
Generation						
Growth (Schedule 13, Lines 1-2)	0.8	5.0	0.0	-	-	-
Sustaining (Schedule 13, Line 3)	299.2	383.4	376.6	300.9	311.0	500.4
Total Generation	300.0	388.4	376.6	300.9	311.0	500.4
Site C Project (Schedule 13, Line 8)	1,725.0	1,361.0	2,789.5	2,708.3	1,754.9	1,043.2
Transmission						
Growth (Schedule 13, Line 4)	121.9	142.9	79.7	125.2	151.5	117.2
Sustaining (Schedule 13, Line 5)	254.4	325.6	349.4	349.9	377.9	393.4
Total Transmission	376.3	468.5	429.1	475.1	529.4	510.7
Distribution						
Growth (Schedule 13, Line 6)	390.5	306.7	321.1	326.6	331.5	333.7
Sustaining (Schedule 13, Line 7)	204.1	219.3	217.7	193.8	190.9	182.4
Total Distribution	594.6	526.1	538.9	520.3	522.4	516.1
Business Support						
Technology (Schedule 13, Line 9)	90.8	69.2	107.1	109.4	88.2	86.6
Properties (Schedule 13, Line 10)	56.0	75.6	51.5	83.4	81.7	92.3
Fleet / Other (Schedule 13, Line 11)	54.8	70.3	60.7	80.1	76.1	57.6
Total	3,197.5	2,959.0	4,353.4	4,277.5	3,363.6	2,806.8
Less: Contribution in Aid	(195.7)	(214.2)	(158.7)	(188.1)	(186.1)	(177.4)
TOTAL	3,001.8	2,744.8	4,194.7	4,089.5	3,177.6	2,629.4
Electrification						
Transmission Load Interconnections - Growth	-	-	3.6	14.6	32.9	29.2
Transmission Regional System Reinforcement - Growth	-	-	2.0	8.0	18.1	16.1
Total Transmission Electrification (Schedule 13, Line 13)	-	-	5.5	22.6	51.1	45.3
Distribution System Expansion and Improvement - Growth (Schedule 13, Line 14)	-	-	1.0	4.0	9.1	8.0
Distribution Electric Vehicle Charging Infrastructure - Sustain (Schedule 13, Line 15)	-	-	-	2.0	2.0	2.0
Total Distribution Electrification	-	-	1.0	6.0	11.1	10.0
Total Electrification (Schedule 13, Line 16)	-	-	6.5	28.7	62.2	55.3
TOTAL	3,001.8	2,744.8	4,201.2	4,118.1	3,239.7	2,684.7

In its F2020 to F2021 RRA, BC Hydro proposed to moderate its planned sustainment capital spending from its previous capital plan by a reduction of $682 million over two years or 22.3 percent over the test period. BC Hydro justified the decrease in spending at that time by referencing its consistently high level of historical system performance. In its Decision, the BCUC expressed concern that the condition of some system assets will deteriorate, and that reduced sustainment spending could be a false economy, leading to significant future increases in maintenance costs.[515] In this Application, BC Hydro has responded to this concern by proposing increases in sustainment capital spending as shown in the two tables above.

With respect to its generation assets, BC Hydro states planned increases in sustainment capital spending over the Test Period are primarily driven by dam safety projects and transmission substation equipment replacements.

[515] BC Hydro Fiscal 2020 to Fiscal 2021 RRA, Decision to Order G-246-20, pp. 82 and p. 87.

A significant portion of the planned dam safety capital expenditures in the Test Period is driven by the detailed design and progression of several large projects, including the following:[516]

- Alouette – Improve Headworks & Surge Tower Seismic Stability;
- Strathcona – Upgrade Discharge;
- Ladore – Spillway Seismic Upgrade;
- John Hart Dam Seismic Upgrade; and
- Bridge River 1 – Improve Slope Drainage.

BC Hydro explains that most of these projects will be in various stages of design over the Test Period with capital additions not expected until after the Test Period.[517]

As for planned increases in sustainment capital for the transmission system, BC Hydro states that they are primarily due to increases in planned spending in substation components including circuit breakers, protection and control systems, stations auxiliary equipment and other power equipment. Projects are mainly driven by end-of-life replacements and compliance with The North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) standards for protection and control systems.[518]

As for its distribution system, BC Hydro states planned sustainment capital spending is decreasing slightly over the Test Period compared to F2022.[519]

As already stated above, BC Hydro notes that the goal to "Control our Costs" is reflected in the current Capital Plan. Specifically, through the development of the Capital Plan, BC Hydro has balanced investment levels with system performance and risk by increasing expenditures where needed, and deferring investments where prudent to do so.[520]

Positions of the Parties

BC Hydro submits the BCUC should find that the capital expenditures and additions forecast over the Test Period are reasonable for the purpose of rate setting.[521] BC Hydro submits it continues to meet its capital delivery performance targets and has deferred investments where prudent to do so.[522] In its Final Argument, BC Hydro confirms that the Capital Plan has a marginal rate impact increase compared to the F2022 RRA capital plan, equating to an additional $23.1 million or approximately one percent in amortization of dismantling costs in the Test Period. BC Hydro submits that this balancing of investment level with system performance and risk is reasonable and appropriate.[523]

BCSEA agrees with BC Hydro that the Capital Plan appropriately balances investment levels with system performance and risk and provides a reasonable basis for setting rates.[524]

The CEC submits BC Hydro's Capital Plan is a reasonable basis for setting its capital expenditures and additions.[525] The CEC recommends that the BCUC approve BC Hydro's capital expenditures, subject to the CEC's

[516] Exhibit B-2, pp. 6-45 - 6-46.
[517] Exhibit B-2, Table 6-8 pp. 6-44 – 6-45; pp. 6-39 – 6-46; Appendix FF.
[518] Exhibit B-2, pp. 6-53 – 6-55; pp. 6-63 – 6-69.
[519] Exhibit B-2, Table 6-30, p. 6-80, Table 6-31, p. 6-81.
[520] Exhibit B-2, pp. 6-13–6-14.
[521] BC Hydro Final Argument, p. 132.
[522] BC Hydro Final Argument, pp. 119–120.
[523] BC Hydro Final Argument, p. 120.
[524] BCSEA Final Argument, p. 21.
[525] CEC Final Argument, p. 81.

specific comments for improvement in capital program metric assessment as summarized below and in the following sections.[526]

The CEC submits that BC Hydro's capital program metric performance, comparing actual project spending to project budgets, does not provide a good view of BC Hydro's cost effectiveness, noting it is difficult to determine if budgets were intentionally or inadvertently overestimated. The CEC submits ongoing analysis of additional metrics would be useful for long-term tracking, adding the CEC can provide useful ratepayer representation working with BC Hydro in a consultative process.[527]

In reply to the CEC's proposed project budget to actual cost metric, BC Hydro submits this metric, although important, is only one of many metrics BC Hydro uses, as detailed in the Application. Taken together, BC Hydro submits its metrics incentivize BC Hydro to perform effectively and efficiently.[528]

Like the CEC and BCSEA, BCOAPO takes no issue with the amount of BC Hydro's proposed capital expenditures and additions for the Test Period.[529]

In contrast to the other interveners in this proceeding, RCIA submits it does not have the necessary information from BC Hydro to evaluate its proposed capital budget. RCIA notes that while BC Hydro confirmed capital expenditures are a significant component of its total expenditures, it aims but fails to ensure that the BCUC has quality, relevant information necessary to evaluate if these expenditures are just and reasonable. RCIA suggests that to address informational asymmetries between BC Hydro and interveners and the BCUC, BC Hydro should provide "compensatory information" necessary to enable parties to formulate effective interrogatories about missing and/or unclear information, develop evidence and provide effective final argument. [530]

In reply, BC Hydro notes RCIA continues to claim that intervention is 'impractical and ineffective' because the evidence to evaluate BC Hydro's capital spending is not available. BC Hydro submits that this is not the case as it has provided extensive information in the Application and has complied with the Guidelines. BC Hydro notes no other intervener has similarly claimed it is unable to effectively intervene in this proceeding. BC Hydro submits all parties have sufficient information to understand, test and challenge BC Hydro's capital expenditures and additions over the Test Period. BC Hydro notes RCIA did not focus its IRs on any particular project or program and instead used the proceeding to challenge the adequacy of the Guidelines. [531] BC Hydro submits that it has filed responses to hundreds of IRs in the proceeding, in addition to the extensive Application materials. BC Hydro submits that this information provides an ample basis for parties to examine and test its planned capital expenditures and additions.[532]

BC Hydro reiterates in its reply that no intervener takes issue with the amount of BC Hydro's proposed capital expenditures and additions in the Test Period.[533]

Panel Determination

The Panel finds that BC Hydro's forecasts of capital additions and capital expenditures for the Test Period, as reflected in its Capital Plan, are reasonable for the purposes of rate setting. As noted by BC Hydro, its current capital planning process remains substantially the same as that submitted for BCUC review in prior RRAs,[534] and

[526] CEC Final Argument, p 92.
[527] CEC Final Argument, pp. 86–87.
[528] BC Hydro Reply Argument, pp. 74–75
[529] BCOAPO Final Argument, p. 49.
[530] RCIA Final Argument, p. 77.
[531] BC Hydro Reply Argument, pp. 66–67.
[532] BC Hydro Reply Argument, p. 69.
[533] BC Hydro Reply Argument, p. 66.
[534] Exhibit B-2, p. 6-1.

no intervener has challenged the reasonableness of these forecasts for the Test Period. While the CEC takes issue with BC Hydro comparing actual project spending to project budgets as an insufficient metric for measuring the cost effectiveness of its capital program, the Panel accepts BC Hydro's submission that this metric, although important, is only one of its many uses, as detailed in the Application and that these metrics incentivize BC Hydro to perform effectively and efficiently.[535] The Panel notes that notwithstanding the CEC's skepticism about the merits of BC Hydro's cost effectiveness metric, it recommends BCUC approval of BC Hydro's capital forecasts for the Test Period.

As for the CEC's submission that additional metrics may be useful for long-term tracking of the cost effectiveness of BC Hydro's capital program, the Panel considers that there is merit to this suggestion. Therefore, we encourage BC Hydro to consult with the CEC and other interested parties in developing and refining such metrics for further RRAs. As BC Hydro has already been directed to bring forward a PBR proposal by December 31, 2023, this may well be an opportune time for them to jointly develop such metrics for review by the BCUC in conjunction with BC Hydro's PBR proposal.

We note that RCIA has deliberately refrained from opining on the reasonableness of BC Hydro's capital forecasts on the basis that the latter has failed to provide the necessary information to enable RCIA to evaluate whether the proposed expenditures are fair and reasonable. However, RCIA, like all interveners, had the opportunity to pose specific IRs regarding any of the capital projects, additions, and expenditures included in the Capital Plan. Notwithstanding, RCIA did not challenge the reasonableness of the inclusion of any specific capital project, addition or expenditure in the Capital Plan during the IR process, opting instead to challenge the adequacy of the Guidelines, which were approved by the BCUC following an open and transparent regulatory process. The Panel acknowledges that because RCIA was established as an intervener group following the conclusion of that proceeding, it did not have the opportunity to participate or provide input into the development of those Guidelines. Not surprisingly, and with the benefit of hindsight, RCIA takes issue with the sufficiency of those Guidelines and suggests that changes to those Guidelines are warranted. We also acknowledge that this is the first time that RCIA has participated in a full review of BC Hydro's RRA involving the Guidelines, with which it is not familiar. However, this does not provide a basis for us to find BC Hydro's preparation of the materials in the capital portion of its Application in compliance with the Guidelines is so inadequate as to prevent parties from evaluating the fairness and reasonableness of the proposed capital investments.

Furthermore, as BC Hydro noted, in addition to the extensive Application materials, it has filed responses to hundreds of IRs in this proceeding, including in respect of the forecast capital additions and expenditures during the Test Period. We acknowledge that significant information asymmetry exists between the applicant and interveners in revenue requirements proceedings which inevitably places the latter somewhat at a disadvantage. Unfortunately, this is true of all such proceedings as neither the BCUC nor interveners are privy to the inner workings and operations of the applicant. However, on balance, we find that the evidence adduced in this RRA forms sufficient basis for parties to examine and test the reasonableness of BC Hydro's planned capital expenditures and additions. Furthermore, we consider that in conducting effective hearings, the BCUC must strike an appropriate balance between ensuring the adequacy of the evidentiary record and regulatory efficiency. One does not necessarily trump the other, and an excess of potentially irrelevant or immaterial information can detract from the efficiency and effectiveness of the regulatory process. Finally, as BC Hydro notes, no other intervener has similarly claimed it is unable to effectively intervene in this proceeding because of any gap in information provided in relation to BC Hydro's forecasts of capital additions and expenditures in the Test Period.

In response to the BCUC's concern expressed in its Decision on the F2021-F2022 RRA that the condition of some system assets will deteriorate, and that reduced sustainment spending could be a false economy, leading to significant future increases in maintenance costs,[536] BC Hydro has proposed an increase in sustainment capital

[535] BC Hydro Reply Argument, pp. 74–75
[536] BC Hydro F2022 RRA, Decision to Order G-246-20, pp. 82, 87.

spending for the Test Period. The Panel finds that increase to be reasonable. In particular, the Panel supports BC Hydro's planned increases in capital spending in the areas of dam safety and substation end of life equipment replacements. Moderating sustainment capital spending in these areas during the Test Period would mean end of life asset replacements at substations and dam safety projects would be delayed. Delaying end of life asset replacements would cause a further deterioration in asset health and could have impacts to future reliability statistics. Similarly, delaying dam safety projects could also have severe consequences.

As for further increasing sustainment capital spending beyond the level planned during the Test Period, while this may improve BC Hydro's asset health overall, the extent of the improvements is uncertain and such increases will have further ratepayer impact. The evidence on the record does not lead us to conclude that BC Hydro is either under- or over-spending on its sustainment capital program at this time. Similarly, the evidence does not support a conclusion that BC Hydro is retiring assets too early or too late. The Panel accepts that BC Hydro continues to strive to strike an appropriate balance between affordability and system performance and risk, by increasing expenditures where needed, and deferring investments where prudent to do so,[537] as reflected in its Capital Plan for the Test Period. In doing so, BC Hydro furthers the goals in BC Hydro's Five-Year Strategy including "Strengthening our Resiliency and Agility" and "Control[ling] Our Costs".

We address BC Hydro's capital planning methodology and the development of the Guidelines in Section 4.5.2 below. We further review RCIA's comments regarding specific gaps in information provided by BC Hydro with respect to its capital projects in Section 4.5.3 below based on the latter's asset planning methodology and strategy, along with RCIA's recommendations for changes to same and to the Guidelines for future RRAs.

4.5.2 Capital Planning Methodology and 2018 Capital Filing Guidelines

As stated above, BC Hydro's capital planning process remains the same as reviewed in prior RRAs. BC Hydro states its capital planning is done in a top-down, bottom-up fashion. The BC Hydro executive team sets long-term capital investment levels, then financial targets are developed for each asset category.[538] BC Hydro explains its different lines of business have different bottom-up planning for their specific asset classes. As an example, for the generation line of business: "Key Facilities" goal is for all major equipment restored to good or fair condition, within ten years; "Strategic Facilities" goal is for equipment in poor or very poor condition will either be refurbished or replaced within ten years; and "Available Facilities" goal is minimal investment.[539]

BC Hydro states it compares favourably to industry peers with respect to its capital and asset management practices.[540] An audit conducted by the BC Auditor General in 2018 found BC Hydro's capital asset management systems and practices reached generally advanced maturity levels overall.[541] A 2014 Black & Veatch survey compared BC Hydro's transmission and distribution Asset Health Index methodology with 15 North American utilities and concluded BC Hydro was among industry leaders. BC Hydro canvassed its North American peers when developing its Generation equipment health rating methodologies and concluded its own methodology was logical, appropriate and cost-effective.[542]

On May 3, 2016, the BCUC established a proceeding to review the regulatory oversight of BC Hydro's capital expenditures and projects (Review). This Review and a concurrent inquiry into BC Hydro's expenditures related to the adoption of the SAP platform, were both initiated in response to a complaint which the BCUC received on December 10, 2015. As part of the Review, BC Hydro sought approval of the 2018 Capital Filing Guidelines

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[537] Exhibit B-2, pp. 6-13–6-14.
[538] Exhibit B-2-1, Appendix N, pp. 3–4.
[539] Exhibit B-2-1, Appendix N, pp. 16–17.
[540] Exhibit B-19, BCUC IR 195.6.
[541] Exhibit B-19, BCUC IR 195.6; Please refer to: https://www.bcauditor.com/sites/default/files/publications/reports/OAGBC_BC-Hydro-Asset-Management_RPT.pdf for the full report of the Independent Audit of Capital Asset Management in BC Hydro.
[542] Exhibit B-19, BCUC IR 2. 195.6.

(Guidelines), which were revised during the course of the proceeding.[543] The Guidelines, with revisions, were approved by the BCUC by Order G-313-19 on December 2, 2019. As noted above, RCIA was established as an intervener group following the conclusion of the Review proceeding and therefore did not participate in the review of the Guidelines.

The Guidelines set out certain information BC Hydro must include in its revenue requirements applications for all individual projects above a specified materiality limit.[544] BC Hydro states the Guidelines reflect the input of interveners in that proceeding and the BCUC's consideration of the purpose of RRA proceedings under the UCA. The Guidelines require BC Hydro to file substantial and detailed information to facilitate the efficient and effective review of BC Hydro's capital expenditures and additions over the Test Period.[545] BC Hydro states it filed the required information in Chapter 6 of the Application, supplemented by numerous appendices as enumerated below:[546]

- Appendix J – summaries of projects over the $20M threshold with spend in the Test Period
- Appendix K – capital project plans, strategies and studies
- Appendix I – spreadsheet listing all projects over $5M with spend in the Test Period, identifying major project filings (CPCN or UCA s.44.2 capital expenditure schedule)
- Appendices L and M – asset health ratings
- Appendix Q – reliability statistics (SAIDI, SAIFI, etc)
- Appendix H – 10-year capital plan
- Appendix O – 5-year Technology Capital Plan
- Appendix N – capital strategy
- Appendix Q – project write-off costs
- Appendix X – 2021 variance explanations

In accordance with the Guidelines, BC Hydro identified 26 projects in Appendix I of the Application with capital expenditures in the Test Period that will, or could potentially, require a CPCN or UCA section 44.2 capital expenditure schedule filing.[547] As the following table shows, BC Hydro has self-identified more projects for CPCN and UCA section 44.2 major project filings recently compared to past years' RRAs:

Table 38: BC Hydro Major Capital Project Filings Since F2017

BC Hydro RRA Proceeding	Number of CPCNs or capital expenditure schedule filings self-identified by BCH	CPCN Applications ordered by BCUC
F2017-F2019	None specifically named (before Review proceeding establishing the Guidelines)	-Metro North Transmission (cancelled) -West Kelowna Transmission/Substation Upgrade -Northwest Substation Upgrade (cancelled and CPCN directive rescinded in F2020/2021 RRA) -Peace to Kelly 500kV Transmission Reinforcement (cancelled) -Mainwaring Substation Upgrade

543 BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects, Decision to Order G-313-19, p.1.
544 2018 Capex proceeding, 2018 capital filing guidelines, Exhibit B-7, Appendix B; BCUC Order G-313-19, Table 3, p. 29.
545 Exhibit B-36-1, p. 4
546 The appendices are summarized on pp. 6-2 – 6-4 of Exhibit B-2.
547 Exhibit B-2-1, Appendix I; Exhibit B-7, BCUC IR 85.1.

BC Hydro RRA Proceeding	Number of CPCNs or capital expenditure schedule filings self-identified by BCH	CPCN Applications ordered by BCUC
F2020-F2021	18, three of which have been filed.	Bridge River Units 1-4 Generators and Bridge River Transmission Projects, jointly
F2022	16, four of which have already been filed	none
F2023-F2025	26, five of which have already been filed	none

Positions of the Parties

BC Hydro submits it does not require approvals for specific capital projects in this proceeding because it has a deemed CPCN for all extensions to its system under section 45(2) of the UCA. The exception to this provision is where the BCUC requires a separate CPCN, either when projects exceed the thresholds in the Guidelines or the BCUC identifies a particular project as warranting review.[548] Expenditure thresholds/materiality limits for BC Hydro's major capital filings are:

a) $100 million threshold for power system projects;

b) $50 million threshold for buildings projects; and

c) $20 million threshold for information technology projects.[549]

BC Hydro submits that the BCUC should not direct BC Hydro to file a CPCN application for any projects below the major project thresholds for the following reasons:[550]

a) There is no indication at this time that any of the projects below the threshold have characteristics that would warrant a higher level of BCUC oversight through a major project filing.

b) Some of the projects are already in implementation, and the deadline for the BCUC to direct BC Hydro to file a CPCN application for these projects has passed.

c) Others are future projects or are in the identification phase with no cost estimate or start date for construction. It would be premature to direct BC Hydro to file a CPCN for these projects.

BC Hydro submits that the Guidelines continue to provide a reasonable basis for the information filed in its RRAs with respect to its capital projects.[551]

The CEC agrees with BC Hydro's reasoning that no CPCNs should be required for projects that are well below the CPCN threshold. The CEC notes the very high number of projects that could be potentially advancing through CPCN applications in future years, which is part of a trend in complexity and number of projects. The CEC submits that if these trends continue, the capital expenditures review aspect of BC Hydro's RRAs might warrant further review and consideration. The CEC submits that further consultation with BC Hydro could result in a much better system for reviewing capital projects and could substantially reduce regulatory costs for CPCN reviews.[552]

[548] BC Hydro Final Argument, p. 121.
[549] BC Hydro Review of the Regulatory Oversight of Capital Expenditures and Projects, Order G-313-19, pp. 27–28.
[550] BC Hydro Final Argument, pp. 122–123.
[551] BC Hydro Final Argument, p. 123.
[552] CEC Final Argument, p. 92

Panel Determination

The Panel accepts BC Hydro's submission that no BCUC approvals for specific capital projects are required for projects which constitute extensions to its system as BC Hydro is deemed to have a CPCN for such extensions under section 45(2) of the UCA. The exception to this provision is where the BCUC requires a separate CPCN, either when projects exceed the thresholds in the Guidelines or the BCUC identifies a particular project as warranting review.[553] For the reasons articulated by BC Hydro, the Panel agrees that none of the projects included in the Test Period that fall below the major projects thresholds should be made subject to further BCUC review because:

- They do not have characteristics that would warrant a higher level of BCUC oversight through a major project filing.
- Some of them are already in implementation, and the deadline for the BCUC to direct BC Hydro to file a CPCN application for these projects has passed; and
- Others are future projects in respect of which it would be premature to direct BC Hydro to file a CPCN at this time.

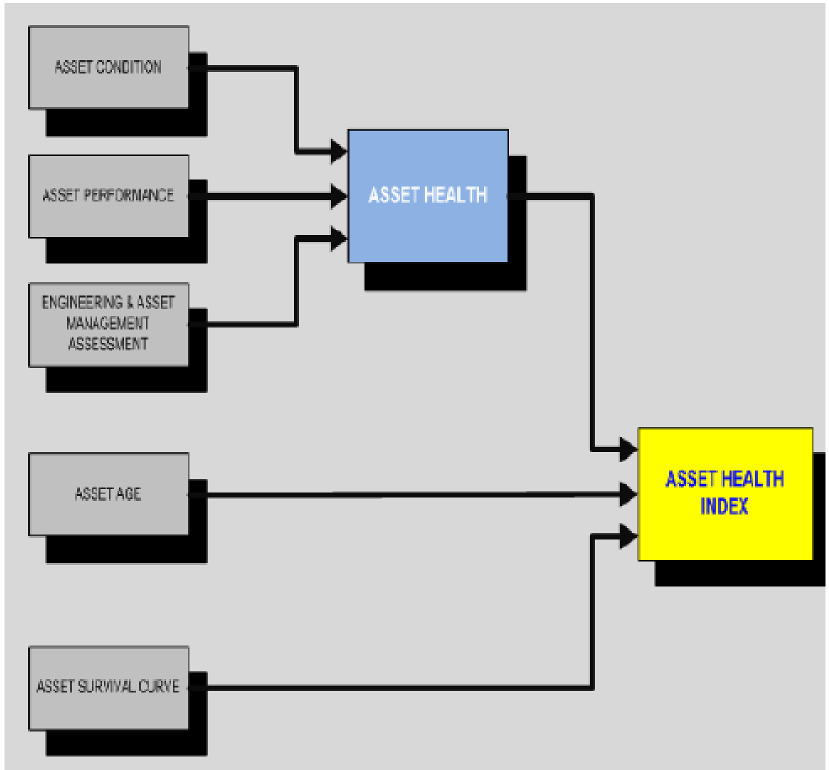
4.5.3 Asset Management Planning and Strategy

BC Hydro's asset management planning and strategy were explored extensively in the proceeding, both in intervener and rebuttal evidence, and at the oral hearing.

BC Hydro assesses the asset health of its Generation, Transmission and Distribution assets to inform the life-cycle management of the assets, including supporting the need for capital investments. BC Hydro uses the projected Asset Health Ratings as a leading indicator to gauge the adequacy of the sustaining capital investment levels while considering the balance between affordability and system performance and risk.[554] BC Hydro uses a methodology called the Asset Health Index to evaluate the health of its Transmission and Distribution assets, as illustrated in the following figure:[555]

[553] BC Hydro Final Argument, p. 121.
[554] Exhibit B-19, BCUC IR 195.1.
[555] Exhibit B-2-1, Appendix M, pp. 1 – 2.

Figure 3: Asset Health Index Methodology



The Asset Survival Curve specifies the average survival rate over time for a group of assets. The Asset Health Index methodology utilizes Gaussian (Normal) distribution to emulate the survival curve of all assets, with curve parameters (Mean Life and Standard Deviation) dependent on the selected asset class.[556] The Survival Curves used by BC Hydro for asset management are not the same as the Iowa Curves used for depreciation purposes.[557]

Mean Life is predominantly used in the Asset Survival Curve.[558] To determine Asset Survival Curves used in the Asset Health Index methodology, BC Hydro considers: manufacturer specifications; historical asset class survival in the field; and BC Hydro asset management and engineering subject matter expertise.[559]

BC Hydro defines Mean Life as the operational life expectancy of the transmission and distribution asset classes that have an asset survival curve under its asset health index methodology.[560] Physical factors, such as wear and tear and decay or deterioration, are typically reflected in the Mean Life. However, functional factors, such as obsolescence and change in technology, and factors such as change in demand, management discretion, and requirements of public authorities are difficult to understand and formulate when an asset is put in service, and so they are not typically used to determine the Mean Life.[561] BC Hydro further explains that although functional factors are not considered in the Mean Life calculations used in determining the health of the equipment, they are considered in BC Hydro's decision making.[562]

556 Exhibit B-8, RCIA IR 94.3.
557 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 847, lines 20 to 24.
558 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 846, lines 15 to 24.
559 Exhibit B-20, RCIA IR 159.3.2; 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 845, Lines 6 to 17.
560 Exhibit B-44, Undertaking No. 13, p. 1.
561 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 842, line 8 to p. 843, line 18.
562 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 843, line 20 to p. 844, line 6.

For the purposes of asset management, BC Hydro uses the term "Mean Life", which is synonymous with the term "Mean Expected Life" used by Midgard in RCIA's evidence.[563]

Because BC Hydro's asset management strategies are based on a life-cycle approach to asset management, it is expected that a portion of assets in the system will be in Poor or Very Poor condition as they come due for replacement.[564] Over the course of the Test Period, BC Hydro states it expects its asset condition to degrade in several major asset categories. Over the next five years, the percentage of substation assets[565] in Poor and Very Poor condition is expected to increase from 20 percent to 22 percent and the percentage of distribution assets in Poor and Very Poor condition is expected to increase slightly from 11 percent to 12 percent. The condition of the assets within BC Hydro's "Available" generation facilities, which provide less than one percent of BC Hydro's annual energy, are expected to continue to deteriorate.[566]

BC Hydro states that its level of capital investment is appropriate even though asset health for some assets is projected to degrade over the next five years because:

- Targeted asset degradation provides more value to customers by balancing asset life, system performance and affordability.
- The power system continues to perform well and customers are satisfied with the reliability performance.
- BC Hydro is managing the safety risks of its assets by prioritizing work on assets that could affect public and/or worker safety.
- BC Hydro will continue to adjust its investment strategies to changes in system performance indicators or maintenance expenditure trends.[567]

As mentioned in Section 1.3 above, during the proceeding, RCIA provided intervener evidence from its expert consultant, Midgard, on BC Hydro's asset condition assessment methodologies. RCIA submits that:

> In BC Hydro's asset condition assessment methodologies, the expected life of assets is an input to asset condition assessment. As stated above, asset condition assessment is a key driver of capital replacement programs sizing. Therefore, as BC Hydro's asset demographics shift towards a larger fraction of older assets, BC Hydro's asset management strategy and asset replacement decision making processes will have an increasingly material impact upon BC Hydro's revenue requirement.[568]

Accordingly, Midgard opines that BC Hydro should be required to provide the following additional information in its RRAs (the "Minimum Data Set"):[569]

1) Asset Records: As with any prudent utility, it is expected that BC Hydro maintains asset records that include key asset information such as asset type, configuration information, Asset Age, Asset Condition, maintenance history, etc. The minimum information needed by interveners from these records is generally as follows:

    a. By Asset Class: Asset Age demographics

    b. By Asset Class: Asset Condition demographics

563 Exhibit B-36-1, A5, p. 12; 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 839.
564 Exhibit B-7, BCUC IR 84.5.
565 BC Hydro states 'percentage of assets' is based on the replacement cost or dollar value of the assets in order to normalize the results across different asset types (Exhibit B-7, BCUC IR 1.84.1).
566 Exhibit B-2, pp. 6-31 – 6-32.
567 Exhibit B-7, BCUC IR 84.7.
568 Exhibit C8-5, p. 2.
569 Exhibit C8-8, p. 25; 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 970, lines 6–14.

2) Mean Service Life: A listing of Mean Service Life for each asset class for which BC Hydro maintains Asset Records.
3) Investment Classification: The proposed Projects and Programs should also be classified and broken down by Investment Classification along with spending broken down by classification.
4) Asset Management Strategies: For each asset class, a brief asset management strategy so that the underlying decision-making strategies of BC Hydro can be evaluated for consistency with corporate optimization objectives and the proposed list of Project and Programs.
5) List of Proposed Projects and Programs: A list of proposed capital investments that represent a significant fraction of the proposed revenue requirement (e.g., similar to the lists currently provided, but organized so that discontinuities can be observed and queried).

Midgard states although the informational asymmetry between utilities, interveners and the BCUC cannot be practically bridged, having access to Mean Life estimates will allow interveners to test utility asset management decisions to develop meaningful argument.[570] Midgard states that when Mean Life, Asset Condition and BC Hydro's investment plans align, interveners will support BC Hydro's capital plans. To the extent they are misaligned, interveners will be able to challenge the inputs to BC Hydro's enterprise optimization activities and "effectively argue to change investments that are based on poor-quality inputs."[571]

In response, BC Hydro states Midgard's evidence is based on an 'oversimplified view' of asset management. BC Hydro states Midgard's evidence suggests investment decisions can be set through an 'unrealistically precise' estimate of asset lives, identification of a single primary driver per project and a ranked list of projects and programs.[572] In contrast, BC Hydro states its approach to asset management recognizes multiple, complex factors influence asset health, including considering system needs and the uncertainty in the remaining life of assets in decision-making. BC Hydro notes that Midgard acknowledges BC Hydro is considered one of the more mature asset managers among North American utilities.[573] BC Hydro states that the age at which an asset will fail is highly uncertain, with a wide uncertainty band, and therefore asset management decisions cannot be validated by Mean Life as suggested by Midgard.[574]

BC Hydro states the list of data Midgard refers to as a "Minimum Data Set" is not required for evaluation of BC Hydro's capital investments. BC Hydro states it files information according to the Guidelines, which were reviewed and approved by the BCUC. The information Midgard requests would require BC Hydro to file a substantial amount of additional information "ranging from engineering design drawings to defect inventories resulting from maintenance inspection," which BC Hydro submits would "materially complicate and lengthen the regulatory process."[575]

BC Hydro states it did not refuse to provide a prioritized list of projects and programs, stating that Appendix I is the list of prioritized investment include in the Capital Plan. BC Hydro states it understands RCIA is requesting a ranked listing of investments, which BC Hydro is unable to provide[576] due to the multi-criteria aspects of capital plan development.[577] BC Hydro states it understands Midgard's expectation is that BC Hydro would prepare a single dimensional ranked list of all capital investments in the Test Period that would show 'marginal' projects. BC Hydro explains that when developing the Capital Plan, decisions are not limited to "in and out," but include

[570] Exhibit C8-8, p. 24.
[571] Exhibit C8-8, p. 26.
[572] Exhibit B-36-1, p. 1.
[573] Exhibit B-36-1, p. 2.
[574] Exhibit B-36-1, p. 3.
[575] Exhibit B-36-1, p. 4.
[576] Exhibit B-36-1, p. 5.
[577] Exhibit B-20, RCIA IR 149.1.

options such as delaying or cancelling investments and funding adjustment increases or decreases. Such decisions are weighed considering assets, asset criticality and long-term asset management strategies. BC Hydro states the 'nuances of these decisions' do not align with a single dimensional ranking system as RCIA proposes.[578]

As for further improvements in its asset management process, BC Hydro confirms in its Application that the Asset Investment Planning (AIP) Tool has been cancelled and the costs included in the Project Write-Off Costs Regulatory Account. BC Hydro states that under IFRS, a project can be placed into "on-hold" or "deferred" status for a period of time. However, if a project is not expected to be re-initiated within a reasonable timeframe or the work completed to date no longer has value, then the project must be cancelled and any capital costs to-date written off.[579] During the oral hearing, BC Hydro states that it is exploring tracking changes in risk on an asset basis after capital projects are completed through its "exploration" of the AIP Tool project, which was mentioned in the F2022 RRA and has since been postponed indefinitely. BC Hydro suggests, however, that "when the time is right" it will proceed with that project.[580]

Positions of the Parties

BC Hydro submits its capital planning processes are unchanged from those submitted in prior RRAs, which the BCUC has found reasonable in its past decisions. BC Hydro submits the validity of its planning approach has been non-contentious to date. BC Hydro notes Midgard/RCIA emphasized that BC Hydro's practices are industry leading, with BC Hydro as being "among the more mature asset managers in North America."[581]

RCIA

RCIA submits that while it agrees in principle with BC Hydro that the regulatory process should avoid duplicating internal asset management processes, it disagrees with BC Hydro on what constitutes adequate evidence.[582] RCIA notes BC Hydro claims it is unable to provide a ranked listing of capital investments. RCIA submits not providing this requested information effectively precludes interveners from determining which investments are "at or near the margin" and from scrutinizing such projects. In response to BC Hydro's statement that it provides a listing of all capital projects in its Application, RCIA submits that the list is not adequate without supplementary information to make evaluating the list practical.[583]

Accordingly, RCIA proposes updating the implementation of the Guidelines, and suggests the following "evolutionary enhancements" be provided by BC Hydro as part of its next RRA: [584]

1) By asset class:
    a) Mean life data set in Microsoft Excel format.
    b) Asset age demographics and Asset condition demographics as follows:
        i) For all Appendix M Asset Classes – Data equivalent to the table of "Transmission Wood Pole Structures Asset Health" (Table 28) with an additional column for "Number of Assets" which is shown in the associated Figure 5.
        ii) For all Appendix L Asset Classes – Provide the graphical data in a Microsoft Excel format along with the Asset Ages. Note: BC Hydro can choose if they want to continue providing

[578] Exhibit B-36-1, pp. 20–21.
[579] Exhibit B-2, p. 1-26.
[580] 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 870, lines 14–25.
[581] BC Hydro Final Argument, pp. 111–112
[582] RCIA Final Argument, p. 58
[583] RCIA Final Argument, pp 58-–59
[584] RCIA Final Argument, pp. 77–78

their current visual representation of the data, but RCIA does not need it if it is provided in Microsoft Excel format.

2) Enhanced Risk Reporting

a) Appendix I: Replace the current pre-capital investment Risk Score (Column AC) showing the single highest uncategorized risk with columns of the highest pre-capital investment risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability).

b) Appendix I: Add columns for the post-capital investment risk scores for the highest risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability). This allows the evaluation of different alternatives based on risk mitigation per investment dollar spent.

c) Appendix J: Replace the currently unquantified pre-capital investment Key Drivers (which are just consequence categories), with the highest risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability). This allows evaluation of the relative criticality of the different pre-investment Key Drivers across the portfolio of investments.

d) Appendix J: Add to Key Drivers, the post-capital investment risk scores for the highest risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability). This allows evaluation of different alternatives based on the risk they mitigate per investment dollar spent so that ratepayers can evaluate the benefits they will receive from the proposed investment.

RCIA contends that the proposed information enhancements are modest and do not drastically affect the length of future RRA filings. Most of the requested information can be provided in Microsoft Excel format or embedded within the materials already presented in the Application, particularly Appendices I and J.[585]

RCIA asserts that it is not arguing or accepting that BC Hydro's current investment classification, asset management strategies or listing of projects and programs is satisfactory. RCIA submits that "far from it," RCIA endorses its expert Midgard's testimony regarding the shortcomings of BC Hydro's filing. RCIA explains that Midgard's proposed investment classification and asset management strategy recommendations are better suited to a process reviewing the Guidelines. RCIA also notes that BC Hydro has only raised concerns about the volume of the additional evidence and not the value of the recommendations.[586]

RCIA submits that if the BCUC accepted RCIA's request for enhanced risk reporting, it is willing to test the information it is seeking in future IRs in the spirit of the BCUC's recommendation in the Guidelines Decision about the value of working with the Guidelines for a full RRA cycle.[587]

In reply, BC Hydro notes RCIA has narrowed its list of additional filing requirements by withdrawing its initial request for investment classification, asset management strategies and lists of programs and projects. However, BC Hydro notes RCIA maintains its requests for Mean Life data, asset age and condition demographics and adds a new request for pre- and post-investment risk scores for projects in Appendices I and J of the Application.[588]

In response to RCIA, BC Hydro submits it justifies its capital spending using its capital planning and delivery processes, reliability and other metrics, strategies, plans and studies, as presented in the Application. BC Hydro notes RCIA's disagreement with BC Hydro's assertion that it is not able to provide a ranked list of investments

[585] RCIA Final Argument, p. 78.
[586] RCIA Final Argument, p. 60–61.
[587] RCIA Final Argument, p. 61.
[588] BC Hydro Reply Argument, p. 66.

suggests that BC Hydro is deliberately withholding information. In contrast, BC Hydro has explained it did not provide a ranked list of capital investments in this proceeding because it does not have one. BC Hydro relies on its advanced level of asset management maturity, as confirmed by the BC Auditor General, as assurance that doing so would not provide a superior outcome.[589]

BC Hydro notes RCIA states a list of capital investment is not adequate without context, suggesting BC Hydro does not provide context. In response, BC Hydro submits it provides extensive context for its capital investments, referring to various appendices in the Application. Further, BC Hydro submits, RCIA is free to request further contextual information through the IR process.[590]

BC Hydro notes that RCIA claims the evidentiary record did not support a fulsome use of Mean Life because BC Hydro did not file any evidence on the differences in causes of retirement. BC Hydro submits RCIA did not ask for Mean Life information until cross examination at the oral hearing, which BC Hydro provided in response to an undertaking. BC Hydro submits RCIA could have requested the information earlier and used it to inform its position.[591]

In reply to RCIA's requests for Mean Life data, asset age and condition demographics, BC Hydro maintains its position that reorienting the regulatory review process around RCIA's position that asset age is foundational would be "inefficient and ineffective." BC Hydro submits that the information RCIA is seeking to build its case would result in arguments that would not be accurate or effective. BC Hydro reiterates its position that other factors are taken into account in developing its Capital Plan, and therefore the capital "will never simply align with mean life and asset condition demographics."[592] BC Hydro submits it can always provide more information, but BC Hydro remains unconvinced that the information RCIA requests would add material value.[593]

As for RCIA's request for pre- and post-investment risk scores, BC Hydro submits RCIA overstates the importance of the information it is requesting. BC Hydro notes, notwithstanding RCIA's assertion that these scores are necessary, RCIA did not request them during the IR process nor were they mentioned in its intervener evidence. Furthermore, BC Hydro points out that pre- and post-investment risk scores are not required by the Guidelines. BC Hydro submits that while it does calculate pre-investment risk scores, it does not calculate post-investment risk scores and does not have the capacity to do so. Therefore, the information that RCIA requests cannot be provided.[594]

Regarding RCIA's requested information, BC Hydro submits RCIA is significantly overstating the benefit of asset age demographics and mean service life information it is requesting and BC Hydro already files materials that cover the substance of the remaining requests. BC Hydro also notes that RCIA generally supports the Guidelines as written.[595] BC Hydro submits reorienting regulatory review in future applications to focus on variances from asset age demographics and Mean Life data would be "detrimental to effective regulation because the data set is the wrong point of reference." BC Hydro submits RCIA has not demonstrated why these data would be a better focus during regulatory review when the "undisputed evidence" is that the data set is only one of many inputs into the planning process. BC Hydro states variances would be the norm rather than the exception.[596] BC Hydro submits participants and the BCUC would be "ill-served" by using RCIA's focus on data sets as the basis for future regulatory oversight.[597]

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[589] BC Hydro Reply Argument, p. 68.
[590] BC Hydro Reply Argument, p. 69.
[591] BC Hydro Reply Argument, p. 69.
[592] BC Hydro Reply Argument, p. 70.
[593] BC Hydro Reply Argument, p. 71.
[594] BC Hydro Reply Argument, pp. 71–72.
[595] BC Hydro Final Argument, pp. 123–124.
[596] BC Hydro Final Argument, pp. 124–125.
[597] BC Hydro Final Argument, p. 126.

BC Hydro submits there is no need to include additional asset condition demographics in future RRAs as BC Hydro already provides "similar but superior information" in Appendices L and M of its RRA Application. BC Hydro submits this information is "easy to digest and interpret."[598]

As for RCIA's proposal for BC Hydro to adopt a new investment classification system based on "primary driver," BC Hydro submits this should be rejected for four reasons:[599]

1. RCIA's concept of classifying investment by primary driver is not used by BC Hydro and would misrepresent the nature of projects, as BC Hydro does not apply a single primary driver structure to investments.
2. The BCUC has rejected the concept of focusing on a primary driver of capital investments to the exclusion of secondary drivers, citing the recent BCUC decision on the Mainwaring proceeding.[600]
3. BC Hydro already provides similar information in line with the nature of the investment and internal management processes. BC Hydro submits it is preferable and more efficient to present its capital information based on its own internal processes rather than attempting to re-sort them into categories proposed by RCIA.
4. BC Hydro submits there is 'significant value' in maintaining consistency with prior RRAs to allow comparisons across test periods.

BC Hydro submits that RCIA's request for asset strategies is satisfied by material filed in Appendix K of the Application, consistent with the Guidelines.[601]

BC Hydro submits it already satisfies RCIA's request for a list of capital programs and projects, providing extensive capital project information in its Application in accordance with the Guidelines. BC Hydro submits that the level of information on its capital projects and programs is extensive and appropriate for RRAs.[602]

BC Hydro submits the BCUC should confirm that the information required by the BCUC's Guidelines, not the information sought by RCIA, is the best information for an effective and efficient review of future applications.[603]

BCSEA

BCSEA supports continued application of the Guidelines to BC Hydro. BCSEA does not support RCIA's recommendation that the BCUC direct BC Hydro to file additional information in an RRA beyond the information contemplated in the Guidelines. In BCSEA's view, the IR process is the appropriate mechanism to obtain information not provided in the original application. If there is any dispute, the proceeding panel can adjudicate.[604]

BCOAPO

[598] BC Hydro Final Argument, p. 127.
[599] BC Hydro Final Argument, pp. 129–130.
[600] BC Hydro Application for CPCN for the Mainwaring Substation Upgrade Project Decision to Order C-4-22, pp. 16–17.
[601] BC Hydro Final Argument, pp. 130–131.
[602] BC Hydro Final Argument, pp. 131–132.
[603] BC Hydro Final Argument, p. 132.
[604] BCSEA Final Argument, p. 24.

BCOAPO submits that as well as identifying the risk score for each project, Appendix I should also identify the “consequence” the score is based on. In BCOAPO’s view this would greatly assist both interveners and the BCUC by providing an initial indication of the basis for each project and help focus discovery.[605]

In response to BCOAPO’s suggestions on how future filings may be improved, BC Hydro submits it is open to making improvements but its Application is already lengthy and requests for additional information should be viewed with caution. BC Hydro agrees, however, with BCOAPO’s suggestion that the consequence the risk score is based on has value and will provide this information in Appendices I and J of future RRA applications.[606]

BCOAPO notes that while the five-scale health rating is available for use by BC Hydro’s asset managers, the information filed in this proceeding regarding the health of Transmission and Distribution assets was only provided at the four-scale level in accordance with the Asset Health Rating index. BCOAPO submits that in future applications, information regarding the Transmission and Distribution assets should be provided using the five scale Asset Health Index.[607] Further, BCOAPO submits that having asset age demographics provided for more significant investments would be useful and likely assist both interveners and the BCUC in focusing further discovery, as it is a readily understood reason for investment.[608]

BCOAPO notes that BC Hydro is employing an investment strategy of allowing a slightly higher percentage of assets to be in Poor and Very Poor condition in certain parts of the power system such as BC Hydro’s substations, where built-in redundancy means that the failure of a single asset will not result in a customer outage. If BC Hydro intends to utilize a similar strategy in its next RRA, BCOAPO submits it would be useful if BC Hydro reports separately the health of transmission and distribution assets where this strategy is being employed versus the health of transmission and distribution assets where it is not being employed.[609]

BCOAPO also endorses Midgard/RCIA’s proposal that BC Hydro adopt a new investment classification scheme based on “primary driver.” BCOAPO notes that in applying its Corporate Risk Matrix to potential project expenditures BC Hydro considers five risk consequence types including Financial Loss, Reliability, Reputational, Environmental and Safety but, when it comes to evaluating the risk score, BC Hydro typically looks at the highest one and comes up with a risk score based on that consequence. In BCOAPO’s view identifying the key consequence for purposes of applying the Risk Matrix is somewhat similar to identifying a primary driver.[610]

In reply, BC Hydro submits it disagrees with the balance of BCOAPO’s requests. BC Hydro submits its common four scale Asset Health Rating scale for transmission, distribution and generation assets is reasonable.[611] BC Hydro disagrees with BCOAPO’s submission that asset age demographics would be useful, referring to its response to RCIA as summarized above. Similarly, BC Hydro disagrees with BCOAPO’s request,[612] to identify a primary driver of capital investments. BC Hydro submits it already arranges its capital investments into categories such as Growth and Sustain, mandatory and committed, among others, referring to its Final Argument. BC Hydro notes RCIA has withdrawn a similar request.[613]

<u>The CEC</u>

[605] BCOAPO Final Argument, p. 42.
[606] BC Hydro Reply Argument, p. 73.
[607] BCOAPO Final Argument, p. 41.
[608] BCOAPO Final Argument, pp. 41-42.
[609] BCOAPO Final Argument, pp. 46-47.
[610] BCOAPO Final Argument, p. 42.
[611] BC Hydro Reply Argument, p. 73.
[612] BCOAPO Final Argument, para. 142
[613] BC Hydro Reply Argument, p. 74.

The CEC recommends the BCUC direct BC Hydro to clarify, through a compliance filing, its intent for a new project in lieu of the AIP Tool initiated in 2018, which has since been canceled. The CEC submits it is concerned, consistent with its submissions in the prior RRA, that BC Hydro is not committing to the advancement of a project aimed at capital planning process improvement.[614] Nonetheless, the CEC recommends approval of BC Hydro's capital expenditures.

In reply, BC Hydro reiterated its explanation in Appendix P to the Application that the full benefits of the AIP Tool can only be realized if an Enterprise Asset Management software platform was first implemented. BC Hydro is initiating the Station Work Management project that is expected to be completed in F2025, which will form the foundation for the Enterprise Asset Management platform. BC Hydro submits that no further clarification is possible or required at this time as the BCUC had observed in the F2020 to F2021 RRA Decision that it had no jurisdiction over BC Hydro's decision of whether or not to implement the AIP Tool.[615]

Panel Determination

In a typical RRA, following review of the information filed in the application, parties develop IRs to request further information on certain projects where further scrutiny is warranted. After the IR process, parties have a better sense of those projects that may warrant further scrutiny such as those which are close enough to the established financial thresholds to trigger a major project filing, or those with public interest issues, or projects that may be viewed as a series of related rather than stand-alone projects. The BCUC's past experience, as is the case in this proceeding, has generally been that the information filed in an RRA, together with IR responses, is sufficient to determine whether the ordering of CPCN applications is warranted in respect of certain projects.

In the case of BC Hydro, as the Table 38 in Section 4.5.2 of our Decision shows, BC Hydro has self-identified more projects for CPCN and UCA section 44.2 major project filings recently compared to past years' RRAs. In light of this recent change in practice, the Panel considers that there is ample opportunity for the BCUC and interveners to test the efficacy and sufficiency of the Guidelines in enabling parties to assess the merits of BC Hydro's proposed major capital investments.

As for RCIA's submissions regarding the need to evolve and update the Guidelines, however, the Panel notes that notwithstanding the BCUC's statement in its Decision to Order G-313-19 that "there is nothing to preclude the guidelines from being refined and updated over time in an evolutionary manner,"[616] only three years and two RRA cycles in the case of BC Hydro have passed since the implementation of those Guidelines. Of those two RRAs, one was an abbreviated BCUC proceeding to establish rates for a one-year test period to regularize BC Hydro's RRA review cycle, in which capital expenditures played a minor role. Based on that limited experience to date and subject to the determinations set out in the following section regarding inclusion of additional information for future RRAs, the Panel considers that a full-scale review of the Guidelines may be premature at this time. Furthermore, changes to the Guidelines might arise as a result of BC Hydro's PBR filing before the end of 2023, which suggests that might be a more opportune time for a thorough review of the Guidelines. Furthermore, BC Hydro has filed an application on March 17, 2023 for BCUC approval of certain changes to the Guidelines including increases to the current thresholds for its major capital project filings and exceptions from the filing requirements for specified projects.[617] Accordingly, RCIA will have the opportunity to raise its specific concerns and recommendations for further review in that proceeding.

In the meantime, however, we find merit to a closer examination of the information BC Hydro files in its RRAs since the establishment of the Guidelines to identify areas of possible refinement at this time. For example, some of the information filed is of great value in understanding BC Hydro's strategies and approaches, such as

[614] CEC Final Argument, p. 91.
[615] BC Hydro Reply Argument, p. 80.
[616] RCIA Final Argument, p. 56.
[617] BC Hydro's Forecasting of BC Hydro Regulatory Filing Requirements Proposal for Major Capital Project Filings application, dated March 17, 2023.

the summaries provided in Appendix K, whereas other information, such as a one-word Project Driver provided as part of a project summary included in Appendix J, has less value and is not well defined.

For information relating to capital costs, in-service dates or start dates of construction, BC Hydro provides in some instances “TBD”. When asked to provide the reason for this in respect of a particular project with a capital addition of $56.8 million in F2025, BC Hydro responded as follows:

> For projects in the Future or Identification phase, To be Determined (TBD) is provided for the Pre-Implementation Cost Estimate, Forecast In-Service Date, Start Date of Construction and Extension Project, for the following reasons:
>
> - For Future phase projects, a problem or opportunity has been identified, but the required response has not yet been determined; and
> - In Identification phase, a number of identified alternative responses are being investigated, and each alternative can result in very different project scope, schedule and cost.
>
> As a result, Pre-Implementation Cost Estimate, Forecast In-Service Date and Start of Construction Date are generally only provided for projects in the Definition phase and later phases.[618]

Providing “TBD” for information required to be filed does not appear to conform to the spirit of the Guidelines. Where it cannot reasonably pinpoint specific dates and costs, it would be more helpful for BC Hydro to provide a range. If project cost ranges were provided for all projects, it may eliminate the need to pursue additional IRs requesting such information, and enable the BCUC to more easily identify those projects that approach the cost thresholds for major project filings. This would also render the regulatory process more efficient.

The Guidelines are intended simply to be guidelines for filings in respect of capital projects and are neither prescriptive nor exhaustive. If they are not working well and need improvement or refinement, it is incumbent upon us to consider changes. BC Hydro has already indicated in the oral hearing that it could add information on Asset Health to its capital project summaries. While the Panel is not convinced that this information would be necessarily helpful in assessing BC Hydro’s capital program during an RRA, or in identifying projects which should require further review through a CPCN application, the information may be useful in revealing, for example, that BC Hydro is actually retiring newly acquired assets much too early, or conversely, deliberating delaying retirements of assets beyond their expected useful lives.

The Panel accepts that there will be some special instances where asset replacements will not be driven by asset health or condition, but rather by compliance or legislative requirements such as BC Hydro’s Streetlight Replacement Program or the Mainwaring Substation Upgrade project, both of which were undertaken in part to remove PCBs in certain assets by a prescribed date. Nonetheless, we would expect such cases to be the exception and not the norm. On balance, we agree with RCIA’s recommendation that more information on capital asset health would be a useful addition in future RRAs to be filed by BC Hydro. **Accordingly, the Panel directs BC Hydro to include the following information, separated by asset class, as part of its next RRA:**

- **Mean life data set in Microsoft Excel format; and**
- **Asset age demographics and Asset condition demographics as follows:**
    - **For all Appendix M Asset Classes – Data equivalent to the table of “Transmission Wood Pole Structures Asset Health” (Table 28) with an additional column for “Number of Assets” which is shown in the associated Figure 5 of Appendix M; and**

[618] Exhibit B-19, BCUC IR 196.5.

- **For all Appendix L Asset Classes – Graphical data in a Microsoft Excel format along with the Asset Ages. BC Hydro can choose if it wants to continue to also provide its current visual representation of the data.**

We also find merit in RCIA's recommendations for BC Hydro to provide enhanced risk reporting by including the following items in Appendices I & J in its next RRA:

- Appendix I: Replace the current pre-capital investment Risk Score (Column AC) showing the single highest uncategorized risk with columns of the highest pre-capital investment risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability).
- Appendix I: Add columns for the post-capital investment risk scores for the highest risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability).
- Appendix J: Replace the currently unquantified pre-capital investment Key Drivers (which are just consequence categories), with the highest risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability).
- Appendix J: Add to Key Drivers, the post-capital investment risk scores for the highest risk score in each of the five risk categories (Safety, Environment, Financial Loss, Reputational, Reliability).

However, we are cognizant of BC Hydro's submissions that it currently does not do any post-capital investment risk scores for any of its projects and does not have the capacity to do so. Accordingly, **the Panel directs BC Hydro to file in its Compliance Filing a proposal for how best to implement RCIA's recommendations for incorporating both pre-capital investment risk scores and post-capital investment risk scores into Appendices I & J and the timing for same in future RRAs.** In doing so, we emphasize our expectation that this will enable interveners and the BCUC to better understand the strategy underlying the formulation of BC Hydro's Capital Plan and the prioritization of capital projects and thereby, reducing the number of IRs relating to same.

We also note that RCIA has endorsed the wisdom of reviewing the impact of any changes that are adopted as a result of its recommendations for a full RRA cycle to ensure that they are workable for all parties and indeed improve rather than impede the regulatory process. We agree and urge all parties to provide their feedback on these changes in BC Hydro's next RRA.

With respect to BCOAPO's submissions, however, we reject the recommendation for BC Hydro to adopt a five scale asset health rating index for transmission and distribution Assets. We agree with BC Hydro that its presentation of a common four scale Asset Health Rating for transmission, distribution and generation assets is reasonable and ensures that there is comparability and consistency in reviewing the relative state of these assets over time. Similarly, we disagree with BCOAPO about the merits of adopting a "primary driver" framework to assess the need for capital investments. We view such a framework as being overly narrow and simplistic, as a project may have multiple drivers, all of which can drive inexorably towards a conclusion that the investment is warranted. There may not be a single "primary driver" for any particular investment that would be determinative. As BC Hydro notes, even the original proponent of that methodology, RCIA, has abandoned that request in this proceeding. The Panel acknowledges, however, that BC Hydro has agreed that BCOAPO's suggestion that the consequence each project risk score is based on has value and will provide this information in Appendices I and J of future RRAs.[619]

As for the CEC's request for the BCUC to direct BC Hydro to clarify its intent with respect to a new project in lieu of the AIP Tool which has since been canceled, we decline to do in light of BC Hydro's submission that no further

[619] BC Hydro Reply Argument, p. 73.

clarification is possible or required at this time as the BCUC had observed in the F2020 to F2021 RRA Decision that it had no jurisdiction over BC Hydro's decision of whether or not to implement the AIP Tool.[620]
We see no basis to deviate from that previous finding.

4.5.4 BC Hydro System Performance and Risk

In its Decision on BC Hydro's Fiscal 2022 RRA, the BCUC stated:[621]

> With respect to system performance, BC Hydro submits that its system is "performing well". However, to the Panel, the evidence presents a mixed picture of system reliability….
>
> The conflicting evidence does not show a clear trend in system performance in any direction. However, the Panel is concerned that BC Hydro's previous reduction in sustainment capital spending may be contributing to a reduction in system reliability. The Panel recommends that the BCUC examine BC Hydro's system reliability statistics when the F2021 data become available to determine whether a declining trend in system performance is emerging.
>
> The Panel also notes that BC Hydro's customer satisfaction index on reliability shows a continuous decline in reported satisfaction from industrial key accounts between F2014 and F2018, the most recent period for which statistics are available, which appears to be accelerating after F2016. The Panel directs BC Hydro to provide updated figures for the customer satisfaction index on reliability in the F2023 RRA.

In its Decision on BC Hydro's F2020 to F2021 RRA, the BCUC stated:[622]

> With respect to BC Hydro's system performance, its current system reliability, as measured by the normalized SAIDI and SAIFI index results, appears stable over the previous ten years and compares favourably to the CEA average. This provides BC Hydro with the opportunity to reduce its sustainment capital spending, but only if the reduction can be done in a manner which does not expose system performance to undue risk and does not allow asset condition to deteriorate to the point where future maintenance costs rise unduly.

BC Hydro states it tracks several system performance and reliability factors annually, reporting updates in its RRAs. Based on the graphs and tables on system reliability provided in the Application, the results since the F2022 RRA show:

- Overall, BC Hydro's normalized[623] reliability indices results for F2012 to F2021 have improved slightly in F2021 over F2020. Non-normalized[624] System Average Interruption Duration Index (SAIDI) results show an increase in outage duration. Non-normalized System Average Interruption Frequency Index (SAIFI) results are relatively constant from F2020 levels.[625,626]

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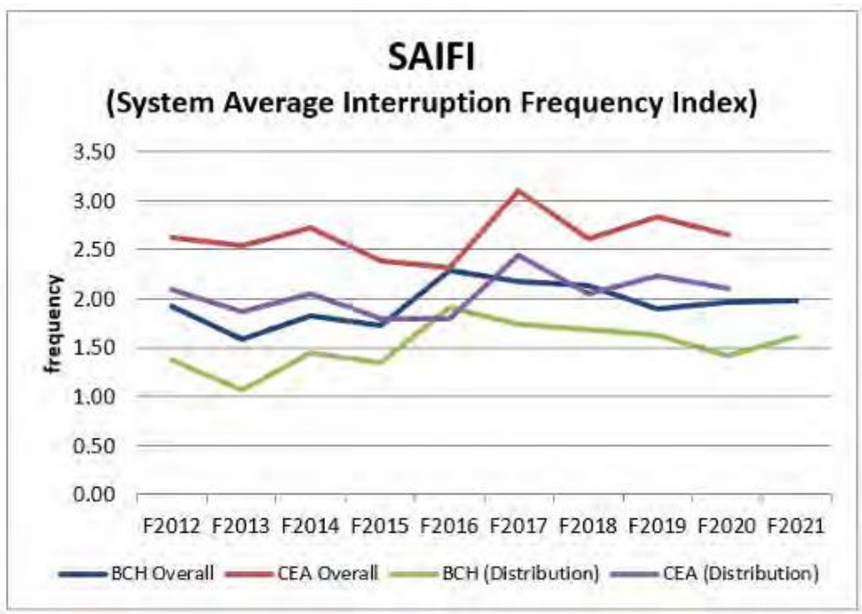
620 BC Hydro Reply Argument, p. 80.
621 BC Hydro F2022 RRA, Decision to Order G-187-21, p. 58.
622 BC Hydro F2020 to F2021 RRA, Decision to Order G-246-20, p. 86.
623 Normalization adjusts for major storms. BC Hydro normalizes using the IEEE Beta 2.5 method, which excludes major event days.
624 Non-normalized results include all events.
625 Exhibit B-2-1-3, Appendix Q, Table 3, p. 9, Figure 1, Figure 2, p. 11.
626 SAIDI – a measure of the amount of time, in hours, an average distribution customer is without power in a year;
SAIFI – a measure of the number of sustained interruptions (longer than one minute) an average distribution customer will experience in one year; CAIDI (customer average interruption duration index)– a measure of the average interruption, in hours, per interrupted distribution customer in a year; CEMI-4 (customers experiencing multiple interruptions) – percentage of customers experiencing four or more outages in a year; %ASAI (average service availability index) – a measure of the percentage of time service is available in the year.

Table 39: Normalized results from F2023-2025 RRA[627]

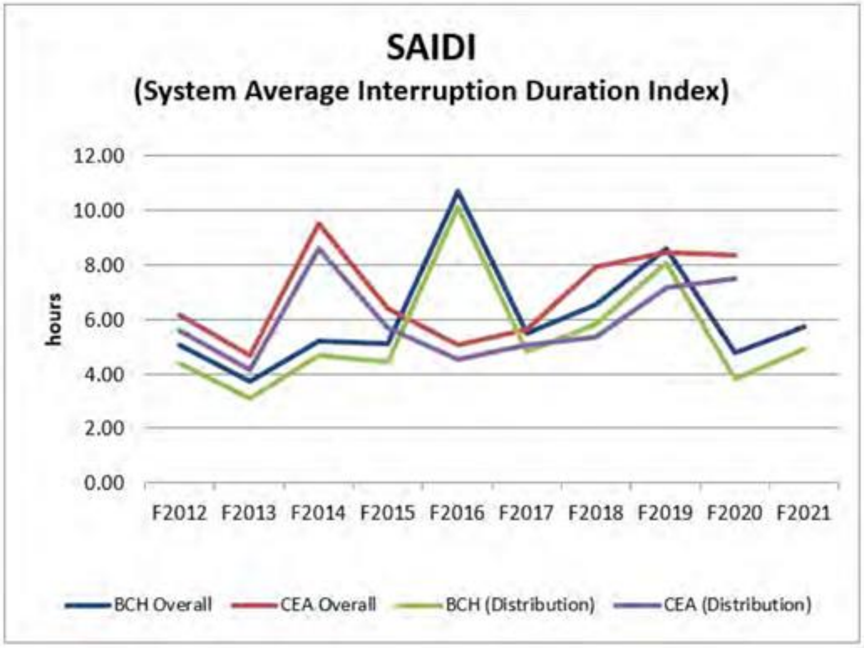
Year	BC Hydro Overall – Normalized using IEEE 2.5 Beta method				
	SAIFI	SAIDI	CAIDI	CEMI-4 (%)	%ASAI
F2012	1.67	3.89	2.34	15.37	99.956
F2013	1.46	3.33	2.28	10.45	99.962
F2014	1.68	4.14	2.46	12.52	99.953
F2015	1.35	3.37	2.49	10.13	99.962
F2016	1.60	3.42	2.14	14.00	99.961
F2017	1.88	4.37	2.33	16.43	99.950
F2018	1.67	3.94	2.36	14.55	99.955
F2019	1.39	3.21	2.32	10.65	99.963
F2020	1.68	3.56	2.12	14.59	99.959
F2021	1.56	3.52	2.25	~~19.19~~14.35	99.960

Figure 4: SAIFI results from F2023-F2025 RRA (Not normalized) [628]



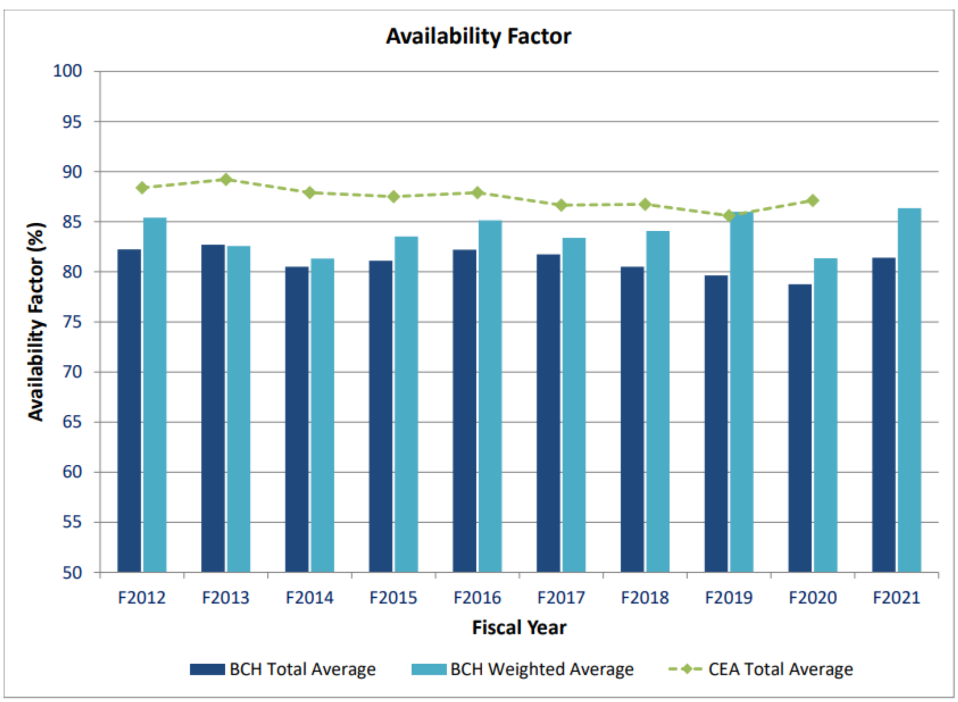
[627] Exhibit B-2-1-3, Appendix Q, p. 3.
[628] Exhibit B-2-1-3, Appendix Q, p. 11.

Figure 5: SAIDI results from F23-25 RRA (not normalized) [629]



- Although still below the total average of major electricity utilities in Canada as reported by the Canadian Electricity Association (CEA), BC Hydro's total average availability factor has improved from a low in F2020. When taken at the BC Hydro weighted average (by size of generator unit) the F2021 results are near the CEA average for F2019 and have recovered from the F2020 low.[630]

Figure 6: F2023-2025 RRA Generator Availability Factor results[631]



[629] Exhibit B-2-1-3, Appendix Q, p. 11.
[630] Exhibit B-2-1-3, Appendix Q, p. 20.
[631] Exhibit B-2-1-3, Appendix Q, p. 20.

- By region, BC Hydro's SAIFI and SAIDI performance are worst in the NIA compared to its other regions. BC Hydro explains that there are challenges with reliability in its NIA due to the remote nature of the systems. BC Hydro confirms that initiatives are underway to improve reliability in the NIA including the following: upgrades to communication and control systems; increased efforts on root cause analysis for outages; improvements in operator training; replacement of automated reclosers; and, prioritization of capital spending on the worst performing circuits.[632]

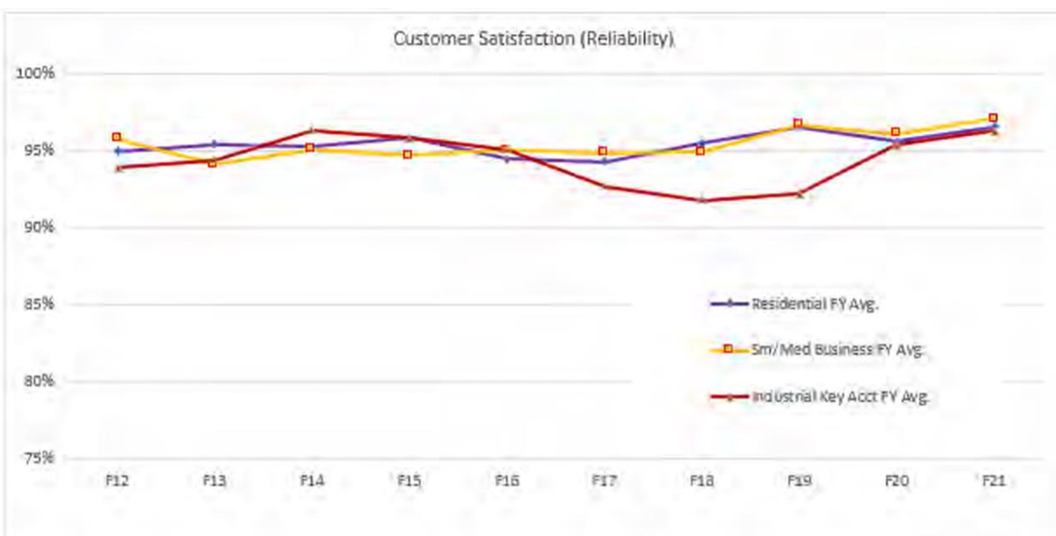
Table 40: Regional SAIDI and SAIFI results from F2023-2025 RRA[633]

	Normalized SAIFI					Normalized SAIDI				
Fiscal Year	LM	NI	SI	VI	NIA	LM	NI	SI	VI	NIA
2017	1.02	3.73	2.32	1.73	11.98	1.82	7.90	4.85	4.43	19.98
2018	1.07	2.24	2.94	1.54	8.70	1.99	4.47	7.10	3.00	15.94
2019	0.96	2.41	2.30	1.42	6.39	2.00	5.72	4.68	3.44	13.98
2020	1.04	2.93	2.71	1.38	8.55	1.97	6.73	5.86	3.02	15.09
2021	1.03	2.65	2.45	1.63	11.60	1.98	7.75	5.21	3.74	28.99

406 Lower Mainland (**LM**), Northern Interior (**NI**), Southern Interior (**SI**), Vancouver Island (**VI**), and Non-Integrated Area (**NIA**).

- By customer group (excluding NIA), customer satisfaction on reliability for industrial customers has improved since F2018. Residential, Small/Medium Business, Industrial Key Account statistics are each over 90 percent for F2020 and F2021. [634]

Figure 7: Customer Satisfaction Index on Reliability[635]



Regarding inclusion of the NIA in statistics on customer satisfaction with reliability, in its decision on F2020 to F2021 RRA, the BCUC directed BC Hydro, in a compliance filing, to provide a proposal for including customers from the NIA in its index customer satisfaction on reliability.[636] BC Hydro states that although the NIA customers are not included in the statistics provided, it is now including customers from the NIA in the index of customer

[632] Exhibit B-7, BCUC IR 83.3 series; Exhibit B-2, Table 6-3, p. 6-29.
[633] Exhibit B-2, Table 6-3, p. 6-29.
[634] Exhibit B-2, Figure 6-8, p. 6-30. Does not include NIA areas. BC Hydro states it will include NIA areas in future statistics.
[635] Exhibit B-2, Figure 6-8, p. 6-30. Does not include NIA areas. BCH will include NIA areas in future statistics.
[636] BC Hydro F2020 to F2021 RRA, Decision to Order G-246-20, p. 86, Directive 25.

satisfaction with reliability.[637] BC Hydro states, starting in F2022, it revised the customer satisfaction program to include a parallel sampling of residential NIA customers each month. However, the Application does not include these results as the F2022 year was not complete and results were not available at the time of the filing of the Application.[638]

Regarding the current state of its asset health, BC Hydro's Asset Health Ratings indicate that approximately 71 percent of major generating components at Key and Strategic generating facilities are rated as Fair or Good. Similarly, approximately 90 percent of the transmission, substation and distribution assets are rated as Fair or Good.[639] BC Hydro states its asset replacement cycle is such that a portion of the assets will be rated as Poor or Very Poor condition as they come due for replacement. In the Test Period, BC Hydro explains this strategy is predominantly targeted at substations, where built-in redundancy means that a failure of a single asset will not result in a customer outage, and on the distribution system, where the installation of automated devices mitigates the customer impact of asset failures.[640]

Regarding its safety performance, BC Hydro states it has not observed an increase in either injuries or near misses resulting from asset failures as a percentage of the overall near misses reported. BC Hydro states that over the Test Period, it will prioritize reviewing and learning from any incidents or near miss incidents that have the potential for fatalities or serious disabling injuries.[641]

In its decision on BC Hydro's Fiscal 2022 RRA, the BCUC directed BC Hydro to file its dam safety vulnerability index for all dams and its aggregate dam safety vulnerability index in the F2023 RRA.[642] In accordance with that directive, BC Hydro has provided the required dam safety information in Appendix FF to the Application.

BC Hydro submits the most recent audit of its dam safety program found:

> BC Hydro has a well-established Dam Safety Program that is in line with international practices with some aspects operating at best practice levels" and that "BC Hydro continues to be a leader in risk assessment in the international dam safety community with a transparent, systematic and robust risk assessment process.[643]

BC Hydro states its investments in dam safety are guided by its dam safety vulnerability index, which characterizes all deficiencies in its dams. A deficiency is defined as an inadequacy or uncertainty or concern in the capacity of the dam to meet its performance goals in accordance with international and Canadian best practices in dam safety management. BC Hydro states its aim is to manage its fleet of dams such that there is no significant deterioration in the risk position and the overall level of risk in kept well within tolerable limits as guided by the Canadian Dam Association's Dam Safety Guidelines and the International Commission on Large Dams' Bulletin on Dam Safety Management.[644]

BC Hydro considers customer interconnection projects to be mandatory investments.[645] BC Hydro states it has made numerous improvements to these processes, including:

- improving oversight and cross company collaboration for customer driven work;

[637] Exhibit B-2, p. 6-30, Footnote 407 to Figure 6-8.
[638] Exhibit B-7, BCUC IR 83.5.
[639] Exhibit B-2, Application, p. 6-31; Exhibit B-19, BCUC IR 195.9.
[640] Exhibit B-19, BCUC IR 195.1.
[641] Exhibit B-2, Application, pp. 6-33 to 6-34.
[642] BC Hydro F2022 RRA, Decision to Order G-187-21, p. 58.
[643] Exhibit B-2, p. 6-39.
[644] Exhibit B-2, Application, pp. 6-39 to 6-42; Exhibit B-2-1, Appendix FF
[645] Exhibit B-2, Application, p. 6-16.

- streamlining process through Work Smart initiatives;
- implementing recommendations from the 2016 Black and Veatch benchmarking study;[646]
- seeking feedback from customers through surveys;[647]
- implementing recommendations from an internal audit review; and
- increasing transparency on interconnection performance.[648]

In addition, BC Hydro expects the volume and complexity of customer interconnection studies to increase due to the Electrification Plan. BC Hydro states continuous efforts and improvements will be required to maintain or exceed the current levels of performance.[649]

Positions of the Parties

BC Hydro submits its capital investments continue to balance affordability with system performance and risk. In support, BC Hydro cites its reliability results, its asset health statistics, and its increased investment in sustainment capital over the Test Period. Further, BC Hydro states its Capital Plan includes funding for implementation of cybersecurity projects and physical security, its continued focus on worker safety, and investments in its dam safety program. BC Hydro submits it continues to improve its interconnection process to respond to customer requests.[650]

Zone II RPG makes submissions comparing reliability and customer satisfaction in the NIA to BC Hydro's larger service territory. Zone II RPG remains concerned about the reliability disparity of the NIA as compared to BC Hydro's integrated area. Zone II RPG submits that this is particularly concerning when BC Hydro cautions that "feasible targeted improvements are expected to improve reliability but may not provide reliability performance comparable to less remote and more dense areas that are not subjected to the same uncontrollable elements."[651] BC Hydro does not guarantee a constant supply of electricity and does not provide financial supports to NIA communities for back-up equipment.[652] Zone II RPG requests that BC Hydro report on the NIA customer satisfaction index on reliability for the next test period to monitor the impact of the new reliability capital expenditures and other measures on NIA customers' satisfaction.[653]

Panel Determination

The Panel acknowledges that in accordance with the previous BCUC directive in the F2022 RRA Decision,[654] BC Hydro has now provided information on its dam safety vulnerability index, which shows that the risks are expected to decline slightly in the near term.

As BC Hydro has noted several times in this proceeding and as interveners have confirmed, BC Hydro's top-down, bottom-up approach to capital project management and its asset management practices are reviewed favourably by studies and external audits. The Panel is satisfied that the effectiveness of these practices is reflected at least in part in BC Hydro's most recent reliability indicators which, with the exception of those for the NIA, are generally trending in a positive direction, with improvement in customer satisfaction and normalized results for SAIDI and SAIFI.

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[646] Exhibit B-2, Application, p. 6-22.
[647] Exhibit B-7-3, BCUC IR 92.1.
[648] Exhibit B-2, Application, pp. 6-22 to p. 6-24.
[649] Exhibit B-19, BCUC IR 199.5.
[650] BC Hydro Final Argument, pp. 112–118
[651] Zone II RPG Final Argument, p. 19 ; Exhibit B-7, BCUC IR 83.4
[652] Zone II RPG Final Argument, p 19
[653] Zone II RPG Final Argument, p. 16
[654] BC Hydro Fiscal 2022 RRA, Decision to Order G-187-21, p. 58

Based on its most recent reliability results, BC Hydro continues to strive to strike an appropriate balance between affordability and system performance and risk, by increasing expenditures where needed, and deferring investments where prudent to do so, as reflected in its Capital Plan for the Test Period.[655] Notwithstanding our observation above, we are concerned that while BC Hydro's normalized reliability indices results for F2012 to F2021 have improved slightly in F2021 in comparison to F2020, they remain below the average of major electricity utilities in Canada, which suggests that additional efforts on the part of BC Hydro to improve reliability may still be warranted.

As for the NIA, the Panel shares Zone II RPG's continued concerns about the reliability disparity of the NIA as compared to the rest of BC Hydro's service territory. As Zone II RPG correctly points out, this disparity is particularly concerning in light of BC Hydro's caution that "feasible targeted improvements are expected to improve reliability but may not provide reliability performance comparable to less remote and more dense areas that are not subjected to the same uncontrollable elements."[656]

The Panel acknowledges that BC Hydro has recently undertaken initiatives to improve reliability in the NIA including the following: upgrades to communication and control systems; increased efforts on root cause analysis for outages; improvements in operator training; replacement of automated reclosers; and, prioritization of capital spending on the worst performing circuits, although the results of these initiatives are not reflected in this Application. The Panel supports these efforts as a good starting point. The Panel also acknowledges that the remoteness of the NIA poses particular challenges to maintaining reliability for this region, but notes that Zone II RPG flagged the need for improvement two RRAs ago, and despite the recent initiatives undertaken, this still appears not to be fully resolved more than three years later. The Panel urges BC Hydro to consider further actions to address this problem on a more timely basis, should reliability in the NIA continue to be an issue. Additional efforts in this regard would also be consistent with BC Hydro's stated commitment, as reiterated in this proceeding, to implementing reconciliation, given the prevalence of Indigenous communities within the NIA.

In the meantime, **the Panel directs BC Hydro to report on the NIA customer satisfaction index on reliability as part of its next RRA.**

Having regard to all of the above, the Panel recommends that the BCUC continue to closely scrutinize BC Hydro's asset health information, sustainment capital spending, reliability performance and customer satisfaction in future RRAs, as trends may emerge over time which may require additional remedial action.

4.6 Depreciation

BC Hydro states that the forecast amortization expense within the revenue requirement includes the amortization of property, plant and equipment in service.[657] In response to Directive 36 of the BCUC's decision in the F2020-F2021 RRA, BC Hydro engaged Concentric Advisors, ULC (Concentric) to perform a depreciation study (Depreciation Study) that reviewed existing depreciation rates and positive salvage percentages. BC Hydro is seeking approval from the BCUC to implement the recommendations from the Depreciation Study for ratemaking purposes beginning in F2022.[658]

The following sections will address:

- Concentric's Depreciation study and Intervener Evidence

[655] Exhibit B-2, p. 6-14.
[656] Zone II RPG Final Argument, p. 19 ; Exhibit B-7, BCUC IR 83.4
[657] Exhibit B-2, Section 8.3, p. 8-3.
[658] Exhibit B-2, Section 8.3.1, pp. 8-5 – 8-6.

- The revised positive salvage percentages recommended by Concentric
- The changes to vehicle asset classes recommended by Concentric
- The contested average service life recommendations made by Concentric and the interveners
- Other issues

4.6.1 Adoption of Revised Average Service Lives

In its Depreciation Study, Concentric recommends an increase to the average service lives of 52 asset classes, a decrease to the average service lives of 45 asset classes, and no change to the average service lives of 217 asset classes.[659]

Both Mr. Bowman, on behalf of AMPC, and Midgard Consulting (Midgard), on behalf of RCIA, submitted evidence that raises concerns over the lack of historical data available for the completion of the actuarial analysis and the selection of peer utilities used in the peer analysis.[660] Mr. Bowman and Midgard recommend BC Hydro adopt alternative average service life estimates which differ from Concentric's recommendations for various accounts.[661]

The Panel addresses the following issues:

- The weight to give the experts' evidence;
- Concentric's Depreciation Study;
- Bowman's alternative;
- Midgard's alternative; and
- Contested average service lives.

4.6.1.1 Expert Evidence

BC Hydro retained Mr. Kennedy, from Concentric Advisors, to prepare the Depreciation Study. BC Hydro states Mr. Kennedy is an expert in depreciation based on his vast experience conducting depreciation studies including:[662]

1. Over 40 years experience in the energy field including conducting approximately 300 depreciation studies, of which about 145 have resulted in either written or oral testimony before regulatory bodies
2. Proving oral testimony approximately 145 times and has been accepted as a depreciation expert
3. Appearing before regulators in every Canadian province and territory except Prince Edward Island, and in nine US states, and has appeared before the Canadian Energy Regulator and the Federal Energy Regulatory Commission
4. Holding a certified depreciation professional (CDP) designation and being a member and former president of the Society of Depreciation Professionals
5. Regularly attending and speaking at depreciation conferences, and reviewing the depreciation studies conducted by other experts

659 Exhibit B-2, Section 8.3.1.2, p. 8-9.
660 Exhibit C7-11, Section 2.2, pp. 11 – 14; Exhibit C8-7, Sections 5.3 and 5.5, pp. 21 – 23 and 24 – 26.
661 Exhibit C7-11, Section 1.1, pp. 3 – 5; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 6.
662 Exhibit B-2-1, Appendix T, Attachment A, pp. 722 – 734; Exhibit B-36, Appendix A, Section II, A17, p. 17; 2022-09-20 Oral Hearing Volume 2 AM, p. 164 Line 13 to p. 166 line 9 and p. 204 line 9 to p. 205 line 3.

AMPC submitted evidence prepared by Mr. Bowman. AMPC states Mr. Bowman is an expert in utility rate regulation with specific expertise in depreciation and net salvage based on the following:[663]

1. Working in public utility regulation since 1998 on behalf of utilities, interveners, governments and regulators[664]
2. Testifying before regulators in six jurisdictions across Canada, across 40 proceedings, including filing evidence or testifying on depreciation and net salvage-related matters[665]
3. Coordinating Yukon Energy's 2005 depreciation filing[666]
4. Testifying in multiple Manitoba Hydro-Electric Board (Manitoba Hydro) proceedings and "six or seven" proceedings in Alberta on depreciation[667]
5. Providing evidence with respect to average service lives in prior BC Hydro RRA[668]
6. Testifying with and being mentored by Patricia Lee, former president of the Society of Depreciation Professionals[669]
7. Experience in matters related to overall utility economics, planning and project design[670]

Concentric states that Mr. Bowman is not a depreciation expert with experience limited to the review of depreciation practices and policies, the testing of the reasonableness of depreciation methods and the testing of the reasonableness of proposed depreciation lives for the purposes of regulatory rate setting. As such, Mr. Bowman's recommendations must be reviewed in the context that Mr. Bowman has a high level and general understanding of the impact of depreciation expense on the revenue requirement.[671]

Concentric states that depreciation is a highly specialized field that requires an understanding that extends past the engineering underlying the physical life of assets. It is essential to understand the manner in which the physical life and the accounting life of assets are similar or different. There are many depreciation concepts and theories that need to be understood fully in order to understand a depreciation study.[672] For example, Concentric submits that Mr. Bowman has a factually and theoretically wrong understanding about the construction of the Observed Life Tables which can lead to inaccurate average service life recommendations. Additionally, the Hydro One peer data utilized by Mr. Bowman has the same limitations in the retirement data as BC Hydro.[673]

BC Hydro states that although Mr. Bowman's evidence was accepted as part of Manitoba Hydro's 2012-2013 and 2013-2014 RRA, the Manitoba Public Utilities Board never accepted Mr. Bowman as an expert in depreciation.[674] Moreover, in the Manitoba Hydro 2014-2015 and 2015-2016 RRA, another consultant, Patricia Lee, was retained to be the depreciation expert by the industrial customer group Mr. Bowman was representing. Mr. Bowman did not have experience in the review of average service lives until the mid 2010s.[675]

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[663] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 406 lines 16 – 19.
[664] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 399 line 18 to p. 401 line 6.
[665] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 401 lines 7 – 18.
[666] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 402 line 7 to p. 403 line 3.
[667] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 403 line 26 to p. 405 line 3.
[668] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 406 lines 6 – 15.
[669] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 404 line 18 to p. 405 line 17.
[670] Exhibit C7-11, Appendix A.
[671] Exhibit B-36, Appendix A, Section III, A16, pp. 16 – 17.
[672] Exhibit B-36, Appendix A, Section III, A18, pp. 17 – 18.
[673] Exhibit B-36, Appendix A, Section III, A18, pp. 18 – 19.
[674] 2022-09-20 Volume 2 PM, p. 449 line 6 to p. 453 line 6.
[675] 2022-09-20 Volume 2 PM, p. 453 line 7 to p. 456 line 6.

RCIA submitted evidence from Midgard, prepared by Mr. Helland and Mr. Oakley. RCIA states Mr. Oakley is an expert in utility rate regulation and Mr. Helland is an expert in general asset and risk management.[676] Specifically, RCIA states Mr. Oakley is a qualified expert in utility rate regulation based on the following expertise: [677]

1. Possessing a bachelor's degree in electrical engineering from the University of Calgary[678]
2. Working in the utility energy business for over 36 years[679]
3. Co-founding principal of Midgard Consulting in 2009[680]
4. Possessing experience with revenue requirement proceedings, rate design applications, cost of service proceedings, resource plan reviews and facility need and citing proceedings with expertise in utility capital planning and development, asset management plans and resource plans[681]
5. Performing work for regulators, utilities and customer groups including testifying before tribunals like the BCUC 20 times, among other things[682]

RCIA states Mr. Helland is an expert in general asset and risk management based on the following expertise: [683]

1. Possessing a bachelor's degree in systems engineering, master's degree in applied science, a master's degree in business administration and certificate in asset management[684]
2. Co-founding principal of Midgard Consulting in 2009 and serving as its CEO from its founding until the end of 2022[685]
3. Serving as the current director of RCIA[686]
4. Possessing experience with revenue requirement proceedings, rate applications, cost of service proceedings and resource plans with expertise in engineering, regulatory and business consulting[687]
5. Performing work for customer groups, regulators and utilities including asset management and risk management work for over 15 Canadian distribution and transmission utilities[688]

Concentric states that although Midgard has broad experience in utility asset management and asset health, the contributing authors have virtually no experience in the determination of average service life estimates nor hold a CPD designation. There are several differences between an asset's maximum life expectation used for asset management and the average service life of a group of assets within an asset class.[689]

For example, Concentric states Midgard makes basic errors which would have been avoided if Midgard's evidence was provided by a qualified CDP including:[690]

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676 2022-09-20 Volume 2 PM, p. 490, lines 17 – 20.
677 Exhibit C8-14. Appendix A, pp. 13 – 20; 2022-09-20 Volume 2 PM, p. 491 line 6 to p. 497 line 18.
678 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 491 lines 6 – 10.
679 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 491 lines 11 – 13.
680 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 491 lines 14 – 17.
681 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 492 lines 6 – 16.
682 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 402 line 17 to p. 497 line 18.
683 Exhibit C8-25, pp. 14 – 16; 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 498 line 24 to p. 502 line 20.
684 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 498 line 24 to p. 499 line 13.
685 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 499 lines 22 – 26.
686 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 500 line 16.
687 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 500 lines 1 – 21.
688 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 500 line 22 to p. 502 line 20.
689 Exhibit B-36, Appendix A, Section IV, A39, p. 44.
690 Exhibit B-36, Appendix A, Section IV, A41, p. 46 – 47.

1. Misuse of the Retirement Experience Index and Bauhan's Scale
2. Determining the maximum life estimates are comparable to average service life estimates
3. Inclusion of Hydro One in Midgard's peer analysis

In the opening statement during the oral testimony, Mr. Helland states that Midgard's role is an independent witness providing opinion evidence to the BCUC that is fair, objective and non-partisan.[691] Mr. Andrews, representing BCSEA, states that Midgard is an acting agent for RCIA which is an advocate in this proceeding. Mr. Helland states that as a professional engineer, he is bound by a code of ethics to act in the public interest and not advocate for one party or another.[692]

Positions of the Parties

BC Hydro submits that its depreciation proposals are based on the recommendations of Mr. Kennedy of Concentric, "an independent expert with vast experience in depreciation studies." BC Hydro submits that the relative experience and depth of analysis warrants the BCUC giving greater weight to Mr. Kennedy's evidence on issues where there are disagreements.[693]

BC Hydro submits that Mr. Bowman's expertise is significantly more limited as he does not conduct depreciation studies, is not a CDP, and was determined not to be a recognized expert in depreciation by the Manitoba Public Utilities Board in 2013.[694]

BC Hydro submits that Mr. Helland and Mr. Oakley, of Midgard, are not certified depreciation professionals and "do not have any formalized training in the area of depreciation theory or practice." BC Hydro notes that the only experience on their CVs with respect to depreciation concerns the hydroelectric facilities for Boralex Ocean Falls Limited Partnership[695] which they confirm has a very small rate base and for which they did not conduct a depreciation study.[696]

BC Hydro further submits that Midgard "is not an 'independent expert' on any reasonable interpretation of that concept" and that Midgard's role is to act as an advocate for residential consumers as an agent of RCIA. BC Hydro notes that Mr. Helland is a director of the RCIA and "retained himself and Midgard to provide evidence."[697]

BCSEA submits that the BCUC should prefer the opinions of BC Hydro's experts over those of RCIA and AMPC, for the reasons BC Hydro sets out in its final argument.[698]

AMPC submits that the BCUC should decide which expert opinion to prefer "based on its views of the substance of the opinions expressed on each point in dispute" rather than through a "global assessment of weight." AMPCsubmits that the BCUC can only weigh the evidence put before it, and to accept expert opinion as reliable, the BCUC must be able to understand the analysis and complete reasoning that led to the formation of the opinion and test its foundation.[699]

[691] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 504 lines 20 – 23.
[692] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 509 line 24 to p. 511 line 10.
[693] BC Hydro Final Argument, pp. 147–148.
[694] BC Hydro Final Argument, p. 149.
[695] BC Hydro uses the term "Boralex Falls" in its Final Argument.
[696] BC Hydro Final Argument, p. 150.
[697] BC Hydro Final Argument, p. 151.
[698] BCSEA Final Argument, p. 31.
[699] AMPC Final Argument, pp. 5-2 to 5-3.

AMPC submits that caution must be taken when receiving evidence from "expert generalists", noting the *Johnson v. Milton (Town)* decision, where the Honourable Mr. Justice Moldaver stated:[700]

> …trial judges who fail to properly perform their gatekeeper function run the risk of having their decision-making function usurped or severely eroded by "expert generalists" who profess to know something about everything and who are only too willing to provide the court with a ready-made solution for any contentious issue that might exist. The problem with such witnesses is that while they appear knowledgeable and generally come across well, upon closer scrutiny, their opinions may well turn out to be little more than concoctions consisting of guesswork, speculation, commonplace information and junk science, with a hint of valid science thrown in for good measure.
>
> Courts must be vigilant to guard against such impermissible evidence. It is trite law that expert witnesses should not give opinion evidence on matters for which they possess no special skill, knowledge or training…

In reply, BC Hydro submits that it has not suggested that the BCUC should "blindly" accept Mr. Kennedy's evidence due to his significant experience, but rather that the BCUC should give greater weight to his evidence on issues where there are disagreements.[701]

AMPC submits that, in contrast to Mr. Kennedy's evidence, Mr. Bowman provides detailed rationales for each service life recommendation that he makes, with all supporting rationales. Further, AMPC submits that BC Hydro's criticism that Mr. Bowman was "selective" in his views ignores his explanations for his approach, and that Mr. Kennedy likewise engaged in a selective review.[702]

AMPC submits that BC Hydro's challenge to Mr. Bowman's evidence "misses the mark," and that Mr. Bowman's evidence "carefully stays within his expertise and only comments on the outputs of the depreciation study and where in his view the available data support longer service lives," which BC Hydro does not dispute. AMPC submits that Mr. Bowman has "special skill and knowledge with depreciation-related matters" and his evidence should be given weight. AMPC submits that the BCUC should not give more weight to the evidence provided by the person with the more impressive CV, but rather weigh the evidence as a whole, including the inputs and reasoning applied by the experts.[703]

AMPC submits that Mr. Bowman's qualifications to testify on asset service lives are "no longer in question." AMPC notes Mr. Bowman's work in public utility regulation since 1988, his specific experience with depreciation since 2005, and his testimony in 40 proceedings before regulators in six jurisdictions across Canada. In response to BC Hydro's criticisms of Mr. Bowman's qualifications, AMPC submits that: [704]

- It is not relevant that Mr. Bowman has not completed a depreciation study because his work is with utilities includes reviewing and supervising the work of different depreciation experts.
- The relevance of Mr. Bowman's lack of a certified depreciation professional designation is unclear, because there is no evidence that this designation is of any relevance to establishing expertise in depreciation.
- Mr. Bowman was not put forward as an expert in depreciation in the 2013 Manitoba Public Utilities Board proceeding, and he was accepted as qualified to provide evidence "analyzing depreciation studies for rate-setting purposes" which is his role in this proceeding.

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[700] AMPC Final Argument, pp. 5-6 to 5-7; *Johnson v. Milton (Town)*, 2008 ONCA 440 at paras. 49-50.
[701] BC Hydro Reply Argument, p. 88.
[702] AMPC Final Argument, pp. 5-2, 5-4.
[703] AMPC Final Argument, p. 5-8.
[704] AMPC Final Argument, pp. 5-8 to 5-11.

In reply, BC Hydro submits that Mr. Bowman's experience and qualifications "do not demonstrate any specialized skill or knowledge in determining average service lives for depreciation purposes" and that the BCUC should assign more weight to Mr. Kennedy's evidence in cases of disagreement. In particular, BC Hydro submits that Mr. Bowman testified that his experience with depreciation did not really start until the mid-2010's, and has been "more focused on general utility regulation and policy matters related to depreciation and net salvage, with less focus on actually reviewing depreciation studies and average service lives, and no experience conducting such studies." BC Hydro disagrees with AMPC's view that Mr. Bowman's lack of a certified depreciation professional designation is irrelevant, and submits that if Mr. Bowman had the designation, it would at least indicate that he had the minimum qualifications to testify on depreciation matters, whereas contrary to AMPC's assertion, it is not apparent to BC Hydro that Mr. Bowman has the required experience in the field to qualify for the designation. BC Hydro further submits that in 2013 the Manitoba Public Utilities Board found that Mr. Bowman was not a depreciation expert, "despite counsel seeking that he be recognized as an 'expert on the appropriate regulatory approach to reflecting the outcome of depreciation studies'."[705]

BCOAPO shares AMPC's concern regarding the weight to be given to Mr. Kennedy's evidence, in particular his heavy reliance on "practices of peers while limiting that data pool to only those for whom Mr. Kennedy has prepared reports" and on his own judgment "without sufficient transparency behind it to inform an evaluation of its strength, reliability and value." BCOAPO is also concerned that Mr. Kennedy has strayed into "numerous areas where he is not an expert, in some cases to override the input received from [BC] Hydro's own subject matter experts."[706]

RCIA submits that the Midgard experts did not claim standing as experts in depreciation studies, but rather in respect of utility rate regulation (Mr. Oakley) and in general asset management and risk management (Mr. Helland). RCIA notes that BC Hydro did not argue that Mr. Oakley and Mr. Helland were not experts in the fields in which they claimed standing. RCIA submits it is apparent that Mr. Oakley and Mr. Helland have "considerable background knowledge in utility asset management in general, transmission, distribution, and generation assets, having been responsible for planning, designing, constructing, maintaining, and operating such assets throughout their careers" and that weight should be given to their evidence on the factors that determine utility asset lives.[707]

In reply, BC Hydro submits that the evidence of Mr. Oakley and Mr. Helland on depreciation "is not informed by any expertise in depreciation and did not follow accepted practices," and should therefore be assigned little weight.[708]

RCIA is also concerned that the BCUC is being asked to trust that depreciation experts are "perfect, and consequently do not need to explain themselves." RCIA notes Mr. Kennedy's comments in the oral hearing:[709]

> "MR. KENNEDY: A: We did write up a more detailed explanation for some of the larger accounts. We did not on that one because it would have been very difficult to write up for all 300 accounts. So we -- that one didn't quite make the cut in terms of size for the write up.
>
> MR. MANHAS: Q: And you'll agree with me that if someone were looking to independently understand how your judgment was applied, they would likely face challenges in doing so, correct?
>
> MR. KENNEDY: A: Well, this is where there's an expectation, I guess maybe of myself, of other independent experts understanding the process that once you're taking completing studies. And this is a challenge when we have people that have never completed studies, and don't understand, have never

[705] BC Hydro Reply Argument, pp. 90–91.
[706] BCOAPO Final Argument, pp. 63–64.
[707] RCIA Final Argument, p. 18.
[708] BC Hydro Reply Argument, p. 92.
[709] RCIA Final Argument, pp. 29–30.

gone through that process. So, sir, I don't know that we necessarily have to explain that in detail what you would do to properly do a depreciation study. That's why we have depreciation professionals, is that's a common, standard practice within depreciation professionals to go through that series of judgement.

MR. MANHAS: Q: Okay, but if the BCUC were wanting to review and understand, given their oversight of BC Hydro's depreciation accounts how you come to your conclusions, there's nothing in your report that would allow them to do that, correct?

MR. KENNEDY: A: In the report itself, no. There is the opportunity through IRs and through the discussion we're having at this very moment. [emphasis added]"

RCIA submits that Mr. Kennedy's stance is that only if supplementary exploration is pursued by interveners is information made available to independently understand his judgements and actual process, and that at best, this approach poses a significant regulatory barrier to meaningful intervener participation, and at worst is an unnecessary erosion of regulatory oversight based on a "trust me" argument.

Panel determinations

The Panel gives weight to Mr. Kennedy's evidence on depreciation studies. The Panel recognizes the value of his 40 years' experience, 300 depreciation studies and his provision of oral testimony on 145 occasions. The Panel gives little weight to Mr. Kennedy's certified depreciation professional designation, which is not a requirement to complete a depreciation study.

That said, the Panel shares the concerns expressed by AMPC, BCOAPO and RCIA regarding the lack of sufficient explanations for Mr. Kennedy's recommendations. Some of Mr. Kennedy's proposed changes to average service lives come with no explanation at all, such as the change from 20 to 25 years for recreational facilities, the first change proposed on the list in Appendix T Table 1. The ones that are explained each contain between a third and half a page of text, most of which pertains to the relevant historical asset retirement data, to which Mr. Kennedy himself assigns low weight.

The Panel is also concerned with Mr. Kennedy's view, expressed in his oral testimony, that "I don't know that we necessarily have to explain that in detail what you would do to properly do a depreciation study." In the Panel's view, that is precisely what an expert is expected to do. From the perspective of regulatory efficiency, it is preferable that expert reports provide sufficient explanations for their opinions without the BCUC and interveners having to resort to information requests to supplement that evidence.

The Panel is mindful of the caution of Justice Moldaver to be vigilant to guard against the "impermissible evidence" of "expert generalists." While Mr. Kennedy has prepared and defended many depreciation studies, he is not an expert in any of the fields that contribute direct technical knowledge or substance to them.

To the extent that Mr. Kennedy's views differ from those of more qualified experts on matters such as engineering, including the evidence provided by BC Hydro's own subject matter experts, it is critical that he can justify these differences.

The Panel gives weight to Mr. Bowman's evidence on the use of depreciation studies by rate-regulated utilities. The Panel recognizes Mr. Bowman's work in public utility regulation since 1988 and his testimony in 40 proceedings before regulators in six jurisdictions in Canada.

The Panel recognizes that Mr. Bowman has never created a depreciation study himself, and that his experience is not as extensive as that of Mr. Kennedy. Further, like Mr. Kennedy, Mr. Bowman is not an expert in any of the fields that contribute technical substance to them. However, the Panel is satisfied that Mr. Bowman has sufficient experience and expertise to provide evidence that challenges the results of the Depreciation Study. Mr. Bowman provided clear explanations of his opinions, and he responded comprehensively to questions posed during the oral hearing.

The Panel gives weight to the evidence of Mr. Oakley in respect of utility rate regulation. The Panel notes Mr. Oakley's degree in electrical engineering and 36 years' experience working with energy utilities, and his contributions to more than 20 proceedings before the Ontario Energy Board, among others.

The Panel recognizes that Mr. Oakley has never created a depreciation study himself. However, unlike Mr. Kennedy, Mr. Oakley has qualifications and experience in the engineering and other factors that are inputs into a depreciation study.

The Panel gives weight to the evidence of Mr. Helland in respect of general asset management. The Panel notes Mr. Helland's degree in systems engineering, master's degree in applied science and certificate in asset management, and his asset management and risk management work for over 15 Canadian distribution and transmission utilities.

The Panel shares BC Hydro's concern regarding the independence of Midgard's experts, given that Midgard also acts as an advocate for residential consumers as an agent of RCIA. The Panel does not consider this sufficient reason to disqualify Midgard's experts from testifying, but the Panel will be cautious in weighing their opinions.

4.6.1.2 Basis of Concentric's Average Service Life Recommendations

Concentric states the recommended average service life estimates for each asset class are based on the following four drivers:

1. An analysis of BC Hydro's retirement data (data driven)[710]
2. Discussions with BC Hydro management and operations representatives[711]
3. Peer comparison analysis, including Ontario Power Generation, Manitoba Hydro, Newfoundland and Labrador Hydro Corporation and FortisBC Inc. (FBC)[712]
4. Concentric's professional judgement[713]

RCIA provides the following table summarizing the frequency of the drivers used to derive the recommended changes to the average service life estimates as part of the current Depreciation Study which was confirmed by Concentric to be accurate:[714]

Table 41: Average Service Life Recommendation Drivers

	BC Hydro Data Driven	BC Hydro Management Driven	BC Hydro Data & Management Driven	BC Hydro Operational Interviews	Peer Data Driven (Non-BC Hydro)	Concentric Driven
Low	98	98	98	42	39	3
Medium	0	0	0	15	37	86
High	0	0	0	41	22	9

710 Exhibit B-2-1, Appendix T, pp. 9 – 11.
711 Exhibit B-2-1, Appendix T, p. 11.
712 Exhibit B-2-1, Appendix T, pp. 11 – 12.
713 Exhibit B-2-1, Appendix T, p. 12.
714 Exhibit B-20, RCIA IR 145.1.

Each driver is discussed in detail below along with the summary finding.

4.6.1.2.1 Historical Asset Retirement Data

BC Hydro provided the following data to Concentric for the purposes of conducting the depreciation study:[715]

1. Current balances by vintage year for each account (aged balances) as at March 31, 2020; and
2. Accounting retirement transactions for all accounts. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired, and the original cost of the asset being retired.

Mr. Bowman raises concerns that the actuarial data provide limited value for most accounts as the data available for the analysis only encompasse 2012 to 2020. Given the long lives of BC Hydro's assets, there are very few if any retirements in many key asset classes.[716]

Concentric clarified that the pre 2011 retirement data were not used as part of the actuarial analysis due to the deemed cost adjustments made when BC Hydro transitioned to the Prescribed Standards on April 1, 2011 and IFRS on April 1, 2017 for accounting purposes.[717] Mr. Kennedy clarified that as part of the deemed cost adjustments, the costs of BC Hydro's assets were adjusted to match the net book value of those asset at the time of adjustment.[718] The actuarial analysis completed as part of a depreciation study requires the comparison of the dollar value of retirements to the dollar value of additions and current costs. When the assets were revalued, this comparison was no longer possible.[719]

BC Hydro states that it does not maintain pre-fiscal 2011 transactional retirement data. Pre-fiscal 2011 data were stored within the legacy PeopleSoft financial system with configuration applying the Canadian Generally Accepted Accounting Principles (CGAAP). Even if the data were available, it would be of limited value because the pre-fiscal 2011 data would be before IFRS deemed cost adjustments, and therefore would not be compatible with the data for F2013 to F2020.[720]

Mr. Kennedy states that he would have liked to incorporate the pre-2011 retirement data including the data from the 2005 Depreciation Study in the actuarial analysis for the current depreciation study.[721] BC Hydro took a snapshot of original cost data of assets in service at the time of the deemed cost adjustments, and following the F2019 deemed cost adjustment BC Hydro continued to record new assets on the books at their original cost.[722] Concentric states the restatement of the pre-2011 retirement data would require a significant number of assumptions and all of the 2005 and prior retirement transactions would need to be restated to a 2019 market value cost base. When looked at in total, Concentric determined that it was not feasible for the data from the 2005 study to be used in the current depreciation study.[723] Contrary to Concentric's statement above, Mr. Layton states only data from the interim period between those two deemed cost adjustments that would need to be adjusted for to reconstruct the required data set.[724]

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[715] Exhibit B-2-1, Appendix T, p. 8.
[716] Exhibit C7-11, Section 2.2, p. 11.
[717] Exhibit B-8, RCIA IR 103.5; Exhibit B-20, AMPC IR 8.1; Exhibit B-36, Section 2, A4, pp. 3 – 4; Exhibit B-36, Appendix A, Section II, A8, pp. 3 – 4; 2022-09-20 Oral Hearing Transcript Volume 2 PM, pp. 286 – 287.
[718] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 223 line 12 to p. 224 line 13.
[719] Exhibit B-36, Appendix A, Section II, A8, p. 4.
[720] Exhibit B-8, AMPC IR 22.6.
[721] Exhibit B-36, Appendix A, Section II, A9, p. 4; 2022-09-20 Oral Hearing Volume 2 AM, p. 239 lines 5 to 10.
[722] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 224 line 10 to p. 225 line 10.
[723] Exhibit B-36, Appendix A, Section II, A9, p. 4.
[724] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 225 lines 11 to 14.

My. Kennedy states that although the pre-2011 retirement data, including the results of the 2005 Depreciation Study, was not used in the actuarial analysis, it was used to inform Concentric's professional judgement.[725] Concentric explained that the limitation on retirement data is not unique to BC Hydro as other utilities such as EPCOR, Hydro One and AltaGas all share the same issue.[726] Due to the limited actuarial analysis, Concentric put heavier reliance on the other drivers in determining the average service life recommendations.[727]

Mr. Bowman states he is not aware of any utility that elected to make its own retirement data unusable like BC Hydro. On the contrary, many utilities go to great lengths to reclaim the retirement data to be able to perform a proper actuarial analysis.[728] The limited retirement data for other utilities such as EPCOR, Hydro One and AltaGas all stem from different circumstances as compared to BC Hydro.[729]

BC Hydro elaborates that it has some operational information regarding which assets are retired, at what age, and for what reason. However, the data exist in separate databases contingent on the type of asset involved. In the majority of instances, BC Hydro's asset databases contains asset installation information, which can be used to determine the age of the asset when it is retired. However, for most asset classes, the reason for retiring an asset from service is not tracked in BC Hydro's asset databases. BC Hydro states the databases and other operational systems may not contain relevant cost information that would allow it to be used in an actuarial analysis for determining recommended asset lives for depreciation purposes since these operational systems were not designed for financial reporting. Concentric states that it was able to gain a general understanding of the number and age of assets retired using the operating system information. However, the actuarial analysis was performed on the financial records from the SAP Financial System which includes information such as the installation and retirement years, account number, and deemed cost at retirement.[730]

In response to RCIA's request, BC Hydro provided the mean lives for transmission and distribution asset classes associated with its Asset Health Index methodology.[731]

Positions of the Parties

BC Hydro submits that Concentric used "all of the available data" in conducting its depreciation study, which consisted of retirement data from 2011 to 2020. BC Hydro explains that the limits on the retirement data are due to the deemed cost adjustments that BC Hydro was required to make when it was required to adopt the accounting principles of IFRS and the US GAAP regulatory accounting standard in 2013. BC Hydro acknowledges that this is a "relatively short experience band" but notes that "in many cases the information provided a large set of retirements from original installation years of assets from as far back as the 1930's." Concentric also used the actuarial review completed for its 2005 depreciation study.[732]

BC Hydro submits that Mr. Bowman and Midgard did not have access to any better data when making their recommendations on depreciation rates, and that Concentric's recommended depreciation rates "are the most fully informed by the available data."[733]

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[725] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 177 line 3 to p. 178 line 8.
[726] Exhibit B-36, Appendix A, Section II, pp. 5 – 7.
[727] Exhibit B-8, RCIA IR 103.5; 2022-09-20 Oral Hearing Volume 2 AM, p. 187 lines 18 to 23.
[728] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 412 lines 18 to 23.
[729] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 239 line 11 to p. 240 line 2 and p. 240 lines 2 to 10 and 16 to 25.
[730] Exhibit B-44, BC Hydro Undertaking No. 4.
[731] Exhibit B-44, BC Hydro Undertaking No. 13.
[732] BC Hydro Final Argument, p. 152.
[733] BC Hydro Final Argument, p. 154.

BC Hydro submits that “given the limits on the data available, Concentric placed more weight on other factors including operational interviews, peer analysis, and professional judgement.” [734] BC Hydro submits that Concentric’s interviews with BC Hydro’s subject matter experts provided it with the necessary background to assess the utility’s physical plant, operating conditions and asset management practices.[735]

AMPC submits that BC Hydro’s accounting data are “limited and therefore of little use in establishing depreciation rates” as a result of two deemed cost adjustments that occurred in F2013 and F2019 respectively that restated the gross asset values on its books to reflect the net book value of the assets at the time of the adjustment. AMPC notes Mr. Kennedy’s evidence that that he gives low weight to the actuarial data and that an “all-inclusive observed life table” would have helped his analysis.[736]

In reply, BC Hydro submits that there is “ample information on which to set depreciation rates” including the 2011 through 2020 asset retirement database, consideration of peers, management and operational meetings, and Concentric’s professional judgment. BC Hydro submits that AMPC overstates the lack of value of the existing data, that the actuarial data did have value in many cases, and that Mr. Kennedy was able to use data from the 2005 depreciation study.[737]

RCIA submits that the most significant limitation of the Depreciation Study is “the poor-quality accounting data provided by BC Hydro to Concentric” that forced Concentric to rely “overly heavily upon operational interviews, peer utilities, and professional judgement.” RCIA submits this is demonstrated by the consistently “low” weighting Concentric applied to BC Hydro data and the higher weightings Concentric applied to its own judgement.[738]

RCIA submits that BC Hydro’s mean life data, provided in Undertaking No. 13, provides an alternative and higher quality source of asset retirement data. RCIA acknowledges that BC Hydro’s mean life data include only a subset of the possible causes of asset retirement, whereas average service live includes all causes of retirement, and that an expert would need to account for the differences in the two for a particular asset. RCIA submits that BC Hydro and its depreciation expert can reasonably be expected to transform a mean life data set into an average service life data set using their collective experience and expertise.[739]

RCIA submits that while the evidentiary record could not be progressed to the point where it contains evidence translating BC Hydro’s mean life data into average service lives, the mean life data provide an upper bound on the average service life “because mean life includes a subset of all causes of retirement.” RCIA submits that the mean life data also provide another reasonableness test, for example that BC Hydro’s recommended average service life may be undermined if it deviates markedly from its mean life estimates.[740]

In reply, BC Hydro submits that there is insufficient evidence to conclude that its mean life data can be “reasonably considered an upper limit on depreciation rates” and that this hypothesis has not been reasonably tested in this proceeding. BC Hydro further submits that there is insufficient evidence to draw any meaningful conclusions from the extent of the difference between mean lives and estimated service lives, and that Midgard’s experts are not familiar with BC Hydro’s mean life data beyond what was provided in Undertaking No. 13.[741]

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[734] BC Hydro Final Argument, p. 153.
[735] BC Hydro Final Argument, pp. 154–155.
[736] AMPC Final Argument, pp. 5-40 to 5-42.
[737] BC Hydro Reply Argument, pp. 93–96.
[738] RCIA Final Argument, pp. 22–23.
[739] RCIA Final Argument, pp. 23–26.
[740] RCIA Final Argument, p. 26.
[741] BC Hydro Reply Argument, p. 136.

BC Hydro further submits that retirement data, which are “actual historical data of retirements of an asset that can be used in an actuarial analysis to determine the average service life of an asset” are not comparable to mean life data, which are engineering estimates of the service life of assets.[742]

RCIA also expresses concern regarding Mr. Kennedy’s “non-transparent reliance” and “apparently contradictory testimony” on his use of the 2005 Depreciation Study. RCIA notes Mr. Kennedy’s rebuttal evidence where he says:[743]

> “When looked at in total, I determined that it was not feasible for the data from the 2005 study to be used in the current depreciation study.
>
> As such, I recommended that the retirement rate analysis prepared based on 2005 data be used as a reference point to test the average service life estimated”

RCIA then notes Mr. Kennedy’s oral testimony:

> “We have that [2005 Depreciation Study], and literally we have that beside us as we were reviewing average service life estimates, and looking at the patterns that existed at that time.”
>
> “So we were in a spot where we had the 2005 study on original -- on original cost base that provided some indications of history, it provided some retirement experience, so we could look at the volume of retirements and what happened at that study. As we were preparing our estimates, part of that blender of information that we had in informing our professional judgment, to use as we looked at the 2011 to 2019 and other interviews.”
>
> “Sitting beside me was the study that we prepared in 2005. … We had some fairly significant retirement data, which allowed us to undertake and review ourselves or refresh our memory, if you will, from the data set that we saw as of 2005.”
>
> “That's my recommendation, to keep the 2005 study, have it sit beside us and then do the study a bit on the limited data we have and try to make some sense of the data that way”
>
> “that if you keep that '05 binder beside me, that information was there, it was knowledgeable to us, we used it, we looked at it, and then we did what we had to do with the data we had. So we did use that historic study”
>
> “I would say yes. We did focus more particularly on the operation interviews as compared to the actuarial analysis, simply because -- yeah, the actuarial study was limited to that short band. We did have the old 2005 study beside us, so that tried to alleviate that.”

RCIA submits that, given the stated importance of the 2005 Depreciation Study to Concentric’s current Deprecation Study recommendations, the “glaring omission of the 2005 Depreciation Study from the current depreciation study and apparently contradictory evidence regarding its actual use” is “at best an unacceptable lack of transparency but is more likely and more problematically a strong bias towards the 2005 Depreciation Study recommended average service lives, regardless of other evidence that was available.” RCIA submits that as a result, Concentric’s recommended average service lives should be treated with caution and weighted accordingly.

[742] BC Hydro Reply Argument, p. 136.
[743] RCIA Final Argument, pp. 27–29.

In reply, BC Hydro submits that Mr. Kennedy's evidence on the use of the 2005 Depreciation Study has been consistent, that RCIA's submission that Concentric was "under the strong and direct influence of the 2005 Depreciation Study as an anchor for the Concentric proposed average service lives" is an overstatement, and that RCIA's submission that Concentric's proposals are biased downwards due to the study are baseless. BC Hydro submits that while Concentric considered historical information from the 2005 study, it in fact recommended changes to the average service lives of 97 asset accounts.[744]

Panel Determination

The Panel finds that BC Hydro's historical asset retirement data used in creating the Depreciation Study have limitations that raise doubts as to the credibility of the recommended changes to asset services lives proposed in the study.

BC Hydro acknowledges that the historical asset retirement data it provided to Concentric to create the Depreciation Study are limited, containing only retirement transactions from 2011 to 2020, and Mr. Kennedy himself gave them low weight in making his recommendations. As a result, Mr. Kennedy put more reliance on other factors, namely interviews with BC Hydro staff, peer comparators and his own judgement, in making his recommendations regarding estimated asset lives.

The Panel accepts BC Hydro's reasons why the retirement data prior to 2011 were not provided to Concentric, namely that its asset valuations were restated as a result of deemed cost adjustments to adopt the accounting principles of IFRS and the US GAAP regulatory accounting standard. However, the Panel is not satisfied that Concentric did not take into consideration other data on asset lives that BC Hydro acknowledges it possesses.

BC Hydro states that it maintains operational records of retirements outside the financial system. It is not clear to the Panel what value these records would have in calculating estimated asset lives, but neither is it clear why they should be discounted entirely when estimating average service lives.

Similarly, BC Hydro provided in Undertaking No. 13 the mean lives, or "operational life expectancy," of 32 asset classes. This evidence was not introduced sufficiently early in the proceeding to allow its relevance to be tested, but again the Panel is not clear why these data would not be considered when estimating average service lives.

For the foregoing reasons, **the Panel directs BC Hydro to include in its next depreciation study consideration of its operational records of asset retirements and asset mean lives to estimate or verify the average service lives of its assets**.

4.6.1.2.2 Management and Operational Interviews

Concentric states that it had discussions with BC Hydro management and operations representative to make an assessment of the physical installations of the BC Hydro plant, and to understand the type of plant in service and the operating conditions of the facilities, including asset management practices. This also included the historic operating conditions that have led to retirement of plant in the past and to understand the current condition of the assets which may impact future retirement plans.[745]

Concentric clarifies that the comments from operations representatives are reflective of a maximum life indication, not an average service life estimate.[746] Concentric states, in the determination of average service life, all factors of retirement must be considered including non-asset condition related physical factors, unplanned functional factors and contingent factors.[747]

[744] BC Hydro Reply Argument, pp. 96–98.
[745] Exhibit B-2-1, Appendix T, p. 11.
[746] Exhibit B-36, Appendix A, Section II, A21, p. 25.
[747] Exhibit B-36, Appendix A, Section III, A40, pp. 45–46.

Mr. Bowman raises concerns on the uncertainty of how Concentric utilized the operational and management interview information in deriving the recommended average service life. Mr. Bowman highlights account C80302 as an example where the operational interview indicates the lives used are too short, yet Concentric has proposed no change to the average service life.[748] Mr. Bowman states that the use of interviews can be very subjective. Additionally, the concept of an asset life has a different meaning across different professions.[749]

During the oral hearing, Mr. Darby, Director of Stations Asset Planning at BC Hydro, and Mr. Kumar, Vice President of Asset Planning at BC Hydro, state that the accounting group within BC Hydro does not consult the asset management group when making decisions on when certain projects should be included in depreciation and nor were Mr. Darby and Mr. Kumar interviewed by Concentric.[750]

Positions of the Parties

AMPC notes that Mr. Bowman is critical of several instances where Mr. Kennedy's recommendations "deviate from the information contained in interviews [with subject matter experts] without explanation (typically downward), given he does not have the subject matter expertise that BC Hydro's own experts have." AMPC submits that the BCUC should place little weight on Mr. Kennedy's interpretation of management and operational interviews where his recommendations deviate from the advice provided by subject matter experts without justification.[751]

In reply, BC Hydro submits that this shows a "critical flaw in Mr. Bowman's approach, which is to accept estimated life information from operational interviews without question." BC Hydro adds that Mr. Bowman himself recognizes that there are differences between engineering and depreciation standards, and that an average service life "is not a minimum, a performance metric, a design life or an engineering life."[752]

Panel Discussion

The Panel finds it appropriate that Mr. Kennedy relies on management and operational interviews in estimating average service lives of assets. BC Hydro's management and operational staff have direct experience with the assets in question, and although they are not put forward as expert witnesses in the proceeding, it is reasonable to assume that at least some of them are qualified engineers, unlike Mr. Kennedy.

For this reason, the Panel expects Mr. Kennedy to justify any recommendations he makes that deviate from the advice from BC Hydro's management and operational staff. The Panel accepts that there may be good reasons for such deviations, but given the absence of reliable asset retirement data, it is imperative that recommendations are based on the best qualified judgements available. Any recommendations from Mr. Kennedy that deviate from advice of BC Hydro's management and operational staff must be explained.

4.6.1.2.3 Peer Comparison

Concentric states that five peer utilities were used in the peer comparison analysis including Ontario Power Generation, Manitoba Hydro, NALCOR, FBC and New Brunswick Power. Concentric selected these peers based on the fact that it has recently completed depreciation studies for all the peers chosen relating to Canadian electric generation, transmission, and/or distribution plants. As such, Concentric is able to make a meaningful

[748] Exhibit C7-11, Section 2.2, p. 14.
[749] Exhibit C7-11, Section 2.2, p. 11.
[750] 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 919 line 8 to p. 920 line 7.
[751] AMPC Final Argument, pp. 5-19, 5-21.
[752] BC Hydro Reply Argument, p. 98.

comparison giving consideration to factors such as, capitalization and retirement policies, maintenance practices, and general operational practices.[753]

Concentric clarifies that the peer analysis was not used to select the average service life, but rather it was used to determine the reasonableness of the average service life selected based on the other drivers:[754]

> So, there's a difference between using a peer analysis as the tool to select the average service life, and the use of the peers to determine the reasonableness of an otherwise done selection. We do the latter. We don't necessarily use the peers to select, we simply use it as a band to check our analysis.

Mr. Bowman raises concerns that Concentric made limited use of the peer analysis as two of the five peers used in the peer analysis are based on confidential information, and that other peers should have been used including Altalink, ATCO Electric and Hydro One.[755] Additionally, the selection of peers limited to those that Concentric prepared depreciation studies leads to a lack of diversity in professional judgement and individual interpretation of those results.[756] Mr. Bowman states the best way to address this weakness is to broaden the data set and draw in more peer data especially from studies performed by other depreciation consultants.[757]

Mr. Bowman states that the peer comparison is the lowest value when looking at lives due to weaknesses such as difficulty linking different asset classes across different utilities and differences in circumstances due to physical properties of the assets, operating conditions, or capitalization or accounting or capital asset planning approaches:[758]

> But peers is [sic] the lowest value in looking at lives, I would say in both Mr. Kennedy's study and in the work that I did. Partially because, you know, it appears because they have a life approved it may be that the life is far off anything any technical expert would say or whatever. It might have been a saw off. It might have been negotiated with customers. You know, it might be a bunch of different considerations that went into it. So you could look to them, but you've got to be careful about taking too much guidance from the peers.

Midgard states Hydro One (Hydro One), Alectra utilities Corporation (Alectra), Manitoba Hydro, ATCO Ltd. (ATCO) and Newfoundland Power Inc. (NPI) are relevant peers for BC Hydro as the peers are all major Canadian utilities that have considerable transmission and distribution assets and have depreciation data available in the public domain.[759] Averaging the depreciation results from these five peers avoids inappropriately anchoring upon or weighting more heavily one data parameter or data source.[760]

Concentric states that although the formal peer comparison analysis only includes peer utilities that it had completed depreciation studies for, Concentric still utilizes general knowledge of the industry, depreciation studies conducted by other consultants and commission decisions from other jurisdictions as part of its professional judgement.[761]

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[753] Exhibit B-2-1, Appendix T, p. 11.
[754] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 205 lines 4 to 10.
[755] Exhibit C7-11, Section 2.2, pp. 13 – 14.
[756] Exhibit C7,11, Section 2.2, p. 14.
[757] Exhibit C7-15, BCUC IR 1.1.
[758] Exhibit C7-11, Section 2.2, p. 10; 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 482 line 25 to p. 483 line 10.
[759] Exhibit C8-7, Appendix B, Section B.1, p. 40.
[760] Exhibit C8-16, BCOAPO IR 7.1 and 7.2; 2022-09-21 Oral Hearing Transcript Volume 3 AM, p. 569 line 24 to p. 576 line 9.
[761] Exhibit B-36, Appendix A, Section II, A14, pp. 14 – 15.

Concentric states that Mr. Bowman and Midgard do not take into account differing circumstances between BC Hydro and other peers not used in the formal peer comparison analysis.[762] It is not sufficient to simply look at the names of accounts to make a comparison. Differences such as the asset material, climate, regulatory environment, and retirement policies will inevitably add complexity to the peer review.[763]

Positions of the Parties

BC Hydro notes that Concentric does not use peer analysis to select average service lives, but rather as "a band against which to check the reasonableness of its analysis." BC Hydro submits that Concentric's choice of peer utilities for which it has recently completed depreciation studies allowed it to account for factors such as capitalization and retirement policies, maintenance practices and general operating practices. Concentric also considered information from other utilities in applying its professional judgement.[764]

BC Hydro submits that neither Mr. Bowman nor Midgard offer a superior approach to peer analysis. BC Hydro notes that Mr. Bowman criticized Concentric for not including AltaLink, ATCO Electric and Hydro One in its peer analysis, but then only used those peers with respect to one asset account. Further, Mr. Bowman's arguments for ignoring peers with shorter lives was "not backed up by any meaningful analysis of the differing circumstances of the peer groups that had longer life estimates." BC Hydro submits that Midgard used five peers, but did not have sufficient information to take into account any distinguishing features of those utilities.[765]

AMPC submits that two issues arise with respect to Mr. Kennedy's reliance on peers. First, Mr. Kennedy only selected peers where he had conducted the depreciation study, so there is no diversity in the professional judgement and individual interpretations provided. For this reason, AMPC submits that the BCUC should consider the additional peer data relied on by Mr. Bowman. Second, there is limited transparency into the data for the five peers relied on by Mr. Kennedy. AMPC notes that Mr. Kennedy was unable to provide the peer data he relied on for Manitoba Hydro, he did not provide the data from New Brunswick Power in a form that allowed accounts to be matched to BC Hydro's, and Ontario Power Generation only comprises generation assets and not transmission or distribution assets.[766]

In reply, BC Hydro submits that Mr. Bowman relies on the same peer comparators as Mr. Kennedy for all but one account. Further, Mr. Bowman's account-by-account evidence shows that his analysis is based heavily on comparison to peer data, however he states that peer comparisons should be given the lowest weighting.[767]

RCIA submits that an additional concern about Concentric's Depreciation Study is the "potential for bias in Mr. Kennedy's professional judgement" resulting from his exclusive use of peer utilities that Concentric has previously studied. In contrast, RCIA submits that Midgard's peer comparators are "less biased because they are not subject to concerns of circularity or predisposition towards one's own previous studies."[768]

In reply, BC Hydro disagrees that Concentric's reliance on peers introduces any bias. BC Hydro notes that Mr. Kennedy relies on studies that are reviewed by regulators in public processes, which BC Hydro submits "guards against any bias." BC Hydro further submits that Concentric has not limited itself to only considering its own studies, but also considers its knowledge of industry trends and issues related to depreciation and the depreciation studies conducted by others. BC Hydro adds that for each study, Concentric considers "all the

[762] Exhibit B-36, Appendix A, Sections III and IV, A20 and A42, pp. 21 – 25 and 47 – 49.
[763] Exhibit B-36, Appendix A, Section II, A13, p. 12.
[764] BC Hydro Final Argument, pp. 155–156.
[765] BC Hydro Final Argument, p. 157.
[766] AMPC Final Argument, pp. 5-19 to 5-21.
[767] BC Hydro Reply Argument, p. 88.
[768] RCIA Final Argument, p. 27.

relevant factors, including actuarial analysis and operational interviews" which prevents the perpetuation of any bias from study to study.[769]

RCIA submits that its approach of setting average service lives to the average of five peer comparators is reasonable because it only took this approach where it identified Concentric results "that were already identified as unreasonable."[770]

In reply, BC Hydro submits that Concentric's approach is superior to that of Midgard, which is to select peers for which it has limited knowledge. BC Hydro submits it is imperative to consider the differences amongst utilities and their assets, and the differing nature of different depreciation studies, before relying on a peer's average service life.[771]

Panel Determination

The Panel places limited weight on peer comparisons in the Depreciation Study when estimating average service lives of BC Hydro's assets.

The Panel is concerned that Mr. Kennedy's selection of peers for whom Concentric has prepared depreciation studies may be too restrictive. Given the large degree to which professional judgement has played a role in setting BC Hydro's average service lives, the Panel would be more comfortable with a greater diversity of professional opinions among the peers.

While the Panel does not find that Concentric has displayed bias in its opinions, we do not agree with BC Hydro's view that Concentric's opinions are free from bias merely because the studies relied on were individually reviewed by regulators in public processes. While each individual study Concentric used as a peer comparator for BC Hydro may have been accepted by other regulators, if there were a systemic bias as a result of Concentric applying the same methodology in each case it would only come to light when examining depreciation studies prepared by other experts.

The Panel accepts that an understanding of the operations and asset accounting practices of the peers allows a more meaningful comparison with BC Hydro. However, the Panel would place more weight on the peer comparisons if they contained estimates of average service lives prepared by a different firm that might possibly apply its judgement in a different manner. An expanded peer comparison might also be of more value if BC Hydro used group accounting, a matter the Panel addresses in Section 4.6.6.2 below.

The Panel is also concerned that, out of a total of five peer comparisons, Mr. Kennedy cannot provide in a useful form the data on which he relies for two of them, and a third comprises only generation assets and not transmission or distribution assets.

The Panel acknowledges Mr. Kennedy's statement in the oral hearing that he used peer comparisons "to determine the reasonableness of an otherwise done selection" rather than as a tool to select average service lives. However, the evidence also shows that he gave "high" weight to peer comparisons in 22 of 98 recommended changes and "medium" weight to 37 recommended changes. The Panel does not agree that it is appropriate to give so much weight to a small number of peer comparisons created by the same firm.

For the foregoing reasons, **the Panel directs BC Hydro to consider a more expansive set of peer comparisons in its next depreciation study, and to endeavour to use peers for which publicly available data can be provided and detailed comparisons made**.

[769] BC Hydro Reply Argument, p. 99.
[770] RCIA Final Argument, p. 20.
[771] BC Hydro Reply Argument, p. 99.

The Panel also places limited weight on the peer comparisons provided by Mr. Bowman. This is consistent with Mr. Bowman's own view, expressed in the oral hearing, that peer comparisons are "the lowest value in looking at lives." The Panel does, however, appreciate Mr. Bowman's use of the publicly available data from Manitoba Hydro, compared to Mr. Kennedy's use of data from that utility that he could not share.

In consideration of the concerns expressed above, the Panel uses peer comparisons to determine the reasonableness of average services lives determined based on other factors, rather than to determine the estimated values of average services lives.

4.6.1.2.4 Professional Judgement

Concentric states that it applies professional judgement when making the average service life recommendations.[772] This includes drawing on Concentric's general knowledge gained from conversations and participation at industry events, reviewing depreciation studies completed by other consultants, reading commission decisions from other jurisdictions, and working in other areas of the regulated rate industry.[773]

During the oral hearing, Mr. Kennedy clarified that in some cases, the manufacturer's information and warranties are also included.[774] Consideration was also given to the results of the 2005 Depreciation Study as part of his professional judgement.[775] Concentric states the use of professional judgement is consistent with accepted depreciation practices.[776] Below is an example of the explanation provided by Concentric for recommending the average service life of account C22005:[777]

> "The assets in this account relate to electric reliability focused buildings throughout British Columbia. These buildings are typically built out of cinder blocks in a variety of styles based on when the buildings were built and the purpose of the building.
>
> The retirements, additions and other plant transactions through the end of fiscal year 2020 were analyzed by the retirement rate method. Retirements for the period 2011 through 2020 of $12,551,395 were recorded and have resulted in actual observed data points as depicted on page 5- 43. The best fitting Iowa Curve using the currently approved 60-year life is the Iowa 60-R5 with a residual measure of 0.3136. An Iowa 65-R3 provides a better visual fit with a residual measure of 0.4645. A review of peer Canadian electric utilities provides a range from 50 years to 75 years. Based on the above and on Concentrics' experience, an Iowa 65-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 65-R3 to represent the future expectations for the investment in this account."

Mr. Bowman states that professional judgement should not be considered an independent source. While judgment plays a part in determining appropriate depreciation rates – for example, which peers to consider, how to balance the three above approaches, and whether the actuarial data can be relied upon - absent one of the above factual data inputs, there is no innate "judgment" that any professional can conjure that would create a new source of comparison.[778]

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[772] Exhibit B-2-1, Appendix T, p. 12.
[773] Exhibit B-36, Appendix A, Section II, A14, pp. 14 – 15.
[774] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 190 line 23 to p. 191 line 19.
[775] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 177 line 3 to p. 178 line 8.
[776] Exhibit B-8, RCIA IR 103.5.
[777] Exhibit B-2-1, Appendix T, p. 17.
[778] Exhibit C7-11, Section 2.2, p. 11.

Midgard states Concentric exercised a considerably greater degree of professional judgement in the Depreciation Study than what is typical in depreciation studies for utilities that provide longer and more complete input datasets.[779]

Concentric states the use of informed professional judgement combined with mathematical fitting is widely regarded as the best method for selecting Iowa cures. As noted in the widely accepted textbook" Depreciation Systems" by Frank K. Wolf and W. Chester Fitch, published by the Iowa State University in 1994:[780]

> "On the surface, removal of judgement from the fitting process may appear to be an advantage, but blind acceptance of mechanical fitting processes will occasionally but consistently result in poor results"

Concentric also notes that the National Association of Regulatory Utility Commissioners (NARUC), in its 1996 publication titled "Public Utility Depreciation Practices", make the following comments on this topic:[781]

> "Depreciation analysts should avoid becoming ensnared in the mechanics of the historical life study and relying solely on mathematical solutions. The reason for making an historical life analysis is to develop a sufficient understanding of history in order to evaluate whether it is a reasonable predictor of the future."
>
> "The analyst should become familiar with the physical plant under study and its operating environment, including talking with the field people who use the equipment being studied."
>
> "….In addition to talking with field people, the analyst should talk with management. Understanding past and present company policies concerning maintenance practices and retirements will determine how well historic retirement patterns will be repeated in the future. Management might also reveal planned future retirements that follow no historic pattern. In such a case, the analyst could modify the historic retirement pattern to reflect management's plans for retirement of certain facilities."

Positions of the Parties

BC Hydro submits that Concentric's use of "informed professional judgement is consistent with accepted depreciation practices," and that Concentric's knowledge base and application of professional judgement "lends considerable weight to its recommended average service lives."[782]

AMPC submits that there are two issues with Mr. Kennedy's application of professional judgement in this proceeding. First, his evidence on average service lives "relies heavily on his application of judgement" but he has not explained how that judgement was applied to reach his ultimate recommendations, and the BCUC cannot place weight on "bare assertions" from an expert. AMPC notes that Mr. Kennedy's 734-page Depreciation Study contains only 10 pages of content explaining his average service lives recommendations and includes explanations for 21 of the more than 300 asset classes he reviewed. According to AMPC, Mr. Kennedy has provided only some of the peer comparator data he relied on. Taken together, AMPC submits that there is both insufficient data and explanation to reconstruct how Mr. Kennedy arrived at his average service lives recommendations, and that the BCUC should place little weight on Mr. Kennedy's application of professional judgement unless it was formed based on information and opinions from qualified individuals, rooted in evidence before the BCUC, and he fully explained how he applied his judgement to form his recommendations.[783]

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779 Exhibit C8-7, Section 5.3, p. 23.
780 Exhibit B-8, RCIA IR 103.5.
781 Exhibit B-8, RCIA IR 103.5.
782 BC Hydro Final Argument, pp. 159-160.
783 AMPC Final Argument, pp. 5-2 to 5-4, 5-18, 5-21

In reply, BC Hydro submits that AMPC's criticism of the depth of Mr. Kennedy's analysis is without merit and that it is clear how he arrived at his recommendations. BC Hydro explains that Mr. Kennedy describes the method applied, and discusses in detail the basis for the key changes in depreciation lives on which he focused. Further, Mr. Kennedy responded to many information requests and when cross-examined on his report and his recommendations provided "forthright, comprehensive and helpful" testimony. BC Hydro submits that the number of pages of the Depreciation Study devoted to the retirement rate analysis has no bearing on the matter and should be disregarded.[784]

Second, AMPC submits that Mr. Kennedy's specific application of professional judgement is problematic because he "readily forms opinions on matters that are outside his expertise."[785] AMPC submits that, while Mr. Kennedy may have experience in conducting depreciation studies, he is not an engineer, accountant, or capital asset manager, and that while he is entitled to rely on subject matter experts on other topics to inform the opinions he reaches on depreciation, he has "no special skill, knowledge or training in those other topics that allow him to reached [sic]informed opinions on them." Nevertheless, AMPC submits, Mr. Kennedy strays beyond his expertise through the "opaque application of his own judgement to reach his recommendations" and has expressly stated he has based his recommendations on topics such as the type and species of wood used in poles. AMPC submits that Mr. Kennedy's evidence on these topics should be given little or no weight, whereas Midgard's witnesses, Mr. Helland and Mr. Oakley, are the only witnesses qualified to speak to the engineering inputs to Mr. Kennedy's depreciation evidence and their evidence should be given considerable weight.[786]

In reply, BC Hydro submits AMPC's argument that Mr. Kennedy has strayed beyond his area of expertise has no merit. BC Hydro explains that Mr. Kennedy is a depreciation expert, "which means that his expertise is primarily in the subject matter of determining the average service lives of utility assets for depreciation purposes, which includes consideration of causes of retirement." BC Hydro submits that Mr. Kennedy correctly speaks with authority regarding the impact of such factors as the materials of poles on the average service lives of assets, and adds that neither Mr. Bowman, Mr. Helland nor Mr. Oakley have his level of knowledge and expertise.[787]

Panel Determination

The Panel finds that Mr. Kennedy's judgement should be given little weight unless it is supported by evidence and adequately explained.

Given the low weight he assigns to the historical asset retirement data, Mr. Kennedy has relied considerably on professional judgement in making his 98 recommended changes to average service lives, ascribing it "medium weight" in 86 cases and "high weight" in 9 cases.

The Panel does not question that Mr. Kennedy has significant experience preparing depreciation studies. However, the Panel agrees with the view taken by Mr. Bowman that professional judgement is not an independent source of evidence. The Panel may choose to rely on the professional judgement of an expert in determining the weight to give conflicting evidence supporting recommendations, but does not consider it appropriate to rely on expert professional judgement that is not supported by evidence or otherwise explained, a path that would risk falling into the trap posed by "expert generalists" noted by Justice Moldaver.

In the Panel's view, Mr. Kennedy's explanations in the Depreciation Study of how he has applied his professional judgement to support his recommended changes to average service lives are inadequate. The explanation used on multiple occasions, for example for account C22005 – Building, Composite Pool, is "Based on the above [evidence] <u>and on Concentric's experience</u>…" [emphasis added]. It is not clear from this explanation whether Mr. Kennedy believes his professional judgement is an additional source of evidence, whether he is relying on

[784] BC Hydro Reply Argument, pp. 87–88.
[785] AMPC Final Argument, pp. 5-18, 5-21.
[786] AMPC Final Argument, pp. 5-5 to 5-8.
[787] BC Hydro Reply Argument, pp. 89–90.

evidence that he has not introduced into the proceeding, or whether he is using his professional judgement to give (unstated) weight to conflicting evidence that is in the proceeding.

BC Hydro's response to AMPC's criticisms of Mr. Kennedy's inadequate explanations is that he "responded to many information requests and when cross-examined on his report and his recommendations provided "forthright, comprehensive and helpful" testimony." It is possible that not so "many information requests" would have been necessary if Mr. Kennedy's explanations in the Depreciation Study had been more comprehensive.

For the foregoing reasons, **the Panel directs BC Hydro to provide more comprehensive explanations of recommended changes to average service lives in its next depreciation study**.

AMPC also submits that Mr. Kennedy "readily forms opinions on matters that are outside his expertise," noting that he is not an engineer, accountant or capital asset manager, whereas BC Hydro submits that Mr. Kennedy correctly speaks with authority regarding the impact of various causes of asset retirement on asset service lives because he "is a depreciation expert."

The Panel gives weight to Mr. Kennedy professional judgement as a depreciation expert when he evaluates the opinions of others, such as engineers and asset managers, on estimated average service lives. However, the Panel gives no weight to unsupported professional judgement of Mr. Kennedy in areas that are not properly those of a depreciation expert, such as engineering.

4.6.1.2.5 Summary Findings

Concentric analyzed 315 asset classes as part of the Depreciation Study including a change in 97 asset classes, no change in 217 asset classes and the addition of one new asset class for EV Charging Stations.[788] Of the 97 asset classes that Concentric recommended a change to the average service life, 83 asset classes were not contested by interveners. Of the 217 asset classes that Concentric recommended no change to the average service life, 170 asset classes were not contested by interveners.[789]

BC Hydro identified assets at specific locations, which are primarily substations, that are scheduled for premature retirement or decommissioning between F2022 and F2035.[790]

As part of the Depreciation Study, Concentric recommends depreciating the locations that have a predetermined terminal retirement date based on the remaining life basis listed below:[791]

Table 42: Terminal Retirement Locations

Site	Economic Planning Horizon	Remaining Life as of March 31, 2020
Balfour	2023	3
Coquitlam	2022	2
Dal Grauer	2035	15
Fairmont	2024	4
Fort Steele	2022	2
George Dickie	2023	3
Glenmore	2024	4
Horne Payne	2025	5
Lougheed	2024	4

[788] Exhibit B-2-1, Appendix T, Table 1, pp. 28 – 33.
[789] Derived from comparing the following exhibits: Exhibit B-2-1, Appendix T, Table 1, pp. 28 – 33; Exhibit C7-11, Section 1.1, pp. 3 – 5; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 24; and RCIA Final Argument, Table 1, p. 9.
[790] Exhibit B-2, Section 8.3.1.5, p. 8-14.
[791] Exhibit B-2-1, Appendix T, p. 13.

Murrin	2035	15
Murrin #1 Dal Grauer Circuit	2033	13
Norgate	2024	4
Quesnel	2022	2
Richmond	2024	4
Scott Road	2023	3
Sumas Way	2024	4
Surrey	2022	2
Wilsey Dam	2029	9

BC Hydro clarified that accelerated depreciation is applied on an asset-by-asset basis at the specific location. Assets that can be repurposed or relocated are excluded from the accelerated depreciation treatment.[792]

As part of Mr. Bowman's expert evidence submitted by AMPC, Mr. Bowman states that the remaining life recommendations effectively overrides the average service life of the equipment in question, and forces depreciation over only the period in which the site will be used. Mr. Bowman believes this is an appropriate approach to manage sites where plans indicate a fixed end date. Mr. Bowman did not review the specific economic planning horizon dates but believes the general approach proposed by Concentric is appropriate.[793]

Positions of the Parties

BC Hydro submits that the BCUC should approve the implementation of Concentric's recommendations in the Depreciation Study for ratemaking purposes, including the adoption of revised useful lives and positive salvage percentages, changes to vehicle asset classes, and creation of a new asset class for EV charging station assets.[794]

BC Hydro submits that Concentric's recommendations should be preferred to the evidence filed by Mr. Bowman and Midgard for the following reasons:[795]

- Mr. Kennedy (of Concentric) has significantly greater expertise with respect to depreciation studies than either Mr. Bowman or Midgard;
- Mr. Kennedy followed a robust methodology consistent with accepted depreciation practices for determining average service lives;
- Mr. Bowman's recommendations are flawed for "numerous reasons"; and
- Midgard's theory about the impact of asset management on average service lives and its method for determining average service lives are "fundamentally flawed."

BC Hydro submits that Concentric's methodology for assessing the average service lives for each BC Hydro asset class gives additional credibility to its recommendations, followed "accepted depreciation standards" and included:[796]

- An analysis of BC Hydro's retirement data;
- Discussions with BC Hydro's management and operations representatives;
- Peer comparison; and
- Concentric's professional judgement.

[792] Exhibit B-7, BCUC IR 105.2.
[793] Exhibit C7-11, Section 2.2, p. 15.
[794] BC Hydro Final Argument, p. 146.
[795] BC Hydro Final Argument, p. 147.
[796] BC Hydro Final Argument, pp. 151–152.

MoveUp submits that the BCUC should approve Concentric's recommendations in the Depreciation Study as filed. MoveUp submits that the filed evidence and oral testimony devoted to challenging the Depreciation Study "may be somewhat naïve, underestimating the complexity of the subject-matter and the sophistication of the analysis and knowledge-base that proposed BC Hydro's proposals." MoveUp agrees with BC Hydro's general characterization that the intervener evidence challenging the Depreciation Study "lacked the depth of expertise required to properly critique these issues."[797]

AMPC submits that Mr. Bowman's recommended service lives for the 35 accounts for which he makes recommendations should be implemented.[798]

The CEC submits that BC Hydro's Depreciation Study would have benefited from site visits and verifications to allow for better validation of assumptions with respect to average service life estimates of BC Hydro's major assets. The CEC also takes issue with the level of professional judgement involved in determining the average service life estimates.[799]

The CEC finds merit in the RCIA evidence concerning the average service lives for transmission conductors, and submits that there is an opportunity to review the average service lives for BC Hydro's larger dams and generating station to recognize longer amortization periods for depreciation purposes.[800]

NTC is concerned about the deemed cost adjustments to BC Hydro's asset values referred to in Mr. Bowman's evidence may have "effectively detached" BC Hydro's depreciation rates from "objectively base actuarial analysis," which might lead to overcharging current ratepayers relative to future ratepayers. NTC submits that Mr. Bowman's recommendations "should be given serious consideration" and concurs with the recommendation that BC Hydro should be directed to undertake a broad review of depreciation on the Waneta assets.[801]

RCIA proposes changes to the average service lives of select asset classes recommended by Concentric because of the differences between Concentric's proposals and "real-world asset lives," BC Hydro's depreciation rates imply it is not achieving material improvements in the average service lives of its transmission and distribution assets, and BC Hydro's average service lives were on average shorter than its Canadian industry peers.[802]

Panel Determination

The Panel has already expressed its concerns with respect to:

- The lack of historical asset retirement data prior to 2011 and Concentric's lack of regard for other BC Hydro asset retirement data;
- The lack of sufficient diversity in Concentric's choice of peer comparators and lack of transparency of data for some of the peers that were chosen; and
- The inadequacy of explanations supporting the use of professional judgement in Concentric's recommendations.

Notwithstanding these concerns, the Panel accepts Concentric's uncontested recommended changes to the average service lives of BC Hydro's assets. The Panel recognizes Mr. Kennedy's experience in developing depreciation studies, and notes that interveners have had opportunities to test his evidence through

[797] MoveUp Final Argument, p. 6.
[798] AMPC Final Argument, p. 5-14.
[799] CEC Final Argument, p. 99.
[800] CEC Final Argument, pp. 99–100.
[801] NTC Final Argument, p. 33.
[802] RCIA Final Argument, p. 14.

information requests and during cross-examination. For the same reasons, the Panel accepts Concentric's recommendations for accelerated depreciation of assets at select locations with predetermined retirement dates, which are uncontested.

However, where interveners have contested Concentric's recommended changes to average service lives, the Panel will examine the evidence for each contested average service life on its merits, in Section 4.6.5 below.

4.6.1.3 Mr. Bowman's Proposed Average Service Lives

Mr. Bowman provides alternative average service life recommendations for a sample of the largest and most critical capital asset accounts.[803] Mr. Bowman states the recommendations are based on a combination of:[804]

1. The current Depreciation Study including Concentric's interview notes and peer analysis
2. The 2005 Depreciation Study
3. The 2010 componentization review
4. Other peer utilities including Altalink, ATCO Electric, Hydro One, and Manitoba Hydro

In oral testimony, Mr. Bowman states that one needs to be careful when taking too much guidance from peers.[805]

Concentric states Mr. Bowman seems to accept the longer estimated lives within the peer group as being directly comparable, whereas he is finding reasons to dismiss the shorter life estimates. Additionally, Mr. Bowman does not consider differing circumstances for the peer group that had longer life estimates, but rather accepts the estimates and considers them as relevant. For example, Concentric states Mr. Bowman's choice in peer utilities is flawed in the following ways:[806]

1. The AltaLink system is generally constructed over rural prairie areas with their right of way largely crossing farms. Additionally, the environmental conditions are less corrosive than the humid salt air environment that some of the BC Hydro system transverses. The high humidity and coastal environment are much more corrosive to steel structures than the predominately dry air with no salt content.
2. The average service lives of AltaLink and ATCO towers are largely driven by the introduction of the Alberta ISO 502.2 construction standard for transmission lines constructed after 2012. The new standards require a significantly enhanced design and fail tolerance standard and are anticipated to have a longer end of life characteristic. BC Hydro has not incurred the same large build out of towers in comparison.
3. Manitoba Hydro's transmission system is largely constructed over farmland and has a very dry environment as compared to the BC Hydro system, which will result in significantly reduced amounts of corrosion.
4. The depreciation study referenced by Mr. Bowman for Hydro One was completed by Fosters Associated and is not the most current depreciation study completed. Moreover, the Hydro One depreciation study was based on a more limited amount of data to support the professional judgement relative to Concentric's depreciation study. Lastly, the Hydro One assets are not impacted by the saltwater environment to which some of the BC Hydro are subjected to.

[803] Exhibit C7-11, Section 1.1, pp. 2 – 5.
[804] Exhibit C7-11, Section 2.3, pp. 16 – 39.
[805] 2022-09-20 Oral Hearing Volume 2 PM, p. 482 line 25 to p. 483 line 10.
[806] Exhibit B-36, Appendix A, Section III, A20, pp. 21 – 25.

Positions of the Parties

BC Hydro submits that Mr. Bowman's recommended depreciation rates are flawed for five main reasons:[807]

1) Mr. Bowman was "selective and favoured lengthening average service lives."
2) Mr. Bowman incorrectly equated recommended lives from operational staff with average service lives when they should be considered maximum lives.
3) Mr. Bowman "searches for reasons to disregard peers with shorter lives, while accepting peers with longer lives without scrutiny."
4) Although Mr. Bowman disagrees with Concentric with relation to peer comparisons, Mr. Bowman acknowledges that "one needs to be careful when taking too much guidance from peers."
5) Mr. Bowman "disregards the impact of continued investment in an account, which has the effect of lowering the average service life."

AMPC submits that Mr. Bowman's recommended service lives for the 35 accounts he makes recommendations should be preferred to those of Mr. Kennedy and implemented.[808]

In response to BC Hydro's criticism that Mr. Bowman's review was "selective and favoured lengthening average service lives," AMPC submits that:[809]

- BC Hydro's unusually complex account structure did not permit a detailed review of every asset class, but Mr. Bowman reviewed the largest and most critical accounts.
- If BC Hydro's proposed service lives were biased toward shorter lives than the available evidence supported, it is no surprise that Mr. Bowman's recommendations fall in the other direction.
- Mr. Kennedy also did not propose changing the average service lives for a substantial majority of BC Hydro's accounts, even through "in many cases the peer review and operational interviews support life extensions."
- Mr. Kennedy appears to confirm some of Mr. Bowman's views when he noted that he was "actually expecting more change than we saw" given the fact that more than 15 years had elapsed since BC Hydro's last depreciation study.

Panel Determination

The Panel will consider the changes to average service lives proposed by Mr. Bowman on their own merits.

The Panel is satisfied that, to the extent Mr. Bowman was "selective and favoured lengthening average service lives", this does not discredit his evidence. The Panel accepts AMPC's argument that Mr. Bowman focused on the "largest and most critical accounts."

The Panel considers that BC Hydro's other criticisms of Mr. Bowman's recommendations are better addressed in respect of specific recommendations when the evidence of other experts can be taken into account, including that of Concentric.

[807] BC Hydro Final Argument, pp. 160–162.
[808] AMPC Final Argument, p. 5-14.
[809] AMPC Final Argument, pp. 5-11 to 5-13.

4.6.1.4 Midgard's Proposed Average Service Lives

Midgard states that, with all else being equal, better asset management leads to increases in more values extracted from the capital assets used. Since BC Hydro is rated as a competent asset manager, BC Hydro should be translating improvements in asset value extraction into longer average service lives relative to peer utilities.[810] In the following table, Midgard provides an example of a potential disconnect between the actual average service life and Concentric's recommended average service life based on 8 years of retirement data:[811]

Table 43: Actual Average Service Life Data Comparison

Asset Description	Average Retirements (2013-2020)	Net Book Value (31 March 2020)	Calculated Actual Average Service Life	Depreciation Report (Average Service Life)
Conductor, Overhead < 60 Kv	$3,928,668/year	$719,759,645	180 years	50 years
Conductor, Overhead > or = 60 Kv	$1,220,266/year	$698,260,582	570 years	55 years

Midgard states although it does not expect that the average service life for these assets for all causes of retirement will prove to be 180 years and 570 years in actual experience, the data clearly point to a significant gap between BC Hydro's current actual practice and the Depreciation Study values.[812]

Mr. Oakley acknowledges that the retirement data used in the above analysis is understated which means the denominator used in calculating the "Calculated Actual Average Service Life" is also understated leading to the "Calculated Actual Average Service Life" being overstated.[813]

Midgard compared selected transmission and distribution assets from the Depreciation Study to the average service lives from a group of peer Canadian utilities to determine a revised recommended set of average service lives.[814]

Midgard selected the following utilities as an appropriate peer group for comparing BC Hydro's transmission and distribution assets because they are major Canadian Utilities, have considerable transmission and distribution assets, and they all have depreciation data available in the public domain:[815]

1. Hydro One;
2. Alectra;
3. Manitoba Hydro;
4. ATCO; and
5. NPI.

Midgard states its average service life recommendations are based on a statistical difference between the peer utilities group and Concentric's recommendations.[816]

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810 Exhibit C8-7, Sections 2.2, 2.3 and 5.4, pp. 7 – 10 and 23 – 24; 2022-09-20 Oral Hearing Volume 2 PM, p. 505 lines 20 – 24.
811 Exhibit C8-7, Section 5.1, Table 2, pp. 19 – 20.
812 Exhibit C8-7, Section 5.1, p. 20.
813 2022-09-21 Oral Hearing Volume 3 AM, p. 595 line 7 to p. 596 line 2.
814 Exhibit C8-7, Section 6, p. 27.
815 Exhibit C8-7, Section 6, p. 28.
816 Exhibit C8-7, Appendix B, Sections B.2 and B.3, pp. 45 – 51.

BC Hydro states Midgard has incorrectly assumed that BC Hydro's recommended annual depreciation reflects or results from BC Hydro's asset management program.[817] BC Hydro states BC Hydro's depreciation accounting policy and procedures do not inform its asset management decisions. These two functions serve different purposes where one is an accounting function and the other defines how assets are managed over their lifecycle to appropriately balance cost, risk, and performance. Although asset management practices can influence the Average Service Life, there are many other factors that impact the average service life of an asset that asset management practices do not influence.[818]

Concentric states Midgard's review and recommendations are loosely based on the completion of a peer analysis of five Canadian electric transmission and distribution utilities. At best, this analysis would provide insight into maximum life indications and are completely devoid of any impact of interim retirement or retirements caused by any non-physical factors such as changes in demand, obsolescence, changes in technology, changes in government and environmental legislations, or storms. In the determination of average service life, all factors of retirement must be included. Ignoring certain factors of retirement will result in average service life recommendations that are longer than appropriate for depreciation purposes.[819]

Mr. Kennedy clarifies that asset management programs or maintenance programs do influence the life of the physical asset with a tendency to increase the engineering life or the maximum expected life. However, other retirement factors must be considered.[820] As a general trend, assets, in particular electric assets, are lasting slightly longer on average.[821]

Concentric states Midgard makes no recognition of the unique environmental considerations or operating conditions between BC Hydro and the peers used for the comparison.[822] Specifically, Concentric states Midgard's choice in peer utilities is flawed in the following ways:

1. Hydro One's depreciation study was based on a more limited amount of data to support the professional judgement relative to Concentric's depreciation study. Additionally, the Hydro One assets are not impacted by the saltwater environment to which some of the BC Hydro's assets are subjected.[823]
2. Alectra adopted the lives from the 2010 Kinectrics study in its most recent rate case, which at best, provided a wide range of reasonable life estimates, and provided little information related to the specific Alectra assets.[824]
3. Manitoba Hydro's transmission system is largely constructed over farmland and has a very dry environment as compared to the BC Hydro system, which will result in significantly reduced amounts of corrosion.[825]
4. ATCO's towers are largely driven by the introduction of the Alberta ISO 502.2 construction standard for transmission lines constructed after 2012. The new standards require a significantly enhanced design and fail tolerance standard and are anticipated to have a longer end of life characteristic. BC Hydro has not incurred the same large build out of towers in comparison.[826]

[817] Exhibit B-36, Section 1, A2, p. 2.
[818] Exhibit B-36, Section 2.2, A7, pp. 5 – 6.
[819] Exhibit B-36, Appendix A, Section IV, A40, pp. 44 – 46.
[820] 2022-09-20 Oral Hearing Volume 2 PM, p. 325 line 24 to p. 326 line 10.
[821] 2022-09-20 Oral Hearing Volume 2 PM, p. 392 lines 24 – 26.
[822] Exhibit B-36, Appendix A, Section IV, A42, pp. 47 – 48.
[823] Exhibit B-36, Appendix A, Section III, A20, pp. 23 – 25.
[824] Exhibit B-36, Appendix A, Section IV, A42, p. 48.
[825] Exhibit B-36, Appendix A, Section III, A20, p. 22.
[826] Exhibit B-36, Appendix A, Section III, A20, p. 21.

5. Midgard has not considered the difference in size and magnitude between BC Hydro and NPI. For example, NPI has a small number of steel towers which provides limited retirement data.[827]

Mr. Helland states BC Hydro's statement that Midgard has incorrectly assumed that BC Hydro's recommended annual depreciation reflects or results from BC Hydro's asset management program is incorrect. Midgard does not assume that BC Hydro's recommended annual depreciation results solely from BC Hydro's asset management program, rather, Midgard's understanding is the same as BC Hydro's, namely that asset management practices influence average service life and there are other factors which impact average service life.[828]

Positions of the Parties

BC Hydro submits that Midgard's theory about the relationship between asset management and depreciation rates is "fundamentally flawed and cannot be relied on to evaluate the results of Concentric's Depreciation Study." First, BC Hydro notes that the result of Concentric's Depreciation Study increases the lives of more asset accounts than are decreased. Second, BC Hydro submits that the evidence Midgard cites to question the reasonableness of Concentric's recommendations is "meaningless" because Midgard is, in essence, comparing Concentric's average service life recommendations against its own calculated "actual average service life," which given Mr. Oakley's acknowledgement that the denominator in his calculation is understated, means that the calculation is incorrect and the comparison is meaningless. Third, BC Hydro submits that the connection between asset management and average service lives for depreciation purposes is "complex and cannot be reduced to the simple assumption that asset management will always increase the lives of assets." The evidence of Mr. Kennedy demonstrates that isolating the impact of asset management programs on average services lives would be challenging, and he has not seen an appreciable increase in average service live estimates for utilities that have implemented large asset management programs.[829]

BC Hydro further submits that Midgard's method of determining its recommended depreciation rates is "also fundamentally flawed and should be given no weight." BC Hydro submits that Midgard has no experience conducting depreciation studies, and Concentric describes numerous errors in Midgard's analysis. Midgard also relies solely on a comparison to five peers, and does not rely, for instance, on any actuarial analysis or operational interviews. BC Hydro submits that Midgard's "simplistic and narrowly-focused approach to depreciation," a simple average of five peer utilities which does not take into account any differences between the peers, is no substitute for "the deep analysis and data that underlies [sic] Concentric's recommended average service lives."[830]

RCIA submits it engaged Midgard to evaluate the results that BC Hydro's asset management program is achieving or plans to achieve as reflected in depreciation rates. RCIA submits that Midgard's evidence is "not a classical depreciation report" but focuses on peer comparisons between BC Hydro's depreciation rates and those of its peers, issues with the Concentric Depreciation Study, causes of asset retirement, and comparison of "actual real-world asset lives and the accounting data that informed depreciation rates."[831]

RCIA submits that BC Hydro's claims that Midgard's evidence about the impact of asset management is "fundamentally flawed" are without merit. RCIA notes that BC Hydro's own expert, Mr. Kennedy, "supports the concept and intuition of asset management impacting the depreciation lives of utility assets, especially longer-lived assets." RCIA quotes Mr. Kennedy's statement:[832]

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[827] Exhibit B-36, Appendix A, Section IV, A42, p. 48.
[828] 2022-09-20 Oral Hearing Volume 2 PM, p. 508 line 7 to 509 line 6.
[829] BC Hydro Final Argument, pp. 163–165.
[830] BC Hydro Final Argument, pp. 165–166.
[831] RCIA Final Report, p. 14.
[832] RCIA Final Argument, pp. 16–17.

> The fact is utility assets are tending to last a little bit longer now than they were say a decade ago, for a number of reasons, when the -- especially the longer mid-term kind of length assets. … The trend is assets are lasting on average slightly longer. <u>And I would say particularly electric assets.</u> [emphasis added]

RCIA submits that although asset management is not the only determinant of average service lives, it is an important determinant that BC Hydro has direct control over, and therefore warrants consideration. RCIA's view is that, all else equal, realizing value through asset management leads to increases in expected average service lives. RCIA notes that Mr. Kennedy "does not conceptually disagree" with the notion that "utilities that utilize asset maintenance program should have assets that live longer than those utilities that don't," although RCIA also notes that Midgard and Mr. Kennedy also appear to agree that good asset management practice means that asset lives increase in some cases and decrease in others.[833]

In reply, BC Hydro submits that RCIA's "selective quotes from Mr. Kennedy" are misleading. BC Hydro submits that Mr. Kennedy's evidence was that the connection between asset management practices and average service lives "is complex and cannot be reduced to the simple assumption that asset management will always increase the lives of assets." As an example, BC Hydro cites Mr. Kennedy:[834]

> Yeah. No, and the point is the asset management programs or maintenance programs do influence the life of the physical asset. Sometimes they're longer, sometimes they're shorter. I would say now most of the peers that we compare to also do asset management programs. Some do them bigger programs, some smaller. But the point of this paragraph was you've got to consider more than just that. Because that tends to give you a longer -- like, asset management programs tend to lead to the engineering life or the maximum expected life. And so you've got to take the other factors or causes of retirement into account as well.

BC Hydro further submits that the underlying theory of Midgard's evidence is flawed and should not be accepted. BC Hydro notes that its overall depreciation expense is in fact reduced due to Concentric's Depreciation Study, as a result of increasing the average service lives of 52 asset classes and decreasing them for 45 asset classes. BC Hydro submits there is no reasonable basis on which one could expect that its asset service lives should be longer that what Concentric has recommended based solely on the existence of asset management practices.[835]

In response to BC Hydro's comments regarding "errors" that Mr. Kennedy attributes to Midgard's evidence, RCIA provides an example from Midgard of Mr. Kennedy's misunderstanding of Midgard's evidence.[836]

RCIA submits that BC Hydro's argument regarding Midgard not following the "preferred methodology" and "accepted depreciation practices" is specious because Midgard follows "reasonable practices for the core of its analysis given the constraints it faces without access [to] the same BC Hydro data and BC Hydro operational personnel as Concentric." RCIA explains that Midgard performed its own "reasonableness check" on the output of Concentric's analysis, which includes the actuarial analysis and operational interviews with BC Hydro's experts, which RCIA notes is the same process Mr. Kennedy follows.[837]

RCIA submits that Midgard's use of peer comparators to recommend revised average service lives is "not inappropriate" because their use was limited to Concentric results that Midgard had already identified as unreasonable "outliers."[838]

[833] RCIA Final Argument, pp. 15–16.
[834] BC Hydro Reply Argument, p. 131.
[835] BC Hydro Reply Argument, p. 133.
[836] RCIA Final Argument, p. 18.
[837] RCIA Final Argument, p. 20.
[838] RCIA Final Argument, p. 20.

RCIA further submits that Midgard's use of five transmission and distribution utilities is appropriate because they are major Canadian utilities, and have "considerable transmission and distribution assets" and have depreciation data in the public domain. RCIA adds that using the average of the data from the five peers has the benefits of "addressing outliers and moderating the influence of any single reference point." As a result, RCIA submits that Midgard avoided the bias that potentially arises from focusing on any single utility, single asset, or single input parameter, an approach also recommended by Mr. Kennedy.[839]

In reply, BC Hydro submits that Midgard's method of determining depreciation rates through an average of peers is flawed and should be given no weight. BC Hydro submits that Mr. Oakland and Mr. Helland "do not have the expertise to make informed recommendations in the area in which they are making recommendations – determining the average service lives for depreciation purposes." BC Hydro adds that it is not appropriate to compare the average service lives of BC Hydro's asset classes with the asset classes of peer utilities without understanding the content of the accounts being compared.[840]

Panel Determination

The Panel does not accept RCIA's proposed methodology for determining average service lives.

First, the Panel does not accept RCIA's theory that BC Hydro's asset management capabilities can demonstrate that its depreciation expense is inappropriate. Given his expertise in depreciation studies, we give more weight to Mr. Kennedy's opinion that the connection between asset management and average service lives for depreciation purposes is "complex and cannot be reduced to the simple assumption that asset management will always increase the lives of assets."

Second, the Panel rejects RCIA's alternative proposal to set average service lives based on a simple average of the respective values of five peers. While the Panel supports the examination of comparable data from peers beyond the limited number used by Concentric, the peers chosen by RCIA may have very different characteristics to BC Hydro.

The Panel will consider the comparable average service lives from the alternative peers proposed by RCIA when we examine the evidence for specific asset classes in Section 4.6.5 below, but only from the perspective of testing Concentric's proposals for reasonableness.

4.6.2 Adoption of Revised Positive Salvage Percentages

BC Hydro is seeking approval to update the positive salvage percentages as recommended by Concentric. Positive salvage percentages primarily relate to the retirement of fleet vehicles and represent the residual value of the vehicles upon retirement.

Of the 329 BC Hydro asset classes, 22 utilize positive salvage percentages. Concentric recommended a decrease to the positive salvage percentages for 19 asset classes, an increase to one asset class and no change to two asset classes. BC Hydro states Concentric's recommended revised useful lives and positive salvage percentages for vehicles result in a reduction in the losses expected on the disposal of vehicles totalling $1.3 million in F2023, $1.4 million in F2024 and $1.0 million in F2025.[841]

[839] RCIA Final Argument, pp. 21–22.
[840] BC Hydro Reply Argument, pp. 133–134.
[841] Exhibit B-2, Section 8.3.1.3, p. 8-12.

Position of the Parties

BC Hydro submits that the BCUC should approve Concentric's recommendations regarding the adoption of positive salvage percentages as set out in the Depreciation Study.[842]

No interveners oppose BC Hydro's request.

Panel Determination

The Panel approves the positive salvage percentages as set out in the Depreciation Study.

The Panel accepts Concentric's unchallenged recommended changes to the positive salvage percentages of BC Hydro's assets. The Panel recognizes Mr. Kennedy's experience in developing depreciation studies, and notes that interveners have had opportunities to test his evidence through information requests and during cross-examination.

4.6.3 Adoption of Changes to the Vehicle Asset Classes

BC Hydro is planning to implement new vehicle asset classes in 2022 to better align the asset class structure for vehicle assets with the management of the vehicle assets. The new asset classes will capture new additions and the existing vehicle assets will be transferred from the old vehicle asset classes to the new vehicle asset classes by the end of F2023.[843]

As part of the Depreciation Study, Concentric found that there is a misalignment between BC Hydro's vehicle asset classes and the management of the vehicle assets. As a result of this misalignment, non-homogenous vehicle classes were being grouped together. This led to losses on retirement as vehicles were retired before the expected end of life or with a lower than expected proceeds from disposition. As a result, Concentric recommends BC Hydro to adopt a new account structure which better aligns the vehicle asset classes to the management of those vehicle assets. In its recommendation, Concentric includes the average service life recommendations for the new vehicle asset classes as well as revised average service life recommendations for the existing vehicle asset classes to be used during the transition to the new vehicle asset classes.[844]

BC Hydro clarified that the new vehicle asset classes recommended by Concentric will be created as part of implementing the recommendations from the Depreciation Study in the SAP system. The transfer of existing vehicle assets to the new vehicle asset classes cannot be completed in 2022 due to the high volume of vehicle assets tracked by BC Hydro. BC Hydro expects to complete the asset transfers in F2023 to allow time to review all vehicle-related assets to ensure proper alignment with the new asset classes.[845]

BC Hydro states the revised average service life recommendations for the existing vehicle asset classes to be used during the transition will result in immaterial differences as compared to if all existing vehicle assets are transferred to the new asset classes in 2022.[846]

Position of the Parties

BC Hydro submits that the BCUC should approve Concentric's recommendations regarding the adoption of changes to vehicle asset classes as set out in the Depreciation Study.[847]

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[842] BC Hydro Final Argument, p. 146.
[843] Exhibit B-2, Section 8.3.1.4, pp. 8-12 – 8-14.
[844] Exhibit B-2-1. Appendix T, pp. 14 – 16.
[845] Exhibit B-7, BCUC IR 104.1.
[846] Exhibit B-7, BCUC IR 104.2.
[847] BC Hydro Final Argument, p. 146.

No interveners opposed BC Hydro's request.

Panel Determination

The Panel approves the adoption of changes to vehicle asset classes as set out in the Depreciation Study.

The Panel accepts Concentric's unchallenged recommendations. The Panel recognizes Mr. Kennedy's experience in developing depreciation studies, and notes that interveners have had opportunities to test his evidence through information requests and during cross-examination.

4.6.4 Creation of a New Asset Class for EV Charging Station Assets

BC Hydro proposes to create a new EV charging station asset class and adopt the average service life as recommended by Concentric. BC Hydro acknowledges that Directive 25 in BCUC Decision and Order G-187-21 on BC Hydro's 2022 RRA denied the depreciation rates for BC Hydro's EV charging stations and recommended that the depreciation rates be reviewed in the BC Hydro Public EVFast Charging Rate Application proceeding. BC Hydro submits that it is appropriate for the BCUC to consider the depreciation rate for EV charging stations in this proceeding, with the benefit of Concentric's expert evidence and recommended depreciation rate for this asset class.[848]

Concentric states these assets are highly technological in nature and are subject to the fast-paced nature of retirements common in technological accounts. As many of the forces of retirements anticipated in this account are related to the pace of change of technology, it is important that this account have a short average service life. There are few peer utilities in Canada with approved lives for EV charging stations; however, Concentric has carried out discussions with personnel at many utilities across Canada in anticipation of upcoming technological changes. In Concentric's view, EV charging station assets are expected to live approximately 5 to 10 years. As such, Concentric recommends an average service life of 7 years to represent the future expectations for the investment in this account.[849]

Concentric clarified that the installation of EV charging stations started approximately 10 years ago which were made by nonregulated private companies. As such, early generation EV charging stations did not have public depreciation rates. There is also limited studies on the average service life of these assets in the public domain. The determination of a reasonable range of 5 to 10 years for EV charging station assets was based on discussions with the BC Hydro staff that are co-ordinating the EV charging project, discussions with the Concentric Future of Energy practice area, review of publicly available information produced by two of the large EV charging station suppliers - ABB and ChargePoint, and attendance at a number of Energy Transitions conferences and industry events. 7 years represented a reasonable expectation near the mid point of the reasonable range.[850]

Based on the relative new nature of EV charging stations, BC Hydro states it is reasonable to revisit the EV Charging Station asset class in the next RRA. Based on input from Concentric and BC Hydro's experience in the intervening years, BC Hydro will submit a revised useful life in the next revenue requirements application if applicable.[851]

As part of the BCUC decision accompanying Order G-18-22, the BCUC directed BC Hydro to file a new application for a permanent EV fast charging rate by no later than December 31, 2022.[852] As part of the new application, the BCUC also directed BC Hydro to propose depreciation rates for the EV charging stations.[853]

[848] Exhibit B-2, Section 8.3.1.2.1, pp. 8-10 – 8-11.
[849] Exhibit B-2-1, Appendix T, p. 24.
[850] Exhibit B-7, BCUC IRs 103.17 and 103.19.
[851] Exhibit B-7, BCUC IR 103.21.
[852] BC Hydro Public EV Fast Charging Rate Application Decision to Order G-18-22, Section 3.8, p. 35.
[853] BC Hydro Public EV Fast Charging Rate Application Decision to Order G-18-22, Section 4.6, p. 51.

BC Hydro states the approval of the average service life for the EV charging station asset class in this proceeding will not impact the BCUC's ability to confirm, deny or alter the depreciation rates proposed in the permanent EV fast charging rate application. BC Hydro notes that it does not expect to change the useful life request in its permanent EV rate application, as it considers the average service life based on the Depreciation Study conducted by Concentric reflects the appropriate life for the asset class. In the event that there was a difference in the Test Period (whether higher or lower), BC Hydro considers that such a difference would not be in scope for deferral to EV Costs Regulatory Account or any other existing regulatory account. If BCUC does not direct that any such difference could be deferred to a regulatory account, the difference would be to the account of the shareholder, all else equal.[854]

Position of the Parties

BC Hydro submits that the BCUC should approve Concentric's recommendation to create a new asset class for Electric Vehicle charging station assets and Concentric's recommended average service life.[855]

No interveners opposed BC Hydro's request.

Panel Determination

The Panel approves the creation of a new asset class for EV charging station assets and the average service life, as recommended by Concentric..

The Panel accepts Concentric's unchallenged recommendations. The Panel recognizes Mr. Kennedy's experience in developing depreciation studies, and notes that interveners have had opportunities to test his evidence through information requests and during cross-examination.

4.6.5 Contested Average Service Life Recommendations

AMPC, the CEC and RCIA submitted average service life recommendations for select asset classes as part of their final arguments.[856]

Below is the Panel's consideration for each of the average service life recommendations that contests against Concentric's recommendations.

4.6.5.1 Towers (C25203)

Table 44: Towers (C25203)

Asset Class	Asset Class Description	Net Book Value (NBV) as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C25203	Tower, Lattice / Asthetic	$1,317,407,653	65	65	AMPC: 75 RCIA: 75

[854] Exhibit B-19, BCUC IR 142.1.
[855] BC Hydro Final Argument, p. 146.
[856] AMPC Final Argument, Chapter 5, pp. 5-22 – 5-40; CEC Final Argument, Section I, p. 8; RCIA Final Argument, Section 4.7, Table 3, pp. 30 – 31.

Concentric does not recommend average service life changes to Account C25203.[857] As part of Concentric's peer analysis, Concentric considered FBC at 50 years, NALCOR at 65 years, New Brunswick Power at 65 years and Manitoba Hydro at 85 years.[858]

Concentric states the "best life/dispersion" Iowa curve for this account is 61-R5, with a residual measure of 0.1473. The residual measure for the existing and currently recommended 65-R3 Iowa curve is 0.4662.[859]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that this asset class includes both steel poles and steel lattice structures. Steel poles should have a similar life to steel towers. There have been standard changes in the last decade to a more reliability based standard, and the size of the structures has increased to meet these new standards. All towers are hot dipped galvanization and galvanized paint can be applied if the galvanization coating wears off. A tower is targeted to live about 100 years. There is a structural corrosion program, and BC Hydro can replace a piece of the tower if it is corroded without having to the replace the entire tower. Major program retirements are typically driven by line moves or because the line is no longer needed, or the size needs to be upgraded/downgraded. Steel towers are generally on steel foundations. The most common foundation is a steel lattice. Foundations need to be removed at the same time as the tower. The removal of the foundation is as much work/cost as the removal of the rest of the tower. The tower is generally dismantled on site.[860]

Mr. Bowman states that the 65-year life was established in the 2005 study, when the account was adjusted from 50 years to 65 years, which is a significant change at one time. Also, in the 2005 study, there was no retirement rate analysis performed. As part of the 2010 componentization review, corrosion protection was moved to a shorter-lived category (C25205) which is amortized over 30 years and is currently proposed to be adjusted to 25 years. At the time of the 2010 componentization review, BC Hydro also produced an internal review of asset lives recommending account C25203 be changed to 75 years based on:[861]

> Implemented a new program to apply a coating to towers. Planning to implement cathodic protection (prevents/slows future rusting) around bases of towers to protect the steel in the ground. New actuals data that wasn't previously available. 75-year average life makes sense based on BCTC [BC Transmission Corporation] experience and new protection programs.

Mr. Bowman states the current operational interview suggests a longer life than 65 years.[862]

Mr. Bowman states Concentric only uses two published peers for this asset class including NALCOR which uses 65 years and FBC which uses 50 years. However, FBC is not directly analogous to BC Hydro as it includes shorter lived components such as wooden poles and fixtures, and does not appear to have been tested in any detail in a regulatory review. Moreover, the analysis Concentric provided in response to first round IRs fails to reflect the two other peers Concentric only provided in the second round of interrogatories including New Brunswick Power which uses 65 years, as well as Manitoba Hydro which uses 85 years.[863]

Mr. Bowman states Concentric's peer analysis excludes several relevant comparators including Altalink which uses 70 years for towers constructed to modern standards, ATCO Electric which uses 67 years for the same assets while being less componentized than BC Hydro and Hydro One which uses 90 years for both steel towers and steel poles and 80 years for composite poles. For ATCO Electric, the effect of a less componentized utility is

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857 Exhibit B-2-1, Appendix T, Table 1 p. 29.
858 Exhibit B-8, AMPC IR 21.1, Attachment 1; Exhibit B-20, AMPC IRs 13.1 and 13.2, Attachment 2.
859 Exhibit B-8, AMPC IR 27.1.
860 Exhibit B-8, AMPC IR 23.1, Attachment 1, pp. 31 – 32.
861 Exhibit C7-11. Section 2.3.1.1, p. 17.
862 Exhibit C7-11, Section 2.3.1.1, pp. 17 – 18.
863 Exhibit C7-11, Section 2.3.1.1, p. 18.

that more short-lived components will be mixed with the main asset. As such, one should expect a longer average life for BC Hydro's assets given the shorter components are tracked separately. For Hydro One, its depreciation study was prepared by Foster Associates which offers a true independent peer analysis.[864]

Mr. Bowman states the retirement data for this account is not significant as this is a mass asset account which does not record the actual retirement of individual assets. Instead, consideration was given to some of the oldest remaining assets which, including the 500 kV Towers from Shrum to Williston approaching the average service life within 9 years, have no information about major pending retirements or replacements.[865]

Based on the above points, Mr. Bowman states that the 65 years adopted for this asset class is excessively short. Instead, Account C25203 Towers should face a life extension to 75 years with monitoring for possible further extensions in future studies.[866]

During the oral hearing, Mr. Bowman testified that half of the investment in this account is new representing the Interior to Lower Mainland line and the Northwest transmission line.[867]

Concentric states throughout the depreciation study process, it routinely discusses tower overhaul programs with client subject matter experts and has a strong understanding of industry wide operating practices regarding corrosion protection of transmission towers.[868]

Mr. Kennedy states that Mr. Bowman seems to blindly accept the longer average service lives within the peer group as being directly comparable, whereas he is finding reasons to dismiss the shorter life estimates. For example, although FBC does include several shorter life assets which would have a shortening influence on the overall average service life, the shorter life assets are a much lower cost and therefore the retirement of these ancillary assets result in small retirement ratios within the observed life table, and therefore have a lesser impact than Mr. Bowman ascribes. In recognition of this broader group of assets within the related FBC account, Mr. Kennedy finds that the 15-year difference between his recommendation in the FBC study and in this BC Hydro study for this account to be reasonable. However, it is not reasonable to assume that the earlier retirement of these less costly assets would drive a 25-year difference as suggested by Mr. Bowman.[869]

Mr. Kennedy states that Mr. Bowman did not undertake an analysis of the differing circumstances for the peer group that had longer average service life estimates. Rather Mr. Bowman blindly accepted the estimates and considers them as relevant. Mr. Kennedy provides the following summary of the differing circumstances:[870]

1. The AltaLink, Manitoba Hydro and Hydro One systems are subject to environmental conditions that are less corrosive than the humid salt air environment that some of BC Hydro's system transverses.
2. The 70-year average service for the AltaLink and ATCO Towers are largely driven by the Alberta ISO 502.2 construction standard for transmission lines constructed after 2012. The new standards require a significantly enhanced design and fail tolerance standard and are anticipated to have a longer end of life characteristic.
3. The 90 year average service life of Hydro One referenced by Mr. Bowman is inaccurate and is not the most current depreciation study completed for Hydro One. An updated depreciation study was completed by Alliance Consulting in April 2021 which recommended a continuation of the existing average service life of 75 years with a slight change top the Iowa curve. As such, the true comparison

864 Exhibit C7-11, Section 2.3.1.1, p. 18.
865 Exhibit C7-11, Section 2.3.1.1, p. 19.
866 Exhibit C7-11, Section 2.3.1.1, p. 19.
867 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 417, lines 11 – 14.
868 Exhibit B-20, AMPC IR 12.3.
869 Exhibit B-36, Appendix A, Section III, A20, p. 22.
870 Exhibit B-36, Appendix A, Section III, A20, pp. 22 – 25.

point is the variance between the 75-year depreciation life used by Hydro One and the 65-year life recommended by Concentric for BC Hydro.

4. The engineering end life of Hydro One's transmission towers is longer than the depreciable life due to forces of retirement other than the pure end of physical life. The average service lives related to the Hydro One's transmission towers were also based on a very limited retirement experience band and included review of only one peer 10-year old study from the province of Ontario and did not consider any non-Ontario electric transmission systems. As such, the Hydro One depreciation study was based on a more limited amount of data to support the professional judgement than Concentric in the case of the BC Hydro review of steel towers. Mr. Kennedy views that given the lack of peer analysis, the limited amount of actuarial data, and the fact that Hydro One towers are depreciated within a group of shorter life assets, a 10-year difference in the depreciable life between the Ontario and BC towers is reasonable.

During the oral hearing, Mr. Bowman clarified that he did not rely on the most recent depreciation report for Hydro One, and that the subject matter experts estimated the steel towers at Hydro One to have an operational life of 90 years while a 75-year life is used for depreciation purposes.[871]

BC Hydro states the mean life for this account is between 65 years and 150 years depending on the structure type.[872] Mr. Kumar testified that BC Hydro has power painting and corrosion protection on transmission towers, and that "our mean asset lives are actually over 100 years for transmission towers because they're absolutely critical for us to manage." [873]

Mr. Oakley testified utilities commonly retrofit existing towers that are 100 years old. Utilities would not put in that investment if they thought the towers are going to be retired.[874]

Midgard recommends an average service life of 65 years based on peer utilities including Hydro One which uses 90 years, Manitoba Hydro which uses 50 years and NPI which uses 50 years.[875]

Mr. Kennedy states that the Midgard recommendations are unreasonably biased to a maximum life based purely on physical end of life factors as compared to an average service life determination to be used for the determination of a regulated depreciation expense. Additionally, the peer lives used in the Midgard analysis are based primarily on two peers, being the 2010 Kinectrics report and the 2021 Hydro One depreciation study. Neither of these peers add significant additional information as the Hydro One average service life analysis was conducted on a similarly short historic experience band for the same reasons that Concentric was required to use a short experience band, and furthermore relied on only one peer, being the 2010 Kinectrics report. The Alectra study relied on the same 10-year-old Kinectrics report in support of their depreciation. Therefore, these two peers were predominantly influenced by the same 10-year-old report.[876]

Mr. Kennedy states the Midgard report is at best providing limited information relating to the maximum life of the assets, which provides only limited benefit in the review of average service life estimates.[877]

[871] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 470 line 3 to p. 471 line 22.
[872] Exhibit B-44, BC Hydro Undertaking No. 13, p. 2.
[873] 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 903 lines 4 – 13.
[874] 2022-09-21 Oral Hearing Transcript Volume 3 AM, p. 602 line 11 to p. 603 line 2.
[875] Exhibit C8-7, P0589-D008-MDL-R01-EXT - (Evidence) Depreciation Lives Information.xlsx, 'Comparison Analysis' tab; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 24.
[876] Exhibit B-36, Appendix A, Section IV, A43, p. 49.
[877] Exhibit B-36, Appendix A, Section IV, A43, p. 49.

Positions of the Parties

BC Hydro submits that the 90 years referenced by Mr. Bowman is in fact the Project Engineering Life of the steel transmission towers, which is more akin to a maximum life rather than the average. While Mr. Bowman conceded that Hydro One depreciates its steel towers over 75 years and acknowledges that the 90-year life comes from the subject matter experts (as opposed to the depreciation expert), he appears to maintain that the 90-year P-Life is equivalent to an average service life. BC Hydro submits that Mr. Kennedy's evidence must be preferred in this instance.[878]

AMPC submits that Mr. Kennedy's rebuttal evidence does not take issue with four of the five pillars grounding Mr. Bowman's evidence. Instead, he only challenges Mr. Bowman's peer analysis even though it was only one of five pieces of information that led to his conclusion. Thus, the remainder of Mr. Bowman's commentary on this issue is uncontroverted and should be accepted and given weight.[879]

AMPC submits that Mr. Kennedy's peer analysis rebuttal falls short. Mr. Kennedy goes outside his expertise as no subject matter expert has confirmed his statement that the environmental conditions for AltaLink and ATCO are less corrosive than the conditions for BC Hydro. There is no evidence that these factors are material to the life of BC Hydro's towers, as they are constructed and maintained. The operational interviews describe a "structural corrosion program" and the "ability to replace a part of the tower if it is corroded without having to replace the entire tower," yet Mr. Kennedy does not explain how these factors could offset this concern. Lastly, there is no discussion as to whether BC Hydro constructs its towers differently (i.e. in more resilient ways) in areas where environmental factors may affect their lives.[880]

AMPC submits that Mr. Kennedy does not explain how much of BC Hydro's system would even be impacted by high humidity coastal air. Most of BC Hydro's large generation assets are in the eastern and northern portion of the province, and its large transmission lines connecting this generation largely flow through the province outside of coast environments. The evidence does not support that Mr. Kennedy's coastal air factor would in fact be material to BC Hydro's overall transmission system investment, even if it were a relevant factor distinguishing BC Hydro from peers.[881]

BC Hydro submits that AMPC's arguments that Mr. Kennedy is opining on matters outside his expertise is without merit. Mr. Kennedy's expertise on depreciation includes the impacts of factors such as the climate on the average service lives of assets. As noted in the IR responses, Concentric routinely discusses tower overhaul programs with client subject matter experts and has a strong understanding of industry wide operating practices regarding corrosion protection of transmission towers. Mr. Kennedy is therefore well placed to understand the impact of these practices on average service lives and make well-informed decisions when comparing to peers.[882]

AMPC submits while Mr. Kennedy highlights that AltaLink and ATCO Electric have constructed many new transmission towers since 2012 to a new ISO construction standard, Mr. Kennedy does not relate this information to the "new program" that BC Hydro's operational interviews from 2010 indicated had been implemented, which led BC Hydro's subject matter experts to recommend a 75-year life at that time, nor to the 100 year lives now recommended by operational staff.[883]

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[878] BC Hydro Final Argument, Part 8(C), p. 150.
[879] AMPC Final Argument, Chapter 5, p. 5-23.
[880] AMPC Final Argument, Chapter 5, pp. 5-23 – 5-24.
[881] AMPC Final Argument, Chapter 5, p. 5-24.
[882] BC Hydro Reply Argument, Part 8.F(a), pp. 105 – 106.
[883] AMPC Final Argument, Chapter 5, p. 5-24.

AMPC submits Mr. Bowman never said that Hydro One depreciates steel towers on a 90-year life, nor has he recommended a 90-year life here. Mr. Bowman's evidence was that Hydro One adopts a 90-year life for both steel towers and steel poles, as indicated in regulatory filings before the Ontario Energy Board (and 80 years for composite poles).[884]

AMPC submits Mr. Bowman did not rely on the Hydro One's more recent depreciation study put to him on cross examination, but instead on the Foster Associate's report from two years prior which showed how these different assets were hybridized.[885]

BC Hydro submits that the study put to Mr. Bowman was more recent and discussed the current and proposed average service life for Towers, which is 75 years which is in contrast to Mr. Bowman's evidence and opening statement that Hydro One uses a life of 90 years. BC Hydro acknowledges that the reference in BC Hydro's Final Submissions to the meaning of a project engineering life was in error, and should be disregarded. However, the same point is apparent from the fact that the 90 years referenced by Mr. Bowman is the operational life estimated by company subject-matter experts and not the average service life recommended in the depreciation study.[886]

AMPC submits BC Hydro's suggestion that a project engineering life is more akin to a maximum life rather than the average is not supported by the evidence nor was it put to Mr. Bowman. As such, no weight should be attached to that submission. Even if this commentary is given weight, given BC Hydro will apply these average service lives as terminal lives when accounting for depreciation, a longer life closer to expected life is warranted.[887]

In response to AMPC's argument that a longer life is warranted given BC Hydro's accounting practices, BC Hydro submits that its accounting practices should not be used as a reason to distort the average service life of the assets.[888]

In reply to Mr. Bowman's statement that the removal of corrosion protection out of this account would increase the average service life, BC Hydro submits that corrosion protection (C25205) has a balance of only $35 million approximately, compared to approximately $1.4 billion in the Towers account (C25203). The removal of this component would have a correspondingly immaterial impact on the average service life of the Towers account.[889]

In reply to Mr. Bowman's reliance on the comment in the 2010 Depreciation Useful Life Review that a 75-year life makes sense, BC Hydro submits that the 2010 Depreciation Useful Life Review was not a full depreciation study as conducted by Concentric for this proceeding and it was ultimately determined that BC Hydro's average service lives were correctly stated at the time.[890]

In reply to Mr. Bowman's reliance on the operational interviews indicating that a tower is targeted to live about 100 years, BC Hydro submits that Concentric has already explained that the reference to 100 years should be read as a maximum life.[891]

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[884] AMPC Final Argument, Chatper 5, p. 5-26.
[885] AMPC Final Argument, Chapter 5, p. 5-26.
[886] BC Hydro Reply Argument, Part 8.F(a), p. 106.
[887] AMPC Final Argument, Chapter 5. p. 5-27.
[888] BC Hydro Reply Argument, Part 8.F(a), p. 106.
[889] BC Hydro Reply Argument, Part 8.F(a), p. 102.
[890] BC Hydro Reply Argument, Part 8.F(a), p. 102.
[891] BC Hydro Reply Argument, Part 8.F(a), p. 102.

BC Hydro submits that the 500 kV towers from Shrum to Williston, which will be 65 years old in 2035, being in satisfactory condition with no plans to replace them, is consistent with Mr. Kennedy's proposed average service life. An average service life of 65 years does not mean that all towers will fail at 65 years. The Iowa 65-R3 curve, as recommended by Concentric, produces a maximum life of 110 years.[892]

In reply to Mr. Bowman's use of peers, BC Hydro submits that Concentric has responded in its rebuttal evidence.[893]

RCIA submits that the BC Hydro mean life of 150 years for lattice towers and 65 years for aesthetic towers provides an upper bound on average service life for these respective tower types. It is reasonable to expect that the majority of BC Hydro's towers are of lattice type rather than aesthetic type, otherwise aesthetic type would be the default tower type for BC Hydro and not require special mention. Consequently, a 150-year upper bound on average service life is markedly longer than the 65-year average service life that BC Hydro currently uses and which Concentric is recommending. Moreover, the expectation that average service life is longer than 65 years aligns with Mr. Oakley's and Mr. Kumar's testimonies.[894]

As a result of the 150 years mean life of lattice towers, expert testimony regarding the life of towers, and AMPC's evidence, RCIA recommends that Concentric's recommendation to keep the average service life unchanged be rejected and the AMPC recommendation be accepted.[895]

In response to RCIA's submission that it is reasonable to expect the majority of BC Hydro's towers to be of the lattice type rather than aesthetic, BC Hydro submits that there is no evidence to support this assumption, which should be disregarded.[896]

BC Hydro submits that the underlying theory of Midgard's evidence is flawed and should not be accepted for the same reasons as described in the Position of Parties in Section 4.6.1.4.[897]

In response to RCIA applying the mean life data provided by BC Hydro as an upper limit on depreciation rates, BC Hydro submits that this is not a hypothesis that has been reasonably tested in this proceeding, and that there is insufficient evidentiary basis to conclude that BC Hydro's mean life data can be reasonably considered an upper limit on depreciation rates. Furthermore, in its review of various asset accounts, RCIA makes judgements on depreciation rates based on the extent of the difference between the average service life and the mean life. BC Hydro submits that there is insufficient evidentiary basis to draw any meaningful conclusions from the extent of the difference between these two numbers. Messrs. Helland and Oakley do not claim to be experts in depreciation and they are not familiar with BC Hydro's mean life data beyond what was provided in response to Undertaking No. 13. As such, BC Hydro submits that Messrs. Helland and Oakley do not have the expertise and RCIA has not provided a reasonable evidentiary foundation to substantiate its theory that BC Hydro's mean life data is an upper limit on depreciation rates.[898]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C25203, "Tower, Lattice / Aesthetic" should be increased from 65 to 75 years, and not remain unchanged as proposed by Concentric.

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892 BC Hydro Reply Argument, Part 8.F(a), pp. 102 – 103.
893 BC Hydro Reply Argument, Part 8.F(a), p. 103.
894 RCIA Final Argument, Section 4.7.2, pp. 33 – 34.
895 RCIA Final Argument, Section 4.7.2, p. 36.
896 BC Hydro Reply Argument, Part 8.G, p. 137.
897 BC Hydro Reply Argument, Part 8.G, pp. 131 – 133.
898 BC Hydro Reply Argument, Part 8.G, p. 136.

The Panel finds that an average service life of 75 years for towers is reasonable because:

- The Panel finds that the mean life for transmission towers is at least 100 years and may be as long as 150 years. BC Hydro defines the mean life of assets as their "operational life expectancy" based on manufacturer specifications, historical asset class survival based on natural deterioration in the field, and BC Hydro asset management and engineering subject matter expertise.[899] BC Hydro stated in the oral hearing that the mean life is "over 100 years for transmission towers," [900] and confirms in an undertaking that the mean life for "metal support structures" is 65 to 150 years.[901]
- The Panel interprets the term "mean life" as being the anticipated maximum life for assets, rather than an average operational life expectancy.
- There is no evidence that BC Hydro plans to retire these assets earlier than their mean life, for example in Concentric's notes from its interviews with BC Hydro employees;
- Although the average service life implied by the best-fitting Iowa curve would be 61 years, there are almost no retirement data for this asset class, so we cannot draw useful conclusions from this fact;
- The peer data, ranging from FBC's average service life at 50 years to Manitoba Hydro's at 85 years, support the Panel's finding of 75 years. As Concentric has stated, the purpose of peer analysis is to determine the reasonableness of the average service life based on other factors, it is not to derive the average service lives.

We note that in 2010 BC Hydro concluded that "75-year average life makes sense based on BCTC experience and new protection programs". While this conclusion was not from a full depreciation study, BC Hydro provides no reasons in this proceeding why it chose not to adopt its own recommendation in 2010.

BC Hydro notes that the 65-year Iowa curve that Concentric recommends for transmission towers implies a maximum life of 110 years. While we do not know the maximum life that would be implied by a 75-year Iowa curve, BC Hydro states that the mean life of metal support structures is up to 150 years, therefore the maximum 110-year life implied by the 65-year Iowa curve is not a basis to reject a 75-year estimated average service life.

4.6.5.2 Poles > or = 60 kV (C25202)

Table 45: Poles > or = 60 kV (C25202)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C25202	Pole Structures > or = 60 kV	$557,766,440	50	50	AMPC: 60 RCIA: 60

Concentric does not recommend average service life changes to Account C25202.[902] As part of Concentric's peer analysis, Concentric considered FBC at 50 years, NALCOR at 43 years, New Brunswick Power at 60 years and

[899] Exhibit B-44, Undertaking No. 13, pp. 1–2.
[900] 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 903 lines 4 – 13.
[901] Exhibit B-44, BC Hydro Undertaking No. 13, p. 2.
[902] Exhibit B-2-1, Appendix T, Table 1 p. 29.

Manitoba Hydro at 55 years.[903] Concentric's Depreciation Study shows that Account C25202 does not have any retirements recorded until the assets reached a vintage of 42.5 years.[904]

Concentric states the "best life/dispersion" Iowa curve for this account is 56-S5, with a residual measure of 0.0360. The residual measure for the existing and currently recommended 50-R2.5 Iowa curve is 0.8481.[905]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that wooden poles should last 70 years. Most are made of Western Red Cedar and are treated at the base. There is a test and treat program on wood poles – first round at 29 years, then every 8-10 years subsequently. Retirements start to pick up at 50 years, with an expected life of 70 years. There is a large inventory of poles at about 40 – 50 years of age. There is occasional stubbing of poles, but it is more often replaced than stubbed. There has not been a large driver of retirements due to needing increased clearance on the BC Hydro system. There is additional corrosion on costal lines which account for approximately 5 percent of the system. These assets are watched more closely. The notes also state that "poles are rarely moved."[906]

In response to IRs, BC Hydro provided the following table outlining the weighted average life of pole structures:[907]

Table 46: Weighted Average Life of Pole Structures

Asset Class	Description	March 31, 2020 Net Book Value ($)	% of total Net Book Value	Proposed Life	Weighted Life
C25202	Pole Structures > or = 60Kv	557,766,440	88.67%	50	44.33
C25204	Pole Structure, Composite >=60kV	7,161,813	1.14%	65	0.74
C25206	Pole Structure Cross Arms > = 60Kv	64,138,713	10.20%	30	3.06
TOTAL		629,066,966			48.13

Mr. Bowman states Account C25202 Poles was extended from 35 years to 50 years in the 2005 study. The retirement data is not of value given this is a mass asset account. Concentric's peer analysis uses equal or shorter lives including 50 years for FBC and 43 years for NALCOR. However, both cases are not comparable to BC Hydro. In the case of FBC, the account includes both longer-lived and shorter-lived assets. More notably, Concentric reports 43 years for NALCOR, but fails to note that the NALCOR account which is set at 43 years is not transmission, but mainly consists of wood poles generally at the distribution level 25 kV and below. It was not until IR No.2 that Concentric clarified that the peer analysis also included Manitoba Hydro which uses 55 years and New Brunswick Power which uses 60 years. Mr. Bowman notes New Brunswick Power also separates out cross-arms from the poles.[908]

Mr. Bowman states BC Hydro's 2010 revisions removed cross-arms from the C25202 Poles account and set these at 30 years (comprising more than 10 percent of the original account), but the C25202 Poles account was not revised upwards at that time. The review of lives in 2010 did recommend that the life be lengthened to 60 years based on the University of Waterloo study and historical data both suggesting a life longer than 50 years.[909]

Although the operational interview notes suggest a longer life, Mr. Bowman states Concentric's decision to propose a 50-year average life for C25202 Poles based on a "high" weighting to the operational interviews

[903] Exhibit B-8, AMPC IR 1.21.1, Attachment 1; Exhibit B-20, AMPC IRs 2.13.1 and 2.13.2, Attachment 2.
[904] Exhibit B-2-1, Appendix T, pp. 175 – 176.
[905] Exhibit B-8, AMPC IR 27.1.
[906] Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 31.
[907] Exhibit B-20, AMPC IR 18.2.
[908] Exhibit C7-11, Section 2.3.1.2, pp. 19 – 20.
[909] Exhibit C7-11, Section 2.3.1.2, p. 20.

appears to contradict that recommendation. Mr. Bowman states this may be a confusion on the part of Concentric in that the request by AMPC to explain retaining the 50-year life for high voltage transmission poles cites the response to AMPC IR 23.1 Attachment 1 page 10, which is in fact a discussion of low voltage distribution poles. The very same document cites the expected life for transmission poles C25202 at 70 years.[910]

Based on the above, Mr. Bowman states that retaining 50 years for the average service life of Account C25202 is not justified. At minimum, the account average life should be adjusted to 60 years, with further monitoring if the 70-year life supported by operations staff can be accommodated in a future depreciation study.[911]

Concentric explains that the University of Waterloo study was a research paper prepared in 2005 which presented a probabilistic approach to minimize the life-cycle cost of inspection and refurbishment of engineering components in large infrastructure systems. The model presented provides a statistical determination of an estimated End-of-Life (EOL) for a group of physical assets. However, it is important to note that the EOL determination as presented in the Waterloo Study is comparable to a maximum life determination in a typical retirement rate analysis prepared for depreciation studies, rather than an average life estimate. The Waterloo Study provides only one of the multiple forces of retirement that wood poles are subjected to, as it determined only the EOL based on physical deterioration and did not consider other causes of retirement.[912]

Mr. Kennedy states that the operational comments were reflective of a maximum life indication as opposed to an average service life estimate. Wooden poles are subject to a variety of forces of retirement and are often replaced prior to the expiration of the maximum physical life. Additionally, the referenced University of Waterloo study projects a maximum life for poles. The estimates of maximum life will always be longer than estimates of average service life, and such would only be comparable to the very tail end of an Iowa survivor curve.[913]

Mr. Kennedy states the Concentric average service life estimate recommendation of 50 years compares well to the Manitoba Hydro average service life estimate of 55 years, given the differences in the operating environment between Manitoba and BC. Based on discussions with northern Canadian electric utilities, the colder and longer winter season in Manitoba tends to lead to slightly longer average life for wooden poles, which also verifies the slightly longer life for wooden poles as compared to the Concentric estimate for BC Hydro.[914]

Midgard recommends an average service life of 50 years based on peer utilities including Hydro One which uses 50 years, Alectra which uses 50 years, Manitoba Hydro which uses 55 years, ATCO which uses 45 years, and NPI which uses 52 years.[915]

BC Hydro states that the mean life for this account is between 70 years and 80 years depending on the geological area.[916]

Mr. Kennedy states that the Midgard recommendations are unreasonably biased to a maximum life as explained in Section 4.6.5.1 of this Decision.[917]

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[910] Exhibit C7-11, Section 2.3.1.2, pp. 20 – 21.
[911] Exhibit C7-11, Section 2.3.1.2, p. 21.
[912] Exhibit B-20, AMPC IR 18.5.
[913] Exhibit B-36, Appendix A, Section III, A21, p. 25.
[914] Exhibit B-36, Appendix A, Section III, A21, pp. 25 – 26.
[915] Exhibit C8-7, P0589-D008-MDL-R01-EXT - (Evidence) Depreciation Lives Information.xlsx, 'Comparison Analysis' tab; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 24.
[916] Exhibit B-44, BC Hydro Undertaking No. 13, p. 2.
[917] Exhibit B-36, Appendix A, Section IV, A43, p. 49.

Positions of the Parties

AMPC submits that the evidence from operational interviews for BC Hydro's 2010 study and BC Hydro's current study and the peer data support a longer life than 50 years. Although Mr. Kennedy indicated that the University of Waterloo study and the 70-year lives identified by operational staff reflect maximum lives, the same concerns with how BC Hydro applies these averages raised previously as end of life apply here to support a longer life. Moreover, Mr. Kennedy provides no explanation as to how he turns a 70-year maximum life into a 50 year average life, particularly when BC Hydro's own staff suggest the uptick in retirements occurs after year 50, suggesting that the bulk of retirements happen between year 50 and year 70.[918]

In reply to AMPC's criticism of Mr. Kennedy's interpretation of the University of Waterloo study, BC Hydro submits that Concentric has provided commentary on this study in response to IRs which indicate that the EOL determination as presented in the Waterloo Study is comparable to a maximum life determination in a typical retirement rate analysis prepared for depreciation studies, rather than an average life estimate. As such, Mr. Kennedy's interpretation should be accepted.[919]

In reply to AMPC's comment that Mr. Kennedy provides no explanation as to how he turns a 70-year maximum life into a 50 year average, BC Hydro submits that Concentric has explained that the depreciable lives for all listed assets are inclusive of all forces of retirement. The maximum physical life is considered in the selection of the depreciable life through the use of the Iowa curve; however, it is expected that the average service life would be significantly shorter than this maximum life.[920]

AMPC submits that Mr. Kennedy provides no evidence or support for what effect the longer winter season would have on the lives of poles, nor does he also adjust for the fact that Manitoba Hydro includes cross-arms in this account. Mr. Kennedy also fails to explain why he did not refer to the 60-year life used by another of his chosen peer comparators, New Brunswick Power, even though those poles should also be exposed to salt water marine air and a more temperate climate.[921]

In reply to AMPC's reference to cross-arms being included in Manitoba Hydro's account, BC Hydro submits that the removal of small components of an account are unlikely to have any material impact, just as it did not to BC Hydro's account. BC Hydro also notes that Concentric does not use peers to select the average service lives, but as a band against which to check the reasonableness of its analysis.[922]

BC Hydro submits that Mr. Kennedy's proposed average service life of 50 years should be approved. BC Hydro's analysis of these accounts, in response to AMPC's IRs, shows why the removal of cross arms has no material impact on the average service life of 50 years. Moreover, the 2010 Depreciation Useful Life Review was not a full depreciation study as conducted by Concentric for this proceeding, and it was ultimately determined that BC Hydro's average service lives were correctly stated at the time.[923]

In reply to Mr. Bowman's interpretation of the operational interviews, BC Hydro submits that Mr. Bowman mistakes maximum lives for average lives. Mr. Bowman also does not recognize the key quote from the operational interviews which is that: "Retirements start to pick up at 50 years [...] There is a large inventory of poles at about 40 – 50 years of age." This is consistent with Mr. Kennedy's recommended 50- year life.[924]

918 AMPC Final Argument, Chapter 5, p. 5-28.
919 BC Hydro Reply Argument, Part 8.F(b), pp. 108 – 109.
920 BC Hydro Reply Argument, Part 8.F(b), p. 109.
921 AMPC Final Argument, Chapter 5, pp. 5-28 – 5-29.
922 BC Hydro Reply Argument, Part 8.F(b), p. 109.
923 BC Hydro Reply Argument, Part 8.F(b), pp. 106 – 107.
924 BC Hydro Reply Argument, Part 8.F(b), pp. 107 – 108.

RCIA submits that a 20-year difference represents a material difference between the BC Hydro mean life and Concentric's recommended average service life. This determination is supported by AMPC's recommendation of a 60-year average service life. As a result, RCIA recommends that Concentric's recommendation to keep the average service life unchanged be rejected and the AMPC recommendation of 60 years be accepted.[925]

BC Hydro submits that the underlying theory of Midgard's evidence is flawed and should not be accepted for the same reasons as described in the Position of Parties in Section 4.6.1.4 of this Decision.[926]

In response to RCIA applying the mean life data provided by BC Hydro as an upper limit on depreciation rates, BC Hydro submits that this is not a hypothesis that has been reasonably tested in this proceeding, and that there is insufficient evidentiary basis to conclude that BC Hydro's mean life data can be reasonably considered an upper limit on depreciation rates as described in Section 4.6.5.1 of this Decision. [927]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C25202, "Pole Structures > or = 60Kv" should remain at 50 years, as proposed by Concentric.

The Panel finds that an average service life of 50 years for poles > or = 60 kV is reasonable because:

- The Panel finds that the mean life for poles > or = 60 kV is between 70 and 80 years. Concentric's notes from interviews with BC Hydro state that wood poles "should last about 70 years," and that retirements "start to pick up at 50 years, with an expected life of 70 years." BC Hydro confirms in an undertaking that the mean life for transmission wood pole structures is 70 – 80 years.
- The Iowa curve for poles > or = 60 kV proposed by Concentric, which uses an estimated average service life of 50 years, implies a maximum life for these assets of almost 90 years[928], while the mean life of BC Hydro's poles is no more than 80 years. Increasing the average service life of the assets from 50 to 60 years, as proposed by AMPC and RCIA, would imply a maximum life even further removed from the mean life of up to 80 years supported by the evidence in this proceeding.
- The peer data, ranging from FBC at 50 years to Alectra at 70 years, do not raise concerns that the proposed figure of 50 years for BC Hydro is extraordinary. The Panel does not take into consideration the figure of 43 years for NALCOR because that figure does not include transmission poles, although it would not change the analysis in any case because the proposed figure of 50 years for BC Hydro is still within the range of peer comparators with or without the 43-year figure from NALCOR.

As noted in Section 4.6.1.2.3 above, the Panel gives low weight to the peer comparators, and does not consider them appropriate for setting average service lives. Rather, as Concentric notes, peer comparators may be used to determine the reasonableness of an average service life based on other factors. Therefore, we decline to consider AMPC's and RCIA's proposed average service life of 60 years based on peer comparators without other more compelling evidence.

Although the average service life implied by the best-fitting Iowa curve would be 56 years, there are almost no retirement data for this asset class, so we cannot draw useful conclusions from this fact.

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925 RCIA Final Argument, Section 4.7.1, p. 33.
926 BC Hydro Reply Argument, Part 8.G, pp. 131 – 133.
927 BC Hydro Reply Argument, Part 8.G, p. 136.
928 Exhibit B-2-1, Appendix T, page 174.

4.6.5.3 Overhead Conductors > = 60 kV (C55101)

Table 47: Overhead Conductors > = 60 kV (C55101)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C55101	Conductor, Overhead > or = 60 Kv	$698,260,582	60	55	AMPC: 60 RCIA: 64

Concentric recommends a revised average service life of 55 years for Account C55101 based on the retirement transactions recorded and Concentric's professional judgement.[929] As part of Concentric's peer analysis, Concentric considered FBC at 51 years, NALCOR at 60 and 45 years, New Brunswick Power at 65 years and Manitoba Hydro at 80 years.[930] Concentric's Depreciation Study shows that Account C55101 does not have any retirements recorded until the assets reached a vintage of 44.5 years.[931]

Concentric states the "best life/dispersion" Iowa curve for this account is 53-R5, with a residual measure of 0.3222. The residual measure for the existing 60-R3 Iowa curve is 0.5395 and the residual measure for the recommended 55-R3 Iowa curve is 0.6568.[932] Concentric states even though the residual measure is higher, the Iowa 55-R3 provides a better visual fit to the historical retirements trend of the investment in this account while remaining within the range of peer Canadian electric utilities.[933]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that there is currently a replacement program related to 69 kV copper conductor located primarily in urban areas. This replacement program is on the scale of $2 million to $3 million per year. The life of the conductor should be the same, if not longer, than the poles.[934]

Mr. Bowman states Concentric has put high weighting on operational interviews and medium on the peer analysis. However, the operational interview notes for Account C55101 conductors are exceedingly brief. It is not clear that the reference to being at least as long as poles means specifically the C25202 account (Poles Structures) or also C25203 (Towers) as the >60 kV conductor would be relevant to both types of structures, but in either case provides limited guidelines on the value Concentric ultimately proposes. As to the copper 69 kV replacement program, it is noted that 69 kV makes up less than 10 percent of Account C55101 and the replacement program affects less than $2 million annually of a $750 million account. As such, the program should not be a material driver, if any, to the average life of this account.[935]

Mr. Bowman states the previous study in 2005 increased the life from 50 to 60 years, and the 2010 Review recommended retaining the 60-year life, as there were "No indicators suggesting a life change."[936]

Mr. Bowman states the peers used by Concentric includes NALCOR at 60 and 45 years, FBC at 51 years, New Brunswick Power at 65 years and Manitoba Hydro at 80 years. The citation for NALCOR is not correct as the 45-year reference is for distribution conductor (<25kV) while the transmission conductor is 60 years. The FBC account includes "conductors, circuit breakers, insulating wires, cables and ground wires, and lightning arresters

[929] Exhibit B-2-1, Appendix T, p. 22.
[930] Exhibit B-8, AMPC IR 21.1, Attachment 1; Exhibit B-20, AMPC IRs 13.1 and 13.2, Attachment 2.
[931] Exhibit B-2-1, Appendix T, pp. 435 – 436.
[932] Exhibit B-8, AMPC IR 27.1.
[933] Exhibit B-7, BCUC IR 103.14.
[934] Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 32.
[935] Exhibit C7-11, Section 2.3.1.3, p. 21.
[936] Exhibit C7-11, Section 2.3.1.3, p. 22.

and associated switches" which appear to be included in other, shorter-lived classes in the case of BC Hydro. At best one peer, FBC, has a shorter life but only when including other items such as breakers and switches which BC Hydro puts in their own asset accounts. The remainder of peers are at 60 years or above. The operational interviews noted the life should be as long as poles are recommended for 60 years, but this reference may be reasonably read to include not only poles but also towers, which are recommended at 75 years. Based on this, there appears to be no basis in the evidence for a downward revision in the life of Account C55101 from 60 years to 55 years [937]

Mr. Kennedy states that Mr. Bowman's recommendation is based on the alignment of this account to the life estimate of Account C25202, which he recommends be set at 60 years. Mr. Kennedy states Mr. Bowman's recommended change to Account C25202 is not reasonable, and therefore, the extension to Account C55101's average service life is also not appropriate.[938]

Midgard recommends an average service life of 64 years based on peer utilities including Hydro One which uses 70 years, Alectra which uses 60 years, Manitoba Hydro which uses 65 years, ATCO which uses 65 years and NPI which uses 60 years.[939]

BC Hydro states the mean life for this account is 70 years.[940]

Mr. Oakley testified during the oral hearing that:

> […] from my experience conductors don't fail.
>
> […]
>
> The reason a conductor gets retired is because the structures fall out from under it. So that's why, if you can extend the life of a structure by ten years, you just added ten years to the conductor too. If you can extend the life of the structure … you win twice. You keep the conductor; you keep the structure. Your asset lives of both categories have improved because of your asset management practice.[941]
>
> I mean, the conductors will stay up there forever if you keep the structures in good shape under them. And we think that BC Hydro's doing a good job of keeping their conductors in the air. We'd expect to see it show up as a depreciation item.[942]

Similarly, Mr. Kumar testified that:[943]

> […] you will see that actually we don't have an extensive conductor replacement program because conductors are actually in very good condition, and -- or in fair condition. So, we don't have a proactive replacement of conductors except for copper replacement on our conductors.
>
> […]

[937] Exhibit C7-11, Section 2.3.1.3, p. 22.
[938] Exhibit B-36, Appendix A, Section III, A22, p. 26.
[939] Exhibit C8-7, P0589-D008-MDL-R01-EXT - (Evidence) Depreciation Lives Information.xlsx, 'Comparison Analysis' tab; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 24.
[940] Exhibit B-44, BC Hydro Undertaking No. 13, p. 2.
[941] 2022-09-21 Oral Hearing Transcript Volume 3 AM, p. 528 line 11 to p. 529 line 8.
[942] 2022-09-21 Oral Hearing Transcript Volume 3 AM, p. 546 lines 9 – 14.
[943] 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 945 lines 2 – 20.

> So, the only conductor replacement program we have is for the copper replacement, and that's akin to the small little sliver of red you will see in that asset health index, which shows that very small portion of our conductor actually is in poor condition.

Mr. Kennedy states that the Midgard recommendations are unreasonably biased to a maximum life as explained in Section 4.6.5.1 of this Decision.[944]

Positions of the Parties

AMPC submits that Mr. Bowman's recommendation should be adopted. AMPC states although Mr. Kennedy placed high weighting on the operational interviews, it is unclear how he reached his recommendation. The operational interview only has two points, which do not support Mr. Kennedy's recommendation. With respect to peers, only one peer has a shorter life than 60 years and it includes other components, while the remaining peers have longer average useful lives. Midgard likewise rejects Mr. Kennedy's shorter recommended life, instead recommending 64 years, supporting Mr. Bowman's views. Lastly, Mr. Kennedy suggests that Mr. Bowman's recommendation is based on the alignment of this account to the life estimate of Account C25202, which Mr. Bowman recommends be set at 60 years. However, Mr. Bowman provided additional reasons for keeping this account at 60 years, including the 2010 operational interviews and the peer data, and Mr. Kennedy has not provided any further justification for the downward revision and therefore fails to justify the change.[945]

The CEC finds merit in, among other things, the RCIA evidence concerning average service lives for transmission conductors.[946]

In reply to AMPC's argument that the operational interviews do not support Mr. Kennedy's position, BC Hydro submits that the operational interviews indicated an ongoing conductor replacement program targeting copper conductor and it was also indicated that conductor life should be approximately the same as poles, which is currently 50 years. This is consistent with Mr. Kennedy's recommendations.[947]

In reply to Mr. Bowman's peer analysis, BC Hydro submits that Concentric's peer analysis recognized that the peer Canadian electric utilities group provides a range from 45 to 85 years which is a wide range. BC Hydro reiterates that Concentric does not use peers to select the average service lives, but as a band against which to check the reasonableness of its analysis. BC Hydro also notes that based on Concentric's recommended Iowa curve of 55-R3, the maximum life of the assets in this account is 93 years.[948]

RCIA submits that BC Hydro's mean life for transmission overhead conductors of 70 years indicates an upper bound on recommended average service life and supports a conductor life longer than the 55 year (transmission) and 50 year (distribution) average service lives that Concentric is recommending. A longer conductor average service life is consistent with Midgard's reasonableness check of 64 years for both transmission and distribution conductor, BC Hydro's retirement data which show few retirements, and Mr. Oakley's and Mr. Kumar's testimony regarding conductors.[949]

RCIA submits that there is no supportable evidentiary basis for Concentric's recommendation to reduce the average service life for transmission conductor from its current 60 years to 55 years, and the totality of evidence clearly indicates that the average service lives for overhead conductors should increase. The average service life for Account C55101 should be at least 60 years, but more reasonably it could be at least as long as the

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[944] Exhibit B-36, Appendix A, Section IV, A43, p. 49.
[945] AMPC Final Argument, Chapter 5, pp. 5-29 – 5-30.
[946] CEC Final Argument, Section II.H, p. 99.
[947] BC Hydro Reply Argument, Part 8.F(c), p. 110.
[948] BC Hydro Reply Argument, Part 8.F(c), p. 111.
[949] RCIA Final Argument, Section 4.7.9, pp. 44 – 45.

transmission structures supporting the conductor based upon BC Hydro's statements that the conductor life should be approximately the same as poles. RCIA's recommended average service life for transmission poles is 60 years and lattice/aesthetic towers is 70 years. Consequently, RCIA is recommending an average service life of 64 years because it is below the mean life cap, is consistent with the average service life of transmission conductor support structures, only slightly exceeds Mr. Bowman's recommendations, and matches the peer comparators in Midgard's recommendation.[950]

BC Hydro submits that the underlying theory of Midgard's evidence is flawed and should not be accepted for the same reasons as described in the Position of Parties in Section 4.6.1.4 of this Decision.[951]

In response to RCIA applying the mean life data provided by BC Hydro as an upper limit on depreciation rates, BC Hydro submits that this is not a hypothesis that has been reasonably tested in this proceeding, and that there is insufficient evidentiary basis to conclude that BC Hydro's mean life data can be reasonably considered an upper limit on depreciation rates as described in Section 4.6.5.1 of this Decision.[952]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C55101, "Conductor, Overhead > or = 60kV" should be reduced from 60 to 55 years, as proposed by Concentric.

The Panel finds that an average service life of 55 years is reasonable because:

- The Panel finds that the mean life for overhead conductor >= 60 kV is 70 years. BC Hydro states in an undertaking that the mean life for conductor systems is 70 years. This is supported by Concentric's notes from interviews with BC Hydro stating that "Conductor life should be approx. the same as poles. The life should be at least as long as poles," and the Panel found above that the mean life for transmission wood pole structures is between 70 and 80 years.
- The proposed life of 55 years for Conductor, Overhead > or = 60kV is greater than the average service life of 50 years for poles (see Section 4.6.5.2 above), which is consistent with BC Hydro's evidence that the life of conductor should be at least as long as the life of the poles supporting it. RCIA's view is also that the average life of conductor should be "consistent with the average service life of transmission conductor support structures".[953]
- The Iowa curve for overhead conductor >= 60 kV proposed by Concentric, which uses an estimated average service life of 55 years, implies a maximum life for these assets of over 90 years[954], while the mean life of these assets is only 70 years. Increasing the average service life of the assets to 60 or 64 years, as proposed by AMPC and RCIA, would imply a maximum life even further removed from the mean life of 70 years supported by the evidence in this proceeding.
- The peer data, ranging from FBC at 51 years to Manitoba Hydro at 80 years, do not raise concerns that the proposed figure of 55 years for BC Hydro is extraordinary. The Panel does not take into consideration the figure of 45 years for NALCOR because that figure does not include transmission conductor, although it would not change the analysis in any case because the proposed figure of 55 years for BC Hydro is still within the range of peer comparators with or without the 45-year figure from NALCOR.

As noted in Section 4.6.1.2.3 above, the Panel gives low weight to the peer comparators, and does not consider them appropriate for setting average service lives. Rather, as Concentric notes, peer comparators may be used

[950] RCIA Final Argument, Section 4.7.9, p. 45.
[951] BC Hydro Reply Argument, Part 8.G, pp. 131 – 133.
[952] BC Hydro Reply Argument, Part 8.G, p. 136.
[953] RCIA Final Argument, p. 45.
[954] Exhibit B-2-1, Appendix T, p. 434.

to determine the reasonableness of an average service life based on other factors. Therefore, we decline to consider AMPC's and RCIA's proposed average service life of 60 and 64 years based on peer comparators without other supporting evidence.

Although the average service life implied by the best-fitting Iowa curve would be 53 years, there are almost no retirement data for this asset class, so we cannot draw useful conclusions from this fact.

4.6.5.4 Overhead Conductors < 60 kV (C55102)

Table 48: Overhead Conductors < 60 kV (C55102)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C55102	Conductor, Overhead < 60 kV	$719,759,645	45	50	RCIA: 64

Concentric recommends the average service life to be revised to 50 years for Account C55102. Concentric states the assets in this account relate to approximately 48,000 kilometers of distribution overhead conductor commonly installed in rural areas of the province and are subject to damage due to motor vehicle accidents as well as damage caused by storms. Prior to 2004, automatic splices were used to connect or repair distribution overhead conductor which resulted in some premature failures. However, since 2004 compression splices have been used which do not have the same risk of premature failure. Major drivers of retirement in this account are system improvement and capacity growth projects. Based on discussions with operations staff BC Hydro believes these assets should have a similar life as distribution wood pole structures. Concentric has recommended maintaining the currently approved life of distribution pole structures at 50 years. Due to its normally smaller conductor sizes, it is expected that distribution overhead conductor should, in general, have a shorter life than transmission overhead conductor. Concentric has recommended lengthening the life of distribution overhead conductor to 50 years.[955]

Concentric states the "best life/dispersion" Iowa curve for this account is 40-R5, with a residual measure of 0.4103. The residual measure for the existing 45-R1 Iowa curve is 0.9229 and the residual measure for the recommended 50-R3 Iowa curve is 0.4796.[956]

As part of Concentric's peer analysis, Concentric considered NALCOR at 60 and 45 years and FBC at 55 years.[957]

In addition to the above based on Concentric's interview notes complied in preparing the Depreciation Study, the subject matter experts state that there are some old copper wires on the system with soft drawn #6 AWG copper that had issues in the past. Work has been done to replace the soft drawn #6 AWG copper in the system. However, it is unclear whether all of the soft drawn #6 AWG copper has been removed from the system. Larger diameter conductors should have a longer life than the smaller conductors. Galvanized steel core with aluminum surrounding is the typical conductor used, although the standard for the large conductor is aluminum (no steel core). As capacity increases, it is expected that the conductor gets bigger and more stable due to size. There have not been any areas with chronic corrosion issues. As such, conductors have been able to run to failure because failure is so rare. System improvement has been a major driver of retirements. These improvements typically result in capacity increases on the system. The life of conductor should be at least the life of the poles.[958]

[955] Exhibit B-2-1, Appendix T, pp. 22 – 23.
[956] Exhibit B-8, AMPC IR 27.1.
[957] Exhibit B-8, AMPC IR 21.1, Attachment 1.
[958] Exhibit B-8, AMPC IR 23.1, Attachment 1, pp. 12 – 13.

Mr. Oakley testified during the oral hearing that:

> […] from my experience conductors don't fail.
>
> […]
>
> The reason a conductor gets retired is because the structures fall out from under it. So that's why, if you can extend the life of a structure by ten years, you just added ten years to the conductor too. If you can extend the life of the structure … you win twice. You keep the conductor; you keep the structure. Your asset lives of both categories have improved because of your asset management practice.[959]
>
> I mean, the conductors will stay up there forever if you keep the structures in good shape under them. And we think that BC Hydro's doing a good job of keeping their conductors in the air. We'd expect to see it show up as a depreciation item.[960]

Similarly, Mr. Kumar testified that:[961]

> […] you will see that actually we don't have an extensive conductor replacement program because conductors are actually in very good condition, and -- or in fair condition. So, we don't have a proactive replacement of conductors except for copper replacement on our conductors.
>
> […]
>
> So, the only conductor replacement program we have is for the copper replacement, and that's akin to the small little sliver of red you will see in that asset health index, which shows that very small portion of our conductor actually is in poor condition.

Midgard recommends an average service life of 64 years based on peer utilities including Hydro One which uses 70 years, Manitoba Hydro which uses 60 years, ATCO which uses 65 years and NPI which uses 60 years.[962]

BC Hydro states the mean life for this asset is 70 years.[963]

Mr. Kennedy states that the Midgard recommendations are unreasonably biased to a maximum life as explained in Section 4.6.5.1 of this Decision.[964]

Positions of the Parties

RCIA submits that a longer conductor average service life, for both transmission and distribution conductors, is consistent with Midgard's reasonableness check of 64 years.[965]

BC Hydro submits that the underlying theory of Midgard's evidence is flawed and should not be accepted for the same reasons as described in the Position of Parties in Section 4.6.1.4 of this Decision.[966]

[959] 2022-09-21 Oral Hearing Transcript Volume 3 AM, p. 528 line 11 to p. 529 line 8.
[960] 2022-09-21 Oral Hearing Transcript Volume 3 AM, p. 546 lines 9 – 14.
[961] 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 945 lines 2 – 20.
[962] Exhibit C8-7, P0589-D008-MDL-R01-EXT - (Evidence) Depreciation Lives Information.xlsx, 'Comparison Analysis' tab; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 24.
[963] Exhibit B-44, BC Hydro Undertaking No. 13, p. 3.
[964] Exhibit B-36, Appendix A, Section IV, A43, p. 49.
[965] RCIA Final Argument, Section 4.7, Table 3, p. 31.
[966] BC Hydro Reply Argument, Part 8.G, pp. 131 – 133.

In response to RCIA applying the mean life data provided by BC Hydro as an upper limit on depreciation rates, BC Hydro submits that this is not a hypothesis that has been reasonably tested in this proceeding, and that there is insufficient evidentiary basis to conclude that BC Hydro's mean life data can be reasonably considered an upper limit on depreciation rates as described in Section 4.6.5.1 of this Decision.[967]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C55102, "Conductor, Overhead < 60 kV" should be increased from 45 to 50 years, as proposed by Concentric.

The Panel finds that an average service life of 50 years is reasonable because:

- The Panel finds that the mean life for overhead conductor < 60 kV is 70 years. BC Hydro states in an undertaking that the mean life for conductor systems is 70 years. This is supported by Concentric's notes from interviews with BC Hydro stating that "Conductor life should be approx. the same as poles. The life should be at least as long as poles," and the Panel found above that the mean life for transmission wood pole structures is between 70 and 80 years.
- The proposed life of 50 years for Conductor, Overhead < 60 kV is equal to the average service life of 50 years for poles (see Section 4.6.5.2 above), which is consistent with BC Hydro's evidence that the life of conductor should be at least as long as the life of the poles supporting it. RCIA's view is also that the average life of conductor should be "consistent with the average service life of transmission conductor support structures".[968]
- The Iowa curve for overhead conductor < 60 kV proposed by Concentric, which uses an estimated average service life of 50 years, implies a maximum life for these assets of 100 years[969], while the mean life of these assets is only 70 years. Increasing the average service life of the assets to 64 years, as proposed by RCIA, would imply a maximum life even further removed from the mean life of 70 years supported by the evidence in this proceeding.
- The peer data, ranging from NALCOR at 45 years to Hydro One at 70 years, do not raise concerns that the proposed figure of 50 years for BC Hydro is extraordinary.

RCIA's proposed figure of 64 years appears to be based on the "reasonableness check of 64 years for both transmission and distribution conductor" submitted in evidence by Midgard.[970] As noted in Section 4.6.1.2.3 above, the Panel gives low weight to the peer comparators, and does not consider them appropriate for setting average service lives. RCIA also notes the evidence of Mr. Oakley that "from my experience conductors don't fail". However, as RCIA also notes, Mr. Oakley added that "The reason a conductor gets retired is because the structures fall out from under it." The average service life of poles < 60 kV (account C25201) is unchanged at 50 years,[971] the same estimated average service life as the conductor < 60kV supported by those poles. We therefore reject RCIA's proposal of 64 years.

[967] BC Hydro Reply Argument, Part 8.G, p. 136.
[968] RCIA Final Argument, p. 45.
[969] Exhibit B-2-1, Appendix T, p. 437.
[970] RCIA Final Argument, p. 44.
[971] Ehibit B-2-1, Appendix T, p. 29.

4.6.5.5 Submarine Cables (C55303 & C55304)

Table 49: Submarine Cables (C55303 & C55304)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C55303	Cable, Submarine > or = 60 Kv	$224,526,383	45	45	AMPC: 55
C55304	Cable, Submarine < 60 Kv	$58,734,303	35	30	AMPC: 35

Concentric does not recommend average service life changes to Account C55303 and recommends the adoption of a 30-year average service life for Account C55303.[972] No peer utilities had comparable assets for Concentric's peer analysis.[973] Concentric's Depreciation Study shows no retirement data for Account C55303 and no retirement data for Account C55304 until assets have reached a vintage of 12.5 years.[974]

For Account C55303, Concentric states the "best life/dispersion" Iowa curve for this account is 50-R5, with a residual measure of 0.2281. The residual measure for the existing 45-R4 Iowa curve is 0.7470 and the residual measure for the recommended 45-R3 Iowa curve is 0.9414.[975]

For Account C55304, Concentric states the "best life/dispersion" Iowa curve for this account is 40-R4, with a residual measure of 0.0046. The residual measure for the existing 35-R3 Iowa curve is 0.0402 and the residual measure for the recommended 30-R3 Iowa curve is 0.0571.[976]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that Account C55303 includes the 500 kV AC to Vancouver Island. Submarine HVDC assets have been decommissioned but have not been removed or fully retired just yet. There are plans to fully retire these in the near future.[977]

Concentric states that discussions with operations and management staff indicated that the remaining assets in Account C55303 excluding the submarine HVDC assets are due to be retired in the near future. Therefore, maintaining the average life of 45 years is in line with discussions with operations and management staff, and the professional judgement of Mr. Kennedy.[978]

Mr. Bowman states Account C55303 appears to include HVDC assets that should properly be retired from rate base and the associated depreciation should not be included in rates as the assets appear to be not used and useful. The related substation or overhead assets should also be removed from rate base. It is not clear if this represents assets that are trivial or material in remaining value. However, it does appear that Concentric mis-spoke and only the 1970s vintage HVDC assets are pending retirement.[979]

Mr. Bowman states that prior to the 2005 Depreciation Study, Account C55303 was depreciated over 40 years. Based on the 2005 Depreciation Study, it was lengthened to 45 years when the main group of assets was already

[972] Exhibit B-2-1, Appendix T, Table 1 p. 29.
[973] Exhibit B-8, AMPC IR 21.1, Attachment 1.
[974] Exhibit B-2-1, Appendix T, pp. 457 – 458 and 460.
[975] Exhibit B-8, AMPC IR 27.1.
[976] Exhibit B-8, AMPC IR 27.1.
[977] Exhibit B-8, AMPC IR 23.1, Attachment 1, pp 32 – 33.
[978] Exhibit B-8, AMPC IR 34.6.
[979] Exhibit C7-11, Section 2.3.1.4, pp. 22 – 23.

over half way through its then 40 year projected life, as the accumulated depreciation was already $310 million of $595 million. Since that time, the asset class has been further subdivided, with the shortest components being carved out to new asset classes, in particular inspections which are amortized over 5 years and pumping plant and instrumentation which are amortized over 25 years. This division is not trivial as it removed about 10 percent of the account presently in service.[980]

Mr. Bowman states the most significant remaining components in Account C55303 are the 500kV cables to Vancouver Island from the mid-1980s, though more than half of the value of the account is relatively new, being added since the 2005 study. No indication of any issues of concern or planned retirement of the major mid-1980's vintage assets, even though these assets are at 40 years in service. Although BC Hydro also indicates it has been addressing issues in regard to the major 500 kV Vancouver Island cables in recent years, primarily through maintenance budgets, and that some capital spending may be required in coming years, the submission does not indicate any expedited planning is underway for retiring and replacing this major asset. BC Hydro only indicates that planning is underway for work within 4 years to "potentially include permanent replacement of certain sections of the cables and its associated components" which is far from a wholesale retirement of what will then be a 45 year old cable system. In fact, the issues to be addressed appear relatively minor in relation to the asset investment, and primarily relate to "…short segments of the cable where the cable is exposed within the terminal stations… which "… thermally expand and buckle between clamps holding the cable in place."[981]

Mr. Bowman states BC Hydro's own asset management strategy states that the major objective of the strategy is to achieve a life of 55 years for transmission cable systems, which is 15 years longer than the life stated by cable manufacturers, by targeted upgrades and refurbishments. Mr. Bowman clarifies that the lives "stated" by cable manufacturers need to read as a typical design standard which most installations exceed, not an average actuarial life.[982]

Mr. Bowman states Concentric's recommendation for a 45-year life is based on a low priority to all data inputs except "operational interviews" which is of medium weight, even though there is nothing in the operational interview notes that indicates the life remains appropriate, and the asset management strategy of reaching 55 years is entirely ignored.[983]

Mr. Bowman also notes that the Gulf Islands submarine cable, which was installed in 1958 and may be in the complementary smaller C55304 Cable, Submarine, < 60 kV, remains in service and is not planned for retirement. A submarine cable mitigation project is planned, and a complementary transmission option is being developed in case the 1958 cable fails, but this experience does not support the concept of a 45 year life. It is not possible to identify this asset in the C55303 database, so it may be in the C55304 asset class, which Concentric recommends reducing the average life of C55304 from 35 years to 30 years.[984]

Mr. Bowman states Concentric's rationale for shortening the Account C55304 life is listed as being weight "low" to every single data input, but "high" to Concentric-driven. At the same time, Concentric does not indicate the basis to which it makes this judgement. Account C55304 is not addressed specifically in any operational meeting notes.[985]

Given the above facts, Mr. Bowman states that a life revision upwards from 45 years for Account C55303 and 30 years for Account C55304 is merited. First for Account C55303, the key high value assets approaching 45 years are not slated for imminent retirement and are seeing reinvestment that will extend their life. Second, since the

[980] Exhibit C7-11, Section 2.3.1.4, p. 23.
[981] Exhibit C7-11, Section 2.3.1.4, pp. 23 – 24.
[982] Exhibit C7-11, Section 2.3.1.4, p. 24.
[983] Exhibit C7-11, Section 2.3.1.4, p. 24.
[984] Exhibit C7-11, Section 2.3.1.4, p. 24.
[985] Exhibit C7-11, Section 2.3.1.4, p. 24.

45-year life was set, the shorter lived components have been removed from C55303, which should be accompanied by a lengthening of the average life of the remaining assets, even if no further life performance data were being assessed at that time. Third, the asset management plan is targeting 55 years of life. Finally, the 1970's vintage assets already achieved in excess of a 40-year life, and it is reasonable to expect that technological improvements since that time could support longer lives particularly on the assets installed since 2005. For the higher voltage submarine transmission, it would appear there is no reason to ignore the BC Hydro asset management objective. The C55303 life should be adjusted to 55 years.[986]

For Account C55304, Mr. Bowman states the experienced life exceeding 60 years for the Gulf Islands cable is at minimum an example of higher performance than Concentric's recommended 30-year life and the existing 35 years. At minimum, the proposal to reduce from 35 years to 30 years, which is unsupported by any evidence in the filing, should be rejected. If BC Hydro confirms the asset management plan for a 55-year life is also the target for < 60 kV assets, a life extension for this account, perhaps to 40 years, should be adopted for moderation, with further monitoring of the potential for added life extension.[987]

For Account C55303, Mr. Kennedy states the asset management strategy to achieve a 55-year life for submarine cables is in line with the 45 year average service life proposed by Concentric. The objective of 55 years relates to the maximum life expected by BC Hydro and is only achieved through the routine interim retirements required due to targeted upgrades and refurbishments. Further, the manufacturer's estimated life of 40 years is five years shorter than the average service life estimated by Concentric.[988]

Mr. Kennedy states Mr. Bowman's evidence further supports the life of 45 years through the comments that the oldest assets currently in service in this account have had significant maintenance spent in recent years including capitalized upgrades, and that there is planning underway for replacement of sections of the cable. While there are no current plans to replace the entire system, upgrades and replacement on the system at the 40-year mark indicate that a life of approximately 45 years is correct.[989]

Mr. Kennedy states Mr. Bowman lacks an understanding of depreciation concepts as demonstrated by his comment that HVDC assets that should properly be retired from rate base and the associated depreciation should not be included in rates as they appear to be not used and useful. Plans and discussions surrounding the future retirements of assets indicate that they will no longer be used and useful at some future time, but in no way indicate that the assets are not used and useful at this point in time. It is typical for utilities to make retirement plans many years before the assets are removed from use and useful service, and a retirement plan should not be taken as a sign that the assets are no longer used and useful.[990]

Positions of the Parties

AMPC submits that because BC Hydro treats average service lives as terminal retirement dates for accounting purposes, it is reasonable to consider these end of life estimates when setting BC Hydro's service lives. To the extent that BC Hydro is capitalizing upgrades, but not making interim retirements that should otherwise be on the books, customers are paying too much in rates.[991]

AMPC submits that Mr. Kennedy's initial conclusion on this account appears flawed, based on his claim that: "Discussions with operations and management staff indicated that the remaining assets in this account are due

[986] Exhibit C7-11, Section 2.3.1.4, p. 25.
[987] Exhibit C7-11, Section 2.3.1.4, p. 25.
[988] Exhibit B-36, Appendix A, Section III, A23, pp. 26 – 27.
[989] Exhibit B-36, Appendix A, Section III, A23, p. 27.
[990] Exhibit B-36, Appendix A, Section III, A23, pp. 27 – 28; 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 248 line 10 to p. 249 line 19.
[991] AMPC Final Argument, Chapter 5, pp 5-30 – 5-31.

to be retired in the near future. Therefore, maintaining the average life of 45 years is in line with discussions with operations and management staff, and the professional judgement of Mr. Kennedy."[992]

Taken together, AMPC submits that the record supports Mr. Bowman's recommendation for Account C55303.

BC Hydro submits that Mr. Bowman's recommendations tend towards the maximum service life rather than the average service life.[993]

BC Hydro submits that consideration of accounting practices is not an appropriate factor in determining the average service life, and AMPC's recommendation would result in depreciating all the assets in this account based on a maximum potential life, even though the average life would be much shorter.[994]

BC Hydro submits that AMPC's claim that there may be interim retirements that should be on the books is baseless. Mr. Kennedy's evidence and testimony are that the objective of 55 years is only achieved through the routine interim retirements required due to targeted upgrades and refurbishments, and that there is planning underway for replacement of sections of the cable. This is consistent with there currently being no retirement in this account.[995]

BC Hydro submits that AMPC's portrayal of Concentric's comment that the remaining assets in this account are due to be retired in the near future is flawed. To clarify, Concentric's response was referring to the pending retirement of HVDC assets, as noted in the operational interviews.[996]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C55303, "Cable, Submarine > or = 60Kv" should remain at 45 years, as proposed by Concentric.

The Panel finds that an average service life of 45 years is reasonable because BC Hydro's Asset Management Strategy aims to achieve a life of 55 years for transmission cable systems, which is reasonably consistent with the maximum life of 75 years implied by the Iowa curve for submarine cable >= 60 kV proposed by Concentric[997]. An average service life longer than 45 years, for example the 55 years proposed by AMPC would imply a maximum life even longer than 75 years and thus even further beyond BC Hydro's target of 55 years.

The Panel finds that Mr. Bowman's evidence that the average service life should increase to 55 years is not compelling. We agree that since the last depreciation study some assets have been removed from this asset account, and that these removed assets might lower the estimated average service life, all else equal. However, this does not provide compelling evidence regarding the estimated average service life for the remaining assets. Mr. Bowman highlights the age of the Gulf Islands submarine cable, installed in 1958, but acknowledges that he does not know whether it is included in this asset account.

Although the average service life implied by the best-fitting Iowa curve would be 50 years, there are no retirement data for this asset class. As a result, the Panel does not consider this to be determinative or indicative.

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992 AMPC Final Argument, Chapter 5, p. 5-31.
993 BC Hydro Reply Argument, Part 8.F(d), p. 111.
994 BC Hydro Reply Argument, Part 8.F(d), p. 112.
995 BC Hydro Reply Argument, Part 8.F(d), p. 112.
996 BC Hydro Reply Argument, Part 8.F(d), p. 113.
997 Exhibit B-2-1, Appendix T, p. 456.

Although the average service life implied by the best-fitting Iowa curve would be 53 years, there are almost no retirement data for this asset class, so we cannot draw useful conclusions from this fact. We also note that there are no peer data in evidence to support the reasonableness of the proposed average estimate.

The Panel directs BC Hydro to explain in its Compliance Filing why the submarine HVDC assets that have been "decommissioned but have not been removed or fully retired" (and also related substation and other assets) have not been removed from rate base.

The Panel determines that the appropriate average service life for depreciation purposes for account C55304, "Cable, Submarine < 60 kV" should remain at 35 years, and not be reduced to 30 years as proposed by Concentric.

BC Hydro provides no compelling reason why the average service life for submarine cable of less than 60 kV should be reduced from 35 to 30 years. Concentric provides no notes from interviews with BC Hydro related to submarine cables < 60 kV, and notes that there are no comparable peers to consider.

Further, Concentric does not explain how it applied its judgement in recommending that the average service life be reduced, or why the average service life of submarine cable < 60 kV should be any different to that of submarine cable > 60 kV, given that BC Hydro aims to achieve an average service life of 55 years for transmission systems.

4.6.5.6 Underground Cables (C55301 and C55302)

Table 50: Underground Cables (C55301 and C55302)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C55301	Cable, Underground < 60 kV	$881,546,451	40	40	RCIA: 55
C55302	Cable, Underground > or = 60 kV	$94,754,670	40	40	RCIA: 55

Concentric does not recommend average service life changes to Accounts C55301 and C55302.[998] As part of Concentric's peer analysis, Concentric considered NALCOR at 60 years and FBC which ranged from 51 years to 55.[999]

For Account C55301, Concentric states the "best life/dispersion" Iowa curve for this account is 50-R3, with a residual measure of 0.1411. The residual measure for the existing 40-R3 Iowa curve is 0.3562 and the residual measure for the recommended 40-R2 Iowa curve is 0.5536.[1000]

For Account 55302, Concentric states the "best life/dispersion" Iowa curve for this account is 50-L4, with a residual measure of 2.7802. The residual measure for the existing 40-R4 Iowa curve is 4.1701 and the residual measure for the recommended 45-R3 Iowa curve is 3.2290.[1001]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that the distribution system consists of approximately 12,000 km of underground cables. The expansion of

[998] Exhibit B-2-1, Appendix T, Table 1 p. 30.
[999] Exhibit B-8, AMPC IR 21.1, Attachment 1.
[1000] Exhibit B-8, AMPC IR 27.1.
[1001] Exhibit B-8, AMPC IR 27.1.

the distribution system has been more underground over the last decade either as a requirement by municipalities or as desired by the developer. There are some older lead oil filled cables that have reached end of life and are being phased out. There is currently 800 km of lead cable left on the system. The lead cables can last as long as 50 years. The newer cables do not get as long of a life. The first generation plastic covered cables had some issues and were more like a 30-year life. Newer plastic cable can last about 40 years.[1002]

For Account C55301, Midgard recommends an average service life of 55 years based on peer utilities including Hydro One which uses 60 years, Alectra which uses 65 years, Manitoba Hydro which uses 45 years, ATCO which uses 55 years and NPI which uses 50 years. For Account C55302, Midgard recommends an average service life of 56 years based on peer utilities including Hydro One which uses 55 years, Alectra which uses 55 years, Manitoba Hydro which uses 45 years, ATCO which uses 40 years and NPI which uses 49 years.[1003]

BC Hydro states the mean life for these accounts is 55 years.[1004]

Mr. Kennedy states that the Midgard recommendations are unreasonably biased to a maximum life as explained in Section 4.6.5.1 of this Decision.[1005]

Positions of the Parties

RCIA submits that BC Hydro's mean life for underground cable of 55 years provides an upper bound on average service life and is markedly different than the current and Concentric recommended average service lives of 40-45 years. The 55-year Midgard peer comparator also indicates that the Concentric value of 40-45 years is not reasonable.[1006]

RCIA states that since underground cables are buried and isolated from other causes of retirement such as action of the elements and human interference, they represent an unusual asset class in that the causes of retirement for mean life are similar to those for average service life. The act of burying the cables protects them from many of the causes of retirement that affect above ground assets and creates a difference between the average service lives and mean lives of above ground assets.[1007]

Since the causes are retirement for mean life and average service life are equivalent and both the mean life and peer comparison reveal a material average service life disconnect, RCIA recommends that the lesser of Midgard average service life and BC Hydro mean life be adopted. In these cases that means an average service life of 55 years is recommended.[1008]

BC Hydro submits that neither the mean life data nor Midgard's peer analysis form a reasonable basis for setting depreciation rates. Further, RCIA's assertion that the causes of retirement considered for depreciation and mean life estimates are similar for these assets is speculative. For example, RCIA has not substantiated what causes of retirement BC Hydro considered in its mean life for this asset account. Further, RCIA has not taken into account the operational interviews which indicate future retirements for these accounts. Lastly, BC Hydro notes that RCIA's recommendation results in a 15 year or 37.5 percent change in these accounts, which is a large increase that is not warranted. BC Hydro submits that there is no information to justify a change in the average service life at this time.[1009]

1002 Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 13.
1003 Exhibit C8-7, P0589-D008-MDL-R01-EXT - (Evidence) Depreciation Lives Information.xlsx, 'Comparison Analysis' tab; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 24.
1004 Exhibit B-44, BC Hydro Undertaking No. 13, p. 3.
1005 Exhibit B-36, Appendix A, Section IV, A43, p. 49.
1006 RCIA Final Argument, Section 4.7.10, p. 46.
1007 RCIA Final Argument, Section 4.7.10, p. 46.
1008 RCIA Final Argument, Section 4.7.10, p. 46.
1009 BC Hydro Reply Argument, Part 8.G, pp. 137 – 139.

BC Hydro submits that the underlying theory of Midgard's evidence is flawed and should not be accepted for the same reasons as described in the Position of Parties in Section 4.6.1.4 of this Decision.[1010]

In response to RCIA applying the mean life data provided by BC Hydro as an upper limit on depreciation rates, BC Hydro submits that this is not a hypothesis that has been reasonably tested in this proceeding, and that there is insufficient evidentiary basis to conclude that BC Hydro's mean life data can be reasonably considered an upper limit on depreciation rates as described in Section 4.6.5.1 of this Decision.[1011]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C55301, "Cable, Underground < 60 kV" should remain at 40 years, as proposed by Concentric.

The Panel determines that the appropriate average service life for depreciation purposes for account C55302, "Cable, Underground > or = 60 kV" should remain at 40 years, as proposed by Concentric.

The only party who contests these proposals is RCIA, which proposes an average service life of 55 years for both accounts.

RCIA submits that the act of burying cables protects them from many causes of retirement that affect above-ground cables, creating a difference in the average service lives of the two types of cable, and thus the appropriate average service life to use is the lesser of Midgard's proposed average service life and BC Hydro's mean life. The Panel does not find this justification compelling. RCIA provides no explanation in its argument to justify Midgard's 55-year figure, beyond noting that it is a "peer comparator." As noted in Section 4.6.1.2.3 above, the Panel gives low weight to the peer comparators, and does not consider them appropriate for setting average service lives.

4.6.5.7 Switchyard Transformers (C52101 to C52106 and C52501 to C52505)

Table 51: Switchyard Transformers (C52101 to C52106 and C52501 to C52505)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C52101	Transformer, Generator, Stepup	$149,033,655	40	40	AMPC: 43-45 RCIA: 43-45
C52102	Transformer, Auto, Bulk System	$55,503,631	45	45	AMPC: 48-50 RCIA: 48-50
C52103	Transformer, Power > 100Mva	$142,550,237	40	40	AMPC: 43-45 Midgard: 47 RCIA: 43-45
C52104	Transformer, Power < 100Mva	$165,945,816	45	45	AMPC: 48-50 RCIA: 48-50
C52105	Transformer, Station Service	$49,632,705	40	40	AMPC: 43-45 RCIA: 43-45

1010 BC Hydro Reply Argument, Part 8.G, pp. 131 – 133.
1011 BC Hydro Reply Argument, Part 8.G, p. 136.

Table 51: Switchyard Transformers (C52101 to C52106 and C52501 to C52505)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C52106	Transformer, Power, Comp Pool	$47,511,268	45	40	AMPC: 48-50 RCIA: 48-50
C52501	Transformer, Voltage, Capacitor	$61,092,548	35	35	AMPC: 38-40 RCIA: 35
C52502	Transformer, Voltage, Oil-Fill	$6,218,219	40	40	AMPC: 43-45 RCIA: 40
C52503	Transformer, Voltage, Gas-Fill	$7,126,605	50	50	AMPC: 53-55 RCIA: 50
C52504	Transformer, Voltage, Encaps.	$7,392,299	45	45	AMPC: 48-50 RCIA: 45
C52505	Transformer, Volt, Comp. Pool	$5,366,687	40	40	AMPC: 43-45 RCIA: 40

Concentric does not recommend life changes to switchyard transformer Accounts C5250x and C5210x aside from a decrease of 5 years for C52106.[1012] Based on Concentric's peer analysis, Account C5210x has a peer range of 50 years to 55 years between FBC and NALCOR and Account C5250x has a peer range between 42 years to 55 years between the same utilities .[1013]

For Account C52101, Concentric states the "best life/dispersion" Iowa curve for this account is 42-L3, with a residual measure of 0.2152. The residual measure for the existing and currently recommended 40-R4 Iowa curve is 0.3147, and the implied maximum life is just over 60 years.[1014]

For Account C52102, Concentric states the "best life/dispersion" Iowa curve for this account is 45-R5, with a residual measure of 0.0000. The residual measure for the existing and currently recommended 45-R4 Iowa curve is 0.0176, and the implied maximum life is nearly 70 years.[1015]

For Account C52103, Concentric states the "best life/dispersion" Iowa curve for this account is 55-R4, with a residual measure of 0.1990. The residual measure for the existing 40-R3 Iowa curve is 1.3442 and the residual measure for the recommended 40-R4 Iowa curve is 1.3274, and the implied maximum life is just over 60 years.[1016]

For Account C52104, Concentric states the "best life/dispersion" Iowa curve for this account is 55-R3, with a residual measure of 0.0699. The residual measure for the existing and currently recommended 45-R3 Iowa curve is 0.1164, and the implied maximum life is 75 years.[1017]

For Account C52105, Concentric states the "best life/dispersion" Iowa curve for this account is 35-L1, with a residual measure of 0.3615. The residual measure for the existing 40-R3 Iowa curve is 0.9206 and the residual measure for the recommended 40-R1.5 Iowa curve is 0.6165, and the implied maximum life is just over 75 years.[1018]

[1012] Exhibit B-2-1, Appendix T, Table 1, p. 30.
[1013] Exhibit B-8, AMPC IR 21.1, Attachment 1.
[1014] Exhibit B-8, AMPC IR 27.1; Exhibit B-2-1, Appendix T, p. 336.
[1015] Exhibit B-8, AMPC IR 27.1; Exhibit B-2-1, Appendix T, p. 339.
[1016] Exhibit B-8, AMPC IR 27.1; Exhibit B-2-1, Appendix T, p. 341.
[1017] Exhibit B-8, AMPC IR 27.1; Exhibit B-2-1, Appendix T, p. 344.
[1018] Exhibit B-8, AMPC IR 27.1; Exhibit B-2-1, Appendix T, p. 346.

For Account C52106, Concentric states the "best life/dispersion" Iowa curve for this account is 55-R4, with a residual measure of 0.5770. The residual measure for the existing 45-R3 Iowa curve is 1.6199 and the residual measure for the recommended 40-R1.5 Iowa curve is 2.2710, and the implied maximum life is just over 75 years.[1019]

For Account C52501, Concentric states the "best life/dispersion" Iowa curve for this account is 40-S5, with a residual measure of 0.0239. The residual measure for the existing and currently recommended 35-R4 Iowa curve is 0.4954, and the implied maximum life is just over 50 years.[1020]

For account C52502, Concentric states that the residual measure for the recommended 40-R3 Iowa curve is 1.1654 and the implied maximum life is just over 65 years.[1021]

For account C52503, Concentric states that the residual measure for the recommended 50-R3 Iowa curve is 0.0737 and the implied maximum life is just over 80 years.[1022]

For account C52504, Concentric states that the residual measure for the recommended 45-R3 Iowa curve is 0.116 and the implied maximum life is 75 years.[1023]

For account C52505, Concentric states that the residual measure for the recommended 40-R4 Iowa curve is 0.9894and the implied maximum life is just over 60 years.[1024]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that the transformers have been very well maintained and lives have been stretched where possible. Based on this, the subject matter experts believe that the 40 to 45-year life may be on the shorter end of expectations for these assets. They further state that assets being installed today may not have the same life as the lives of assets historically, but on the other hand, the impact of the new technology is unknown. As such, there are both life shortening and life lengthening forces at work. They conclude that there isn't enough experience with the newer assets to have a reasonably certain idea of the average service life of the newer assets as the retirements have not occurred yet. Specifically for Account C52106 Transformer, Power, Comp Pool, the subject matter experts state the Electronic Temperature Monitoring device on the unit transformers needs to be replaced at least once during the life of the transformers as it only has a life of 15 years whereas the transformers have an expected life of 40 to 45 years. The cost of the Electronic Temperature Monitoring replacement is relatively small at roughly $50,000 per transformer. Currently BC Hydro treats replacements as a betterment.[1025]

Mr. Bowman states in addition to Concentric's peers, Manitoba Hydro uses 50 years.[1026]

Mr. Bowman states that based on the evidence, the switchyard transformers accounts, C5250x and C5210x, should receive a comprehensive but modest upward movement of 3 to 5 years. This would include rejection of Concentric's proposed reduction in average service life for account C52106.[1027]

[1019] Exhibit B-8, AMPC IR 27.1; Exhibit B-2-1, Appendix T, p. 348.
[1020] Exhibit B-8, AMPC IR 27.1; Exhibit B-2-1, Appendix T, p. 379.
[1021] Exhibit B-2-1, Appendix T, p. 382.
[1022] Exhibit B-2-1, Appendix T, p. 385.
[1023] Exhibit B-2-1, Appendix T, p. 387.
[1024] Exhibit B-2-1, Appendix T, p. 389.
[1025] Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 18.
[1026] Exhibit C7-11, Section 2.3.2, p. 27.
[1027] Exhibit C7-11, Section 2.3.2, pp. 26 – 28.

Mr. Kennedy states Mr. Bowman has no basis for his recommendation to increase the average service lives of these asset classes by 3 to 5 years other than comparison to Manitoba Hydro. Mr. Bowman was not able to match the accounting structure of Manitoba Hydro with BC Hydro. As such, there is simply no professional estimation logic to his recommendation.[1028]

Mr. Kennedy clarified during the oral hearing that the subject matter experts' estimate of 40 – 45 year life assumes the assets actually survive to the end of life. There are other forces of retirement, such as forces of nature and capacity requirements, that are not factored into the subject matter experts' estimate. The subject matter experts were also not sure if the different design and tolerances from various manufacturers will affect the life of the asset. As such, Concentric "backed off" a little from the subject matter experts' estimate to account for other forces of retirement.[1029]

Mr. Kennedy also clarified that: [1030]

> Transformers are a particularly unique bird in some ways, in that we now understand from a lot of discussion with operational staff that transformers may be one of those assets in, well, they don't make it like they used to. We used to look at power transformers and they would be a half inch of cast iron casings to them. Now it's very a very thin wall. They've manufactured, with the advent of computer design and computer engineering and computerized engineering, they are able to build transformers to a much tighter tolerance to meet the needs that they do. Which drives some efficiency both in cost and various installation issues or segments.

Mr. Kennedy states that based on this, many electric system operators are not expecting future transformers to live as long as the historic ones because they don't have the same built-in tolerance to extreme faults. The shortening of average service lives of transformers is a result of the changes in design of transformers which is not unique to BC Hydro or anybody else.[1031]

Mr. Kennedy elaborates that with an understanding of the design, Concentric can research the manufacturer's warranties. This is then combined with the bank of knowledge from attending conferences and discussing with various utilities to make some judgment on whether future transformers are going to retire the same way as historically based on the way they are designed and built.[1032]

Midgard recommends the following average service lives:[1033]

1) 40 years for Account C52101 based on peer utilities including Hydro One which uses 50 years, Alectra which uses 45 years, Manitoba Hydro which uses 35 years, ATCO which uses 50 years and NPI which uses 42 years.
2) 47 years for Account C52103 based on peer utilities including Hydro One which uses 50 years, Alectra which uses 45 years, Manitoba Hydro which uses 50 years, ATCO which uses 50 years and NPI which uses 42 years.
3) 45 years for Account C52104 based on peer utilities including Hydro One which uses 50 years, Alectra which uses 45 years, Manitoba Hydro which uses 50 years, ATCO which uses 50 years, and NPI which uses 42 years.

[1028] Exhibit B-36, Appendix A, Section III, A25, pp. 28 – 29.
[1029] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 194 line 10 to p. 195 line 26.
[1030] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 189 line 18 to p. 190 line 11.
[1031] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 190 lines 12 – 22.
[1032] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 190 line 23 to p. 191 line 19.
[1033] Exhibit C8-7, P0589-D008-MDL-R01-EXT - (Evidence) Depreciation Lives Information.xlsx, 'Comparison Analysis' tab; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 24.

4) 35 years for Account C52501 based on peer utilities including Hydro One which uses 35 years, Alectra which uses 30 years, Manitoba Hydro which uses 35 years and NPI which uses 42 years.

BC Hydro states the mean life for these accounts ranges from 53 years to 75 years depending on the voltage of the transformers.[1034]

Mr. Kennedy states that the Midgard recommendations are unreasonably biased to a maximum life as explained in Section 4.6.5.1.[1035]

Positions of the Parties

AMPC submits that Mr. Kennedy did not explain the rationale for the downward revision of average useful life for Account C52106.[1036]

BC Hydro disagrees with AMPC that there is insufficient evidence to justify the change to Account C52106. Concentric's determination to reduce the average service life of this account from 45 to 40 years was based primarily on the operational interviews and Concentric's judgement. The notes from the operational interviews stated that the 40-to-45-year life may be on the shorter end of reasonable for assets currently in service and that assets being installed today may not have the same life as the life of assets historically. However, no one is certain exactly what the impact of the next technology will be. There are both life shortening, and life lengthening forces at work.[1037] BC Hydro submits Mr. Kennedy explained how his professional judgement was factored into the analysis during his oral testimony.[1038]

BC Hydro submits that Concentric's recommendation to reduce the life of C52106 by five years, and maintain the life of the remaining accounts, is reasonable and should be approved.[1039]

AMPC submits that Mr. Kennedy may have misread Mr. Bowman's evidence based on Mr. Kennedy's suggestion that Mr. Bowman provides no basis for his choice of the 3-to-5-year increase other than comparison to Manitoba Hydro for Accounts C5250x and C5210x. Mr. Bowman based his recommendation on the fact that multiple peers are well outside the range used by BC Hydro for these assets, coupled with the fact there was an absence of evidence that BC Hydro was having any issues with these assets. Further, the fact that BC Hydro will use these as terminal lives for its depreciation expense further warrants an upward revision.[1040]

AMPC submits that Mr. Kennedy does not justify his decision not to recommend changes to Accounts C5250x and C5210x, excluding C52106, based on the lack of evidence to warrant a change. It is not clear what efforts were made to determine whether a change was warranted, and as such no weight should attach to this.[1041]

For Accounts C5250x and C5210x excluding C52106, BC Hydro submits that there is no information provided in the operational interviews, peer review or from Concentric's knowledge of the Canadian electric industry to justify a change in the average service life at this time.[1042]

[1034] Exhibit B-44, BC Hydro Undertaking No. 13, p. 2.
[1035] Exhibit B-36, Appendix A, Section IV, A43, p. 49.
[1036] AMPC Final Argument, Chapter 5, p. 5-31.
[1037] BC Hydro Reply Argument, Part 8.F(e), pp. 113 – 114.
[1038] BC Hydro Reply Argument, Part 8.F(e), pp. 114 – 115.
[1039] BC Hydro Reply Argument, Part 8.F(e), p. 113.
[1040] AMPC Final Argument, Chapter 5, p. 5-32.
[1041] AMPC Final Argument, Chapter 5, p. 5-32.
[1042] BC Hydro Reply Argument, Part 8.F(e), p. 115.

BC Hydro submits that Mr. Bowman's recommended change of 3-5 years is imprecise and not supported. Mr. Bowman's recommendation to increase these accounts by 3-5 years relied primarily on peer analysis, despite acknowledging the difficulty in aligning the asset classes among the utilities. BC Hydro submits that the peer analysis is too uncertain a basis on which to adjust these accounts.[1043]

For Accounts C5210x, RCIA submits that AMPC's recommended upward move in average service lives is consistent with BC Hydro's mean lives for station transformers of 53-75 years which exceeds the recommended AMPC moves (i.e., AMPC's recommendations are lower than the mean life upper bound). As a result, RCIA recommends adopting the adjustments indicated as reasonable by Mr. Bowman.[1044]

For Accounts C5250x, RCIA submits that there is a material disconnect between the average service life range of 35 – 55 years and the actual physical reality based on the mean life range of 30 – 45 years. As such, RCIA does not recommend adopting AMPC's recommendation and recommends accepting the Concentric recommendations.[1045]

BC Hydro submits that the underlying theory of Midgard's evidence is flawed and should not be accepted for the same reasons as described in the Position of Parties in Section 4.6.1.4 of this Decision.[1046]

In response to RCIA applying the mean life data provided by BC Hydro as an upper limit on depreciation rates, BC Hydro submits that this is not a hypothesis that has been reasonably tested in this proceeding, and that there is insufficient evidentiary basis to conclude that BC Hydro's mean life data can be reasonably considered an upper limit on depreciation rates as described in Section 4.6.5.1 of this Decision.[1047]

Panel Determination

The Panel determines that the appropriate average service lives for depreciation purposes for accounts C52101, 52102, 52103, 52104, 52105 and C52501, 52502, 52503, 52504, 52505 should remain unchanged, as proposed by Concentric.

The Panel finds the existing average service lives for accounts C52101, 52102, 52103, 52104, 52105 and C52501, 52502, 52503, 52504, 52505 are reasonable because :

- BC Hydro's mean life for these assets is 53 – 75 years; interpreting the mean life as a maximum life, the mean life of 53 to 75 years is consistent with the maximum life implied by Concentric's proposed Iowa curves for these asset accounts.
- Concentric's notes from interviews with BC Hydro are inconclusive, demonstrating "both life shortening and life lengthening forces at work" [1048]. This evidence does not provide a compelling basis for a change to the average service lives for these accounts.
- The proposed average service lives from Concentric are all either within or close to the range of peers: 42 years (Newfoundland) to 55 years (NALCOR) for accounts C52101, 52102, 52103, 52104, 52105, and 42 (FBC) to 55 years for accounts C52501, 52502, 52503, 52504, 52505.

AMPC's basis for proposing an increase to the average service lives of these accounts is the evidence of Mr. Bowman, who bases his proposal of a 3-5 year increase on "primarily a comparison to peers combined with a

[1043] BC Hydro Reply Argument, Part 8.F(e), pp. 115 – 116.
[1044] RCIA Final Argument, Section 4.7.3, p. 37.
[1045] RCIA Final Argument, Section 4.7.5, pp. 39 – 40.
[1046] BC Hydro Reply Argument, Part 8.G, pp. 131 – 133.
[1047] BC Hydro Reply Argument, Part 8.G, p. 136.
[1048] Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 18.

dearth of operational notes indicating any material issues with the condition of the existing assets."[1049] As noted in Section 4.6.1.2.3 above, the Panel gives low weight to the peer comparators, and does not consider them appropriate for setting average service lives.

The Panel determines that the average service live for depreciation purposes for account C52106, "Transformer, Power, Comp Pool" should remain at 45 years, and not reduced to 40 years as proposed by Concentric.

BC Hydro has not provided compelling evidence to justify the reduction in the average service life for account C52106. Mr. Kennedy identifies one factor that might reduce the average service life, namely that modern transformers are built "to a much higher tolerance" with thinner casings.[1050] However, Concentric's notes from interviews with BC Hydro are inconclusive, demonstrating "both life shortening and life lengthening forces at work."[1051]

Mr. Kennedy also states that, based on his experience, "future transformers are not going to live quite as long as the historic ones" and that this is "not unique to BC Hydro." This may be true, but it is not yet demonstrated in the historical retirements at BC Hydro or the peer comparisons.

Further, the historical retirement data from BC Hydro are best fitted by an Iowa curve with a 55-year average service life, which suggest an increase rather than a decrease in the average service life.

Taken together, these factors are not sufficient to demonstrate to the Panel that a decrease in the average service life for account C52106 is justified.

4.6.5.8 Switchyard Breakers (C54101 to C54105)

Table 52: Switchyard Breakers (C54101 to C54105)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C54101	Breaker, Air / Magnetic	$21,292,313	20	20	AMPC: 23-25 RCIA: 23-25
C54102	Breaker, Gas (Sf6) 12 / 25 kV	$159,161,060	30	35	AMPC: 38-40 RCIA: 35
C54103	Breaker, Bulk / Min Oil / Air Blast	$20,199,247	45	45	AMPC: 48-50 RCIA: 45
C54104	Breaker, Gas (Sf6), 69 To 500 kV	$407,786,390	45	45	AMPC: 48-50 RCIA: 45
C54105	Breakers, Composite Pool	$14,582,978	35	35	AMPC: 38-40 RCIA: 38-40

Concentric does not recommend average service life changes to Account C5410x with the exception of Account C54102 which includes a recommendation for a 35-year average service life.[1052] Specifically for Account C54102, Concentric states the recommendation was based on the retirements recorded. Peer utilities typically group all breakers into a single account. Consequently, the peer review is of limited value. Discussions with BC Hydro

1049 Exhibit C7-11, Section 2.3.2, p. 28.
1050 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 189, line 19 – p. 191, line 19 (Kennedy).
1051 Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 18.
1052 Exhibit B-2-1, Appendix T, Table 1 p. 30.

operations staff indicate that the life of this account should increase due to the life increases in similar accounts.[1053] As part of Concentric's peer analysis, Concentric considered FBC which is 50 years.[1054]

For Account C54101, Concentric states that the residual measure for the recommended 20-R3 Iowa curve is 0.3304 and the implied maximum life is just over 30 years.[1055]

For Account C54102, Concentric recommends the "best life/dispersion" Iowa curve for this account of 35-R3, with a residual measure of 0.0843. The residual measure for the existing 30-R3 Iowa curve is 0.1179 and the implied maximum life is just under 60 years.[1056]

For Account C54103, Concentric states that the residual measure for the recommended 45-R3 Iowa curve is 0.611 and the implied maximum life is 75 years.[1057]

For Account C54104, Concentric states the "best life/dispersion" Iowa curve for this account is 47-R4, with a residual measure of 0.0945. The residual measure for the existing 45-R2.5 Iowa curve is 0.3419 and the residual measure for the recommended 45-R3 Iowa curve is 0.2258 and the implied maximum life is 75 years.[1058]

For Account C54105, Concentric states that the residual measure for the recommended 35-R4 Iowa curve is 0.482 and the implied maximum life is just over 50 years.[1059]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that the transmission related breakers are predominately SF6 Breaker technology. Few bulk oil breakers remain, but most have been replaced and the remainder are targeted for replacement in the near future. The oil breakers are beyond both useful and financial lives. The SF6 Breakers are generally about midlife. There are no large scale replacements planned for SF6 breakers. There were a few trouble breakers (first generation leaked oil) that have been replaced but most are still young in life. For distribution related breakers, there is a move away from SF6 Breakers to vacuum technology due to climate change concerns.[1060]

Mr. Bowman states in addition to Concentric's peers, Manitoba Hydro uses 50 years and NALCOR uses 60 years.[1061]

Mr. Bowman states the most significant account, C54104 Breaker, Gas (SF6, 69 to 500 kV) has no substantiation for maintaining the life at a level below that of peers. Further, this account is highlighted as one that will be affected by Site C assets, so an unusually short life could have far more material impacts in future. The only life revision proposed by Concentric is for Account C54102 from 30 to 35 years. There is no special commentary in the operational notes, nor inputs from the peer analysis, supporting this revision as a priority as compared to broadly moving the group of station accounts to lives that are closer to the peer group.[1062]

Mr. Bowman states that based on the evidence, the switchyard breaker accounts, C5410x, should receive a comprehensive but modest upward movement of 3 to 5 years including the adoption of Concentric's proposed increase in average service life for account C54102 of 5 years.[1063]

[1053] Exhibit B-2-1, Appendix T, p. 22.
[1054] Exhibit B-8, AMPC IR 21.1, Attachment 1.
[1055] Exhibit B-2-1, Appendix T, p. 404.
[1056] Exhibit B-2-1, Appendix T, p. 406; Exhibit B-8, AMPC IR 27.1.
[1057] Exhibit B-2-1, Appendix T, p. 408.
[1058] Exhibit B-2-1, Appendix T, p 411; Exhibit B-8, AMPC IR 27.1.
[1059] Exhibit B-2-1, Appendix T, p. 414.
[1060] Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 19.
[1061] Exhibit C7-11, Section 2.3.2, p. 27.
[1062] Exhibit C7-11, Section 2.3.2, p. 27.
[1063] Exhibit C7-11, Section 2.3.2, pp. 26 – 28.

Mr. Kennedy states Mr. Bowman does not provide an account-by-account description for his recommendation to increase the average service lives. With the exception of Account C54104, Mr. Bowman relies on the idea that these accounts may be too short based on peers. However, Mr. Bowman makes no direct comparison to the relevant account of the peers, nor to any impact of environmental conditions such as the saltwater environment over a large portion of BC Hydro assets as compared to the inland assets of FBC or Manitoba Hydro. Mr. Kennedy also notes that Mr. Bowman did not compare to the shorter life comparison of ATCO Electric and AltaLink for these accounts. It appears as though Mr. Bowman relied solely on the lives of Manitoba Hydro and FBC in his assessment to conclude that all accounts have lives which are too short.[1064]

During the oral hearing, Mr. Kennedy clarified that ATCO uses 49 years and AltaLink uses 47 years for these asset classes.[1065]

Mr. Kennedy states there is insufficient evidence to suggest a change to the average service lives of Accounts C5410x with the exception of C54102. Likewise, Mr. Bowman does not have any justification for extending the average service lives of these assets.[1066]

For both accounts, Midgard recommends an average service life of 45 years based on peer utilities including Hydro One which uses 45 years and Alectra which also uses 45 years.[1067]

BC Hydro states the mean life for these accounts ranges between 40 years and 55 years depending on the voltage of the breakers.[1068]

Mr. Kennedy states that the Midgard recommendations are unreasonably biased to a maximum life as explained in Section 4.6.5.1 of this Decision.[1069]

Position of the Parties

AMPC states Mr. Kennedy is critical of Mr. Bowman for not including ATCO Electric and AltaLink as part of his analysis. However, the average service lives of 49 years for ATCO Electric and 47 years for AltaLink support Mr. Bowman's recommended broad increase to the existing average service lives.[1070]

AMPC submits that Mr. Kennedy's evidence does not defend his failure to recommend changes to these accounts. Given the dearth of information provided by BC Hydro, considerable weight should be given to the peer analysis because BC Hydro's peers universally use lives greatly in excess of those used by BC Hydro. As such, Mr. Bowman's recommended life extensions should be implemented.[1071]

BC Hydro notes that Mr. Bowman does not identify a specific life, but rather a range which is imprecise. BC Hydro submits that Mr. Bowman's peer analysis is flawed and that his recommendation should not be accepted. Instead, Mr. Kennedy's opinion should be given more weight and should be accepted.[1072]

[1064] Exhibit B-36, Appendix A, Section III, A27, p. 30.
[1065] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 252 line 4 to p. 253 line 4.
[1066] Exhibit B-36, Appendix A, Section III, A27, pp. 30 – 31.
[1067] Exhibit C8-7, P0589-D008-MDL-R01-EXT - (Evidence) Depreciation Lives Information.xlsx, 'Comparison Analysis' tab; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 24.
[1068] Exhibit B-44, BC Hydro Undertaking No. 13, p. 2.
[1069] Exhibit B-36, Appendix A, Section IV, A43, p. 49.
[1070] AMPC Final Argument, Chapter 5, pp. 5-32 – 5-33.
[1071] AMPC Final Argument, Chapter 5, pp. 5-33.
[1072] BC Hydro Reply Argument, Part 8.F(f), pp. 116 – 117.

RCIA submits that the mean life data provided by BC Hydro appears to provide clarification in certain cases, notably for C54104 Break, Gas (SF6, 69 to 500kV) which have a mean life of 40-45 years and the lower voltage breakers which have longer mean lives than higher voltage breakers. Consequently, when BC Hydro's mean lives for breakers of 40-55 years is compared to BC Hydro's current and Concentric's recommended average service lives, mean life data provide a cap on AMPC's recommendations in certain cases. As a result, RCIA recommends adopting Mr. Bowman's recommendations when they are not capped by BC Hydro's mean life estimates. But when Mr. Bowman's recommendations are capped by BC Hydro's mean life estimates, Concentric's recommendations should be accepted.[1073]

BC Hydro submits that the underlying theory of Midgard's evidence is flawed and should not be accepted for the same reasons as described in the Position of Parties in Section 4.6.1.4 of this Decision.[1074]

In response to RCIA applying the mean life data provided by BC Hydro as an upper limit on depreciation rates, BC Hydro submits that this is not a hypothesis that has been reasonably tested in this proceeding, and that there is insufficient evidentiary basis to conclude that BC Hydro's mean life data can be reasonably considered an upper limit on depreciation rates as described in Section 4.6.5.1 of this Decision.[1075]

Panel Determination

The Panel determines that the appropriate average service lives for depreciation purposes for accounts C54101, 54103, 54104, 54105 should remain unchanged, as proposed by Concentric.

The Panel finds the existing average service lives for accounts C54101, 54103, 54104, 54105 are reasonable because:

- BC Hydro's mean life for these assets is 40 - 55 years; interpreting the mean life as a maximum life, the mean life range of 40 to 55 years is broadly consistent with the maximum life implied by Concentric's proposed Iowa curves for these asset accounts, although the implied maximum lives for accounts C54103 and C54104 are 75 years, which is more than marginally higher than the 55-year range for the mean lives.
- Concentric's notes from interviews with BC Hydro provide no indication that the current estimate of average service lives are inappropriate.
- For the one account for which Concentric provides an Iowa curve analysis, C54104, the implied average service live is 47 years, demonstrating that the current and proposed figure of 45 years is reasonable.
- The range of peers is 47 years (ALTALink) to 60 years (NALCOR). While most of the average service lives for these accounts are within or close to the range, account C54101 (20 years) and C54105 (35 years) fall more than marginally outside the range. However, we note Concentric's view that the peer review is of limited value because peers typically group all breakers into a single account.

AMPC's basis for proposing an increase to the average service lives of these accounts is the evidence of Mr. Bowman, who bases his proposal of a 3-5 year increase on "primarily a comparison to peers combined with a dearth of operational notes indicating any material issues with the condition of the existing assets"[1076]. As noted in Section 4.6.1.2.3 above, the Panel gives low weight to the peer comparators, and does not consider them appropriate for setting average service lives.

[1073] RCIA Final Argument, Section 4.7.6, pp. 41 – 42.
[1074] BC Hydro Reply Argument, Part 8.G, pp. 131 – 133.
[1075] BC Hydro Reply Argument, Part 8.G, p. 136.
[1076] Exhibit C7-11, p. 28.

The Panel determines that the appropriate average service life for depreciation purposes for account C54102 should increase from 30 to 35 years, as proposed by Concentric.

The Panel finds the average service life of 35 years for account C54102 is reasonable because :

- BC Hydro's mean life for these assets is 40 - 55 years; interpreting the mean life as a maximum life, the mean life range of 40 to 55 years is broadly consistent with the maximum life implied by Concentric's proposed Iowa curve for account C54102 of just over 60 years.
- For account C54102, the best fitting Iowa curve has an estimated service life of 35 years.
- The range of peers is 47 years (ALTALink) to 60 years (NALCOR). However, we note Concentric's view that the peer review is of limited value because peers typically group all breakers into a single account.

AMPC's basis for proposing an increase to the average service lives of these accounts is the evidence of Mr. Bowman, who bases his proposal of a 3-5 year increase on "primarily a comparison to peers combined with a dearth of operational notes indicating any material issues with the condition of the existing assets"[1077]. As noted in Section 4.6.1.2.3 above, the Panel gives low weight to the peer comparators, and does not consider them appropriate for setting average service lives.

4.6.5.9 Buswork (C55401)

Table 53: Buswork (C55401)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C55401	Buswork & Station Conductor	$396,373,692	60	55	AMPC: 60 RCIA: 60

Concentric recommends a revised average service life of 55 years for Account C55401. Concentric states that this was based on the retirement transactions recorded, the peer average service life of 50 years and Concentric's professional judgement. [1078]

Concentric states that the "best life/dispersion" Iowa curve for this account is 63-R4, with a residual measure of 0.0432. This compares to the residual measure of 0.0464 for Iowa curve 60-R4, used as a basis for the current 60-year average service life. The residual measure for the Iowa curve 55-R4, proposed by Concentric to represent this asset class, is 0.0836.[1079]

A review of peer Canadian electric utilities provides an estimate of 50 years. Based on the above and on Concentrics' experience, an Iowa 55-R4 is a reasonable expectation for the investment in this account.[1080]

As part of Concentric's peer analysis, Concentric considered FBC and NALCOR which both use 50 years.[1081]

Operational interview notes for Account C55401 have not been provided in the evidentiary record of this proceeding.[1082]

1077 Exhibit C7-11, p. 28.
1078 Exhibit B-2-1, Appendix T, p. 23.
1079 Exhibit B-8, IR 27.1, p. 20.
1080 Exhibit B-2-1, Appendix T, p. 23.
1081 Exhibit B-8, AMPC IR 21.1, Attachment 1.
1082 Exhibit B-8, AMPC IR 23.1, Attachment 1.

As part of an undertaking, Concentric clarified it may be necessary to further reduce the life of this account to 50 years in future depreciation studies. However at this time, there is not sufficient evidence to recommend a shorter life. Due to the concept of gradualism and moderation and the lack of evidence for a further shortening, Concentric recommends a life of 55 years at this time.[1083]

Mr. Bowman states Concentric weighted all drivers as "low" with the exception of peers which was "medium". While BC Hydro notes FBC at 50 years, BC Hydro fails to note that this 50-year category applies to the entire average of substation equipment, not just the longest-lived.[1084]

Mr. Bowman states the existing 60 year average service life for Account C55401 was approved as part of the 2005 Depreciation Study as an extension to the 40 year average service life before. The 60-year average service life was reconfirmed during the 2010 analysis.[1085]

Mr. Bowman states that based on the evidence, Account C55401 should retain the existing 60-year average service life.[1086]

Midgard recommends an average service life of 49 years based on the average figure of 48.75 years of peer utilities Hydro One which uses 45 years, Alectra which uses 55 years, Manitoba Hydro which uses 40 years and ATCO which uses 55 years.[1087]

Mr. Kennedy states that the Midgard recommendations are unreasonably biased to a maximum life as explained in Section 4.6.5.1 of this Decision.[1088]

Positions of the Parties

AMPC submits that to the extent Mr. Kennedy is critical of Mr. Bowman for overreliance on peers where other information is not available, he does the same in analogous circumstances. Similarly, Mr. Kennedy is critical of Mr. Bowman for failing to match the accounts during the peer comparison, yet Mr. Kennedy is guilty of the same as exemplified by his use of FBC at 50 years despite FBC including the entire average of substation equipment.[1089]

AMPC submits there is insufficient basis on which to modify this account's average service life, and Mr. Kennedy provides no further evidence in his rebuttal evidence nor any explanation as to how he reached his recommendation. As such, the current 60-year average service life should be retained.[1090]

BC Hydro submits that contrary to Mr. Bowman, Concentric believes that it may be necessary to further reduce the life of this account to 50 years in future depreciation studies. However, there is not sufficient evidence to recommend a shorter life at this time.[1091]

RCIA submits that BC Hydro did not provide a mean life for this asset class. As a result, the evidence shows a mixture of recommendations. Midgard's peer comparator of 49 years is approximately equal to Concentric's

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[1083] Exhibit B-44, BC Hydro Undertaking No. 3, p. 3.
[1084] Exhibit C7-11, Section 2.3.2, p. 28.
[1085] Exhibit C7-11, Section 2.3.2, p. 28.
[1086] Exhibit C7-11, Section 2.3.2, pp. 26 – 28.
[1087] Exhibit C8-7, P0589-D008-MDL-R01-EXT - (Evidence) Depreciation Lives Information.xlsx, 'Comparison Analysis' tab; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 24.
[1088] Exhibit B-36, Appendix A, Section IV, A43, p. 49.
[1089] AMPC Final Argument, Chapter 5, p. 5-33.
[1090] AMPC Final Argument, Chapter 5, pp. 5-33 – 5-34.
[1091] BC Hydro Reply Argument, Part 8.F(g), p. 117.

peer comparator of 50 years, but is materially lower than AMPC's recommendation of 60 years. Given the dearth of high-quality analytic data and inconsistent recommendations, RCIA recommends that BC Hydro's current average service life of 60 years be retained.[1092]

BC Hydro submits that the underlying theory of Midgard's evidence is flawed and should not be accepted for the same reasons as described in the Position of Parties in Section 4.6.1.4 of this Decision.[1093]

In response to RCIA applying the mean life data provided by BC Hydro as an upper limit on depreciation rates, BC Hydro submits that this is not a hypothesis that has been reasonably tested in this proceeding, and that there is insufficient evidentiary basis to conclude that BC Hydro's mean life data can be reasonably considered an upper limit on depreciation rates as described in Section 4.6.5.1 of this Decision.[1094]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C55401, "Buswork & Station Conductor" should remain at 60 years, rather than reduced to 55 years as proposed by Concentric.

Concentric states that the best fitting Iowa curve to the actual retirement transactions recorded in this account is 63-R4, with a residual measure of 0.0432, which implies an average service life of 63 years. However, Concentric then explains that it proposes a 55-year average service life based on its "experience" and its review of Canadian peers which "provides an estimate of 50 years."

Concentric has previously stated[1095] that it uses peer reviews not to select the average service life, but rather to determine the reasonableness of the average service life selected based on the other drivers. The Panel accepts this, and therefore gives low weight to the "estimate of 50 years" which Concentric produces from its peer review.

Further, Concentric provides no support for the "experience" it also uses to justify its proposed 55-year estimate.

The Panel does not consider it appropriate to derive the average services for assets solely by fitting Iowa curves to historical retirement data. However, in this instance the historical data are directionally in conflict with Concentric's recommendation, and Concentric has not provided sufficient explanation as to why it made its recommendation. Therefore, there is insufficient evidence to justify the reduction in average service life from 60 to 55 years.

4.6.5.10 Dams and Powerhouse (C21001 and C22003)

Table 54: Dams and Powerhouse (C21001 and C22003)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C21001	Dam, Embankment / Concrete	$2,585,419,374	100	100	AMPC: 110 The CEC: 150

[1092] RCIA Final Argument, Chapter 5, pp. 47 – 48.
[1093] BC Hydro Reply Argument, Part 8.G, pp. 131 – 133.
[1094] BC Hydro Reply Argument, Part 8.G, p. 136.
[1095] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 205 lines 4 to 10.

C22003	Powerhouse, Integral With Dam	$604,849,994	100	100	AMPC: 110 The CEC: 150

Concentric does not recommend average service life changes for Accounts C21001 and C22003.[1096] No retirements of any amount have been recorded nor recommended for retirement.[1097]

For Account C21001, Concentric states the "best life/dispersion" Iowa curve for this account is 100-S5, with a residual measure of 0.0000. The residual measure for the existing 100-R4 Iowa curve is 0.1089 and the residual measure for the recommended 100-R3 Iowa curve is 0.2812.[1098] The implied maximum life of the recommended 100-R3 Iowa curve is 170 years.[1099]

For Account C22003, Concentric states the "best life/dispersion" Iowa curve for this account is 110-R5 with a residual measure of 0.0000. The residual measure for the existing 100-R4 Iowa curve is 0.0498 and the residual measure for the recommended 100-R1.5 Iowa curve is 0.5341.[1100]

As part of Concentric's peer analysis, Concentric considered the average service lives used by Ontario Power Generation at 100 years, NALCOR at 110 years and FBC at 70 years. Concentric states that a peer review was conducted to ensure that BC Hydro remained within a reasonable band of estimates for this asset. While Concentric completed a detailed peer review, the nature of dam safety throughout North America requires a careful understanding of all circumstances before recommending an average service life estimate and results in the peer review needing careful consideration to ensure circumstances are the same amongst all utilities considered.[1101]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that all dams are subject to the Canadian Dam Association guidelines and are regulated under the BC Dam Safety Regulations. The standards are constantly evolving, which means there is ongoing work to ensure that dams are safe and meet all regulations. There are dams on the system that go back to the 1900s. The oldest dams are still in relatively good shape, but are designed to a different standard back when they were built. For these dams, there are extra studies to document deficiencies and proper maintenance, and upgrades are planned and carried out to address deficiencies and improve performance. In general, dams are designed for a service life of 100 years. Upgrades to dams are ongoing which maintain the 100 year life. BC Hydro has decommissioned some dams, including one "earlier this year at Bugaboo." Powerhouse buildings "will have a long life – likely similar to the dam."[1102]

Specifically, the subject matter experts state that the Willsey dam in the Shushwap area of B.C. is in good shape with no major issues. The dam at Coquitlam needed to be replaced approximately 10 years ago as it was found to be deficient to the Canadian Dam Association guidelines. The new dam was built downstream of the old dam. The old dam remains in place but is not relied upon to contain the reservoir. Lastly, the John Hart and La Joie dams have ongoing capital upgrades.[1103]

During the oral hearing, Mr. Darby confirmed that BC Hydro was seeing significant capital investments in dams due to seismic-related issues.[1104]

1096 Exhibit B-2-1, Appendix T, Table 1, p. 28.
1097 Exhibit B-8, AMPC IRs 34.2, 34.3 and 34.4.
1098 Exhibit B-8, AMPC IR 27.1.
1099 Exhibit B-2-1, Appendix T, p. 52.
1100 Exhibit B-8, AMPC IR 27.1.
1101 Exhibit B-20, AMPC IRs 27.1 and 27.2.
1102 Exhibit B-8, AMPC IR 23.1, Attachment 1, pp. 25 – 26; 2022-09-20 Oral Hearing Transcript Volume 2 AM, pp. 299 – 300.
1103 Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 26.
1104 2022-09-22 Oral Hearing Transcript Volume 4 AM, p. 958 line 24 to p. 959 line 14.

For Account C22003, the subject matter experts indicated that the powerhouse is subject to a life similar to the dam, with a life of approximately 100 years. Further, these discussions also indicated that there are some shorter life assets included in this account, such as the elevator and HVAC system. Consequently, Concentric recommends a lower mode curve for this account than for Account C21001. This is consistent with the experience of peer utilities and the professional judgement of Mr. Kennedy.[1105]

For Account C21001, Mr. Bowman states the only actuarial life history of relevance will arise from extremely old facilities, many of which would have been constructed with different materials and standards and only a few utilities in Canada have experience with this asset reaching end-of-life. Mr. Bowman notes that FBC's depreciation study indicates no material assets in their category "Reservoirs, Dams and Waterways" that exceed 35 years. As such, it does not appear to offer useful actuarial support.[1106]

Mr. Bowman states Concentric has not considered Manitoba Hydro which uses a 125 year depreciation life combined with a 140 year life span to each plant with limited exceptions. One such exception is the Pointe du Bois plant which was constructed in 1906 with a 125 year depreciation life and a 134 year life span.[1107]

Mr. Bowman states the largest current investment in Account C21001 is the Waneta dam which was reviewed by the BCUC[1108] and was noted to have been acquired with a conservative economic planning horizon of 40 years or a 104 year life based on a construction date of 1954. BC Hydro is expected to make rehabilitation spending on Waneta to extend its life estimate. Mr. Bowman states the rehabilitation spending appears to relate primarily to shorter lived components of the entire Waneta Dam.[1109]

Mr. Bowman states BC Hydro's current study indicates no material retirements for Accounts C21001 or C22003 and the previous study similarly showed few if any retirements over the long-term that would be sufficient to detail support for the 100 year life, as opposed to alternatives.[1110]

Based on the above, Mr. Bowman states BC Hydro has not sufficiently justified retaining the 100 year life from past studies. First, peer utilities, including Manitoba Hydro and NALCOR, have adopted higher ranges for similar assets in these asset classes. Second, this class being dominated by the vintage assets at Waneta that BC Hydro already expects to live beyond 104 years as a "conservative" life. Third, the pending new Site C investment should be expected to have a longer life given modern construction practices. As such, there is little reason to expect that these asset classes will fail to match the performance of Manitoba Hydro's 1906 vintage Pointe du Bois plant which has a 125 year depreciation rate. While an increase in their lives from 100 to 125 years would not be unreasonable, in the interests of moderation an increase to 110 years should be the minimum adopted.[1111]

Further, Mr. Bowman also recommends BCUC to direct BC Hydro to undertake a broad review of depreciation on the Waneta assets to ensure that the depreciation rates are not driving unjustified accelerated depreciation inconsistent with the expected performance and retirements associated with the Waneta facilities.[1112]

Mr. Kennedy states that Mr. Bowman's concern regarding Waneta's average service life estimates being at odds with the economic life is an example of Mr. Bowman failing to understand depreciation concepts. The Waneta

[1105] Exhibit B-8, AMPC IR 34.6; Exhibit B-8, AMPC IR 12.1 Attachment 1, p. 1; AMPC IR 23.01, Attachment 1, page 26.
[1106] Exhibit C7-11, Section 2.3.3.1, p. 30.
[1107] Exhibit C7-11, Section 2.3.3.1, p. 30.
[1108] BC Hydro Waneta 2017 Transaction Application proceeding.
[1109] Exhibit C7-11, Section 2.3.3.1, p. 31.
[1110] Exhibit C7-11, Section 2.3.3.1, p. 32.
[1111] Exhibit C7-11, Section 2.3.3.1, p. 32.
[1112] Exhibit C7-11, Section 2.3.3, p. 30.

assets were purchased with a forecasted economic life of approximately 40 years. That does not mean that the interim survivor curve must be higher than 40 years, or that there will not be retirements within those 40 years. The concept of the average service should not be mistaken for the average life of a group of assets, nor should a group of assets be assigned a life based on the expected life of a singular location. Further, it is important to remember the weighting of the Waneta assets to individual accounts. If the dam or powerhouse encompasses the majority of the purchase price and is expected to live through to the 100-year recommended average service life, then assigning an economic life based around that estimate is reasonable. This does not mean that every individual asset will attain 40 more years, but that the majority of the investment (i.e., the dam and the powerhouse) are expected to live 40 years.[1113]

Mr. Kennedy states Mr. Bowman's confusion surrounding the economic life and the average service life for the Waneta assets illustrates a larger misunderstanding. The Waneta assets are included in various accounts, with differing expected lives. As is typical in group accounting, it is expected that some assets within these groups will have lives longer or shorter than the average life assigned to them. While BC Hydro accounts for the life of individual assets rather than the group as a whole, it is still expected that individual assets will retire at different times. It is impossible to predict the life of any singular asset due to the many forces of retirement that utilities face. It is entirely consistent with group accounting practices for some assets within a group to have a life that is longer than the average service life assigned to the group. If some of the Waneta assets have been maintained in a manner that extends their life beyond the typical life in the group or will have a life that is longer than the group as a whole for some other reason, that does not invalidate the estimate for the other assets in the group. In just the same manner that a single asset being retired before the average service life should not be used to set the overall life of the group, neither should an asset being retired after the average service life extend the life of the group.[1114]

Mr. Kennedy states that it is extremely important to understand capital additions and retrofits that are required in British Columbia related to the hardening of the dams to meet the Canadian Dam Association requirements in the province of BC because of the potential of seismic activity.[1115] Additionally, the accounting retirements as a result of the renovation may not have historically been booked under the accounting rules in place at the time. If retirement transactions had been booked in the accounting ledgers, the retirement activity on the BC Hydro dams would far exceed the retirement ratios of either the Manitoba Hydro or NALCOR. As such, the shorter average service life estimate for the BC Hydro dams is entirely appropriate.[1116]

During the oral hearing, Mr. Bowman testified that future investment in assets do not necessarily indicate a limitation on the life of the original investment, or indicate a need for shorter depreciation lives unless it is being undertaken in a manner that results in some material portion of the original investment being removed or retired. Otherwise, the original investment remains and continues to be subject to depreciation over many more years.[1117] Mr. Bowman further states that although utilities think 100 years is too long to think about, many have lengthened the average service life estimate as time went on.[1118]

Positions of the Parties

AMPC submits that Mr. Bowman's recommendations should be preferred for these accounts. AMPC submits that there "is nothing testable" about Mr. Kennedy's comment, which arose for the first time in the rebuttal evidence, that the level of capital expenditures undertaken by BC Hydro far exceeds that of any other hydro utilities in the country due to seismic requirements. Mr. Kennedy does not cite what seismic rules he is referring

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[1113] Exhibit B-36, Appendix A, Section III, A28, pp. 31 – 32.
[1114] Exhibit B-36, Appendix A, Section III, A28, pp. 32 – 33.
[1115] Exhibit B-36, Appendix A, Section III, A29, pp. 33 – 34.
[1116] Exhibit B-36, Appendix A, Section III, A29, pp. 33 – 34; 2022-09-20 Oral Hearing Volume 2 AM, pp. 254 – 255.
[1117] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 416 lines 4 – 16.
[1118] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 484 lines 10 – 21.

to, why seismic risks, which are largely a concern on BC's coast, are relevant to BC Hydro's dams in the interior of BC, what retirements BC Hydro would have incurred if properly accounted for, or what the difference in magnitude is between BC Hydro and its peers. Instead, Mr. Kennedy relies on a black box of "based on my detailed discussions." AMPC states this is not sufficient to be reliable evidence.[1119]

In response to AMPC's assertion that the seismic considerations referred to by Mr. Kennedy were raised for the first time in his rebuttal, BC Hydro submits that this was already discussed in response to AMPC IR 2.27.1 and is consistent with the information from the operational interviews.[1120]

AMPC submits, for the purpose of depreciation, new investments in capital are not a driver for depreciation lives unless a portion of the original investment is being removed. Mr. Kennedy has given no indication of what, if any, of the major embankment dam or powerhouse asset would have been retired during a seismic upgrade. Adding new supports, or underpinning, or other structural enhancements does not necessarily lead to any retirement of the dam structure.[1121]

In response to AMPC's claim that an investment in new capital is not a driver of depreciation unless it results in a portion of the original investment being removed, BC Hydro submits that the life of the new investment itself must also be taken into account. If the new investment has a shorter life than the original investment, then it should decrease the average service life of the account, all else equal.[1122]

AMPC submits that if BC Hydro has been retiring portions of these assets without recording those retirements, it has been improperly charging customers for portions of assets that are no longer providing utility service. This does not justify shortening the lives of current assets, when customers today are already paying too much in depreciation expense because BC Hydro is failing to adequately account for retirements.[1123]

In response to AMPC's statement that BC Hydro retiring a portion of these assets without recording those retirements does not justify shortening the lives of the assets, BC Hydro submits it has followed historical accounting rules and is following practice consistent with other utilities. First, BC Hydro is proposing to maintain the current average service lives of these assets, not shorten them. Second, Mr. Kennedy's evidence was that retirements may not have historically been booked under the accounting rules in place at the time, and that all utilities have difficulty estimating what to retire when making capital investment in dams. The key point is that the capital investments in BC exceed those in other provinces and this mitigates adopting the higher lives used by Manitoba Hydro and NALCOR.[1124]

NTC agrees that Mr. Bowman's recommendations, specifically on the review of depreciation on the Waneta assets, should be considered.[1125]

BC Hydro submits that Concentric's recommendation to not change the average service lives of these accounts is more reasonable based on the discussions with subject matter experts, peer analysis, and Mr. Kennedy's professional judgement.[1126]

BC Hydro submits that Mr. Bowman's recommendation to increase the average useful lives to 110 years is largely based on a peer analysis including Manitoba Hydro and NALCOR. Mr. Kennedy has provided a response

[1119] AMPC Final Argument, Chapter 5, pp. 5-35 – 5-36.
[1120] BC Hydro Reply Argument, Part 8.F(h), pp. 119 – 120.
[1121] AMPC Final Argument, Chapter 5, p. 5-36.
[1122] BC Hydro Reply Argument, Part 8.F(h), p. 120.
[1123] AMPC Final Argument, Chapter 5, p. 5-36.
[1124] BC Hydro Reply Argument, Part 8.F(h), pp. 120 – 121.
[1125] NTC Final Argument, Section 5.1, p. 33.
[1126] BC Hydro Reply Argument, Part 8.F(h), pp. 117 – 118.

to this in the rebuttal evidence including the implication of increased seismic standards due to potential seismic activities and that BC Hydro may have significantly higher retirement ratios if historic retirements were recorded.[1127]

In response to Mr. Bowman's statement that the evidence regarding Waneta confirms that a longer life is appropriate, BC Hydro submits that the interpretation of the Waneta information is incorrect as per Mr. Kennedy's rebuttal evidence on Mr. Bowman's misunderstanding of depreciation concepts.[1128]

BC Hydro notes that AMPC does not make any mention in its argument of Mr. Bowman's recommendation for a review of the depreciation rates for the Waneta assets, although it is supported by NTC. For the same reasons set out in Mr. Kennedy's rebuttal evidence on Mr. Bowman's misunderstanding of depreciation concepts, BC Hydro submits that no review of the depreciation rates for the Waneta assets is required. Rather, the average useful lives of the various asset classes in which the Waneta assets fall are being reviewed in this proceeding.[1129]

In response to Mr. Bowman's statement that Site C should last longer than 100 years, BC Hydro submits that Mr. Bowman's views of the life of Site C are no more than speculation. It is important to keep in mind that the average service life is only an average and it is to be expected that some assets in this account will last longer than the 100 years. In subsequent depreciation studies, the average service lives will be reviewed again and can take into account any new information regarding Site C that may suggest an increase is warranted.[1130]

The CEC submits that with Site C coming into service in the Test Period, there is an opportunity for BC Hydro to revisit the average service lives for its larger dams and generating stations, including Site C, to recognize longer amortization periods for depreciation purposes. The CEC understands that BC Hydro will continue to use some of these assets well into the future, some for 100 to 150 years. As such, the CEC recommends the dams and integrated powerhouse facilities be depreciated over 150 years based on the evidence in the proceeding.[1131]

In response to the CEC's recommendation of a 150-year life for these accounts, BC Hydro submits that the CEC has not provided any sound basis for this recommendation and that extending the life of these accounts by 50 years would not be reasonable at this time. BC Hydro submits that, based on the above, Concentric's recommended 100-year life should be approved.[1132]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C21001, "Dam, Embankment / Concrete"" should remain at 100 years, as proposed by Concentric.

The Panel determines that the appropriate average service life for depreciation purposes for account C22003, "Powerhouse, Integral With Dam"" should remain at 100 years, as proposed by Concentric.

The evidence demonstrates that some of BC Hydro's current dams may live longer than 100 years. Concentric's notes from interviews with BC Hydro demonstrate that BC Hydro has dams "that go back to the 1900s" which are "still in relatively good shape." Also, BC Hydro recently estimated the life of the Waneta dam, which it purchased in 2017, at 104 years, which is the only direct evidence the Panel has of a recent, considered estimate of the life of a BC Hydro dam.

[1127] BC Hydro Reply Argument, Part 8.F(h), pp. 118 – 119.
[1128] BC Hydro Reply Argument, Part 8.F(h), pp. 121 – 122.
[1129] BC Hydro Reply Argument, Part 8.F(h), p. 122.
[1130] BC Hydro Reply Argument, Part 8.F(h), p. 122.
[1131] CEC Final Argument, Section I, p. 8 and Section II.H, p. 99.
[1132] BC Hydro Reply Argument, Part 8.F(h), p. 122.

However, the estimated service life is an average value, not a maximum value. The fact that some of BC Hydro's current dams are lasting more than 100 years does not conclusively demonstrate that the average life of BC Hydro's dams is more than 100 years. BC Hydro may have dams in operation today that will last less than 100 years, and dams that have previously been decommissioned with lives of less than 100 years, in which case an average service life of 100 years may be appropriate.

BC Hydro has limited historical data available on dam asset retirements, and lists no retirements in the retirement rate analysis of the depreciation study.[1133] However, BC Hydro states that some dams have been decommissioned, but provides no evidence on the age of those dams at retirement. The Panel does not find this evidence to be helpful. The peer data range widely from 70 years (FBC) to 125 years (Manitoba Hydro), which is also not helpful.

The Iowa curve recommended by Concentric, which has a 100-year average service life, implies a maximum life of 170 years. The evidence that BC Hydro has some dams more than 100 years old is consistent with this Iowa curve. What would indicate that the 100-year average service life is not appropriate is to observe average retirements occurring at an age of more than 100 years.

Based on the paucity of evidence to demonstrate that the average service life of 100 years is inappropriate for account C21001, the Panel accepts it as reasonable. The Panel also accepts the same average service life for account C21002 on the basis that, according to BC Hydro, powerhouses have a similar life to dams.

That said, these asset accounts are significant, with a combined NBV of $3.2 billion, and once BC Hydro's Site C dam is included, the NBV of this account will become even more significant. **The Panel directs BC Hydro to provide, in its next depreciation study, a more comprehensive analysis of the age of its current dams and of the dams it has decommissioned**. The Panel discusses BC Hydro's next depreciation study in Section 4.6.6.3 of this Decision.

4.6.5.11 Waterwheels, Turbines and Generators (C41001 to C41008 and C42001 to C42004)

Table 55: Waterwheels, Turbines and Generators (C41001 to C41008 and C42001 to C42004)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C41001	Runner / Water Wheel	$129,066,780	50	55	AMPC: 60-65
C41002	Governor System, Turbine	$59,391,792	50	55	AMPC: 25-40
C41003	Casing, Embedded / Spiral Case	$101,495,415	50	50	AMPC: 55-60
C41004	Shaft, Turbine	$24,922,000	50	50	AMPC: 55-60
C41005	Gates, Wicket	$43,958,271	50	50	AMPC: 55-60
C41006	Cover, Head	$30,942,616	50	50	AMPC: 55-60
C41007	Turbine, Hydro, Comp. Pool	$372,737,026	50	55	AMPC: 60-65
C41008	Bearings For Wicket Gate	$3,380,775	25	25	AMPC: 30-35
C42001	Coils, Stator	$185,601,601	30	35	AMPC: 40-45
C42002	Rotor, Generator	$204,813,100	50	50	AMPC: 55-60

[1133] Exhibit B-2-1, Appendix T, pp. 53-55.

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C42003	Generator, Composite Pool	$346,757,075	50	50	AMPC: 55-60
C42004	Major Maintenance - Rewedging	$4,730,030	25	25	AMPC: 30-35

Concentric does not recommend average service life changes to Accounts C4100x and C4200x with the exception of C41001, C41002, C41007 and C42001. For Accounts C41001, C41002 and C41007, Concentric recommends a revised average service life of 55 years. For Account C42001, Concentric recommends a revised average service life of 35 years.[1134]

For Account C41001, Concentric states the "best life/dispersion" Iowa curve for this account is 60-R4, with a residual measure of 0.0073. The residual measure for the existing 55-R2 Iowa curve is 0.2480 and the residual measure for the recommended 55-R4 Iowa curve is 0.0114. The implied maximum life of the recommended 55-R4 Iowa curve is just over 80 years.[1135]

For Account C41002, Concentric states the "best life/dispersion" Iowa curve for this account is 60-S5, with a residual measure of 0.0523. The residual measure for the existing 50-R4 Iowa curve is 0.8028 and the residual measure for the recommended 55-R4 Iowa curve is 0.5227. The implied maximum life of the recommended 55-R4 Iowa curve is just over 80 years.[1136]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that the governors under Account C41002 were traditionally analogue in nature. There is a move towards digital governors. Analogue governors are expected to last 40 years while digital governors are expected to last 15 to 20 years. Roughly one-third to one-half of the governors are digital.[1137] No notes are available for the other asset classes.

For Account C41003, Concentric states the "best life/dispersion" Iowa curve for this account is 50-R5, with a residual measure of 0.0000. The residual measure for the existing 50-R4 Iowa curve is 0.0119 and the residual measure for the recommended 50-R3 Iowa curve is 0.0586.[1138]

For Account C41004, Concentric states that the residual measure for the recommended 50-R3 Iowa curve is 0.0586 and the implied maximum life is just over 80 years.[1139]

For Account C41005, Concentric states that the residual measure for the recommended 50-R2.5 Iowa curve is 0.01132 and the implied maximum life is just under 90 years.[1140]

For Account C41006, Concentric states that the residual measure for the recommended 50-R3 Iowa curve is 0.0586 and the implied maximum life is ust over 80 years.[1141]

For Account C41007, Concentric states the "best life/dispersion" Iowa curve for this account is 60-R5, with a residual measure of 0.0726. The residual measure for the existing 50-R4 Iowa curve is 0.7324 and the residual

[1134] Exhibit B-2-1, Appendix T, Table 1 p. 29.
[1135] Exhibit B-2-1, Appendix T, p. 254; Exhibit B-8, AMPC IR 27.1.
[1136] Exhibit B-2-1, Appendix T, p. 256; Exhibit B-8, AMPC IR 27.1.
[1137] Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 27.
[1138] Exhibit B-8, AMPC IR 27.1.
[1139] Exhibit B-2-1, Appendix T, p. 261.
[1140] Exhibit B-2-1, Appendix T, p. 263.
[1141] Exhibit B-2-1, Appendix T, p. 265.

measure for the recommended 55-R3 Iowa curve is 0.6834. The implied maximum life of the recommended 55-R3 Iowa curve is just over 90 years.[1142] Concentric states even though the residual measure is higher, the longer average service life of the Iowa 55-R3 is a reasonable expectation of the investment in this account and aligns with other BC Hydro accounts that are similar in nature and fits within the range of peer experience.[1143] Concentric states that a life as long as 100 years may be appropriate. However, Concentric believes an extension in life to 100 years is not warranted at this time. Based on peer utilities as well as Concentric's professional judgement, 55 years is a reasonable expectation for this account. The life of 55 years brings BC Hydro into alignment with peer utilities while maintaining a gradual increase in life. It is expected that there may be future life extensions in this account if current life indications persist over future depreciation studies.[1144]

For Account C41008, Concentric states that the residual measure for the recommended 25-R3 Iowa curve is 0.1311 and the implied maximum life is just over 40 years.[1145]

For Account C42001, Concentric states the "best life/dispersion" Iowa curve for this account is 35-S5, with a residual measure of 0.0959. The residual measure for the existing 30-R2.5 Iowa curve is 0.9785 and the residual measure for the recommended 35-R3.5 Iowa curve is 0.4210. The implied maximum life of the recommended 35-R3.5 Iowa curve is 55 years.[1146] Concentric states that it has analyzed the available retirement data available. Peer utilities do not typically have an account with coil assets alone, and as a consequence, the peer review is of limited value. Based on the above and on Concentrics' experience, an average service life of 35 years is a reasonable expectation for the investment in this account. BC Hydro has a currently approved life of 30 years for Account C42001. While there have been limited interim retirements suggesting a life potentially longer than 35 years may be appropriate, the concept of gradualism and moderation was used in selecting the life for Account C42001. A life extension of five years represents a 17 per cent increase in life, which was viewed to be reasonable at this time. Future depreciation studies will need to weigh the impact of the large single year retirement at age 30.5 against the lack of interim retirements throughout the life of this account carefully before recommending any further life lengthening.[1147]

For Account C42002, Concentric states the "best life/dispersion" Iowa curve for this account is 52-R5, with a residual measure of 0.0959. The residual measure for the existing 50-R4 Iowa curve is 0.2131 and the residual measure for the recommended 50-R3 Iowa curve is 0.3839. The implied maximum life of the recommended 50-R3 Iowa curve is just over 80 years.[1148]

For Account C42003, Concentric states the "best life/dispersion" Iowa curve for this account is 48-R4, with a residual measure of 0.0730. The residual measure for the existing and currently recommended 50-R3 Iowa curve is 0.2584. The implied maximum life of the recommended to-R3 Iowa cruve is just over 80 years.[1149]
As part of Concentric's peer analysis, Concentric considered Ontario Power Generation, NALCOR and FBC which had a range between 40 years to 70 years based on the specific asset class.[1150]

Mr. Bowman states Concentric considered actuarial data and management interview are of low importance, with peers spanning "low" to "high" importance, and operational interviews "low" to "medium". However, the only direct commentary from the subject matter experts was for governors in Account C41007 which states that analogue governors have a life of 40 years and digital governors have a life between 15 to 20

[1142] Exhibit B-2-1, Appendix T, p. 267;Exhibit B-8, AMPC IR 27.1.
[1143] Exhibit B-7, BCUC IR 103.11.
[1144] Exhibit B-2-1, Appendix T, p. 21; Exhibit B-8, AMPC IR 28.2.
[1145] Exhibit B-2-1, Appendix T, p. 270.
[1146] Exhibit B-2-1, Appendix T, p. 278; Exhibit B-8, AMPC IR 27.1.
[1147] Exhibit B-2-1, Appendix T, p. 21; Exhibit B-8, AMPC IR 29.1.
[1148] Exhibit B-2-1, Appendix T, p. 281; Exhibit B-8, AMPC IR 27.1.
[1149] Exhibit B-2-1, Appendix T, p. 284; Exhibit B-8, AMPC IR 27.1.
[1150] Exhibit B-8, AMPC IR 21.1, Attachment 1.

years. Despite this, Concentric recommends lengthening the life of C41002 to 55 years. Concentric appears to also ignore the fact that the 2010 BC Hydro review recommended shortening the life of post-1990 governors at 25 years while keeping the older pre-1990 governors at 50 years.[1151]

For Account C41002, Mr. Bowman states that it is reasonable that the asset account should use a life appropriate for the type of asset being installed. BC Hydro had previously recommended 25 years for post-1990 assets, and this appears to remain reasonable assuming the account can be split based on install date or technology. If the account cannot be split, a move to a life between 25 and 40 years, which represents the relative mix of analogue and digital governor investment, is appropriate.[1152]

For the remaining accounts, Mr. Bowman states that the upward revisions proposed by Concentric do not appear sufficiently material to accord with the peer comparisons. Among BC Hydro's peers, the Waterwheel, Turbines and Generators class tends to be consolidated under one asset class in most cases. Concentric notes that FBC uses a 70 year life for the account, and Ontario Power Generation also mostly uses 70 years, but uses 50 years for Wicket Gates, while NALCOR uses a range from 45 years to 80 years. Manitoba Hydro uses 60 years for turbines and generators, with 50 years for governors. Broadly speaking, the peer utilities are universally longer than BC Hydro even when ignoring the more componentized nature of BC Hydro's accounts and the use of separate accounts for shorter-lived assets.[1153]

Mr. Bowman also states that it is important to consider the implications of the Waneta investment in these accounts. For example, the Waneta generators comprise one-third of the entire C42003 account. However, as a 50 year asset, these generators are being carried as a $65 million investment as of March 31, 2021. Adopting a $4 million per year depreciation has these units fully depreciated by 2037. A complete disposal of all Waneta generator investment by 2037 is inconsistent with the "conservative" nature of the economic assumptions when the plant was purchased. Similar effects would arise for the other Waterwheels, Turbines and Generators accounts for Waneta.[1154]

Given the lack of retirement data, the lack of information outside of peer comparators for the Waterwheels, Turbines and Generators accounts, and the notably longer lives adopted almost universally by peers, Mr. Bowman states the average service lives for these accounts should be increased 5-10 years, aiming for the major accounts being set at 60 years.[1155]

For Account C41002, Mr. Kennedy states that approximately two-thirds of the current governor assets are still analog. While these analog governors have a life of 45 to 50 years, a number of analog assets are older than 50 years and remain in service. While BC Hydro plans to retire this aging fleet, through the course of the Depreciation Study period many of these aged governors will remain in service. As such, Mr. Kennedy continues to recommend that the average service life of this account should be lengthened to 55 years. During the next depreciation study, based on the asset split between analog and digital equipment, the life of this account will be reviewed again.[1156]

For the other accounts, Mr. Kennedy states that these are large accounts to which he has already made average service life increases from the currently approved estimates. Mr. Bowman's recommendations represent a 10 to 15 percent adjustment to the already adjusted lives. Mr. Bowman has not reviewed any of the operating practices or retirement policies of the peers used by Mr. Bowman in his evidence. The BCUC should not consider the unsubstantiated broad-based recommendations for these accounts to be reasonable.[1157]

[1151] Exhibit C7-11, Section 2.3.3.2, pp. 32 – 33.
[1152] Exhibit C7-11, Section 2.3.3.2, p. 33.
[1153] Exhibit C7-11, Section 2.3.3.2, pp 33 – 34.
[1154] Exhibit C7-11, Section 2.3.3.2, p. 34.
[1155] Exhibit C7-11, Section 2.3.3.2, p.
[1156] Exhibit B-36, Appendix A, Section III, A30, p. 34.
[1157] Exhibit B-36, Appendix A, Section III, A31, pp. 34 – 35.

Positions of the Parties

For Account C41002, AMPC submits that Mr. Kennedy's statement that approximately two-thirds of the current governor assets are still analog supports Mr. Bowman's recommendation for a blended account given the actual lives experienced for the two classes. AMPC states that it is the newest, and likely highest cost, governors that would be digital and require their lives to be shortened to ensure proper capital recovery over this shorter life.[1158]

In response to AMPC's submission that Mr. Kennedy's evidence supports splitting Account C41002, BC Hydro submits that there is no need to split this account, as the single account with a single life can reasonably address the depreciation of the assets.[1159]

For Accounts C4100x and C4200x excluding C41002, AMPC submits that the factors discussed by Mr. Bowman, including peer utilities generally using longer average service lives, implications with Waneta assets, as well as lack of actual experienced retirements in these accounts, support longer lives than those proposed by Mr. Kennedy.[1160]

AMPC submits that Mr. Kennedy's rebuttal evidence does not undermine Mr. Bowman's recommendations. While Concentric has recommended increases, those increases do not go far enough, and there is nothing to suggest Mr. Bowman's recommendations go too far even accounting for the need for incrementalism in making changes to depreciation accounts. If there are any relevant factors from the referenced peers that would contradict Mr. Bowman's recommendation, Mr. Kennedy would have brought them into the evidence. AMPC states that the BCUC should make an adverse inference against Mr. Kennedy for his failure to do so.[1161]

In response to AMPC's argument that Concentric's recommendation does not "go far enough," BC Hydro states Mr. Kennedy has applied the principle of gradualism in his recommendations as explained in the evidence which should be accepted.[1162]

In response to AMPC's statement that an adverse inference should be made against Mr. Kennedy for not explaining the contradicting operating practices and retirement policies of the peer utilities, BC Hydro submits that Mr. Kennedy's point is sound. Mr. Bowman has considered peer information without a sufficient understanding of those peers. Concentric does not use peers to select the average service lives, but as a band against which to check the reasonableness of its analysis. As Mr. Bowman himself notes: "you've got to be careful about taking too much guidance from the peers."[1163] BC Hydro states the key point for these accounts is the application of the principle of gradualism. A broader increase, as recommended by Mr. Bowman, could be considered in the next depreciation study. BC Hydro submits that Mr. Kennedy's opinion should be given more weight in this case and accepted.[1164]

For Mr. Bowman's recommendations for Accounts C4100x and C4200x excluding C41002, BC Hydro submits Mr. Bowman's recommendations are imprecise and should not be accepted. For accounts C41007 and C42001, BC Hydro submits that Concentric's recommendation to increase the lives by five years should be accepted. For the other accounts, BC Hydro submits that there is insufficient information to justify a change. As stated by

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1158 AMPC Final Argument, Chapter 5, p. 5-38.
1159 BC Hydro Reply Argument, Part 8.F(j), p. 126.
1160 AMPC Final Argument, Chapter 5, p. 5-37.
1161 AMPC Final Argument, Chapter 5, p. 5-38.
1162 BC Hydro Reply Argument, Part 8.F(i), pp. 123 – 125.
1163 BC Hydro Reply Argument, Part 8.F(i), pp. 125 – 126.
1164 BC Hydro Reply Argument, Part 8.F(i), pp. 125 – 126.

Concentric, there was no information provided in the operational interviews, peer review or from Concentric's knowledge of the Canadian electric industry to justify a change in the average service life at this time.[1165]

Regarding Mr. Bowman's statement on the implications of Waneta, BC Hydro submits that Mr. Bowman's interpretation of the Waneta information is incorrect as Mr. Bowman misunderstands depreciation concepts as described in Section 4.6.5.10 above for dams and the powerhouse.[1166]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C41002, "Governor System, Turbine" should remain at 50 years, and not increase to 55 years as proposed by Concentric.

While the estimated average service life implied by the best fitting Iowa curve is 60 years, Concentric's notes from interviews with BC Hydro indicate that BC Hydro is moving from analog governers, with an expected life of 40 years, to digital governers, which are expected to last 15 to 20 years, and that roughly one third of governers are digital. This would, other things being equal, reduce rather than increase the average service life of the assets in this account. The Panel is not willing to accept a proposal to increase the average service life of these assets without an adequate explanation.

The Panel agrees with Mr. Bowman that there is a case for splitting account C41002 into two accounts, to separate the analog and digital governers which have different anticipated lives. However, we are satisfied with BC Hydro's response that there is no need to do this. Whether or not BC Hydro splits account C41002 into two accounts, we still exepct BC Hydro to provide a satisfactory explanation for any future proposals to change the estimated service lives of these assets.

The Panel determines that the appropriate average service life for depreciation purposes for accounts C41001 and C41007 and C42001 should increase by 5 years, as proposed by Concentric, and the appropriate average service life for depreciation purposes for accounts C41003, C41004, C41005, C41006, C41008, C42002, C42003, C42004 should remain unchanged, also as proposed by Concentric.

AMPC's basis for proposing an increase to the average service lives of these accounts is the evidence of Mr. Bowman, who bases his proposal of a 5 – 10 year increase on "the lack of information outside of peer comparators for the Waterwheels, Turbines and Generators accounts, and the notably longer lives adopted almost universally by peers."[1167] As noted in Section 4.6.1.2.3 above, the Panel gives low weight to the peer comparators, and does not consider them appropriate for setting average service lives.

4.6.5.12 Gates (C23604)

Table 56: Gates (C23604)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C23604	Gate	$339,741,067	40	45	AMPC: 50

[1165] BC Hydro Reply Argument, Part 8.F(j), pp. 122 – 123.
[1166] BC Hydro Reply Argument, Part 8.F(i), p. 123.
[1167] Exhibit C7-11, p. 34.

Concentric recommends a revised average service life of 45 years for Account C23604.[1168] As part of Concentric's peer analysis, Concentric considered Ontario Power Generation at 50 years, NALCOR at 80 years, and FBC at 40 years.[1169]

Concentric states the "best life/dispersion" Iowa curve for this account is 45-R5, with a residual measure of 0.0563. The residual measure for the existing 40-R2.5 Iowa curve is 0.5206 and the residual measure for the recommended 45-R4 Iowa curve is 0.1240.[1170]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that there has been a large amount of investment based on a growing industry knowledge to ensure reliability for spillway gates.[1171]

Concentric clarified that the assets in Accounts C23604 are:

> […] related to gates and the component parts of gates required for the safe function of the hydro electric generation dams. In recent years, there has been a large amount of investment in these accounts due to the growing industry wide knowledge of the safe and reliable construction and maintenance of these assets.
>
> […]
>
> The selection of an average service life estimate is often dependant on the historical information available. As the previous depreciation study was conducted 15 years prior to the current depreciation study, there has been a large amount of information gained about the assets in these accounts. While this information has indicated that a life shortening from the previous estimate of 50 years was required, it has also indicated that a life of 40 years was too short. Consequently, Concentric has fine tuned the estimate to result in an average service life estimate of 45 years for these accounts.

Mr. Bowman states this account was shortened to 40 years from 50 years in the 2005 Concentric Depreciation Study. Although Concentric's recommendation appears to be driven by the peer analysis and operational interviews with both weighed at "medium", the operational notes say nothing of life. The interview notes only state that there has been a lot of investment to ensure reliability which notionally would be understood to link to a modest factor supporting lengthening of life. While Concentric's peer analysis shows a range of 40 years to 80 years, Manitoba Hydro uses 65 years for water control structures and 80 years for spillways, where gates may reside.[1172]

Mr. Bowman states Concentric's recommendation is entirely inconsistent with Waneta's conservative economic planning horizon of 40 years. Waneta related assets within this account make up over $5 million of the $13 million in depreciation for this account and are projected to be fully depreciated within 18-19 years of the 2021 net book valuation of $98 million. Absent the proposed life adjustment, the assets should be fully amortized within 13-14 years of 2021.[1173]

Moreover, Mr. Bowman states it is also important to consider the Site C investment, which will add 50 percent to this account's net book value when it comes into service.[1174]

[1168] Exhibit B-2-1, Appendix T, Table 1 p. 28.
[1169] Exhibit B-8, AMPC IR 21.1, Attachment 1.
[1170] Exhibit B-8, AMPC IR 27.1.
[1171] Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 27.
[1172] Exhibit C7-11, Section 2.3.3.4, p. 35.
[1173] Exhibit C7-11, Section 2.3.3.4, pp. 35 – 36.
[1174] Exhibit C7-11, Section 2.3.3.4, p. 36.

Mr. Bowman states that it would appear appropriate to revert to the 50 year life used for Account C23604 as of the depreciation study prior to 2005. This would be more consistent with the assumptions underpinning the Waneta purchase, and would reflect the reliability investments highlighted in the operational interviews. More importantly, this would bring BC Hydro closer to the range used by most of the peers, which is the highest weighted source of life comparisons available in this account.[1175]

Mr. Kennedy states that the assets contained in Account C23604 are steel structures that are susceptible to corrosion at a faster rate in BC than in Manitoba or in the inland locations of the NALCOR plants. A moderated life extension of 5 years already represented an 11 percent increase in the average service life estimate, and a larger change is not appropriate.[1176]

Positions of the Parties

AMPC submits Mr. Bowman's recommendation to increase the average service life for Account C23604 should be warranted based on the reasons as set out in Mr. Bowman's evidence.[1177]

AMPC submits that Mr. Kennedy is not an engineer capable of speaking to corrosion, or a hydrologist capable of speaking to the corrosiveness of water that goes through gates. Specifically, Mr. Kennedy does not explain why BC's water is more corrosive, why NALCOR's inland plants are less susceptible to corrosion than BC Hydro's inland generation like Waneta or Site C, or why BC Hydro has not designed and established the specifications for its gates to be of increased resistance to this corrosion. AMPC submits that Mr. Kennedy's comments on the matter of corrosion should be given no weight.[1178]

BC Hydro submits that AMPC's argument regarding Mr. Kennedy being not qualified to speak to corrosion rates is without merit. The impacts of factors such as corrosion on the average service life of assets are within the scope of expertise of a depreciation expert.[1179]

In regards to the concept of gradualism, AMPC submits Mr. Bowman's recommendation is sufficiently gradual.[1180]

BC Hydro submits that Concentric has already explained, as part of the IRs, why being consistent with the historic average service life prior to the 2005 Concentric Depreciation Study is not reasonable.[1181]

As for the peers referenced by Mr. Bowman, BC Hydro states Mr. Kennedy has explained, as part of his rebuttal evidence, that the corrosive environment to which the assets in Account C23604 makes it not comparable to Manitoba Hydro or in the inland locations of NALCOR.[1182]

Regarding Mr. Bowman's statement on the implications of Waneta, BC Hydro submits that the interpretation of the Waneta information is incorrect as Mr. Bowman misunderstands depreciation concepts as described in Section 4.6.5.10 above for dams and the powerhouse.[1183]

[1175] Exhibit C7-11, Section 2.3.3.4, p. 36.
[1176] Exhibit B-36, Appendix A, Section III, A32, p. 35.
[1177] AMPC Final Argument, Chapter 5, p. 5-38 – 5-39.
[1178] AMPC Final Argument, Chapter 5, p. 5-39.
[1179] BC Hydro Reply Argument, Part 8.F(k), p. 128.
[1180] AMPC Final Argument, Chapter 5, p. 5-39.
[1181] BC Hydro Reply Argument, Part 8.F(k), p. 127.
[1182] BC Hydro Reply Argument, Part 8.F(k), p. 128.
[1183] BC Hydro Reply Argument, Part 8.F(k), p. 128.

In reply to Mr. Bowman's statement that Site C assets should last longer, BC Hydro submits, similar its reply in Section 4.6.5.10 above for dams and the powerhouse, that Mr. Bowman's views of the life of Site C are no more than speculation. In subsequent depreciation studies, the average service lives will be reviewed again and can take into account any new information regarding Site C that may suggest an increase is warranted.[1184]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C23604, "Gate" should increase from 40 years to 45 years, as proposed by Concentric.

The Panel finds that an average service life of 45 years for account C23604 is reasonable because:

- The best fitting Iowa curve, which is recommended by Concentric, has an average service life of 45 years.
- The recommended average service life of 45 years is within the peer range of 40 years (FBC) and 80 years (NALCOR).

The Panel is not persuaded by Mr. Bowman's evidence, on which AMPC relies for its proposal to increase the average service live of this asset account to 50 years, for the following reasons:

- The fact that this account used to have an average service life of 50 years in 2005 is not compelling. Too much water has passed through the gates since 2005 for this conclusion to be relevant today.
- As noted in Section 4.6.1.2.3 above, the Panel gives low weight to the peer comparators, and does not consider them appropriate for setting average service lives.
- The fact that Waneta assets will be fully depreciated in 18-19 years does not give the Panel any indication of the age of the assets at retirement, merely when they will be retired.
- The fact that Site C might add 50 percent to the NBV of this account does not indicate anything to the Panel regarding the average service life of the assets in the account.

4.6.5.13 Software (C80302)

Table 57: Software (C80302)

Asset Class	Asset Class Description	NBV as at March 31, 2020	Existing Average Service Life	Concentric Recommended Average Service Life	Contested Recommended Service Life
C80302	Software, Enterprise Systems	$67,023,205	10	10	AMPC: 11-12

Concentric does not recommend average service life changes to Account C80302.[1185] As part of Concentric's peer analysis, Concentric considered NALCOR which uses 7 years and FBC which uses 8 years.[1186]

Based on Concentric's interview notes compiled in preparing the Depreciation Study, the subject matter experts state that Account C80302 contains the SAP, Passport, Sharepoint, and other Enterprise level software. SAP is essentially fully depreciated as it is about 10 years old excluding the recently implemented SAP – Supply Chain Applications. There are ongoing upgrades to the individual SAP modules which include betterments and functional enhancements to the specific modules. Betterments can also include vendor-provided technical

1184 BC Hydro Reply Argument, Part 8.F(h), p. 122 and part 8.F(k), p. 128.
1185 Exhibit B-2-1, Appendix T, Table 1 p. 32.
1186 Exhibit B-8, AMPC IR 1.21.1, Attachment 1.

upgrades, functional enhancements, and security upgrades and patches to keep the application within vendor support requirements. The betterments are assigned 5 year lives under a separate asset account because they are associated with the ERP application that will be used by BC Hydro for at least that many additional years. There is also a trend toward cloud ERP solutions that may be deemed intangible assets.[1187]

BC Hydro provided a breakdown of fully depreciated assets within Account C80302 that are still in service.[1188] BC Hydro also states SAP is scheduled for various upgrade in F2023-F2025 to maintain vendor support after 2027.[1189]

Mr. Bowman states the depreciation expense for Enterprise Software (C80302) is among the costliest accounts in the asset class breakdown at $20 million per year. Almost $7 million per year of depreciation expense, or over one-third of the account, relates to the Supply Chain Applications, which were approved to proceed in BCUC Order G-78-19.[1190]

As part of BC Hydro's Supply Chain Applications Project Phase Two Application, BC Hydro states that the benefits of the Supply Chain Applications (SCA) will cease at the end of the ten-year accounting life of the IT asset, but that it is reasonable to expect the software will continue to be in use beyond the ten-year period. While it is reasonable to expect the new IT system to be in place for more than ten years, BC Hydro has only calculated reduced cost and effort cash flow benefits for a period equal to the ten year accounting life of the IT asset placed in service bythe SCA Project.[1191]

Mr. Bowman states Concentric's recommendation to retain the 10 year average service life is based on a "high" weighting to operational interviews, and "medium" to peers. In this case, where the data relate to a limited number of mainframe software packages with relatively short lives, BC Hydro's own experience and expectations should be the main driver of life analysis.[1192]

Mr. Bowman states the operational interviews notes are consistent with BC Hydro's evidence which note that there is material SAP investment remaining in service despite being past its 10 year life projection.[1193]

Mr. Bowman states just and reasonable rates do not arise from adopting depreciation lives that are likely to be too short. In the case of enterprise software, the already experienced life of SAP software led to excessive depreciation over an unreasonably short period. Expectations of the same occurring with the very large Supply Chain Application cannot be supported based on the information available.[1194]

Mr. Bowman states an additional major software package is the SMI Energy Analytics software which is used for multiple functions on smart metering data, and was installed between 2013 and 2016 for a total cost of over $33 million.[1195] The net book value at March 31, 2021 was $14 million, and depreciation expense totals over $5 million per year, meaning the asset has an average remaining life of less than 3 years (i.e., to 2024). The Application notes a number of related software investments but nothing of the scale needed to replace the SMI Energy Analytics software.[1196] In short, absent further detail on an expectation that BC Hydro expects to retire in

[1187] Exhibit B-8, AMPC IR 23.1, Attachment 1, p. 21.
[1188] Exhibit B-20, AMPC IR 11.5, Attachment 1.
[1189] Exhibit B-2, Section 6.5.1.5, p. 6-103.
[1190] Exhibit C7-11, Section 2.3.4.1, pp. 36 – 37.
[1191] BC Hydro Supply Chain Applications Project Phase Two Application, Exhibit B-1, Section 3.4, pp. 3-18 – 3-19.
[1192] Exhibit C7-11, Section 2.3.4.1, p. 37.
[1193] Exhibit C7-11, Section 2.3.4.1, p. 37.
[1194] Exhibit C7-11, Section 2.3.4.1, pp. 37 – 38.
[1195] Exhibit C7-11, Section 2.3.4.1, p. 38; Exhibit B-20, AMPC IR 23.1.
[1196] Exhibit C7-11, Section 2.3.4.1, p. 38; Exhibit B-2, Section 6.5.1.5, p. 6-103.

full the SMI Energy Analytics software in favour of a major replacement, there does not appear to be a reasonable likelihood that this major software package supports the 10 year average life either.[1197]

Mr. Bowman states NALCOR and FBC apply their asset lives to a much larger set of software, including what BC Hydro includes in Mid Range (C80303, at 5 years), Upgrades (C80305, at 2 years) and PC Software (C80314, at 4 years), so there is no readily available conclusion that the peers are using any shorter life than BC Hydro across the Software categories. Further, it is noted that FBC's depreciation study indicates that 8 years is used for non-AMI software of all types, but that AMI software is set at 10 years, which is not indicated in Concentric's peer review in this proceeding.[1198]

Based the software discussed above, Mr. Bowman states that a 10 year average life for an asset account that focuses only on large enterprise or mainframe software packages is not supported. BC Hydro's evidence indicates that this life is too short for the experienced life of SAP, and for the projected life of the major Supply Chain Application. The same conclusion likely applies to the SMI Energy Analytics software package, which it appears is likely not slated for outright retirement in F2024, particularly given BC Hydro's apparent recent reinvestments into this package. On this basis, Mr. Bowman recommends a small lengthening of life for Account C80302 category is likely merited. As the life of the account is still relatively short, a 1-2 year extension is likely a reasonable adjustment to implement at this time. Despite this short length of adjustment, this is still a 10-20 percent increase, the effect on the fairness to ratepayers over time will be material.[1199]

Mr. Kennedy states that Mr. Bowman fails to recognize that capital investment related to newer versions and upgrades are made throughout the life of the software package as a whole. While the upgrades to the Enterprise software systems are capitalized to a shorter life account, the new version or release renders some of the original investment as redundant to the new investment. As such, not all of the investment at the time of the original installation can be expected to last for the complete life of the software package including new versions and releases. Therefore, the average life of the investment will be shorter than the overall life of the software in total.[1200]

Positions of the Parties

AMPC submits that Mr. Bowman and Mr. Kennedy are not in disagreement over the basic fact that BC Hydro typically continues to use software beyond the ten year life of this account in the cases of SAP, Supply Chain Application, and SMI Energy Analytics. The disagreement is the interpretation of that fact. Mr. Bowman suggests this reflects the longer lives of this software, whereas Mr. Kennedy suggests it arises due to capital investment due to newer versions and upgrades that are made throughout the life of the software package as a whole.[1201]

AMPC submits that Mr. Kennedy gave no examples of his assertion that some aspects of the original software investment were retired. Also, if BC Hydro is not accounting for these interim retirements of software throughout its life, this software should not also receive a shorter life accounting for these retirements that are never booked. In essence, current ratepayers would be paying increased depreciation expense over the shorter life without benefitting from reduced depreciation expense for the portions that are retired on an interim basis.[1202]

AMPC submits that BC Hydro also provided no rebuttal evidence that the software in question, or any components of its original investment, were slated for removal or discontinuance. Outside of the original

[1197] Exhibit C7-11, Section 2.3.4.1, p. 38.
[1198] Exhibit C7-11, Section 2.3.4.1, p. 38.
[1199] Exhibit C7-11, Section 2.3.4.1, pp. 38 – 39.
[1200] Exhibit B-36, Appendix A, Section III, A33, pp. 35 – 36.
[1201] AMPC Final Argument, Chapter 5, p. 5-40.
[1202] AMPC Final Argument, Chapter 5, p. 5-40.

investment uninstalled from the functions for which it was purchased, the investment should be depreciated over the period in which it is providing benefits. Similar to physical assets, absent a disposal, the original purchase continues to provide value even if further investment was undertaken over time to increase functionality or security.[1203]

Based on this, AMPC submits Mr. Bowman's recommendation should be preferred.[1204]

BC Hydro submits that Concentric's opinion is that there is no information provided in the operational interviews, peer review or from Concentric's knowledge of the Canadian electric industry to justify a change in the average service life at this time.[1205]

In response to Mr. Bowman's view that BC Hydro's experience with SAP and expectation for new packages like Supply Chain Applications warrants a 1-to-2-year increase in the average service life of Account C80302, BC Hydro submits that Mr. Kennedy already explained, in his rebuttal evidence, that ongoing upgrades render portions of the original investment redundant. As such, not all of the investment at the time of the original installation can be expected to last for the complete life of the software package, including new versions and releases, and therefore the average life of the investment will be shorter than the overall life of the software in total.[1206]

In response to AMPC's argument that BC Hydro should be accounting for interim retirements, BC Hydro submits AMPC is missing the point of Mr. Kennedy's rebuttal, which is that not all of the investment at the time of the original installation can be expected to last for the complete life of the software package including new versions and releases. Therefore, the average life of the investment will be shorter than the overall life of the software in total.[1207]

Panel Determination

The Panel determines that the appropriate average service life for depreciation purposes for account C80302, "Software, Enterprise Systems" should remain at 10 years, as proposed by Concentric.

The Panel finds that an average service life of 10 years for account C80302 is reasonable because:

- The recommended average service life of 10 years is within the peer range of 7 years (NALCOR) and 10 years (FBC).
- There is nothing in Concentric's notes from interviews with BC Hydro staff to demonstrate that the average age at which enterprise software is benig retired is more than 10 years.

The Panel is not persuaded by AMPC's proposal to increase the average service life by 1 – 2 years, based on Mr. Bowman's evidence. We are persuaded by BC Hydro's evidence that the lives of some enterprise software assets in this account are shortened due to software upgrades, which cause some or all of the original value of the software to be retired from this account and the value of the upgrade to be recorded in a different asset account. Therefore, even though some enterprise software has a total life greater than 10 years, its life in this account may not be that long.

1203 AMPC Final Argument, Chapter 5, p. 5-40.
1204 AMPC Final Argument, Chapter 5, p. 5-40.
1205 BC Hydro Reply Argument, Part 8.F(l), p. 128.
1206 BC Hydro Reply Argument, Part 8.F(l), p. 129.
1207 BC Hydro Reply Argument, Part 8.F(l), p. 129.

4.6.6 Other Issues

4.6.6.1 Reconstruction of Historical Asset Retirement Data

Concentric states that the pre 2011 retirement data were not used as part of the actuarial analysis due to the deemed cost adjustments made when BC Hydro transitioned to the Prescribed Standards on April 1, 2011 and IFRS on April 1, 2017 for accounting purposes.[1208] Mr. Kennedy clarified that as part of the deemed cost adjustments, the costs of BC Hydro's assets were adjusted to match the net book value of those assets at the time of adjustment.[1209] The actuarial analysis completed as part of a depreciation study requires the comparison of the dollar value of retirements to the dollar value of additions and current costs. When the assets were revalued, this comparison was no longer possible.[1210]

BC Hydro states that it does not maintain pre-fiscal 2011 transactional retirement data. Pre-fiscal 2011 data were stored within the legacy PeopleSoft financial system with configuration applying the Canadian Generally Accepted Accounting Principles (CGAAP). Even if the data were available, it would be of limited value because the pre-fiscal 2011 data would be before IFRS deemed cost adjustments, and therefore would not be compatible with the data for F2013 to F2020.[1211]

Concentric states that it would have liked to incorporate the pre-2011 retirement data including the data from the 2005 depreciation study in the actuarial analysis for the current Depreciation Study.[1212] BC Hydro took a snapshot of original cost data of assets in service at the time of the deemed cost adjustments, and that following the F2019 deemed cost adjustment BC Hydro continued to record new assets on the books at their original cost.[1213] Concentric states the restatement of the pre-2011 retirement data would require a significant number of assumptions and all of the 2005 and prior retirement transactions would need to be restated to a 2019 market value cost base. When looked at in total, Concentric determined that it was not feasible for the data from the 2005 study to be used in the current Depreciation Study.[1214] Contrary to Concentric's statement above, BC Hydro states only data from the interim period between those two deemed cost adjustments that would need to be adjusted for to reconstruct the required data set.[1215]

Concentric states that although the pre-2011 retirement data, including the results of the 2005 Depreciation Study, was not used in the actuarial analysis, it was used to inform Concentric's professional judgement.[1216] Concentric explained that the limitation on retirement data is not unique to BC Hydro as other utilities such as EPCOR, Hydro One and AltaGas all share the same issue.[1217]

Position of the Parties

AMPC submits that BC Hydro should be directed to reconstruct its missing historical asset retirement data to allow for a proper actuarial analysis as part of its next depreciation study. AMPC notes the evidence of Mr. Layton that BC Hydro would only need to reconstruct the data from the period between the two deemed cost

[1208] Exhibit B-8, RCIA IR 103.5; Exhibit B-20, AMPC IR 8.1; Exhibit B-36, Section 2, A4, pp. 3 – 4; Exhibit B-36, Appendix A, Section II, A8, pp. 3 – 4; 2022-09-20 Oral Hearing Transcript Volume 2 PM, pp. 286 – 287.
[1209] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 223 line 12 to p. 224 line 13.
[1210] Exhibit B-36, Appendix A, Section II, A8, p. 4.
[1211] Exhibit B-8, AMPC IR 22.6.
[1212] Exhibit B-36, Appendix A, Section II, A9, p. 4; 2022-09-20 Oral Hearing Volume 2 AM, p. 239 lines 5 to 10.
[1213] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 224 line 10 to p. 225 line 10.
[1214] Exhibit B-36, Appendix A, Section II, A9, p. 4.
[1215] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 225 lines 11 to 14.
[1216] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 177 line 3 to p. 178 line 8.
[1217] Exhibit B-36, Appendix A, Section II, pp. 5 – 7.

adjustments. AMPC further submits that BC Hydro should be directed to file as part of its compliance filing a plan to retore the missing data.[1218]

In reply, BC Hydro submits that it should not be directed to attempt to reconstruct its historical asset retirement data because the data are not needed to set depreciation rates, there is no evidence that reconstruction is feasible or how much it might cost, and that the cost is not warranted.[1219]

BC Hydro adds that its snapshot of original cost data before conversion was never adjusted for asset additions, retirements or transfers that occurred subsequent to the conversion, and that it is "no longer possible to compare the dollar value of additions and current costs, as required for actuarial purposes." BC Hydro submits that even if it could reconstruct the data between the 2013 and 2019 deemed cost adjustments, BC Hydro would still be missing the data from 2005 to 2010, when it went through an accounting system change and did not retain the transactional retirement data.[1220]

BCOAPO submits that BC Hydro should be directed to investigate "the costs and time required to develop a consistent and comparable set of historic data and maintain it going forward" within 6 to 12 months after the BCUC issues its decision in order that direction can be provided to BC Hydro as to the BCUC's expectations for the next depreciation study.[1221]

Panel Determination

The Panel directs BC Hydro to file with the BCUC as a compliance filing, within 3 months of the date of this Decision, an analysis of the following:

- **The feasibility, effort and cost of reconstructing BC Hydro's historical asset retirement data prior to 2011.**
- **The value of using reconstructed historical asset retirement data compared to using BC Hydro's operational records of asset retirements and their mean lives to estimate or verify the average service lives of its assets.**

The Panel has already expressed its concerns regarding the paucity of BC Hydro's historical asset retirement data, and the resulting reliance by Concentric on qualitative factors such as professional judgement. Considering the significance of the depreciation expense as a proportion of the total revenue requirement, the Panel is not satisfied that BC Hydro has done enough to demonstrate that it cannot reasonably recreate the single most valuable quantitative source of evidence on which a depreciation study relies.

The Panel recommends that the BCUC consider directing BC Hydro to reconstruct the historical asset retirement data if BC Hydro's compliance filing indicates this to be reasonable, and that the reconstructed data be used in BC Hydro's next depreciation study.

4.6.6.2 Consideration to use Group Accounting for Capital Assets

Concentric states BC Hydro's current account structure makes peer review difficult. However, difficulties comparing accounts is a typical problem for depreciation studies. As there is no formal Uniform System of Accounts across Canada, it is essential that depreciation experts have an in-depth knowledge of the assets included in each account of each specific peer. It is not sufficient to simply look at the names of accounts to

[1218] AMPC Final Argument, pp. 5-40 to 5-42.
[1219] BC Hydro Reply Argument, pp. 93–96.
[1220] BC Hydro Reply Argument, pp. 93–96.
[1221] BCOAPO Final Argument, p. 67.

make a comparison. Differences such as the asset material, climate, regulatory environment, and retirement policies will inevitably add complexity to the peer review. A complex series of accounts adds some degree of difficulty to the peer review, however decisions such as the account structure should never be made in the interest of creating an easier peer review.[1222]

To illustrate, for BC Hydro's asset account C22007, Concentric states peer utilities do not typically have an account with the envelope related assets alone. Consequently, the assets in this account tend to have longer lives in peer utilities and therefore, the peer review is of limited value.[1223]

Mr. Bowman states for most utilities, grouped accounting methods are adopted where all assets of a given class are grouped and a single depreciation rate applied to the group.[1224] However, BC Hydro does not use group accounting.[1225] In BC Hydro's case, every asset is depreciated over either the life that the asset experiences, or the adopted depreciation life, whichever is shorter. This means an asset will always fully depreciate either before or at the average life chosen. In contrast, most utilities use a group depreciation approach. So, for assets that have a 50 year service life, the average depreciation period for the assets will be 50 years, with assets retiring both before and after that average. BC Hydro uses the average life from Concentric as if it is the maximum life. "[This] means comparisons appear utilities should acknowledge that equivalence can only occur when BC Hydro's lives are longer than those for a utility who uses group accounting."[1226]

Positions of the Parties

AMPC submits BC Hydro should be directed to investigate and implement group accounting for its asset accounts as part of the next RRA to make it more analogous to its peers and allow depreciation studies to occur on a like-for-like basis, and because BC Hydro's current approach harms present-day ratepayers relative to future generations and there is no compelling reason to continue it. AMPC explains that for a typical utility that uses group accounting, the average service lie is in fact an average, whereas due to its unit accounting treatment, BC Hydro's average service lives are "effectively applied as terminal retirement dates" and assets are fully depreciated once they reach their "average" life. AMPC submits that BC Hydro's approach skews its collection of depreciation expense to recover its capital more quickly than the average life for its assets.[1227]

In reply, BC Hydro submits that there is no evidence in this proceeding whether group accounting methods are feasible for BC Hydro under IFRS or what the cost would be to investigate or implement such a change. There is also no evidence whether changing to group accounting will in fact have a favourable rate impact, as AMPC appears to assume. BC Hydro submits that if the BCUC is interested in exploring group accounting, it would be amenable to investigating and reporting back to the BCUC in the next RRA, but that there should be no direction to implement a different approach before details are known about the feasibility, cost and time required to implement any change.[1228]

BC Hydro further submits that AMPC's suggestion that BC Hydro's accounting practice should be taken into consideration when choosing the average service lives "reveals a bias in AMPC's assessment" because the determination of average service lives is unrelated to the accounting practice that uses the average service lives to depreciate the assets, and shows that Mr. Bowman has leaned toward choosing a maximum service life rather than an average service life.[1229]

[1222] Exhibit B-36, Appendix A, Section II, A13, pp. 12 – 13.
[1223] Exhibit B-2-1, Appendix T, p. 18.
[1224] Exhibit C7-11, Section 2.1, p. 8.
[1225] Exhibit C7-11, Section 2.2, p. 10; 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 414 lines 23 – 24.
[1226] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 414 line 24 to p. 415 line 13.
[1227] AMPC Final Argument, pp. 5-14 to 5-16.
[1228] BC Hydro Reply Argument, pp. 92–93.
[1229] BC Hydro Reply Argument, p. 93.

RCIA shares similar concerns as AMPC and argues that BC Hydro's accounting practices create an unfair bias towards accelerated depreciation. RCIA recommends that BC Hydro be directed to alter its accounting practices so that depreciation collection reflects the life over which assets will render service.[1230]

Panel Determination

The Panel directs BC Hydro to submit an analysis on the use of group accounting by December 31, 2023.

The Panel finds that group accounting has the potential to improve comparability between BC Hydro and its peers for depreciation purposes. The Panel notes the evidence of Concentric that some BC Hydro asset classes, e.g. C22007 – Buildings, Envelope, are not typically broken out in this level of detail.

The Panel considers that, to the extent that group accounting would improve BC Hydro's comparability with its peers, it would be beneficial to adopt this practice prior to the next depreciation study (see Section 4.6.6.3 below).

4.6.6.3 Timing of the Next Depreciation Study

BC Hydro is forecasting depreciation expense to be $1.15 billion, $1.18 billion, and $1.24 billion for fiscal years 2023, 2024 and 2025.[1231] In comparison, BC Hydro is forecasting a revenue requirement of $5.33 billion, $5.53 billion and $5.78 billion for each of the same fiscal years respectively.[1232]

As part of the Depreciation Study, Concentric notes that the depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity.[1233]

Mr. Bowman states depreciation is about the pace of recovering capital investments already made, to ensure fairness between current and future customers. Utilities typically update their depreciation estimates on a relatively routine basis, intending generally smaller and gradual changes to be the norm. Failing to make adjustments when merited can lead to excessive deferral of fair cost levels, and more severe changes in later years.[1234]

Mr. Bowman states BC Hydro's last depreciation study was dated March 31, 2005, which was filed with the BC Hydro F2007-F2008 RRA. In the study, it was noted that continued surveillance and periodic revisions are normally required to maintain continued use of appropriate depreciation rates. Additionally, Mr. Bowman states BC Hydro had a partial depreciation analysis performed in 2010 which was filed with the BC Hydro F2012-F2014 RRA. The partial depreciation study did not analyze retirement history nor recommend any changes to average service lives.[1235]

Mr. Bowman states that it is advisable to sustain a pattern of routine depreciation updates that roughly matches a cycle of 3 to 7 years, or about every second major rate update. In the case of BC Hydro, with the long time frame since the last study, the broad number of issues and adjustments that need to be dealt with at this time, and the need to improve the quality of actuarial assessment and peer comparability, it is likely a study may be required in each of the next few general rate application (GRA)s, to permit issues to be addressed in an orderly fashion. After that, reversion to a cycle of 3 to 7 years, or every second GRA, is advisable.[1236]

[1230] RCIA Final Argument, p. 50.
[1231] Exhibit B-2, Chapter 8.3, Table 8-2, p. 8-4.
[1232] Exhibit B-2, Chapter 1.5, Table 1-4, p. 1-59.
[1233] Exhibit B-2-1, Appendix T, p. 11.
[1234] Exhibit C7-11, Section 2.1, p. 6.
[1235] Exhibit C7-11, Section 2.1, p. 6.
[1236] Exhibit C7-19, RCIA IR 1.1.

BC Hydro states that it plans to obtain depreciation studies approximately every 2 to 3 revenue requirement application cycles. BC Hydro believes that this aligns with Concentric's advice that depreciation rates should be reviewed periodically. BC Hydro considers obtaining a depreciation study every 2 to 3 revenue requirement application cycle appropriately balances the benefits of a depreciation study to the costs of obtaining one.[1237]

For reference, Mr. Layton states the current depreciation study is estimated to cost $500,000 to $600,000 dollars. $200,000 pertains to the study itself, and the remainder is the regulatory support through answering Irs, providing rebuttal evidence and other activities.[1238]

Position of the Parties

MoveUP recommend that, if the BCUC is inclined to stipulate a general frequency cycle for BC Hydro to undertake future depreciation studies, it should be set at the upper end of the five- to ten-year duration suggested by Mr. Kennedy in the hearing.[1239]

No other parties made submissions on the date of BC Hydro's next depreciation study.

Panel Discussion

BC Hydro's most recent comprehensive depreciation study prior to the one it filed as part of this RRA examined assets in service as of March 31, 2005, over 15 years ago. Also, BC Hydro's depreciation expense is a significant part of its total revenue requirement, $1.2 billion out of a total revenue requirement of $5.3 billion in 2023. For these reasons, it is not surprising that there was considerable intervener interest in the topic of depreciation in this proceeding.

The Panel has already commented in Section 4.6.1 of this Decision on the limitations of the current Depreciation Study, including the lack of historical asset retirement data prior to 2011, and for these reasons the Panel finds that BC Hydro's next depreciation study should be submitted as soon as is reasonably possible.

The Panel also finds that the next depreciation study could be materially improved if BC Hydro addresses the relevant directives made by the Panel elsewhere in this Decision, and in particular if BC Hydro were able to reconstruct its historical asset retirement data prior to 2011. However, the BCUC will not be able to assess the feasibility, costs and benefits of reconstructing these data until BC Hydro fulfils the Panel's directive in Section 4.6.6.1 above. Therefore, we do not direct BC Hydro to file its next depreciation study by a particular date, but instead recommend that the BCUC consider directing BC Hydro to file its next depreciation study as soon as possible, once the BCUC has been able to consider BC Hydro's response to the directive in Section 4.6.6.1 above.

4.6.6.4 More Thorough Assessment of Distribution Related Assets

Mr. Bowman states that given the excessive range of functions and accounts, it was not possible to fully explore other major accounts that affect revenue requirement, particularly distribution accounts where BC Hydro's lives are well below the peer averages.[1240] These include:[1241]

1) C52201 – Distribution transformers: This account has over $1.1 billion in March 31, 2021 deemed cost and over $45 million in depreciation expense and is the second highest annual depreciation expense behind only C21001 Embankment and Concrete Dams. BC Hydro uses a 35-year life.

[1237] Exhibit B-36, Section 2.2, A8, p. 6.
[1238] 2022-09-20 Oral Hearing Transcript Volume 2PM, p. 359 lines 1 to 10.
[1239] MoveUP Final Argument, p. 5.
[1240] Exhibit C7-11, Section 2.3, p. 16.
[1241] Exhibit C7-20, Zone II RPG IR 2.2.

Newfoundland Hydro uses 55 years, and Fortis BC uses 42 years. In addition, though not cited by Mr. Kennedy, ATCO Electric in Alberta uses 50 years (recently increased from 40 years).

2) C55201 and C55202 Services: These two accounts have almost $0.45 billion in March 31, 2021 deemed cost, and over $12.7 million in annual depreciation expense. BC Hydro uses 45 year lives. Newfoundland Hydro uses 60 years, and Fortis BC uses 55 years.

3) C55301 Underground distribution cable. This account has over $1 billion in March 31, 2021 deemed cost, and over $34 million in annual depreciation expense. BC Hydro uses a 40 year life. Newfoundland Hydro uses 60 years, and Fortis BC uses 55 years. In addition, though not cited by Mr. Kennedy, ATCO Electric in Alberta uses 55 years.

Mr. Bowman recommends it would be appropriate to include the above accounts in a more thorough and detailed assessment.[1242]

Position of the Parties

AMPC submits the recommendations made by Mr. Bowman on distribution-related accounts of C52201 (Distribution transformers) C55201 and C55202 (Services) and C55301 (Underground distribution cable) should be accepted.[1243]

BC Hydro submits that Mr. Bowman makes no recommendations, but rather explains that he did not review these accounts and only comments that the existing lives are lower compared to peers. BC Hydro submits that given that Mr. Bowman did not review these accounts and makes no recommendations, Concentric's recommendation to continue with the current, BCUC-approved lives for these accounts should be accepted.[1244]

Panel Discussion

The Panel has already noted that BC Hydro's next depreciation study should be more comprehensive. The Panel sees no further action is necessary with respect to AMPC's request, and notes BC Hydro's observation that AMPC is not proposing changes to the average service lifes of the accounts listed above.

4.7 Net Salvage

BC Hydro is requesting approval to implement the net salvage percentages recommended by Concentric in the Depreciation Study for ratemaking purposes using the "Traditional Method" effective F2026.[1245] As part of its next RRA, BC Hydro plans to describe the phase-in approach for review and approval, and request approval of a Net Salvage Regulatory Account to facilitate the implementation of net salvage.[1246]

Based on this, the Panel addresses the following questions:

1. Which method of net salvage, if any, should BC Hydro adopt?
2. Based on the method chosen, what is the appropriate net salvage percentages to apply?
3. Is the exclusion of certain asset classes from net salvage appropriate?
4. When should net salvage be implemented?

[1242] Exhibit C7-11, Section 2.3, p.16.
[1243] AMPC Final Argument, Chapter 5, p. 5-1.
[1244] BC Hydro Reply Argument, Part 8.F(m), pp. 129 – 130.
[1245] Exhibit B-2, Section 8.4.4, p. 8-28; Exhibit B-19, BCUC IR 206.1.
[1246] Exhibit B-2, Section 8.4.4, p. 8-28.

4.7.1 Net Salvage Methodology

In response to Directives 39 and 40 from the BCUC's F2020-F2021 RRA Decision and Order No. G-246-20, BC Hydro retained Concentric to assess methodologies used for recovery of dismantling costs, recommend an appropriate methodology, perform a net salvage study for determination of negative salvage rates, and evaluate whether the implementation of net salvage rates is appropriate for BC Hydro.[1247]

As part of its Depreciation Study, Concentric discussed five methods of net salvage which may be applicable for BC Hydro:[1248]

1. Use of the Traditional Method to calculate the required net salvage percentages;
2. Use of the Constant Dollar Net Salvage to calculate the required net salvage percentages;
3. Expensing cost of removal as incurred (also known as "Pay as you go");
4. Capitalizing cost of removal to the installation cost of replacement; and
5. Trust Fund and Securitization methods.

The Traditional Method involves using historical net salvage data, informed professional judgment which incorporates a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the net salvage estimates from Concentric's studies of other electric utilities to derive recommended net salvage percentages which are then recovered from ratepayers as part of depreciation.[1249]

The Constant Dollar Net Salvage method involves estimating what the future retirement costs would be based on prospective inflation assumptions and historical net salvage data adjusted for past inflation, and performing a discounted cashflow analysis to determine how much should be recovered as part of the current period's revenue requirement.[1250]

The "Pay as you go" method is what BC Hydro currently uses and involves estimating and including the cost of retirement in the revenue requirement of the test period in which it is anticipated.[1251]

Capitalizing the cost of removal to the installation cost of replacement involves capitalizing the costs of removal for replacement projects to the installation costs associated with the new asset. The retirement costs of the replaced assets are then recovered through the depreciation on the new replacement asset.[1252]

The Trust Fund and Securitization methods involve the creation of an external fund for the purpose of financing future costs of removal with customers paying a surcharge on the current use to find the future obligation.[1253]

The table below is a summary of the pros and cons analysis provided by Concentric for each method:[1254]

Table 58: Pros and Cons of Different Net Salvage Methodologies

Net Salvage Methodologies	Pro	Con
Traditional Method	• Currently approved by the BCUC for FortisBC Inc, FortisBC Energy, and Pacific Northern Gas	• Does not deal with the issue of technological change in the assets currently being retired as compared

[1247] Exhibit B-2, Section 8.4.1, pp. 8-19 – 8-20.
[1248] Exhibit B-2-1, Appendix T, pp. 708 – 709.
[1249] Exhibit B-2-1, Appendix T, pp. 16 and 709 – 710.
[1250] Exhibit B-2-1, Appendix T, pp. 710 – 712.
[1251] Exhibit B-2-1, Appendix T, pp. 712 – 713.
[1252] Exhibit B-2-1, Appendix T, pp. 713-714.
[1253] Exhibit B-2-1, Appendix T, pp. 714 – 715.
[1254] Exhibit B-2-1, Appendix T, pp. 709 – 716.

Net Salvage Methodologies	Pro	Con
	• Generationally equitable • Most widely used and accepted method • Adjusts for inflation in the future requirement of net salvage • Well understood by most regulators	to those historically retired • Assumes the future work to retire assets will be the same as historic work • Can prematurely erode rate base
Constant Dollar Net Salvage Method	• Currently approved by the OEB for Enbridge Gas • Generationally equitable • Adjusts for inflation in the future requirement of net salvage • Reduces the net negative salvage burden on current customers • Calculations are similar to the calculations for Asset Retirement Obligations as defined by IFRS	• Method often rejected because of the complexity • Requires specific estimates of historic inflation and future discount rates
Expense Cost of Removal As incurred (Pay as You Go Approach)	• No estimate of either historic or future inflation required • Potential reduction in forecast error • Is compliant with most accounting guidelines	• Not generally equitable • Increased utility risk
Capitalizing the Cost of Removal to the Installation Cost of Replacement	• No estimate of either historic or future inflation required • Potential reduction in forecast error • Reduces the need for any type of regulatory deferral account treatment	• Not generally equitable providing that service • Inflates and compounds the amount of future depreciation expense with each generation of asset replacement • Increased utility risk
Trust Fund and Securitization Method	• Provides a means to recover costs from ratepayers that benefit from the assets during the life of the asset • Growing trust fund lowers the customer contribution amounts • Securitization provides utility with a near-term infusion of cash to offset the seeding of the trust funds	• Regulatory oversight can be an administrative burden • Securitization tends to reduce future utility earnings • Credit ratings are sensitive to increasing capital costs • Deterioration of credit metrics • Reduced financing flexibility • Crowding out new rate base investments

Concentric evaluated the methods of net salvage based on seven objectives:[1255]

[1255] Exhibit B-2-1, Appendix T, p. 718.

Table 59: Summary of Compliance of Each Option to the Overall Objectives

SUMMARY OF COMPLIANCE OF EACH OPTION TO THE OVERALL OBJECTIVES

Option / Principle	Traditional Method	Constant Dollar Net Salvage (CDNS)	Expense Cost of Removal as incurred	Capitalizing Cost of Removal as an Installation cost of replacement Assets	Trust Funds and Securitization Methods
1. Matching depreciation expense to used and useful rate base	1	2	4	5	3
2. Ability to respond to changes in Cost of Removal estimates	3	2	1	4	5
3. Ability to deal with the impacts of inflation	3	1	4	5	2
4. Impact on the revenue requirement	3	2	5	4	1
5. To ensure the future cost of removal/retirement requirements are adequately provided for	1	2	4	5	3
6. Provides for a smoothed method	2	3	5	4	1
7. Regulator Acceptance	1	5	2	4	3
Total Ranking	**14**	**17**	**25**	**31**	**17**

Concentric states that it is aware of four utilities that moved away from the Traditional Method within the last 20 years including Altalink LP, Enbridge Gas Distribution, Manitoba Hydro and Yukon Electric Corporation Limited.[1256] At the same time, Concentric notes that many utilities who collect net salvage have been doing so in excess of 20 years. To Concentric's knowledge, there are 17 Canadian utilities which use the Traditional method to net salvage.[1257] Mr. Kennedy testified that the Traditional Method is still by far the most widely used approach in North America.[1258]

[1256] Exhibit B-8, AMPC IR 38.7.
[1257] Exhibit B-8, AMPC IR 38.6.
[1258] 2022-09-20 Oral Hearing Volume 2 AM, p. 264 line 23 to p. 265 line 3.

Based on its evaluation, Concentric recommends BC Hydro adopt the Traditional Method to implement net salvage.[1259]

Evidence of Mr. Bowman

AMPC filed evidence from its expert, Mr. Bowman, which recommends BC Hydro implement the following alternative net salvage methodologies:[1260]

1. Interim retirements: When the costs of removing an asset from service are incurred to facilitate the installation of a new asset, the removal costs are added to the new asset's costs.
2. Terminal retirements: As it becomes possible to estimate the fair value of the cost and the timing for removing assets, a decommissioning liability for those assets should be recognized at that time and amortized into rates over the period from when the estimates are prepared until the asset is decommissioned.

Mr. Bowman states the Traditional Method is inferior due to the following issues:

1. A better equitable outcome, in real economic terms, arises from collection of salvage costs later in an asset's life rather than earlier.[1261] Mr. Bowman states the following factors support this:
    a. The cost profile of most assets reduces over time as the asset is depreciated, rate base is reduced, and the total carrying costs for capital therefore declines. This is because depreciation is already imposed in nominal terms meaning today's customers pay more in inflation-adjusted, or real, terms, because the rate base gets paid down over time meaning today's customers pay more towards the utility's return on a set of assets than future customers, and because assets are typically built to accept or support utility load growth in meaning today's customers are already paying more to facilitate lower cost future service. This concept was echoed by the Alberta Utilities Commission in its decision for the ATCO 2015-2017 Transmission General Rate Application.[1262]
    b. The assumption that any carry forward, other than perhaps undepreciable land value, to the second generation is unfair to customers in the second generation of the asset is flawed because there is considerable value that is transferred from the first generation of customers to the second. The first generation of ratepayers are depreciating (on a straight-line basis) all costs to acquire, licence, remove any existing occupying infrastructure, and prepare the site for the first generation of use, plus under BC Hydro's proposal all costs to similarly prepare the site for the second generation of use, all within the first generation of the asset. Imposing this collection on an equal nominal basis through all years of the asset's first generation exaggerates the load on existing customers. This concept was explained by Commissioner Lyttle in the decision for the ATCO 2015-2017 Transmission General Rate Application.[1263]
2. BC Hydro's proposal is not in keeping with standard practice. The most relevant peers for BC Hydro would appear to be Manitoba Hydro and Newfoundland Hydro, as each is Crown-owned, makes use of very long-lived assets, is regulated in respect of all major functions, and is in the process of integrating large new capital projects in the last or next few years. Both of these utilities use effectively the same approach as Mr. Bowman's recommendation. Other relevant utilities also use or have been directed to explore methods that are alternatives to the "traditional" method including Altalink, Yukon Energy

[1259] Exhibit B-2-1, Appendix T, p. 720.
[1260] Exhibit C7-11, Section 3.10, p. 57.
[1261] Exhibit C7-11, Sections 3.4, p. 45.
[1262] Exhibit C7-11, Section 3.5, pp. 47 – 48; Exhibit C7-11, Appendix B, Section 6.0, pp. B-6 – B-13.
[1263] Exhibit C7-11, Section 3.5, pp. 48 – 51.

Corporation, EPCOR, AltaGas and ATCO.[1264] Specifically, Mr. Bowman is not aware of any utilities that transitioned to the Traditional method in the recent years.[1265]

3. Reimplementing the Traditional Method is frustrated by the decisions of the BCUC to draw down the previous balance from 2005-2017 (over $200 million), which must now be re-established, and adversely impacts regulatory stability. The proposal is particularly ill-suited in a case where better and more modern approaches to net salvage, which also better suit the IFRS accounting standard, have been adopted by BC Hydro's peers and are available to BC Hydro as well.[1266]
4. The most inferior time to charge net salvage using the Traditional Method is when large new additions to plant are occurring. As the initiation of major new capital in rate base brings with it pressures on straight-line depreciation, interest, and returns on rate base, the added pressures from the traditional approach to net salvage are ill-timed. As such, the timing for Site C is not supportive of moving to the Traditional Method.[1267]
5. The Traditional Method suffers from potential obfuscation of spending on dismantling costs, where the current approach offers a high visibility to the regulator.[1268]
6. The Traditional Method has a high degree of exposure to assumptions about future inflation. There is an implicit inflationary index built into the net salvage percentage calculated using the Traditional Method that implies historical inflation is reflective of future inflation.[1269]
7. There are incentives for utilities to collect net salvage early. Since monies collected for net salvage are for future expenses, they are typically applied as an offset to rate base, operating to reduce the overall total cost of capital until the amounts are spent.[1270] If BC Hydro's allowed return continues to be fixed, that offsetting benefit is lost and the harm to ratepayers from the traditional approach would be even greater. In the event the BCUC is in favour of early collection of net salvage as proposed by BC Hydro, serious consideration should be given to the trust fund and securitization approach where any cash provided to BC Hydro for the purposes of future net salvage should not be considered an offset to rate base or any form of deferral, but should be externally invested, as a bona fide trust fund or securitization. This would appear to be the only option available to ensure ratepayers at least benefit somewhat from the time value of the collections imposed on them.[1271]

Mr. Bowman also states Concentric's evaluation of the various methods of net salvage in the Depreciation Study is unreliable for the following reasons:[1272]

1. Concentric's conclusions do not accord with the issues laid out above. Concentric's evaluation of the net salvage methodologies appears highly subjective and incorrect. For example, Concentric lists the traditional approach as the method highest rated for "regulator acceptance". However, Concentric gives no examples of regulators adopting or speaking favourably about imposing the traditional approach, and ignores the multiple examples noted above of regulators rejecting the traditional approach (e.g., Yukon Energy), transitioning away from this approach (e.g., Altalink), or recommending utilities study alternatives (e.g., AltaGas or ATCO Gas). It is also not apparent that regulators have any lower acceptance of the approaches adopted by Manitoba Hydro nor of Newfoundland Hydro, which were approved out of regulatory processes.

[1264] Exhibit C7-11, Sections 3.4 and 3.6, pp. 45 and 52 – 53; Exhibit C7-11, Appendix B, Section 4.0, pp. B-4 – B-5.
[1265] Exhibit C7-22, BCOAPO IR 7.1.
[1266] Exhibit C7-11, Sections 3.4 and 3.7, pp. 45 and 53 – 54.
[1267] Exhibit C7-11, Sections 3.4 and 3.8, pp. 45 and 54; Exhibit C7-15, BCUC IR 12.1; Exhibit C-7-22, BCOAPO IR 7.2.
[1268] Exhibit C7-11, Sections 3.4 and 3.9, pp. 46 and 55; Exhibit C7-11, Appendix B, Section 4.0, pp. B-4 – B-5.
[1269] Exhibit C7-11, Appendix B, Section 5.0, pp. B-5 – B-6.
[1270] Exhibit C7-11, Appendix B, Section 3, pp. B-3 – B-4.
[1271] Exhibit C7-15, BCUC IR 11.2.
[1272] Exhibit C7-11, Section 3.10, p. 56.

2. It is unclear how Concentric determines that the other methods to net salvage will not recover the amount necessary to retire the asset. It is also not clear how Concentric reconciles this conclusion with the “active recent decisions out of regulators who have represented their duties in adopting approaches other than the traditional approach.”
3. Concentric adopts no criteria dealing with some of the most critical flaws of the Traditional Method such as the extreme reliance on long-dated hypotheses about what costs will be incurred to remove assets, nor the significant front-end loading of costs that arises from the traditional approach.

Mr. Bowman offers the following alternative evaluation of the Traditional Method and his recommendation:[1273]

Table 60: Mr. Bowman Net Salvage Methodology Evaluation

Criteria	Concentric Approach	Mr. Bowman Approach[1274]
Alignment and matching of the depreciation expense to the rate base providing used and useful service	Low to Moderate	High
Ability of the method to respond to changes in the cost of removal estimates	Moderate	High
Ability to deal with the impacts of inflation	Unknown	High
Impact on the revenue requirement	High	Lower
To ensure the future cost requirements are adequately provided for	Yes.	Yes.
Provide for a smoothed methods of Cost of Removal/Retirement recovery	Low	High
Regulator acceptance	No evidence of regulators adopting this approach in recent years	Multiple examples of regulators adopting this approach in recent years

Based on the above considerations, Mr. Bowman states the approaches used by BC Hydro’s closest peers are far more suitable for BC Hydro’s situation than either the current approach, or the approach recommended by BC Hydro and Concentric.[1275]

<u>Rebuttal evidence</u>

BC Hydro and Concentric responded to the issues raised by Mr. Bowman on the Traditional Method as follows:

1. The movement away from the previous Future Removal and Site Restoration Fund in 2005 was due to changes in accounting standards. The funds have since been drawn down between fiscal 2005 and 2018 to cover actual retirement costs which resulted in lower customer rates for that time period which

[1273] Exhibit C7-15, BCUC IR 13.5.
[1274] Mr. Bowman coins this as “Altalink/Manitoba Hydro/NALCOR Approach.”
[1275] Exhibit C7-11, Section 3.10, p. 56.

raised the intergenerational equity concerns as outlined in Directive 40 of the BCUC's Decision and Order No. G-246-20 on BC Hydro's F2020-F2021 RRA.[1276]

2. The impact of Site C on net salvage expenses is limited to 0.02 percent in annual bill increases between fiscal 2026 and 2031.[1277] Additionally, not every Site C asset has a proposed net salvage percentage at this time.[1278] Mr. Bowman is incorrect in suggesting that the most inferior time to charge net salvage using the Traditional Method is when large new additions to plant are occurring. When the recovery of the costs to retire the asset at the end of its life is allocated over the entire period of the asset providing utility service, all users of the system contribute to the entire cost of the asset over the complete life of the asset being in service. Delaying costs to the end of the project's life is a high-risk approach that has not been successful in other utilities such as NALCOR.[1279] Due to sustaining capital throughout the life of the project, the cost of the project does not decrease during the later years which does not create room for additional expenses.[1280]

3. There is no loss of transparency as BC Hydro will record and report its net salvage expenses separately from accumulated depreciation. BC Hydro expects to propose the establishment of a new Net Salvage Regulatory Account to record the net salvage transactions which will be separate from accumulated depreciation. BC Hydro's reporting of regulatory account shows the components of the activity for each regulatory account (e.g., amortization is shown separately from additions/reductions). The actual dismantling costs incurred will be separately presented as account reductions and will be clearly reported.[1281]

4. Mr. Bowman favors backend loading the recovery of net salvage requirements and shifting "a very significant cost burden to future ratepayers."[1282] Allocating net salvage costs during the life of the related plant is more appropriate and equitable and is in accordance with authoritative texts and most Uniform Systems of Accounting including those published in Alberta, Ontario, the Canada Energy Regulator (formerly the National Energy Board of Canada) and the Federal Energy Regulatory Commission. Delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage. Many jurisdictions across Canada recognize the regulatory benefit and fairness to the inclusion of the recovery of the net salvage requirements over the period of time that assets are providing regulatory service including, but not limited to, the BCUC, the Alberta Utilities Commission, and the Ontario Public Utilities Board.[1283] Lastly, if utilities waited until the net salvage costs are more finite to start collecting, they will have less time to collect a large amount as compared to collecting a little over a long period of time.[1284]

5. While Mr. Bowman provides a significant amount of Commissioner Lyttle's comments, he fails to disclose that it was from a dissenting opinion from the majority decision which approved the use of the Traditional Method to Net salvage. Commissioner Lyttle provided a dissenting view of the reasonableness of the traditional method and suggested that a sinking fund type method that transfers a burden of recovery of costs of retirement to future users could be considered equitable as current users are paying a higher amount of return due to the higher rate base of the asset in the early portion of its life.[1285]

[1276] Exhibit B-36, Section 3, A9, p. 7.
[1277] Exhibit B-36, Section 3, A10, p. 8.
[1278] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 369 lines 13 to 24.
[1279] Exhibit B-36, Appendix A, Section III, A37, pp. 41 – 42; 2022-09-20 Oral Hearing Volume 2 AM, p. 272 lines 7 – 21.
[1280] 2022-09-20 Oral Hearing Transcript Volume 2 AM, p. 270 line 9 to p. 273 line 11.
[1281] Exhibit B-36, Section 3, A11, pp. 8 – 9.
[1282] Exhibit B-36, Appendix A, Section III, A35, pp. 37 – 38.
[1283] Exhibit B-36, Appendix A, Section III, A36, pp 39 – 40.
[1284] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 339 lines 5 to 11.
[1285] Exhibit B-36, Appendix A, Section III, A37, pp. 40 – 41.

6. Other utilities have transitioned to the Traditional Method for net salvage in the last 10 years including FortisBC Energy Inc., FortisBC Inc., Pacific Northern Gas and American Water Missouri.[1286]
7. Ratepayers benefit from the time value of money for funds collected by BC Hydro related to future net salvage expenses as the money can be used as working capital to offset other requirements for cash for the utility through their working capital. Specifically, BC Hydro plans to use the funds to lower the financing charges associated with interest costs. BC Hydro has not considered accruing interest on the funds collected.[1287]

Positions of the Parties

BC Hydro submits that its proposed traditional approach to net salvage should be approved for the following reasons: [1288]

- The BCUC had identified the potential for intergenerational inequity to result from the current methodology, and BC Hydro agrees.
- Concentric evaluated various approaches and recommended the Traditional Approach to net salvage, which will address intergenerational inequity.
- Mr. Bowman's approach does not address intergenerational inequity and should not be accepted.

BC Hydro submits that its current "pay as you go" approach can result in intergenerational inequity because the cost of dismantling is recognized at a point in time after the asset's service life rather than being recognized equally over the life of the asset while it is in service. As a result, the ratepayers at the asset's end of life, who may differ from those at the beginning or throughout the asset's life, will bear the full cost of dismantling the asset.[1289]

BC Hydro submits that the traditional approach to net salvage will address the issue of intergenerational inequity. BC Hydro submits that the traditional method of net salvage is equitable because those customers benefiting from the asset in service are responsible for the total cost of the asset, including the costs of retirement of the asset. BC Hydro points to Concentric's evidence that the traditional method of net salvage is "most appropriate for BC Hydro at this time", consistent with recent approvals by the BCUC, and "is also the most accepted method of recovering future costs of removal by regulators throughout North America." [1290]

BC Hydro submits that Mr. Bowman's proposal for net salvage should be rejected for the following reasons:[1291]

1) BC Hydro argues that Mr. Bowman's proposal for net salvage would not address intergenerational equity concerns because the cost of retiring assets would be applied to future ratepayers who may never have benefited from the retired assets, shifting "a significant cost burden to future ratepayers." [1292]
2) BC Hydro also argues that Mr. Bowman's proposal for net salvage is "contrary to the widely accepted view that the current users of the system should be responsible for the costs of removal for the assets currently providing service".[1293]

[1286] Exhibit B-36, Appendix A, Section III, A37, p. 43; 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 370 line 17 to p. 371 line 17.
[1287] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 366 line 15 to p. 368 line 8.
[1288] BC Hydro Final Argument, pp. 166-167.
[1289] BC Hydro Final Argument, pp. 166-167.
[1290] BC Hydro Final Argument, pp. 167, 169.
[1291] BC Hydro Final Argument, pp. 169–177.
[1292] BC Hydro Final Argument, p. 170.
[1293] BC Hydro Final Argument, pp. 171.

3) Contrary to Mr. Bowman's characterization of the Traditional Method as being rare, BC Hydro submits that the traditional method is "by far the most widely used approach" and has been accepted by regulatory bodies across Canada.[1294]

4) Contrary to Mr. Bowman's view that implementing traditional net salvage would be ill-advised with Site C entering rate base, BC Hydro submits that it is optimal to adopt the traditional approach when large projects enter rate base. [1295]

5) BC Hydro argues that its proposed traditional approach to net salvage retains transparency, and does not suffer from "potential obfuscation of spending on dismantling costs" as claimed by Mr. Bowman. BC Hydro explains that it will record and report on both its net salvage expense and actual dismantling costs incurred, and expects to propose the establishment of a new net salvage regulatory account to record net salvage transactions separately from accumulated depreciation.[1296]

BCSEA submits that it supports BC Hydro's proposed traditional approach to net salvage because it promotes intergenerational equity. BCSEA further submits that Mr. Bowman's proposed approach does not address intergenerational equity and should not be accepted.[1297]

The CEC submits that it supports BC Hydro's proposed traditional approach to net salvage rates.[1298]

MoveUP does not expressly support BC Hydro's proposed traditional approach to net salvage, but notes that AMPC's proposal is "a particularly stark effort to shift cost from current ratepayers onto future generations." MoveUP notes problems with AMPC's approach, including the "glib assumption" that "'all required approvals, confirmed social acceptability on its use, competing land interests settled, and complementary infrastructure' that were in place when an asset was constructed will remain unchanged over the decades."[1299]

AMPC submits that the BCUC should reject BC Hydro's proposal to implement the traditional approach, and should instead adopt Mr. Bowman's recommended approach which capitalizes the cost of interim retirements, and only collects for terminal retirements once there is some certainty about an asset's retirement date and the costs to remove it. [1300]

According to AMPC, there are "many shortfalls" with the traditional approach. AMPC submits that the traditional approach is "heavily exposed to assumptions about future economic conditions, like inflation" and that depreciation studies "typically assume that the next fifty years will look like the past fifty years." This concern is exacerbated by the fact that under the traditional approach, net salvage amounts are recovered on a straight-line basis rather than based on an estimate of real dollars, which means that current ratepayers will always pay more on a real dollar basis than future ratepayers.[1301]

AMPC submits that, in BC Hydro's specific case, ratepayers would not receive the typical benefits associated with accruing net salvage since BC Hydro's return is fixed and not tied to a return on rate base. AMPC adds that BC Hydro's rebuttal evidence suggests that, even if BC Hydro's future return were to be determined based on rate base, it is not known whether the net salvage regulatory liability would be included in rate base, which adds to AMPC's concerns.[1302]

[1294] BC Hydro Final Argument, pp. 172.
[1295] BC Hydro Final Argument, pp. 172–174.
[1296] BC Hydro Final Argument, p. 175.
[1297] BCSEA Final Argument, p. 32.
[1298] CEC Final Argument, p. 101.
[1299] MoveUp Final Argument, pp. 6–7.
[1300] AMPC Final Argument, p. 6.
[1301] AMPC Final Argument, p. 5-44.
[1302] AMPC Final Argument, p. 5-45.

In AMPC's view, Mr. Bowman's recommended approach to net salvage provides "better intergenerational equity" than BC Hydro's proposed traditional approach. AMPC submits that understanding the intergenerational equity associated with net salvage approaches requires consideration of all the costs and benefits associated with an asset over time, not just those associated with net salvage.[1303]

AMPC submits that regulated assets typically provide service at reduced cost to customers over their life because:[1304]

- Straight line depreciation on a nominal basis means that today's ratepayers pay more in real terms than do future ratepayers;
- Rate base associated with regulated assets gets paid down over time, so where the utility earns a regulated return, ratepayers pay less over time; and
- Assets are typically built to accommodate load growth, so today's customers generally pay more for service to facilitate future service.

AMPC submits that Mr. Bowman's proposed approach to net salvage for terminal asset retirements addresses intergenerational equity "by shifting net salvage expense away from current customers that are paying more than their fair share for these assets to those who benefit from these assets when at a lower cost." AMPC explains that BC Hydro would establish a decommissioning liability once it is possible to estimate the cost and timing for removal, and amortize that liability into rates such that it is fully paid once the asset is decommissioned. All customers paying this net salvage expense are customers who also benefit from the asset while it remains in service.[1305]

AMPC submits that Mr. Bowman's proposed approach to net salvage for interim asset retirements "likewise matches benefits to costs" and that capitalizing the replacement costs as part of the replacement asset "fairly reflects the value provided to customers across generations." AMPC submits that it is "fair across time for future customers to pay the cost to salvage costs associated with these assets because of the corresponding benefits they receive." [1306]

In reply, BC Hydro submits that AMPC's position that Mr. Bowman's approach is more equitable is based on the "false premise" that customers pay "more than their fair share" of asset costs during the early years of an asset compared to the later years. BC Hydro acknowledges that the cost of depreciation calculated on a straight-line basis may decrease over time due to the impact of inflation, but submits this is a feature of the time value of money that applies to all ongoing costs. BC Hydro submits that the recovery of depreciation expense and return on equity over the life of an asset "is just and reasonable and fairly recovers the cost of assets."[1307]

BC Hydro further submits that Mr. Bowman's proposed approach to net salvage either makes marginal improvements to BC Hydro's current pay as you go approach or exacerbates its inequity. BC Hydro explains that for terminal asset retirements, Mr. Bowman's approach offers "only a very marginal improvement" as net salvage would only be recovered at the very end of the asset's life rather than after the asset is retired. BC Hydro adds that RCIA's submission that there will be "considerable lead time…measured in decades rather than years" is not based on any evidence and should be disregarded. For interim asset retirements, BC Hydro submits

1303 AMPC Final Argument, pp. 5-45 to 5-46.
1304 AMPC Final Argument, p. 5-46.
1305 AMPC Final Argument, p. 5-50.
1306 AMPC Final Argument, p. 5-51.
1307 BC Hydro Reply Argument, pp. 139–140.

that Mr. Bowman's approach exacerbates intergenerational inequity by "foisting all net salvage costs entirely on future generations of customers that will not be benefiting from the asset at all."[1308]

AMPC submits that under Mr. Bowman's proposed approach, both for terminal and interim asset retirements, net salvage costs are determined closer to the time of retirement and are not subject to the same concerns about "reliance on assumptions rooted far into the future as the traditional approach is." [1309]

In reply, BC Hydro submits that Mr. Bowman's proposed approach to net salvage is "far more exposed to assumptions about future conditions" than the traditional approach, which undermines its purported benefits for customers. BC Hydro provides the following examples: [1310]

- Mr. Bowman's assumption that there will be "room" to collect net salvage at the end of an asset's life is highly uncertain, and Mr. Kennedy has testified that there is in fact no such "room".
- Mr. Bowman's assumption that today's customers will pay more for service than future customers due to load growth is premised on continued load growth and assumptions about the costs to serve that increasing load, and is "deeply uncertain."
- Mr. Bowman's approach is based on the uncertain premise that assets at the end of their life will be an "exceptional gift" to future customers. BC Hydro submits that while this may be the case for some assets, it is highly uncertain whether it will be true for all assets. BC Hydro adds that it estimates positive net salvage for some assets, and reiterates that it has excluded from net salvage those assets where removal is not applicable or expected to be minimal.

AMPC submits that Newfoundland Hydro and Manitoba Hydro, both Crown-owned utilities that make use of very long-lived assets, use "effectively the same approach" to net salvage as Mr. Bowman's proposal. Further, this approach is becoming more pervasive, particularly in Alberta, where AltaLink and EPCOR both recover some or all salvage costs related to replacement projects as part of the capital cost of the replacement asset, and AltaGas and ATCO Gas have recently been directed to investigate alternatives to the traditional approach.[1311]

AMPC submits that many of the utilities Mr. Kennedy cites as using the traditional method of net salvage are "like comparing apples to oranges." AMPC explains that owners of coal-fired generators and pipeline utilities are different in their abandonment liabilities that need to be accrued for, whereas these concerns do not extend to a large electric utility like BC Hydro where key infrastructure may have "an indefinite life for all intents and purposes."[1312]

In reply, BC Hydro submits that AMPC does not dispute that the traditional approach to net salvage is the most widely used approach, and in BC Hydro's view the approach has been so extensively adopted because it is considered to be "the most equitable approach to the recovery of net salvage." BC Hydro submits that AMPC's submission that the comparison of approaches is "like comparing apples to oranges" is not substantiated by any analysis and is speculative. BC Hydro points out that Mr. Bowman was "not even aware of many utilities that used the Traditional Approach." [1313]

BC Hydro further submits that the Alberta Utilities Commission (AUC)'s decision to approve an approach similar to that of Mr. Bowman's for AltaLink was specific to the circumstances facing AltaLink at that time, and that BC

[1308] BC Hydro Reply Argument, pp. 144–145.
[1309] AMPC Final Argument, p. 5-51.
[1310] BC Hydro Reply Argument, p. 150.
[1311] AMPC Final Argument, pp. 5-52 to 5-53.
[1312] AMPC Final Argument, p. 5-55.
[1313] BC Hydro Reply Argument, pp. 145–146.

Hydro is not in similar circumstances. As a result, BC Hydro submits that the AUC decision referred to by AMPC should not be followed.[1314]

AMPC submits that the factors that make the traditional approach to net salvage inequitable are magnified during periods where large capital projects such as Site C are coming online, and that while BC Hydro's current net salvage proposal does not extend to a large portion of Site C's assets, there is no reason to expect that Site C will be exempted going forward. AMPC submits that Site C is expected to come online while BC Hydro has an energy surplus for a decade or more, thus Mr. Bowman's justification for his approach that current customers pay for infrastructure needed for future load growth applies "with even more force." AMPC adds that BC Hydro's current customers are also being required to pay for load growth by funding BC Hydro's Electrification Plan spending, and thus adding to the case for delaying net salvage recovery.[1315]

In reply, BC Hydro submits that AMPC's argument that current ratepayers "will soon be bearing significant costs associated with Site C as a result of front-ending recovery of net salvage" rests on a misunderstanding about the net salvage costs of dams. BC Hydro explains that 56 of its asset classes have been assigned zero net salvage value, including account C21001 (dam, embankment / concrete), which has a net book value of over $2.5 billion, and other dam-related accounts, thus excluding from net salvage those assets where removal is not applicable or is expected to be minimal. BC Hydro refers to its final submission that adoption of the traditional approach to net salvage is optimal when large projects such as Site C enter rate base as this facilitates the recovery of net salvage costs from ratepayers over the entire life of the asset.[1316]

BC Hydro further submits that after Site C comes into service, and without the effects of the Electrification Plan, its energy surplus will be eliminated in F2029. BC Hydro adds that the length of the surplus and the fact that Site C was approved by the Province and not through a BCUC CPCN process is irrelevant to the net salvage question. Further, BC Hydro submits that its Electrification Plan will produce benefits for customers, and in any case is also irrelevant to determining the most equitable approach to net salvage.[1317]

AMPC submits that re-implementing the traditional approach to net salvage, which BC Hydro abandoned in 2005, is contrary to regulatory stability, which should "aid in achieving durable and predictable approaches to setting rates." AMPC submits that during the 12-year period after 2005 ratepayers benefited from not having to contribute towards salvage-related costs, and not having to pay any salvage-related costs that were incurred, and as a result BC Hydro's proposed approach means that current ratepayers will be required to pay substantially increased costs to address BC Hydro's "failure to collect salvage since 2005." [1318]

In reply, BC Hydro submits that AMPC's claim that BC Hydro recently decided to abandon the traditional approach to net salvage in 2005 is misleading. BC Hydro states that the change in approach happened in 2004 when the Canadian Generally Accepted Accounting Principles changed to asset retirement obligation accounting, which was adopted by BC Hydro and approved by the BCUC in the Decision and Order G-96-04. BC Hydro submits that the history from 2004 has little bearing on the issue of the equitable approach to the recovery of net salvage. [1319]

BC Hydro submits that the traditional approach to net salvage is in fact "a durable and predictable approach to ratemaking, which has been widely used throughout Canada for many years," whereas Mr. Bowman's approach

[1314] BC Hydro Reply Argument, pp. 146–148.
[1315] AMPC Final Argument, p. 5-56.
[1316] BC Hydro Reply Argument, pp. 140–-142.
[1317] BC Hydro Reply Argument, pp. 142–143.
[1318] AMPC Final Argument, p. 5-57.
[1319] BC Hydro Reply Argument, p. 148.

has been adopted by “only a few other utilities and not demonstrated to be ‘durable and predictable.’” BC Hydro adds that the evidence of Mr. Kennedy is that Mr. Bowman’s approach has “repeatedly failed.” [1320]

AMPC submits that Mr. Bowman’s recommended approach to net salvage increases transparency of salvage-related costs, which “should in the long run impose cost discipline on BC Hydro.” AMPC explains that under the traditional method, a utility’s spending on reclamation or dismantling costs is effectively charged to accumulated depreciation and often not forecast in an RRA, or at least with any accuracy. AMPC submits that this justification supports adoption of Mr. Bowman’s recommended approach to net salvage.[1321]

In reply, BC Hydro submits that the traditional approach to net salvage will not result in any loss of transparency because BC Hydro will “clearly record and report on its net salvage expense” separately from accumulated depreciation.[1322]

Finally, AMPC submits that even if the BCUC does not agree with Mr. Bowman’s primary recommendation, it should at a minimum implement his alternate recommendation that a constant dollar net salvage approach be applied to levelize the real dollar rate impacts. AMPC considers that current customers are “already overburdened by the real dollar impacts of depreciation, and will be even more so once Site C comes online,” and paying their share of net salvage costs on a real dollar basis would “ensure intergenerational equity.”[1323]

In reply, BC Hydro submits it is agreeable to the BCUC directing that “collected net salvage amounts should collect interest to offset the impact of inflation.” BC Hydro considers this to be a simpler and more efficient solution than the constant dollar net salvage approach, which as described by Concentric requires complex calculations and for this reason is often rejected.[1324]

BCOAPO submits that with respect to interim asset retirements, it is “both reasonable and consistent with the principal [sic] of intergeneration equity that ‘the costs to remove the asset from service should be added to the costs of the new asset” as recommended by Mr. Bowman.”[1325]

BCOAPO further submits that with respect to terminal asset retirements, it is necessary to consider the question of intergenerational equity holistically. From this perspective, BCOAPO submits that Mr. Bowman’s proposed approach to net salvage is fairer from an intergenerational equity perspective than BC Hydro’s proposed traditional approach.[1326]

BCOAPO submits that adopting Mr. Bowman’s proposed approach to net salvage, whereby estimates of net salvage costs would not be developed until later in the life of assets, would provide the time to allow for “the accumulation of additional data and to allow BC Hydro to carry out a full net salvage study on the individual asset class basis.” [1327] However, BCOAPO questions whether now is an appropriate time to implement net salvage, as “we would be, in essence, playing Russian Roulette because Hydro has not yet provided an estimate of the cost of implementing any changes.” BCOAPO submits that in the absence of and inability to test the evidence of the cost of such a change, approval of net salvage would be imprudent.[1328]

1320 BC Hydro Reply Argument, pp. 148–149.
1321 AMPC Final Argument, pp. 5-57 to 5-58.
1322 BC Hydro Reply Argument, p. 151.
1323 AMPC Final Argument, p. 5-52.
1324 BC Hydro Reply Argument, pp. 149–150.
1325 BCOAPO Final Argument, p. 70.
1326 BCOAPO Final Argument, pp. 71–72.
1327 BCOAPO Final Argument, p. 70.
1328 BCOAPO Final Argument, p. 72.

In reply, BC Hydro submits that the cost of implementing net salvage is not the issue, but rather the focus should be on taking the correct approach. BC Hydro submits that the cost of implementation should not be a barrier to the adoption of the traditional approach to net salvage.[1329]

BCOAPO submits that in the event the BCUC decides that the recovery net salvage costs should be carried out over the entire life of an asset, then the Constant Dollar Net Salvage Approach is preferable to the Traditional Approach because it will result a greater proportion of the net salvage costs being recovered in the later years of an asset's life.[1330]

RCIA submits that AMPC's recommended approach to net salvage for both interim and terminal asset retirements is preferable to BC Hydro's proposed traditional approach.[1331] RCIA submits that the key consideration is not which net salvage methodology is more popular, but rather which methodology addresses the circumstances of BC Hydro.[1332]

RCIA submits that BC Hydro's current "Pay as you go" approach to interim asset retirements is adequate because there are "regular streams of interim retirements for most asset classes" and aligns with AMPC's recommended approach rather than BC Hydro's proposed traditional approach.[1333]

RCIA submits that AMPC's proposal regarding terminal asset retirements has fewer intergenerational and inflation risk issues. AMPC submits that these issues are mitigated because "no monies are collected until BC Hydro has visibility into when a major terminal retirement will occur," and because there will be considerable lead time "measured in decades rather than years" allowing future ratepayers to benefit from assets for decades while also contributing to their terminal retirement cost.[1334]

In reply, BC Hydro submits that RCIA mischaracterizes the traditional approach to net salvage as "collecting monies for terminal retirement as soon as an asset enters service." BC Hydro submits that the traditional approach to net salvage "only starts to collect money when the asset enters service and does so over the asset's life, meaning that ratepayers that benefit from the asset are the ones that pay for it." (emphasis in original).[1335]

NTC submits that Mr. Bowman's proposed approach to net salvage "should be given serious consideration." NTC submits that this approach "appears imminently [sic] reasonable, especially for long-lived projects, since the cost and timing of the (possible) removal of the assets will not be known until much closer to the time of its ultimate termination, removal, or replacement."[1336]

Panel Determination

The Panel approves BC Hydro's use of the traditional method of accounting for net salvage.

The Panel finds that the traditional method of net salvage is more equitable to ratepayers of different generations than BC Hydro's current pay as you go approach. Under the traditional approach, net salvage is collected from ratepayers from the moment an asset enters service. This matches the recovery of the net salvage cost to the service provided by the asset more closely than the pay as you go approach, which only recovers the cost of net salvage after an asset leaves service and is not recovered while the asset was in service. This is potentially inequitable as the net salvage amounts are collected from ratepayers who may be different from those who benefited from the use of the asset during its life.

[1329] BC Hydro Reply Argument, p. 150.
[1330] BCOAPO Final Argument, p. 72.
[1331] RCIA Final Argument, p. 55.
[1332] RCIA Final Argument, p. 52.
[1333] RCIA Final Argument, p. 52.
[1334] RCIA Final Argument, p. 54.
[1335] BC Hydro Reply Argument, p. 150.
[1336] NTC Final Argument, pp. 33–34.

The Panel also notes that the traditional method of net salvage is the most widely accepted approach in Canada, and was recently approved by the BCUC for FortisBC Energy Inc., FortisBC Inc. and Pacific Northern Gas.

The Panel finds that the traditional method of net salvage is more appropriate to BC Hydro's current circumstances than Mr. Bowman's proposed approach, which is supported by AMPC and others, for the following reasons.

Under Mr. Bowman's proposed approach to net salvage, no net salvage amounts are recoverable when assets are initially put into service, so ratepayers enjoy the benefits of the utility's assets without paying for their eventual net salvage costs. If an asset is replaced, the net salvage costs associated with the replaced asset are recovered from ratepayers enjoying the benefits of the new asset, who may be different from the ratepayers during the life of the replaced asset. The Panel finds this to be inequitable.

If an asset is taken out of service and not replaced, Mr. Bowman proposes collecting net salvage from ratepayers only once it becomes possible to estimate the fair value of the cost and the timing for removing assets, and that the total net salvage would be recovered by the time the asset leaves service. Thus the ratepayers who enjoyed the benefits of the asset before its net salvage cost and timing could be estimated do not pay those costs. The Panel also finds this to be inequitable.

The Panel also finds that Mr. Bowman's proposed approach to net salvage is no less exposed to future economic assumptions than the traditional method of net salvage. While the traditional method requires an estimate of the net salvage cost and timing, both these factors may be re-estimated during the life of the asset and the net salvage recoveries adjusted such as through future depreciation studies. Mr. Bowman's proposed approach relies on the notion that there will be "room" towards the end of the life of an asset for ratepayers to be able to afford the cost of net salvage. The Panel is persuaded by Mr. Kennedy's evidence that this approach "has been tried a few times, and it's failed each and every time" because of the sustaining capital that must be invested during the life of an asset to preserve its usefulness.

The Panel now addresses a number of criticisms of the traditional method of net salvage raised by AMPC and others.

AMPC's view is that intergenerational equity associated with net salvage costs requires consideration of all the costs and benefits associated with an asset over time, and that today's ratepayers pay "more than their fair share" of asset-related costs due to inflation, load growth, and the value of the "exceptional gift" to future ratepayers when assets are replaced rather than terminally retired.

The Panel agrees that using the straight-line method of depreciation, the recovery of depreciation costs declines in real terms as a result of inflation. It is also true that today's ratepayers may, but not necessarily do, incur some of the cost of assets that are sized for future load growth. However, as BC Hydro has noted from the evidence of Mr. Kennedy, utilities also incur the cost of sustaining capital during the life of the asset. The consideration of absolutely all the costs and benefits of utility assets that AMPC submits is required to determine the appropriate net salvage method is beyond the scope of this proceeding.

The Panel is satisfied that the traditional method is a reasonably equitable approach to recovering net salvage costs from ratepayers, and that no alternative approach canvassed in this proceeding provides a clearly more equitable approach.

The Panel does not consider the timing of the Site C dam entering service is a reason not to adopt the traditional method of net salvage. The Panel has already found that not recovering net salvage costs from the start of an asset's life is inequitable. The increase in rates as a result of Site C, including the recovery of its net salvage amounts, is equitable because today's ratepayers will enjoy the use of the Site C assets. AMPC's point appears to relate to the affordability of Site C costs, which is not relevant to the choice of an appropriate net salvage methodology for BC Hydro.

The Panel is not concerned that the traditional method of net salvage is less transparent than Mr. Bowman's proposed method. The Panel is satisfied with BC Hydro's explanation that it intends to record and report on net salvage costs separately from accumulated depreciation.

The Panel does not agree with AMPC and BCOAPO that constant dollar net salvage is a more appropriate method for BC Hydro than the traditional method of net salvage. The Panel has already found that the traditional method of net salvage is equitable, and is persuaded by Concentric's evidence that the constant dollar net salvage approach requires "complex calculations and for this reason is often rejected." The Panel notes BC Hydro's comment that it would be agreeable to being directed to collect interest on collected net salvage amounts to offset the impact of inflation. The Panel considers that there is insufficient evidence in this proceeding to justify such a direction, but **directs BC Hydro to address in its next RRA whether collecting interest on collected net salvage amounts to offset the impact of inflation is just and reasonable**.

4.7.2 Net Salvage Percentages

BC Hydro seeks approval to implement the net salvage rates, as recommended by Concentric in the Depreciation Study, for ratemaking purposes effective F2026.[1337]

Concentric recommends the net salvage percentages as described in Table 1 of the Depreciation Study.[1338] The net salvage percentage recommendations were based on a combination of cost of removal (dismantling) and gross salvage transactions requiring the recovery of net salvage through March 31, 2020, comparison of the net salvage estimates from Concentric's studies of other electric utilities, and informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry.[1339]

Concentric states the estimates of net salvage percentages for the mass property accounts were based in part on historical data related to actual retirement activity for the years 2011 through 2020 at the functional group level. Gross salvage and cost of removal related to experienced retirements were used. Given that the historical data were available at an aggregated functional level, Concentric recommends that the net salvage percentages be determined at a functional level as follows:[1340]

- Generation accounts – 10 percent
- Transmission accounts – 30 percent
- Distribution accounts – 20 percent
- General Plant accounts – 5 percent
- Vehicle accounts – Various

In the development of the estimated net salvage percentage for each of the above functional groups, Concentric states that it has removed specific accounts that would not be expected to incur costs of removal or retirement, and any assets with an existing Asset Retirement Obligation.[1341]

Concentric states percentages of the cost of plant retired were calculated for each component of net salvage on an annual, three-year, five-year, and on a cumulative moving average basis. The same net salvage percentage

[1337] Exhibit B-2, Section 8.4.1, p. 8-20; Exhibit B-19, BCUC IR 206.1.
[1338] Exhibit B-2-1, Appendix T, pp. 28 – 33.
[1339] Exhibit B-2-1, Appendix T, pp. 8 and 16; Exhibit B-8, AMPC IR 22.2.
[1340] Exhibit B-2-1, Appendix T, Table 1 and 3, pp. 16, 20 – 33 and 35.
[1341] Exhibit B-2-1, Appendix T, p. 16.

was applied to all assets within the same functional group for accounts within the group that would be expected to incur costs of removal or retirement.[1342]

Section 6 of the Depreciation Study shows the calculated net salvage percentages for each functional level based on the available retirement data which show actual net salvage percentages of 38 percent for generation, 60 percent for distribution, 115 percent for transmission and 5 percent for other assets.[1343]

Concentric clarifies that the net salvage percentages recommended are moderated to be lower than what the actual historical data suggest based on its professional judgement of what is reasonable.[1344]

Concentric states that the net salvage percentages could be determined on a more detailed level (e.g., by asset class). However, as the historical data are only available on an aggregated functional level, the determination would not be reliant on historical data, but rather peer data and professional judgement. This results in less accurate estimates. However, Concentric expects that the net salvage percentages would not materially change given the weighting by deemed investment dollars and the average service life estimates. As such, the net salvage expense should be similar when applied to the functional group level.[1345]

BC Hydro clarifies that the net salvage percentages will need to be approved in the current Test Period in order to be implemented in the next test period. If the decision to approve the net salvage percentages is not provided in this Application, then BC Hydro would bring the proposals and implementation plan in the subsequent revenue requirements application, but expects that it would not be able to implement a change to net salvage (if approved in that revenue requirements application) until the following application. BC Hydro states this is because implementing net salvage would require new processes and system changes. Undoing such changes and then returning to the previous system would be costly in terms of time and effort.[1346]

Positions of the Parties

The CEC submits that it supports BC Hydro's proposed traditional approach to net salvage rates.[1347]

Panel Determination

The Panel approves the net salvage rates proposed by BC Hydro, contained in the Concentric report in Exhibit B-2, Appendix T, pp. 28 to 33, for use in the next test period.

The net salvage rates provided by Concentric are based on the traditional method of calculating net salvage, which the Panel has approved in Section 4.7.1 above.

The Panel notes that, while some interveners disagreed with BC Hydro's proposed method of calculating net salvage, no interveners raised concerns over the proposed net salvage rates.

The Panel notes that some of the net salvage percentages proposed by Concentric, on which the net salvage rates are based, are significantly lower than would be suggested by the actual asset retirement evidence. For example, Concentric proposes net salvage of 10 percent for generation assets, whereas the historical evidence demonstrates that the average net salvage amount between 2011 and 2020 was 38 percent. **The Panel directs BC Hydro, in its next depreciation study, to explain in detail why the recommended net salvage percentages differ from what would be suggested by the actual asset retirement evidence**.

[1342] Exhibit B-2-1, Appendix T, p. 17.
[1343] Exhibit B-2-1, Appendix T, pp. 681–684.
[1344] Exhibit B-19, BCUC IR 206.5.
[1345] Exhibit B-19, BCUC IR 206.3.
[1346] Exhibit B-8, AMPC IR 38.4.
[1347] CEC Final Argument, p. 101.

4.7.3 Excluded Asset Classes

In the development of the estimated net salvage percentage for each functional group, Concentric removed specific accounts that would not be expected to incur costs of removal or retirement, and any assets with an existing Asset Retirement Obligation.[1348]

Below is a table prepared by BC Hydro describing the asset classes that are excluded from net salvage and the potential regulatory treatment:[1349]

Table 61: Excluded Asset Classes

Category	Description	Potential Regulatory Treatment
Asset classes with net salvage rate of 1.0	Asset classes presented in Table 1 of Appendix T of the Application with a recommended salvage rate of 1.0 shown in Recommended Net Salvage column of the table are excluded from net salvage expense	These asset classes have been excluded as removal of the assets is not applicable (e.g. land rights), removal costs are expected to be minimal or the assets (e.g., dams) are expected to be maintained and remain in-service for the foreseeable future. For assets where removal is not applicable or removal costs are expected to be minimal, there is no regulatory treatment necessary as there is no or minimal impact to ratepayers (regardless of period). For assets such as dams, specific assets could be added to net salvage if a decision is made that the assets will be removed at a future date.
Asset classes with net salvage rate of <1.0	Asset classes presented in Table 1 of Appendix T of the Application with a value of less than 1.0 in the Recommended Net Salvage column (e.g., certain vehicle-related asset classes) have positive salvage values (as can be seen in the Recommended Positive Salvage Rate column) which are incorporated in the determination of depreciation expense under IFRS and excluded from negative net	Regulatory treatment is not required as the inclusion of positive net salvage in the calculation of depreciation expense achieves intergenerational equity.

[1348] Exhibit B-2-1, Appendix T, p. 16.
[1349] Exhibit B-19, BCUC IR 206.11.

Category	Description	Potential Regulatory Treatment
	salvage.	
Assets with asset retirement obligations	Assets with existing asset retirement obligations (e.g., 1L18 submarine cables) are excluded from net salvage	Regulatory treatment is not required as asset retirement obligation treatment results in asset removal costs being included in rates over the life of the asset through depreciation and accretion expense. This treatment achieves intergenerational equity.
Asset classes in the "Plant not studied" category	Asset classes presented in Table 1 of Appendix T of the Application under the heading Plant Not Studied are excluded from net salvage expense.	This category consists mainly of land and land rights where removal is not applicable and right-of use assets where either removal is not required or removal costs are expected to be minimal. For assets where removal is not applicable or removal costs are expected to be minimal, there is no regulatory treatment necessary as there is no or minimal impact to ratepayers (regardless of period).
Assets with potential future asset retirement obligations	Assets currently included in net salvage may be removed in future periods if, as a result of future events, an asset retirement obligation is required under accounting rules for assets where an asset retirement obligation currently does not exist.	These assets will be included in net salvage unless an asset retirement obligation (ARO) arises, in which case an ARO will be established and the treatment of the net salvage liability existing at the time will need to be determined.

Mr. Layton elaborated during the oral hearing that some Site C assets fall under the category of asset classes with net salvage rate of 1.0 which is excluded for the purpose of net salvage at this time.[1350]

Positions of the Parties

The CEC submits that it supports BC Hydro's proposed traditional approach to net salvage rates.[1351]

Panel Determination

The Panel approves BC Hydro's exclusion of specified asset classes from net salvage, as identified above in Table 61 of this Decision.

The Panel agrees with BC Hydro's reasons for the exclusion of each of the asset classes BC Hydro proposes to exclude from its net salvage calculations and regulatory treatment, which are described in Table 61 above.

[1350] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 369, lines 13 to 25.
[1351] CEC Final Argument, p. 101.

4.7.4 Net Salvage Implementation

BC Hydro expects to include an implementation plan in its next RRA and is expecting to phase in the implementation of net salvage percentages over six years, commencing in F2026.[1352] BC Hydro states that it is not feasible to implement net salvage in the current Test period as the following items need to be completed:[1353]

- Establish net salvage expense policy and procedures;
- Determine specifically how net salvage will be calculated (e.g., monthly, one-year lag) and how variances to plan will be treated;
- Determine the approach to record net salvage transactions in the financial system;
- Refine the estimates of impacts to customer rates; and
- Finalize an implementation plan.

BC Hydro expects most of the items to take until the end of F2024 to complete. BC Hydro intends to consult with Concentric and peer utilities which have implemented net salvage to consider the changes needed to its internal processes and systems. These inputs will inform BC Hydro's implementation plan. For the phase-in period, it will be refined along with the associated rate impacts as part of ongoing forecasting in the lead-up to the next revenue requirements application, informed by feedback in this proceeding.[1354]

BC Hydro clarifies that no additional work has been done on the items listed above aside from the information already presented in the Application as it has been focused on the 2023-2025 RRA and supporting the evidence filed.[1355]

BC Hydro proposes to conduct this work over the Test Period and propose a fully developed implementation plan, in the next revenue requirements application, that would phase in net salvage beginning in F2026 at the earliest.[1356]

BC Hydro provided the estimated impact on its revenue requirements and rates for implementing net salvage accounting in each of F2023 and F2026, with a phase in period of 0, 3, 6 and 10 years. In general, rates go up the earlier net salvage is implemented and the shorter the phase-in period. For example, BC Hydro estimates cumulative rate impact of implementing net salvage in F2023 with 0-year phase-in to be a 0.9 percent increase in rates from F2023 to F2025.[1357]

If net salvage is implemented in the current Test Period with a deferral account set up to capture any variances between the forecast net salvage and the actual net salvage expenses based on the results of the implementation plan for net salvage accounting, BC Hydro believes the following pros and cons are applicable:[1358]

Pros:

- Net salvage accounting is implemented three years earlier than currently proposed

Cons:

- Proper policies or procedures will not be in place

[1352] Exhibit B-2, Section 8.4.4, p. 8-23; Exhibit B-19, BCUC IR 206.1.
[1353] Exhibit B-2, Section 8.4.4, p. 8-23.
[1354] Exhibit B-7, BCUC IR 106.1; Exhibit B-19, BCUC IR 206.7.
[1355] Exhibit B-7, BCUC IR 106.1.1; 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 373 lines 9 to 16.
[1356] Exhibit B-2, Section 8.4.4, p. 8-23.
[1357] Exhibit B-7, BCUC IR 106.2
[1358] Exhibit B-19, BCUC IR 206.14; 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 377 lines 19 to 25.

- Manual net salvage entries need to be calculated and entered into the SAP system since there would not be enough time to implement an automated SAP solution
- Increased likelihood of error and low confidence in the accuracy or completeness of the information
- Timing of the issuance of BCUC Order(s) may result in differences between the fiscal year of recognition in BC Hydro's financial statements and the fiscal year forecast in Revenue Requirements Applications and may cause delays in the completion and authorization of BC Hydro's quarterly or annual financial statements
- Negative rate impact (i.e., rates would be higher) over the Test Period

BC Hydro states that if the BCUC elects to not issue any approvals regarding BC Hydro's Net Salvage request until the next RRA, then BC Hydro expects that it will not be able to implement net salvage until the following RRA. BC Hydro believes that net salvage requires an entire set of processes and systems that is not easily implemented, or undone. It is therefore reasonable and appropriate for the BCUC to approve BC Hydro's approach to net salvage in advance of implementation.[1359]

Positions of the Parties

BC Hydro requests BCUC approval to implement net salvage rates effective F2026 using a phased-in approach. BC Hydro submits that it is not feasible to implement net salvage in the Test Period because it will take approximately two years to implement the policies and procedures and to make the necessary changes to BC Hydro's SAP financial system. Implementing net salvage in SAP will "reduce the likelihood of error and increase confidence in the implementation" compared to implementing net salvage manually in the Test Period.[1360]

BC Hydro submits that a phased-in approach to implementing net salvage will mitigate its short-term rate impacts. BC Hydro explains that with a six-year phase-in period, the incremental net salvage expense in F2026 would only be $10 million higher than if the current approach were retained, whereas with no phase-in period the increase would be $59 million. BC Hydro proposes that if the BCUC approves a phase-in approach for net salvage, it will include a phase-in proposal in its next RRA.[1361]

BCSEA agrees with BC Hydro that it would not be feasible to implement a new approach to net salvage in the current Test Period, and submits that a phased-in approach commenting in the next test period would mitigate rate impacts.[1362]

Panel Determination

The Panel approves BC Hydro's request to implement net salvage rates effective F2026.

The Panel agrees with BC Hydro that implementing net salvage rates in F2026 rather than in the Test Period will reduce the likelihood of errors and increase confidence in the implementation.

The Panel also agrees with BC Hydro that a phased-in basis may be appropriate to mitigate short-term rate impacts. However, there is insufficient evidence in this proceeding to enable the Panel to consider all the other factors that might affect rates in the following test period, and hence whether a phased-in approach is necessary. **The Panel directs BC Hydro to submit a proposal in its next RRA to explain how the net salvage rates should be phased in**.

[1359] Exhibit B-8, AMPC IR 38.4.
[1360] BC Hydro Final Argument, pp. 175–177.
[1361] BC Hydro Final Argument, p. 177.
[1362] BCSEA Final Argument, p. 32.

The Panel notes that no interveners oppose the implementation date of F2026 or the phased-in basis for the implementation.

4.8 Regulatory Accounts

BC Hydro is requesting approval for the establishment the Load Attraction Costs Regulatory Account, changes to the Mandatory Reliability Standards Costs (MRS) Regulatory Account and the Dismantling Cost Regulatory Account, and the establishment of a recovery mechanism for eight regulatory accounts. BC Hydro also confirms in the Application that it proposes no changes with respect to the recovery of the LCE component of the DSM Regulatory Account.

The following table summarizes the regulatory accounts that BC Hydro is requesting changes to and where in this Decision those requests are discussed:

Table 62: Regulatory Account Approvals Sought

Regulatory Account	Location in this Decision
Load Attraction Costs Regulatory Account	Section 4.8.4
Mandatory Reliability Standards Costs (MRS) Regulatory Account	Section 4.8.1
Dismantling Cost Regulatory Account	Section 4.8.4
Low Carbon Fuel Credits Regulatory Account	Section 4.8.4
Fiscal 2022 Depreciation Study Impact Regulatory Account:	Section 4.8.4
Cost of Energy Variance Accounts	Section 4.11.1
Site C Regulatory Account	Section 4.8.2
Customer Crisis Fund (CCF) Regulatory Account	Section 4.8.4
Mining Customer Payment Plan Regulatory Account	Section 4.8.4

Real Property Sales Regulatory Account	Section 4.8.4
Electric Vehicle (EV) Costs Regulatory Account	Section 4.8.3
DSM Regulatory Account	Section 4.8.4

4.8.1 Mandatory Reliability Standards Costs Regulatory Account

BC Hydro is requesting approval to:[1363]

- Defer actual unplanned MRS costs to the MRS Costs Regulatory Account, effective in F2023 and on an ongoing basis,
    - Related to the implementation of new or revised MRS adopted as a result of a future Assessment Report filed with the BCUC where the BCUC's adoption of such new or revised MRS occurred too late to be reflected in the forecast for the Test Period; and
    - Incurred in a test period to address possible non-compliances with MRS, if and as required, where the work related to such possible non-compliance was identified too late to be reflected in the forecast for the test period.
- Recover amounts deferred to the MRS Costs Regulatory Account in respect of completed fiscal years, including any under/over recovered balance from F2022, over the next test period, starting in F2026 and on an ongoing basis, subject to BCUC review and approval of these amounts;
- Apply interest to the balance of the account based on BC Hydro's 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.

The MRS Costs Regulatory Account was established in F2022 and BC Hydro was approved to defer the actual costs of its unplanned MRS activities incurred in F2022 and to apply interest to the balance of the regulatory account based on its current weighted average cost of debt. The BCUC also approved BC Hydro to recover the forecast cost of $15.9 million for the unplanned MRS activities in F2022 and the forecast interest applied over that test period. However, the BCUC denied BC Hydro's request to recover any remaining balance in the regulatory account at the end of that test period over the subsequent test period. Instead, recovery of any remaining balance at the end of the F2022 test period is subject to the BCUC examining the actual costs and activities incurred in F2022.[1364]

For the current Test Period, BC Hydro clarifies that it is proposing to defer actual amounts incurred (not forecast amounts) to the MRS Costs Regulatory Account.[1365] With respect to the recovery of the balance in the regulatory account, BC Hydro proposes to provide the total actual MRS costs deferred, including supporting details, in a subsequent RRA to enable the BCUC to determine the extent of cost recovery. Recovery of the amounts in the regulatory account would be subject to BCUC review of the details provided.[1366]

[1363] Exhibit B-2, pp. 7-12 – 7-13.
[1364] BC Hydro's Application for Mandatory Reliability Standards Costs Regulatory Account for Fiscal 2022, Order G-26-22, Appendix A, p. 6.
[1365] Exhibit B-2, p. 7-12.
[1366] Exhibit B-2, p. 7-12.

BC Hydro explains that this account is necessary because MRS will continue to evolve and it expects that there will continue to be unplanned costs to implement and maintain compliance with MRS requirements in the foreseeable future.[1367] BC Hydro states that since MRS compliance usually requires immediate attention, the expenditures cannot be delayed and included in the forecast costs of a future RRA.[1368]

BC Hydro states that historically, the unplanned costs related to the adoption of new or revised standards and costs related to mitigation activities were smaller and discrete in nature compared to the magnitude and scope of those experienced in recent years.[1369] BC Hydro considers future annual actual unplanned MRS costs could be material as the actual unplanned in-scope costs for the Test Period are not predictable.[1370] BC Hydro also provided FBC as an example of a peer utility that is allowed variance treatment of similar MRS costs via exogenous factor treatment.[1371]

BC Hydro has identified one item that is expected to result in unplanned work and costs in F2023, which was determined to be required after the completion of the forecast for the Application, meeting the proposed criteria for deferral. Specifically, BC Hydro expects to incur approximately $5 million in unplanned compliance-related costs during F2023 because of certain mitigation activities.[1372] If the requested changes to the MRS Costs Regulatory Account are not approved, then BC Hydro requests approval to include this cost in its operating cost forecast forF2023, which would result in approximately a 0.1 percent increase in F2023 rates. BC Hydro also requests the opportunity to update its preliminary estimate of $5 million, as well as add any additional estimates available since the filing of the Application, via a compliance filing to this proceeding.[1373]

Positions of the Parties

BC Hydro submits that the BCUC has consistently approved exogenous factor treatment of FBC's incremental MRS costs, which is similar to the deferral treatment that BC Hydro is seeking, in that it focuses on uncontrollable and unforeseen nature of the costs.[1374]

BCOAPO submits the BCUC should establish a $10 million threshold for the annual variances, such that variances would only be recoverable if they exceeded this amount.[1375]

The remaining interveners either do not oppose or do not provide a position on BC Hydro's proposal.

In reply, BC Hydro submits that BCOAPO's proposal is not based on sound regulatory principles and that none of its regulatory accounts have a materiality threshold where only variances exceeding the threshold would be recoverable.[1376] Further, the materiality threshold under FBC's MRP is not applicable to BC Hydro under forecast cost of service regulation and the BCUC's considerations supporting the use of a materiality threshold are not applicable to the MRS Costs Regulatory Account.[1377] BC Hydro explains that it previously used a $10 million threshold to determine whether a regulatory account should be established, not to establish a threshold where only variances exceeding the threshold are recoverable. BC Hydro submits that its unplanned MRS costs satisfy its previously used threshold because the estimated unplanned MRS costs in F2022 are $15.9 million.[1378]

[1367] Exhibit B-2, p. 7-11.
[1368] Exhibit B-7, BCUC IR 94.6.
[1369] Exhibit B-19, BCUC IR 189.1.
[1370] Exhibit B-7, BCUC IR 94.5.
[1371] Exhibit B-19, BCUC IR 190.1.
[1372] Exhibit B-2, pp. 7-11 – 7-12.
[1373] Exhibit B-7, BCUC IR 94.4.
[1374] BC Hydro Final Argument, pp. 136 – 137.
[1375] BCOAPO Final rgument, p. 55.
[1376] BC Hydro Reply Argument, p. 76.
[1377] BC Hydro Reply Argument, p. 77.
[1378] BC Hydro Reply Argument, p. 78.

Panel Determination

The Panel approves for BC Hydro to defer the following actual costs to the MRS Costs Regulatory Account, commencing in F2023 and on an ongoing basis:

- **Unplanned costs related to the implementation of new or revised MRS adopted as a result of a future Assessment Report filed with the BCUC where the BCUC's adoption of such new or revised MRS occurred too late to be reflected in the forecast for the test period; and**
- **Unplanned costs, excluding assessed penalties, incurred in a test period to address possible non-compliance with MRS, if and as required, where the work related to such possible non-compliance was identified too late to be reflected in the forecast for the test period.**

The Panel also approves BC Hydro to:

- **Recover amounts deferred to the account in respect of completed fiscal years, including any under/over recovered balance from F2022, over the next test period, starting in F2026 and on an ongoing basis, subject to BCUC review and approval of these amounts; and**
- **Apply interest to the balance of the MRS Costs Regulatory Account based on BC Hydro's weighted average cost of debt.**

The Panel does not approve BC Hydro's request regarding the recovery of interest charges. Instead, the Panel authorizes BC Hydro to recover the actual interest charged to the account for amounts related to any completed fiscal years over the next test period, subject to BCUC review and approval of these amounts. Consistent with the treatment of the recovery of costs deferred to this account, which are subject to BCUC review and approval, any recovery of the related interest charges applied to the account should also be subject to BCUC review and approval.

The Panel accepts BC Hydro's proposal to provide supporting details on the amounts deferred to this regulatory account. **Accordingly, the Panel directs BC Hydro to provide, in all future RRAs, the total actual MRS costs deferred, including supporting details, to enable the BCUC to determine the amount that should be recovered from ratepayers.**

The Panel is satisfied that the costs BC Hydro proposes to defer to the MRS Costs Regulatory Account could be material and difficult to accurately predict and are largely uncontrollable. The Panel accepts that MRS will continue to evolve and that the related compliance activities normally cannot be delayed, and as such BC Hydro should not be discouraged from performing the necessary activities. The Panel is also satisfied that interest should be applied to the balance in the account based on BC Hydro's weighted average cost of debt, which is consistent with the interest applied to its other regulatory accounts where interest is applicable.

The Panel is not persuaded by BCOAPO's argument to establish a threshold for the account, whereby only variances exceeding $10 million are recoverable. The Panel notes that FBC is allowed variance treatment of similar MRS costs via exogenous factor treatment, which includes a materiality threshold under FBC's MRP. However, since BC Hydro's Test Period revenue requirement is being reviewed under a cost of service regulatory regime, there is insufficient regulatory justification at this time to establish such a threshold.

4.8.2 Site C Regulatory Account

BC Hydro is requesting approval to:[1379]

- Commence recovery of the forecast balance of the Site C Regulatory Account as at December 31, 2024 on January 1, 2025 over the forecast weighted average life of the Site C assets of 84 years; and

[1379] Exhibit B-2, p. 7-21.

- On an ongoing basis commencing in the test period beginning in F2026, amortize the forecast balance in the Site C Regulatory Account at the end of the prior test period over the remaining weighted average useful life.

The Site C Regulatory Account captures costs related to the Site C project that are not eligible for capitalization under accounting standards. BC Hydro states that the regulatory account was created to match the recovery of the costs not eligible for capitalization with the benefits that the Site C project will produce over its useful life.[1380] Accordingly, BC Hydro plans to continue deferring costs related to the Site C project that are not eligible for capitalization under IFRS and apply interest to the balance until all Site C units are placed in-service.[1381]

The forecast balance at December 31, 2024 of $617.5 million in the Site C Regulatory Account consists of $366.3 million of pre-development costs, $2.7 million of insurance costs, $223.8 million of interest, and $24.6 million of IFRS interest adjustment. The pre-development costs include identification and definition phase costs comprised of engineering design, legal, environmental, project management, Indigenous relations, communications, and finance.[1382]

BC Hydro expects Unit 1 of the Site C project to come into service in December 2024 and Unit 2 in February 2025. BC Hydro states that ratepayers will begin to receive the benefits of Site C as the units come into service. Accordingly, BC Hydro requests to commence recovery of the forecast balance in the Site C Regulatory Account on January 1, 2025 over 84 years, which is the forecast weighted average expected useful life of the Site C assets.[1383] BC Hydro considers that its proposed amortization period and method would result in intergenerational equity and it is consistent with how the Site C assets will be depreciated.[1384] Other BC Hydro regulatory accounts that have amortization periods related to the useful life of an asset include the Smart Metering and Infrastructure Program Regulatory Account and the IFRS Property, Plant and Equipment Regulatory Account.[1385]

BC Hydro expects the Site C project to be fully in-service during the next test period and the actual balance in the Site C Regulatory Account to be known at that time for amortization in future test periods. Thus, to ensure that ratepayers will be charged the actual costs deferred to the Site C Regulatory Account, BC Hydro also requests on an ongoing basis commencing in the next test period to amortize the forecast balance in the regulatory account at the end of the prior test period over the remaining weighted average useful life.[1386]

Since not all the Site C units will be placed in-service at the same time, an approach where the recovery of the Site C Regulatory Account is based on the forecast in-service date of the units was explored in IRs. Under this approach, the revenue requirement would be reduced by approximately $0.2 million in F2025 and $0.6 million in F2026.[1387] However, BC Hydro states that this approach would increase the complexity of the amortization calculation of the regulatory account, and it would require an arbitrary assignment of the regulatory account balance to the individual units.[1388]

The impact to the Test Period rates and the impact to the estimated total interest that the Site C Regulatory Account would attract under shorter amortization periods of 5 to 50 years were also explored in IRs. Generally, a shorter amortization period would result in a higher rate impact, but a lower amount of interest would be

[1380] Exhibit B-2, p. 7-20.
[1381] Exhibit B-2, p. 7-21.
[1382] Exhibit B-19, BCUC IR 202.3.
[1383] Exhibit B-2, p. 7-20.
[1384] Exhibit B-7, BCUC IR 98.4.
[1385] Exhibit B-7, BCUC IR 98.2.
[1386] Exhibit B-2, pp. 7-20 – 7-21.
[1387] Exhibit B-7, BCUC IR 98.1.
[1388] Exhibit B-7, BCUC IR 98.3.

applied to the regulatory account over its life. For example, if the regulatory account was amortized over 5 years, it would result in a 2.70 percent rate increase in F2025, which is a 0.52 percent higher rate than applied for in the Application, but total interest applied of $271 million over the life of the regulatory account. However, the rate increase for F2025 based on an amortization period of 84 years is 2.18 percent (as applied for), but would result in total interest applied of $1.024 billion over the life of the regulatory account.[1389]

Positions of the Parties

BC Hydro submits that the forecast weighted average useful life of the assets is an objective measure of the benefit period and that a shorter amortization period would result in intergenerational inequity and higher bill impacts. BC Hydro also submits that commencing the amortization of the regulatory account when the depreciation of the major civil structures commences (i.e. when the first unit goes into service) is appropriate and aligns with IFRS accounting rules.[1390]

Although BCOAPO is silent on the amortization period, it suggests a staggered approach should be adopted to phase-in the recovery of the regulatory account, subject to any compelling administrative difficulties, because it would be more consistent with the matching principle. This approach is meant to match the in-service date of the generating units because they are expected to be brought into service at differing times from December 2024 to November 2025.[1391]

In reply, BC Hydro submits that while BCOAPO's suggested staggered approach would reduce the revenue requirements by approximately $0.2M in F2025 and up to $0.6M in future years, the administrative simplicity of BC Hydro's proposed approach, which aligns with IFRS, outweighs the short-term benefits of reducing the revenue requirements. Further, a staggered approach would require an arbitrary assignment of the Site C Regulatory Account balance to the individual generating units.[1392]

The CEC recommends the amortization period be extended to 150 years to reflect the "permanent useful life" anticipated for hydroelectric facilities.[1393]

In reply to the CEC, BC Hydro submits that there is no reasonable justification for a 150-year amortization period as the estimated lives for the range of major assets classes related to Site C are 40 to 100 years.[1394]

The other interveners either did not oppose or did not provide a position on BC Hydro's proposal.

Panel Determination

The Panel approves BC Hydro to:

- **Commence recovery of the forecast balance of the Site C Regulatory Account as at December 31, 2024 over the forecast weighted average life of the Site C assets, commencing January 1, 2025.**
- **On an ongoing basis commencing in the test period beginning in F2026, amortize the forecast balance in the Site C Regulatory Account at the end of the prior test period over the remaining weighted average useful life.**

The Panel directs BC Hydro to recalculate the forecast weighted average life of the Site C assets in its Compliance Filing based on any adjustments resulting from the determinations and directives contained in this Decision regarding the service lives of the Site C assets.

The Panel finds that amortizing the Site C Regulatory Account over the forecast weighted average useful life (or service life) of the Site C assets would promote intergenerational equity.

1389 Exhibit B-7, BCUC IR 98.5; Exhibit B-19, BCUC IR 202.2.
1390 BC Hydro Final Argument, p. 141.
1391 BCOAPO Final Argument p. 60.
1392 BC Hydro Reply Argument, pp. 83 – 84.
1393 CEC Final Argument, p. 97.
1394 BC Hydro Reply Argument, pp. 84 – 85.

The Panel notes that the approval of an amortization period for the Site C Regulatory Account does not fetter any future BCUC review of the prudency and recoverability of the Site C project capital costs and deferred costs, as discussed in Section 5.3 of this Decision.

The Panel rejects BCOAPO's suggestion for a staggered approach to phase in the recovery of the Site C Regulatory Account. The Panel is not convinced that the rate impacts associated with a staggered approached outweigh the associated administrative complexity. In addition, the evidence in the proceeding does not support that a staggered approach would align with IFRS.

4.8.3 Electric Vehicle Costs Regulatory Account

BC Hydro is requesting approval to:[1395]

- Recover the forecast March 31, 2022 balance of the EV Costs Regulatory Account over the Test Period and recover any balance remaining at the end of the Test Period over the next test period;
- Continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; and
- Recover the forecast interest charged to the account each year beginning in F2023.

In the F2022 RRA Decision, the BCUC approved the establishment of the EV Costs Regulatory Account to defer any actual operating costs, depreciation, and cost of energy amounts related to BC Hydro's EV charging stations that meet the definition of a prescribed undertaking under the GGRR for fiscal years 2020 and 2021. In addition, the BCUC approved the application of interest to the balance of the regulatory account based on BC Hydro's current weighted average cost of debt. However, the BCUC denied BC Hydro's proposed recovery mechanism for the regulatory account and instead directed BC Hydro to apply for a recovery mechanism in the Application. The BCUC also directed that all F2022 costs related BC Hydro's EV charging stations that are prescribed undertakings be deferred to the EV Costs Regulatory Account. The BCUC stated that it is prudent to defer the recovery of these costs until the conclusion of the BCUC's review of BC Hydro's application for public EV fast charging rates because that proceeding could address issues that may impact the cost recovery of EV charging station costs from BC Hydro's non-EV fast charging customers.[1396]

In the F2022 RRA Decision, the BCUC found that the deferral of costs related to BC Hydro's EV charging stations that are prescribed undertakings to the EV Costs Regulatory Account meets the requirements of section 18(2) of the CEA because the BCUC is allowing BC Hydro to recover its costs incurred pending the conclusion of the proceeding to review BC Hydro's public EV fast charging rate.[1397]

In accordance with the BCUC's directive in the F2022 RRA Decision, BC Hydro is requesting a recovery mechanism for the EV Costs Regulatory Account in the Application. BC Hydro states that since the EV Costs Regulatory Account only captures amounts attributable to F2020 to F2022, it is not forecasting the deferral of any further costs, other than interest, to this regulatory account over the Test Period. Therefore, it is requesting to recover the forecast $7.4 million F2022 ending balance of the regulatory account over the Test Period and to recover any remaining balance, due to differences between actual and forecast costs for F2022, over the next test period.[1398]

[1395] Exhibit B-2, p. 7-31.
[1396] BC Hydro Fiscal 2022 RRA Decision and Order G-187-21, pp. 101 – 102.
[1397] BC Hydro F2022 RRA Decision and Order G-187-21, p. 102.
[1398] Exhibit B-2, p. 7-30; Exhibit B-2-1, Appendix A, Schedule 2.2., Line 160.

BC Hydro states that it plans to close this regulatory account in the next test period and transfer any remaining residual interest in the account to the Total Finance Charges Regulatory Account. BC Hydro also points out that 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.[1399]

BC Hydro has forecast revenue and costs for F2023 to F2025 related to its EV fast charging service in the Test Period revenue requirements, as shown in the following table.

Table 63: F2023 to F2025 EV Infrastructure Revenue and Costs[1400]

	Reference		F2023 Plan	F2024 Plan	F2025 Plan
Public Charging Revenue	Included in Appendix A, Schedule 14, line 26		1.0	1.8	2.8
Low Carbon Fuel Credits[1]	Included in Appendix A, Schedule 15, line 35		0.0	0.0	0.0
Total Revenue			**1.0**	**1.8**	**2.8**
Operating & Maintenance Costs	Appendix A, Schedule 5, line 14	Base budget	2.3	2.3	2.4
		Incremental Electrification	0.2	0.3	0.4
Cost of Energy	Included in Appendix A, Schedule 4, line 1		0.1	0.2	0.4
Depreciation	Included in Appendix A, Schedule 7, line 1		1.3	1.7	2.1
Total Costs			**4.0**	**4.6**	**5.3**

1 Revenue from low carbon fuel credits has been estimated by taking the actual credits in the most recent year they were claimed (137 credits in 2018) divided by the total credits claimed that year (153,535 in 2018) multiplied by the total forecast LCFC average revenue each year in the Test Period. The resulting figure rounds to zero in millions.

During the current proceeding, the BCUC's review of BC Hydro's application for public EV fast charging rates concluded and the BCUC issued its decision on January 26, 2022 (EV Rates Decision). In that decision, the BCUC denied BC Hydro's request to establish its proposed EV fast charging rates as permanent and instead directed BC Hydro to file a new application for permanent EV fast charging rates by December 31, 2022. The EV Rates Decision also stated that the BCUC would consider approving a rate based on a levelized recovery of all costs, such that the rate reflects all of the costs required to provide EV fast charging service, including the previous years' costs net of related revenue.[1401] The BCUC also directed BC Hydro to establish a separate class of service for its EV fast charging service in its application for permanent EV fast charging rates.[1402] BC Hydro's interim rates for EV fast charging, which were approved effective May 1, 2021, remain in place until permanent rates are set by the BCUC.[1403] Subsequently, the BCUC extended, upon request, the deadline for the filing of BC Hydro's application for permanent EV fast charging rates, from December 31, 2022, to June 30, 2023.[1404]

1399 Exhibit B-2, p. 7-30.
1400 Exhibit B-2-3-1, Table 10-14, p. 10-56.
1401 BC Hydro EV Fast Charging Rates Application, Decision and Order G-18-22, p. 37.
1402 Ibid, p. 55.
1403 Ibid, p. 37; Order G-89-21.
1404 BC Hydro Extension Request for Public EV Fast Charging Service Rates Application, Order G-391-22.

BC Hydro considers that the directives in the EV Rates Decision do not require changes to BC Hydro's requested approvals regarding the EV Costs Regulatory Account. BC Hydro states that it has not determined its proposed approach for determining its EV fast charging rate or in respect of the previous years' under-recoveries related to its EV fast charging service, which would be included in its application for permanent EV fast charging rates. However, BC Hydro explains that if the EV Costs Regulatory Account were to be used as the mechanism to recover the previous years' under-recoveries over time, then the regulatory account would need to include both costs and revenues. BC Hydro's EV fast charging revenue for F2022 is currently captured in the Load Variance Regulatory Account.[1405] BC Hydro also points out that Direction No. 8 to the BCUC, as amended by OIC No. 123 issued March 7, 2022, prohibits the deferral of any return on equity associated with its EV fast charging service.[1406]

Notwithstanding, BC Hydro states that the regulatory account is not required to recover the previous years' under-recoveries for three reasons. First, the EV Costs Regulatory Account was not established to facilitate a levelized rate. Second, the determination of the costs related to EV charging stations, including costs incurred prior to the final determination of the EV fast charging rate, and the benefits of the EV fast charging service, is a rate design issue. Third, actual EV fast charging costs and revenues, including related Low Carbon Fuel Credit revenues, are already directed to be separately tracked, which will inform its proposed rate design for a permanent EV fast charging rate. This will enable reporting to the BCUC on the recovery of actual costs and revenues and will enable the BCUC to set future rates to ensure the appropriate customers pay the appropriate costs over time. Furthermore, BC Hydro states that regulatory accounts are generally not used, or necessary to be used, to ensure that a particular rate recovers costs associated with that customer class and there is no reference to such an account type in the BCUC's Regulatory Account Filing Checklist.[1407]

Positions of the Parties

BC Hydro submits that its proposed recovery mechanism is compatible with the directions arising from the EV Rates Decision. BC Hydro also submits that it is not necessary to defer all costs and revenues related to its EV fast charging service to this regulatory account and notes that Direction No. 8 prohibits the deferral of any associated return on equity.[1408]

With respect to BC Hydro's proposed recovery mechanism, it notes for the BCUC's consideration that it could direct BC Hydro to update the F2022 balance in the EV Costs Regulatory Account with the actuals in its compliance filing, so that the balance in this account could be completely cleared over the Test Period and eliminate the need for the account in the next RRA.[1409]

The CEC submits that the balance in the EV Costs Regulatory Account should be recovered in EV charging rates.[1410] The remaining interveners either do not oppose or do not provide a position on BC Hydro's proposal.

In reply, BC Hydro submits that regulatory accounts are generally not used, or necessary to be used, to ensure that a particular rate recovers costs associated with that customer class. BC Hydro is already required to track its EV fast charging costs, and an EV charging rate can be designed to recover those costs without the aid of a regulatory account.[1411]

[1405] Exhibit B-19, BCUC IR 142.1.
[1406] Exhibit B-19, BCUC IR 142.5.
[1407] Exhibit B-19, BCUC IR 142.1.
[1408] BC Hydro Final Argument, p. 143 – 144.
[1409] BC Hydro Final Argument, pp. 142 – 143.
[1410] CEC Final Argument, p. 97.
[1411] BC Hydro Reply Argument, p. 85.

Panel Determination

The Panel denies BC Hydro's request to recover the forecast March 31, 2022 balance of the EV Costs Regulatory Account over the Test Period and the request to recover any balance remaining at the end of the Test Period over the next test period.

The EV Rates Decision stated that the BCUC would consider a rate based on a levelized recovery of all costs, including the previous years' costs net of related revenue, and directed BC Hydro to establish a separate class of service for its EV fast charging service. It would be premature to begin recovering the costs in the EV Costs Regulatory Account considering that BC Hydro has not yet received any approval of a permanent EV fast charging rate or the recovery of the previous years' costs from its EV fast charging customers, and an application requesting permanent EV fast charging rates has not been filed. Therefore, the Panel cannot determine that the balance of the regulatory account should be recovered from all ratepayers.

The Panel does not agree with BC Hydro that its proposed recovery mechanism is compatible with the directions arising from the EV Rates Decision. The Panel is not persuaded that these prior years' costs could be recovered under an EV fast charging rate without the aid of a regulatory account and still be aligned with regulatory principles.

Considering the BCUC's determinations in the EV Rates Decision noted above, revenues related to EV fast charging should be included in the regulatory account to allow for the full consideration of revenues and costs as part of the permanent EV rates application that is to be filed later this year. The regulatory account should be continued until at least the approval of permanent EV fast charging rates for BC Hydro. The Panel expects that, at that time, there would be additional information for the BCUC to determine whether and how this regulatory account should be continued, and any related recovery mechanism. This approach is also consistent with the BCUC's finding in the F2022 RRA Decision that the deferral of costs related to BC Hydro's EV charging stations that are prescribed undertakings to the EV Costs Regulatory Account meets the requirements of section 18(2) of the CEA.

The Panel notes that actual costs have been deferred to this regulatory account up to and including F2022, therefore, deferring actual F2022 revenue to this account is consistent with the treatment of the costs in that period. However, going forward, both forecast revenue and costs should be deferred to this account because BC Hydro should be assuming some forecasting risks and the regulatory account should only change the timing of the cost recovery and not the amount.

The Panel notes that BC Hydro's forecast costs related to its EV fast charging service shown in Table 63 above do not include any finance costs associated with its EV fast charging infrastructure. While the Panel accepts that any associated return on equity cannot be deferred as a result of Direction No. 8, there is no evidence in this proceeding to suggest that any finance costs associated with BC Hydro's EV fast charging capital assets should not be deferred.

Therefore, the Panel directs BC Hydro to:

- **Transfer the F2022 EV fast charging service revenue from the Load Variance Regulatory Account to the EV Costs Regulatory Account;**
- **Remove the Test Period forecast revenue, including the Low Carbon Fuel Credits revenue, and costs related to its EV fast charging service, including finance costs associated with the EV fast charging capital assets, from the revenue requirement;**
- **Commencing in F2023, and until directed otherwise by the BCUC, defer the actual revenue, including the Low Carbon Fuel Credits revenue, and costs related to its EV fast charging service, including**

finance costs associated with the EV fast charging capital assets, to the EV Costs Regulatory Account; and

- **Change the name of the EV Costs Regulatory Account to the EV Fast Charging Regulatory Account.**

The Panel approves BC Hydro's request to continue to apply interest to the balance of the EV Costs Regulatory Account (or EV Fast Charging Regulatory Account) each year based on its current weighted average cost of debt. However, the Panel denies BC Hydro's request to recover the forecast interest charged to the account each year beginning in F2023. The recovery of any interest charges, along with the recovery of any other balances, from this regulatory account should be considered at the same time as or after BCUC approval of the permanent EV fast charging rates.

4.8.4 Remaining Regulatory Account Requests

In this section, the Panel addresses BC Hydro's requests regarding:

- the Load Attraction Costs Regulatory Account,
- the Dismantling Costs Regulatory Account,
- the Low Carbon Fuel Credit Regulatory Account,
- the Fiscal 2022 Depreciation study Impact Regulatory Account,
- the Customer Crisis Fund Regulatory Account,
- the Mining Customer Payment Plan Regulatory Account,
- the Real Property Sales Regulatory Account, and
- the DSM Regulatory Account.

<u>Load Attraction Costs Regulatory Account</u>

BC Hydro is requesting approval to:[1412]

- Establish the Load Attraction Costs Regulatory Account to defer actual load attraction operating costs in F2023 to F2027;
- Apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt;
- Amortize from the account each year the forecast interest charged on the account each year;
- Amortize the forecast annual operating cost amount from the account, starting the fiscal year following the expenditures, into rates over the benefit period of 20 years;
- Recover over the next test period, the forecast account balance at the end of a test period related to the difference between the amortization of the forecast annual load attraction operating cost amount and the calculation of the amortization based on the actual annual load attraction operating cost amounts; and
- Recover over the next test period, the forecast account balance at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to the account during that test period.

[1412] Exhibit B-2, p. 7-10.

BC Hydro is requesting to establish the Load Attraction Regulatory Account as a new benefit matching account to defer actual operating costs related to Load Attraction. Load Attraction is one of the components of BC Hydro's Electrification Plan. BC Hydro's Load Attraction programs aim to attract new load to BC Hydro's system while BC Hydro has an energy surplus, which benefits customers by reducing rate increases.[1413] BC Hydro expects to incur Load Attraction operating costs of $52 million over the five-year term of the Load Attraction programs, of which $27 million are expected to be incurred over the Test Period.[1414]

BC Hydro plans to incur Load Attraction costs over a five-year period, but it estimates the Load Attraction programs will provide benefits to customers over 22 years, which is the average load weighted life of the projects under the programs.[1415] Although BC Hydro estimates benefits over 22 years, it proposes a 20-year amortization period for the regulatory account to be conservative and to account for the uncertainty of these new loads.[1416]

BC Hydro states that its proposal to apply interest to the regulatory account at its weighted average cost of debt rate is consistent with its approach for other regulatory accounts that attract carrying costs. [1417]

As mentioned in Section 2.4.2 of this Decision, after the filing of the Application the Government of B.C issued the Electrification Plan Direction, which states the following:[1418]

3 (1) The commission must allow the authority to establish a load-attraction costs regulatory account.

(2) The commission must allow the authority to defer to the load-attraction costs regulatory account

(a) up to $52 million in costs incurred by the authority during the period beginning April 1, 2022 and ending March 31, 2027 to provide the load-attraction program, and

(b) interest on the balance in the account.

(3) The commission must allow the authority to amortize from the load-attraction costs regulatory account for each fiscal year the forecast

(a) interest on the balance in the account, and

(b) annual load-attraction amortization amount, calculated on the assumption that the costs to provide the load-attraction program for the fiscal year will be amortized over a period of 20 years.

(4) In setting rates for the authority for a fiscal year, the commission must not disallow for any reason the recovery in rates from persons who receive or may receive service under the specified rate schedules of the forecast amounts amortized under subsection (3) (a) and (b) for the fiscal year.

(5) In setting rates for the authority for a test period, the commission must not disallow for any reason

(a) the recovery in rates from persons who receive or may receive service under the specified rate schedules of the amount, if any, by which actual amounts described in subsection (3) (a) and (b) for the previous test period exceed the forecast amounts under that subsection for that period, or

(b) the refunding in rates to persons who receive or may receive service under the specified rate schedules of the amount, if any, by which the actual amounts described in subsection (3) (a) and (b) for the previous test period are less than the forecast amounts under that subsection for that period.

[1413] Exhibit B-2, pp. 7-6 – 7-7.
[1414] Exhibit B-2, p. 7-8.
[1415] Exhibit B-2, pp. 7-7 – 7-8.
[1416] Exhibit B-2, p. 7-9.
[1417] Exhibit B-2, pp. 7-9 – 7-10.
[1418] OIC No. 355, B.C. Reg 156/2022,), section 3.

(6) For the purposes of this section, interest is to be calculated for each fiscal year at the rate equal to the authority's weighted average cost of debt for the fiscal year.

(7) Except on application by the authority, the commission must not order the authority to close the load-attraction costs regulatory account.

Dismantling Cost Regulatory Account

BC Hydro is requesting approval to:[1419]

- Continue to defer any variances between forecast and actual dismantling costs in F2023 to F2025 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 from the account each year the forecast interest charged to the account each year; and
- Continue to recover the forecast account balance at the end of a test period over the next test period.

BC Hydro is requesting approval to continue to defer variances between forecast and actual dismantling costs to the Dismantling Cost Regulatory Account until it implements net salvage rates in the next test period.[1420] In the F2022 RRA Decision, the BCUC approved BC Hydro's request for continued use of this regulatory account to defer cost variances related to F2022. In that decision, the BCUC accepted that BC Hydro's net salvage report was necessary to analyze how forecast dismantling costs should be recovered on an ongoing basis.[1421] BC Hydro's proposal to implement net salvage rates is discussed in Section 4.7 of this Decision.

Low Carbon Fuel Credits Regulatory Account

BC Hydro is requesting approval to recover the balance of the Low Carbon Fuel Credits Regulatory Account through the DARR mechanism. BC Hydro's proposal to return to the DARR table mechanism to recover the balance of its Cost of Energy Variance Accounts is discussed in Section 4.11.1 of this Decision.[1422]

By Order G-248-21, the BCUC approved the establishment of the Low Carbon Fuel Credits Regulatory Account to capture, on an ongoing basis, the difference between forecast and actual miscellaneous revenue from low carbon fuel credits and to apply interest on the balance of this regulatory account based on BC Hydro's current weighted average cost of debt. The BCUC also directed BC Hydro to request an amortization method for the regulatory account in the current Application.

BC Hydro's low carbon fuel credit revenues are a result of BC Hydro transferring its credits to Powerex based on a transfer pricing agreement. As such, low carbon fuel credit variances experienced by BC Hydro are offset by variances in Trade Income, which are deferred to the TIDA and recovered using the DARR mechanism.[1423]

Fiscal 2022 Depreciation Study Impact Regulatory Account

BC Hydro is requesting to:[1424]

[1419] Exhibit B-2, p. 7-14.
[1420] Exhibit B-2, pp. 7-13 – 7-14.
[1421] BC Hydro Fiscal 2022 RRA, Decision to Order G-187-21, pp. 70 – 71.
[1422] Exhibit B-2, p. 7-15.
[1423] Exhibit B-2, p. 7-15.
[1424] Exihibit B-2, p. 7-16.

- Recover the forecast March 31, 2022 balance of the Fiscal 2022 Depreciation Study Impact Regulatory Account over the Test Period;
- Apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt;
- Recover the forecast interest charged to the account each year beginning in F2023; and
- Recover any remaining balance at the end of the Test Period, as a result of actual amounts being different than the forecast amount, over the following test period.

BC Hydro is requesting to recover the $29.1 million F2022 forecast ending balance of the Fiscal 2022 Depreciation Study Impact Regulatory Account over the Test Period.[1425] Alternatively, BC Hydro points out that the BCUC could direct BC Hydro to update the F2022 ending regulatory account balance with the actual balances in a compliance filing. This approach would result in the entire balance in the regulatory account being cleared by the end of the Test Period and eliminate the need for the account in the next RRA.[1426]

In the F2022 RRA Decision, the BCUC directed BC Hydro to establish the Fiscal 2022 Depreciation Study Impact Regulatory Account to capture the variances arising in F2022 resulting from any changes to the depreciation expense determined in the depreciation study and to apply interest to this account based on BC Hydro's weighted average cost of debt. The BCUC also directed BC Hydro to apply for a recovery mechanism for the regulatory account in the Application.[1427] BC Hydro's depreciation study is discussed in Section 4.6 of this Decision.

<u>Customer Crisis Fund Regulatory Account</u>

BC Hydro is requesting approval to:[1428]

- Recover the $40.8 million forecast March 31, 2022 balance for the COVID Relief Fund for residential customers in the CCF Regulatory Account over the Test Period;
- Continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; and
- Recover the forecast interest charged to the account each year attributable to the COVID Relief Fund for Residential Customers balance from the account each year beginning in F2023.

The CCF Regulatory Account captures amounts attributable to BC Hydro's CCF Pilot Program and its COVID Relief Fund for Residential Customers. The forecast balance in the CCF Regulatory Account at the end of F2022 is summarized in the following table, as corrected in an errata filed by BC Hydro:[1429]

Table 64: Summary of CCF Regulatory Account Forecast Balance at March 31, 2022

[1425] Exhibit B-2, pp. 7-15 – 7-16; Exhibit B-2-1, Appendix A, Schedule 2.2, line 178.
[1426] Exhibit B-7, BCUC IR 96.2.
[1427] Exhibit B-2, p. 7-15.
[1428] Exhibit B-2, p. 7-24.
[1429] Exhibit B-2-6, Table 7-3, p. 7-23.

($ million)	Customer Crisis Fund Pilot Program Balance	COVID Relief Fund for Residential Customers Balance
Rate Rider Revenue	~~(11.1)~~(11.9)	n/a
COVID-19 Bill Credits	n/a	37.3
Internal Costs	~~5.7~~6.4	1.2
Interest	~~(0.5)~~(0.4)	2.3
Total	(5.9)	40.8

The BCUC had ordered BC Hydro to terminate the CCF Pilot Program effective May 31, 2021, and approved BC Hydro's request to rescind the related CCF rate rider, effective June 1, 2021.[1430] Subsequently, the Government of B.C. issued Direction to the British Columbia Utilities Commission Respecting the Customer Crisis Fund Program (CCF Direction). The CCF Direction directs the BCUC to enable BC Hydro to defer up to $5 million to the CCF Regulatory Account related to CCF grants issued to customers and BC Hydro's internal costs to administer the program to enable the continuation of grants under the program.[1431] The amounts deferred to this account are expected to reduce the CCF Pilot Program portion of the balance of the regulatory account, such that any remaining amounts would be minimal.[1432] BC Hydro states that it will propose a mechanism for recovery or return of any remaining balance in the CCF Regulatory Account in its next RRA.[1433]

As mentioned in Section 2.4.3 of this Decision, after the filing of the Application, the Government of B.C. amended the CCF Direction to enable BC Hydro to defer up to $11 million, which is an additional $6 million, to the CCF Regulatory Account related to CCF grants issued to customers and BC Hydro's internal costs to administer the program. Concurrently, the Government of B.C. issued the Account Credits Direction, which includes direction to the BCUC to allow BC Hydro to transfer $6 million to the CCF Regulatory Account from the Trade Income Deferral Account.[1434]

Pursuant to the Government of B.C.'s Direction to the British Columbia Utilities Commission Respecting COVID-19 Relief (COVID-19 Direction),[1435] the BCUC approved BC Hydro's application to amend its Electric Tariff to implement its COVID Relief Fund and to allow amounts credited to residential customers to be deferred to the CCF Regulatory Account.[1436] The COVID Relief Fund was a temporary program available until June 30, 2020.[1437]

Since BC Hydro's program related to the COVID Relief Fund has concluded, BC Hydro is proposing to recover the $40.8 million forecastF2022 ending balance over the Test Period because there are no future benefits for ratepayers associated with these costs. BC Hydro also points out that section 4 of the COVID-19 Direction indicates that the recovery period for the CCF Regulatory Account from all ratepayers is to be determined by BC Hydro.[1438] Specifically, section 4 of the COVID-19 Direction states that in setting rates, the BCUC:

> (a) must allow the authority to recover, over a period determined by the authority, from all persons in British Columbia who receive or may receive service from the authority, the following amounts:

[1430] BC Hydro Customer Crisis Fund Evaluation Reports ,Order G-144-21; BC Hydro Application to Rescind Rate Schedule 1903 Customer crisis Fund Rate Rider, Order G-162-21.
[1431] OIC No. 365, B.C. Reg 163/2021.
[1432] Exhibit B-2, p. 7-23.
[1433] Exhibit B-2, p. 7-24.
[1434] OIC No. 571, B.C. Reg 224/2022, Account Credits Direction, section 9.
[1435] OIC No. 159, B.C. Reg 76/2020.
[1436] BC Hydro COVID-19 Customer Relief Program, Order G-79-20.
[1437] Exhibit B-2, p. 7-22.
[1438] Exhibit B-2, p. 7-23.

(i) the balance of the customer crisis fund regulatory account;

(ii) despite section 3 (3) of the Direction to the British Columbia Utilities Commission Respecting Mining Customers, the balance of the mining customer payment plan regulatory account, and

(b) must not disallow for any reason the recovery in rates of the amounts referred to in paragraph (a).

Mining Customer Payment Plan Regulatory Account

BC Hydro is requesting approval to:[1439]

- Recover the $7.4 million forecast March 31, 2022 balance for COVID-19 Relief measures for commercial customers in the Mining Customer Payment Plan (MCPP) Regulatory Account over the Test Period;
- Continue to apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt; and
- Recover the forecast interest charged to the account each year attributable to COVID-19 Relief measures for commercial customers from the account each year beginning in F2023.

The MCPP Regulatory Account captures amounts attributable to the following two programs:

- MCPP amounts (specifically, any impaired amounts related to participating customers in Tariff Supplements (TS) 90, 97, 98, and 99); and
- COVID-19 Relief measures for commercial customers.

The forecast balance in the MCPP Regulatory Account at the end of F2022 is summarized in the following table:[1440]

Table 65: Summary of MCPP Regulatory Account Forecast Balance at March 31, 2022

($ million)	Industrial Customer Impairment Losses (TS 90, 97, 98, 99)	COVID-19 Relief Measures for Commercial Customers
Impaired Receivables	0.1	n/a
COVID-19 Bill Credits	n/a	6.9
Internal Costs	0	n/a
Interest	0	0.5
Total	0.1	7.4

In accordance with section 3(2) of OIC No. 123, issued on February 29, 2016, the BCUC authorized BC Hydro to establish the MCPP Regulatory Account for the original TS 90. This program closed on March 14, 2021, with no balance in the regulatory account. However, BC Hydro has not proposed the closure of the regulatory account pending further forthcoming information from the Government of B.C. regarding the continuation of the program.[1441]

[1439] Exhibit B-2, p. 7-27.
[1440] Exhibit B-2, Table 7-4, p. 7-26.
[1441] Exhibit B-2, p. 7-25.

In accordance with OIC No. 319, issued on June 19, 2020, BC Hydro announced new COVID-19 relief measures, including three new industrial customer payment plan tariff supplements (TS 97, TS 98, and TS 99) that allowed certain industrial customers to temporarily defer a portion of their bills, with repayment plus interest following the payment deferral period. The ability for participating customers to defer bill payments under these tariff supplements closed during F2021.[1442]

BC Hydro is not proposing to recover the $0.1 million forecast balance related to the industrial customer impairment losses because BC Hydro expects full repayment from these customers by September 30, 2021, as required under the tariff supplements, and therefore does not expect any remaining balance.[1443]

Pursuant to the COVID-19 Direction,[1444] the BCUC approved BC Hydro's application to waive charges for eligible commercial customers for a period up to June 30, 2020, and to defer the waived charges and BC Hydro's administrative costs related to the COVID-19 relief for commercial and industrial customers to the MCPP Regulatory Account. The BCUC also approved the application of interest to the regulatory account at BC Hydro's weighted average cost of debt.[1445]

Since BC Hydro's COVID-19 Relief measures for commercial customers is complete, BC Hydro is proposing to recover the $7.4 million forecast F2022 ending balance over the Test Period because there are limited future benefits for ratepayers associated with these costs. BC Hydro also points out that section 4 of the COVID-19 Direction indicates that the recovery period for the MCPP Regulatory Account from all ratepayers is to be determined by BC Hydro.[1446]

<u>Real Property Sales Regulatory Account</u>

BC Hydro is requesting approval to:[1447]

- Continue to recover the balance in the Real Property Sales Regulatory Account through the realization of actual net gains over the Test Period;
- Continue to apply interest to the balance of the account based on BC Hydro's current weighted average cost of debt; and
- Refund or recover the remaining balance at the end of the Test Period over the next test period.

BC Hydro is requesting to continue to recover the balance in the Real Property Sales Regulatory Account through the realization of actual net gains over the Test Period.[1448]

The Real Property Sales Regulatory Account was established by Order G-48-14 pursuant to the Government of B.C.'s Direction No. 7 to the British Columbia Utilities Commission.[1449] The regulatory account defers the variances between BC Hydro's forecast and actual real property gains and losses from real estate sales, with interest applied to the account based on BC Hydro's weighted average cost of debt. BC Hydro states that the regulatory account was intended to smooth the recognition of gains and losses from real property sales while ensuring that ratepayers receive the benefits from the sales.[1450]

1442 Exhibit B-2, p. 7-25.
1443 Exhibit B-2, pp. 7-26 – 7-27.
1444 OIC No. 159, B.C. Reg 76/2020.
1445 BC Hydro Customer Relief Program Application, Order G-79-20.
1446 Exhibit B-2, p. 7-26.
1447 Exhibit B-2, p. 7-29.
1448 Exhibit B-2, p. 7-29.
1449 OIC No. 097,B.C. Reg 28/2014.
1450 Exhibit B-2, p. 7-27.

Beginning in F2015, BC Hydro included $10 million in forecast net gains from real property sales in each year of its revenue requirement. The recording of these gains was consistent with BC Hydro's target of $50 million of net gains from real property sales over a five-year period (i.e. F2015 to F2019). In its F2020 to F2021 RRA, BC Hydro increased the net gains target from $50 million to $100 million and extended the timeframe to achieve this target to the end of F2024.

However, since actual net gains had been less than forecast due to sales taking longer to occur than planned, a balance recoverable from ratepayers had accumulated in the Real Property Sales Regulatory Account. Consequently, in the BCUC's F2020 to F2021 RRA Decision, the BCUC directed BC Hydro to forecast net gains of $0 in its revenue requirement, which would result in the accumulated balance in the regulatory account being reduced by any actual net gains realized on the sale of properties. The BCUC also directed BC Hydro to provide a proposal on how it plans to recover the any remaining balance in the regulatory account from ratepayers in the Application.[1451] BC Hydro has continued forecasting net gains of $0 in its revenue requirement since the BCUC's F2020 to F2021 RRA Decision.[1452]

The actual balance in the Real Property Sales Regulatory account at the end of F2021 was $47 million.[1453] BC Hydro states that it continues to make progress in its active property sales. For example, BC Hydro completed a property sale with a net gain of approximately $15 million in F2022.[1454] BC Hydro also expects to complete other sales by the end of F2024, consistent with its target of totalling a net gain of $100 million. Over the Test Period, BC Hydro expects real property sales to result in realized net gains exceeding the $47 million ending F2021 balance. As such, BC Hydro states that there could be a balance owing to ratepayers by the end of the Test Period. BC Hydro proposes to refund to or recover from ratepayers any remaining balance in the regulatory account over the next test period.[1455]

DSM Regulatory Account with Respect to Low Carbon Electrification Expenditures

Pursuant to the Direction to the British Columbia Utilities Commission Respecting Undertaking Costs, BC Hydro's expenditures incurred with respect to its Low Carbon Electrification Program under sections 4(3)(a) to (d) of the GGRR are deferred to the DSM Regulatory Account. In the BCUC's decision to BC Hydro's Fiscal 2022 RRA, the BCUC directed BC Hydro to provide a discussion in the current Application of whether LCE expenditures deferred to the DSM Regulatory Account should be recovered only from the beneficiaries of these expenditures, and if so the method that this could be accomplished.[1456] BC Hydro's LCE Program is discussed in Section 4.1 of this Decision.

In response to the BCUC's directive, BC Hydro proposes no change to the recovery of the LCE component of the DSM Regulatory Account, in that they should continue to be recovered from all ratepayers over a 15-year amortization period. BC Hydro proposes this for two reasons:[1457]

1) All customers benefit from BC Hydro's LCE programs under sections 4(3)(a) to (d) of the GGRR. This is because BC Hydro's LCE Programs are expected to reduce rates and GHG emissions. Further, many of BC Hydro's actions are directed at breaking down barriers to electrification generally, rather than directed at any particular customer.

2) To the extent that a subset of customers could be identified that more directly benefit from LCE actions under sections 4(3)(a) to (d) of the GGRR, recovering the costs from these customers would undermine the carrying out of a prescribed undertaking. This is because recovering the costs from these customers

[1451] BC Hydro F2020 to F2021 RRA, Decision and Order G-246-20, p. 127.
[1452] Exhibit B-2, p. 7-28.
[1453] Exhibit B-2, p. 7-28.
[1454] Exhibit B-7, BCUC IR 100.2.
[1455] Exhibit B-2, p. 7-29.
[1456] Exhibit B-2-3-1, pp. 10-50 – 10-51.
[1457] Exhibit B-2-3-1, pp. 10-51 – 10-52.

> would effectively "claw back" any incentive provided to these customers to electrify. BC Hydro points out that section 18 of the CEA prohibits the BCUC from doing anything that prevents a public utility from carrying out a prescribed undertaking.

As mentioned in Section 2.4.2 of this Decision, the Electrification Plan Direction was enacted during the current proceeding. Section 4 of the Electrification Plan Direction, among other things, sets out that up to $193.7 million in costs incurred in F2022 to F2027 to provide BC Hydro's LCE Program can be deferred to the DSM Regulatory Account, it sets out the amortization period as 15 years, and it requires the BCUC to allow recovery of the forecast annual LCE amortization amount from BC Hydro's ratepayers. Section 6 of the Electrification Plan Direction states that the BCUC:

> must allow the apportionment of the amounts to be recovered or refunded in either of the following ways:
>
> (a) so that the charges under the specified rate schedules are all increased or decreased, as the case may be, by the same percentage;
>
> (b) so that, for each specified rate schedule, the increase or decrease in charges under the schedule will generate substantially the same revenue under the schedule as the apportionment described in paragraph (a)."

Positions of the Parties

BC Hydro submits that its proposed regulatory account requests should be approved. With respect to the following regulatory account requests, BC Hydro submits:

- The Load Attraction Costs Regulatory Account: the Electrification Plan Direction requires the BCUC to approve the Load Attraction Costs Regulatory Account as proposed by BC Hydro.[1458]
- The Dismantling Cost Regulatory Account: continuing to use the Dismantling Cost Regulatory Account until it has implemented net salvage accounting is just and reasonable as it maintains the *status quo* over the Test Period.[1459]
- Real Property Costs Regulatory Account: BC Hydro's proposal is supported by actual property sales made during the proceeding and it promotes rate stability. BC Hydro submits that there is no need to amortize the account balance over the Test Period because it expects to clear the balance in the account through further net gains on sales and thus, amortizing the balance over the Test Period would result in higher rates than necessary.[1460]
- DSM Regulatory Account: Section 6 of the Electrification Plan Direction means that the amounts to be recovered from or refunded to ratepayers with respect to its LCE expenditures cannot be allocated in greater weightings to certain specified rate schedules compared to others.[1461]

Interveners either do not oppose or do not provide a position on BC Hydro's proposal.

Panel Determination

The Panel notes that the Electrification Plan Direction requires the BCUC to approve BC Hydro's requests related to the Load Attraction Costs Regulatory Account and the DSM Regulatory Account, as set out in the Application. **Therefore, pursuant to the Electrification Plan Direction, the Panel approves BC Hydro's requests related to**

1458 BC Hydro Final Argument, p. 133.
1459 BC Hydro Final Argument, p. 1.
1460 BC Hydro Final Argument, p. 142.
1461 BC Hydro Final Argument, p. 197.

the Load Attraction Costs Regulatory Account, as set-out in Section 7.3.1 Application, and approves BC Hydro's request to not change the recovery of the LCE Program component of the DSM Regulatory Account.

The Panel notes that Section 4 of the Electrification Plan Direction requires the BCUC to allow BC Hydro to defer to the DSM Regulatory Account up to $193.7 million in costs incurred in F2022 to F2027 to provide its LCE Program and to amortize these costs over 15 years for recovery from all BC Hydro ratepayers. **Therefore, pursuant to the Electrification Plan Direction, the Panel authorizes BC Hydro to defer to the DSM Regulatory Account up to $193.7 million in costs incurred in F2022 to F2027 to provide the LCE Program. The Panel also authorizes BC Hydro to amortize from the DSM Regulatory Account each fiscal year, the forecast annual LCE amortization amount, calculated on the assumption that the costs to provide its LCE Program for the fiscal year will be amortized over a period of 15 years.**

The Panel notes that the COVID-19 Direction requires the BCUC to approve the recovery of the balance in the CCF Regulatory Account and in the MCPP Regulatory Account from all of BC Hydro's ratepayers over the period requested by BC Hydro in the Application. With respect to BC Hydro's requests to continue applying interest to these accounts at its weighted average cost of debt, this approach is consistent with BC Hydro's other regulatory account where interest charges are applied and there is no reason provided in this proceeding to suggest that a different approach is appropriate. **Therefore, the Panel approves BC Hydro's requests related to the CCF Regulatory Account and the MCPP Regulatory Account, as set-out in Section 7.3.3.5 and Section 7.3.3.6 of the Application, respectively.**

The Panel notes that subsequent to the filing of the Application, the CCF Direction was amended to require the BCUC to allow BC Hydro to defer up to $11 million to the CCF Regulatory Account for the CCF grants issued to customers and BC Hydro's internal costs to administer the program. **Therefore, pursuant to the amended CCF Direction, the Panel authorizes BC Hydro to defer up to a maximum of $11 million to the CCF Regulatory Account for the amounts incurred by BC Hydro to administer the CCF Pilot Program and the grants provided to residential customers under the CCF Pilot Program.**

The Panel finds that BC Hydro's requests related to the remaining regulatory accounts are reasonable and the Panel notes that interveners do not oppose these requests. **Therefore, the Panel approves BC Hydro's requests related to the following regulatory accounts:**

- **Dismantling Cost Regulatory Account, as set out in Section 7.3.2.2 of the Application;**
- **Low Carbon Fuel Credits Regulatory Account, as set out in Section 7.3.3.1 of the Application;**
- **Real Property Sales Regulatory Account, as set out in Section 7.3.3.7 of the Application;**
- **Fiscal 2022 Depreciation Study Impact Regulatory Account, as set out in Section 7.3.3.2 of the Application, with the exception that BC Hydro is directed to recover the actual (instead of the forecast) F2022 ending balance of the account, based on the depreciation rates approved by the BCUC in this Decision, over the Test Period.**

The Panel directs BC Hydro to update the F2022 ending regulatory account balance with the actual balance in its Compliance Filing and to close the Fiscal 2022 Depreciation Study Impact Regulatory Account once the account balance is zero.

4.9 Demand-Side Management

In October 2021, the BCUC requested[1462] that BC Hydro file its DSM expenditure schedule for F2023 (at a minimum), including expenditures in the NIA and for capacity-focused DSM, in the F2023 to F2025 RRA

[1462] Exhibit A-3

proceeding. In December 2021, BC Hydro filed its F2023 to F2025 DSM expenditure schedule (DSM Plan), seeking acceptance of $295.7 million over the Test Period, replacing the "placeholder" amounts that were included in the original Application.[1463]

BC Hydro is also seeking acceptance of a revised DSM expenditure schedule of $85.4 million for F2022,[1464] discussed in Section 4.9.4 below.

BC Hydro states that should the BCUC accept BC Hydro's DSM Expenditure Schedules, BC Hydro proposes to reflect the necessary adjustments due to the updated DSM expenditures, as well as any other required changes, in a complete set of Appendix A financial schedules in a compliance filing following the BCUC's decision on the Application.[1465]

4.9.1 Legislative framework

Pursuant to section 44.2(3) of the UCA, after reviewing an expenditure schedule, the BCUC, subject to subsections (5.1) and (6), must accept the schedule if it considers that making the expenditures referred to in the schedule is in the public interest, or reject the schedule. The BCUC may also accept or reject part of an expenditure schedule, pursuant to section 44.2(4) of the UCA.

Section 44.2 (5.1) of the UCA sets out the relevant factors[1466] that the BCUC must consider in its review of BC Hydro's DSM expenditure schedule. That section states that in addition to considering the interests of persons in B.C. who receive or may receive service from BC Hydro, the BCUC must consider several items, including:

- B.C.'s energy objectives;
- A long-term resource plan filed by BC Hydro under section 44.1 of the UCA; and
- if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

Section 4 of the Demand-Side Measures Regulation[1467] (DSM Regulation), defines the DSM cost-effectiveness tests to be used by the BCUC in evaluating a DSM application under subsection 44.2(5.1)(d) of the UCA. The DSM Regulation defines the process for determining cost-effectiveness of the demand-side measures for the purposes of section 44.2(5.1)(d) of the UCA.

While the Panel must consider each of the above factors in determining whether to accept all or part of the expenditure schedule as being in the public interest, it is not obliged to make specific findings in respect of each of those factors. In addition, the Panel is bound to apply the terms of government directions. Pursuant to the Electrification Direction,[1468] the BCUC must allow BC Hydro to defer certain expenditures related to LCE to the DSM regulatory account,[1469] and allow BC Hydro to amortize these amounts over a period of 15 years. Section 4.8.4 of this Decision provides additional details on this topic. Direction No. 7, rescinded in 2019, previously required that the BCUC allow BC Hydro to defer costs rising from its development, implementation, and

1463 Exhibit B-10, p. 1; Table 3 on page 5 summarizes the differences between the placeholder and actual DSM amounts requested.
1464 Exhibit B-10, p. 4.
1465 Exhibit B-20, BCOAPO IR 173.4.
1466 Section 44.2(5.1)(c) addresses the extent to which the expenditure schedule is consistent with applicable requirements of section 19 of the Clean Energy Act, which deals with the construction or purchase of clean or renewable resources. This section is not considered to be a directly relevant factor when considering an expenditure schedule for demand side measures.

1467 OIC No. M271, BC Reg. 326/2008.
1468 OIC No. 355, B.C. Reg. 156/2022, section 4(1). See also Direction to the BCUC Respecting Undertaking Costs OIC No. 100, B.C. Reg. 77/2017.
1469 The DSM regulatory account was established under Order G-55-95.

administration of demand-side measures, including costs arising from specified demand-side measures and public awareness programs in the DSM Regulatory Account, and to amortize these amounts over 15 years.[1470]

4.9.2 F2023 to F2025 DSM Expenditures

BC Hydro's DSM Plan has been developed in the context of BC Hydro's 2021 Integrated Resource Plan (2021 IRP) Base Resource Plan. The 2021 IRP considered options for the level of DSM and lays out the Base Resource Plan elements for energy efficiency and capacity savings.[1471] In the F2022 RRA Decision, the BCUC noted that it expects BC Hydro to provide evidence in this Application to support any proposed spending on capacity-focused DSM beyond F2022. [1472]

BC Hydro states the DSM Plan is designed to be consistent with the 2021 IRP's Base Resource Plan. The Test Period includes the initial ramp up of activity needed to position BC Hydro to reach the energy savings outlined in the Base Resource Plan by F2030. Activities over the Test Period include BC Hydro's first demand response (DR) programs and plans to move forward with voluntary time-varying rates.[1473]

The DSM Plan includes expenditures for DSM in the NIA and for Non-Wires Alternative projects, both of which were outside of the scope of the 2021 IRP. DSM in the NIA is outside the scope of the 2021 IRP because the 2021 IRP is focused on the future demand for electricity on the integrated system. Non-Wires Alternatives are potential solutions for capacity constraints at the level of an individual substation. The planning for distribution and the non-bulk transmission system is not addressed in the 2021 IRP.[1474]

The following table outlines the planned expenditures over the Test Period. BC Hydro has also provided tables of the planned energy (Table 67) and capacity savings (Table 68) in the Application, reproduced below.[1475]

Table 66: F2023 to F2025 DSM Expenditure Summary ($ million)

	F2023 Plan	F2024 Plan	F2025 Plan	F2023 – F2025 Total
Energy Efficiency Rate Structures	0.5	0.5	0.7	1.6
Energy Efficiency Programs				
Residential	26.0	29.0	32.2	87.2
Commercial	15.4	15.0	16.6	47.1
Industrial	22.5	22.7	29.4	74.5
Total Energy Efficiency Programs	**63.9**	**66.6**	**78.3**	**208.8**
Capacity-focused Rate Structures	0.4	1.6	0.8	2.8
Capacity-focused Programs	1.0	4.0	6.6	11.7
Capacity-focused Program Enabling	2.1	1.9	1.8	5.8
Total Capacity-Focused	**3.5**	**7.5**	**9.2**	**20.3**
Portfolio Supporting Initiatives	21.6	21.5	21.9	65.0
Total	**89.5**	**96.1**	**110.1**	**295.7**

[1470] OIC No. 97, B.C. Reg. 28/2014 was repealed by OIC No. 51, B.C. Reg 24/2019.
[1471] Exhibit B-10, p. 2
[1472] BC Hydro Fiscal 2022 RRA, Decision and Order G-187-21, p. 81.
[1473] Exhibit B-10, p. 3.
[1474] Exhibit B-10, p. 3
[1475] See Exhibit B-10, Tables 6, 7 and 8, pp 14–15; See also Attachment 1, Section B for a more detailed breakdown.

Table 67: F2023 to F2025 New Incremental Energy Savings (Cumulative annual GWh/year)

	F2023 Plan	F2024 Plan	F2025 Plan
Codes and Standards[10]	254	242	228
Energy Efficiency Rate Structures	119	119	119
Energy Efficiency Programs			
Residential	43	45	48
Commercial	40	42	43
Industrial	141	147	201
Total Energy Efficiency Programs	**224**	**233**	**291**
Capacity-focused Rate Structures	0	4	9
Capacity-focused Programs	0	0	0
Total Capacity-Focused	**0**	**4**	**9**
Total	**598**	**599**	**647**

Table 68: F2023 to F2025 New Incremental Capacity Savings (Cumulative annual MW)

	F2023 Plan	F2024 Plan	F2025 Plan
Codes and Standards	49	46	43
Energy Efficiency Rate Structures	9	9	9
Energy Efficiency Programs			
Residential	12	12	14
Commercial	6	6	6
Industrial	17	18	24
Total Energy Efficiency Programs	**35**	**36**	**44**
Capacity-focused Rate Structures[11]	0	13	26
Capacity-focused Programs	0	21	54
Total Capacity-Focused	**0**	**34**	**80**
Total	**93**	**126**	**177**

BC Hydro states that it intends to maintain a similar level of DSM to that of recent years, noting the following changes:[1476]

- In the residential sector:
  - Increasing expenditures for the Home Renovation Rebate program to reflect an expected increase in participation in the heat pump offer.
  - Additional assistance to Indigenous customers, low-income customers and customers in the NIA to help them to reduce their energy consumption.
- In the commercial sector:
  - Adjustments to reflect expected participation levels and a ramping up of Commercial Energy Management Activities in F2025 to prepare for increased activities in F2026 onwards.[1477]
  - Reflect the planned wind down of the Commercial New Construction Program, which is expected to complete in F2023. This program has been replaced by a codes and standards approach.[1478]
- In the industrial sector:
  - Increased expenditures to support an expected increase in participation in existing programs.

[1476] Exhibit B-10, p. 18.
[1477] Exhibit B-10, Attachment 1, p. 33.
[1478] Exhibit B-10, Attachment 1, p. 30.

Activities in the Test Period which are related to the anticipated ramp up to meet the energy and capacity savings levels outlined in the 2021 IRP's Base Resource Plan include the following:

- Starting in F2025, increasing industrial and commercial expenditures for energy studies for new projects and energy management activities.
- Development of an online marketplace for residential customers to purchase energy efficient measures from retailers.
- Applying for approval of voluntary time-varying rates options for residential customer, and home EV charging. The DSM Plan includes costs for public awareness, education and supporting tools for the new rates.[1479]
- The launch of three capacity focused DSM activities, including an EV connected charger rebate offer in F2023, followed by an EV Demand Response offer, and a Residential Peak Saver offer in F2024.[1480]

BC Hydro is also transitioning from the pilot phase to implementation of Non-Wires Alternative (NWA) solutions. These NWA solutions investigate opportunities to geographically focus efficiency and capacity-focused DSM activities to address a constraint at the level of a specific substation and thereby defer a capital upgrade. As NWA opportunities are at the level of individual substations, they are outside of the scope of the 2021 IRP. BC Hydro is targeting substations that have a load growth forecast with peak demand that exceeds the design capacity of the substation in a four-to-eight-year time frame. BC Hydro is planning to initiate three Non-Wires Alternative projects, with the Hope substation as the first full implementation of an NWA project.[1481]

4.9.2.1 DSM in the NIA

BC Hydro developed the DSM Plan for the NIA program independently of the 2021 IRP.[1482] The F2022 RRA Decision[1483] noted that achievable cost-effective opportunities for BC Hydro to reduce the use of diesel in the NIA may have been overlooked, and the BCUC encouraged BC Hydro to consider implementing DSM activities in the NIA on their own merits.

BC Hydro notes that the Covid-19 pandemic resulted in lower participation in low-income programs in the NIA, and a slow-down in other DSM activities, but its planned savings in the commercial and industrial sector were not affected in F2022.[1484] BC Hydro is in the process of developing a performance measurement framework with Indigenous communities for the NIA program to report on addressing community goals and barriers.[1485]

NIA expenditures are increasing from $2.9 million to $3.7 million over the Test Period, which more than doubles the annual expenditures in the NIA relative to F 2022 plan amounts.[1486] BC Hydro states it is adding new energy savings measures, increasing incentive levels on existing energy savings measures, and adding enabling support for Indigenous Nations to increase their capacity to advance energy efficiency, and reduce reliance on diesel generated electricity over the Test Period.[1487] The DSM Plan in the NIA includes continuing support for Great Bear Initiative (GBI) Climate Action Coordinator Network for Coastal First Nations over the next three years, and additional Climate Action Coordinator positions in Indigenous remote communities in B.C., including in the

[1479] Exhibit B-10, p. 20.
[1480] Exhibit B-10, p. 20.
[1481] Exhibit B-10, p. 22.
[1482] Exhibit B-10, p. 21.
[1483] BC Hydro Fiscal 2022 RRA, Decision and Order G-187-21, p. 81
[1484] Exhibit B-10, p. 11-12
[1485] Exhibit B-2, p. 1-47; Exhibit B-20, Zone II RPG IR 64.1
[1486] Exhibit B-10, p. 22; Attachment 1, p. 17
[1487] Exhibit B-10, p. 21; Exhibit B-20, Zone II RPG IR 72.1

NIA.[1488] BC Hydro notes that Indigenous communities that have a Climate Action Coordinator position through the Coastal First Nations Great Bear Initiative Climate Action Network tend to participate in DSM programs more than communities that don't have this type of staff resource in place. [1489] BC Hydro is continuing to seek input on barriers to participation that Indigenous communities, including those in the NIA, through a process evaluation of the Indigenous Communities Conservation Program, which was due to be completed in 2022.[1490]

Positions of the Parties

Zone II RPG submits that BC Hydro's DSM expenditures in the NIA are in the public interest and cost-effective as they relate to BC Hydro's F2023 to F2025 DSM Expenditures Schedule.[1491] Zone II RPG welcomes BC Hydro's increased DSM expenditures in the NIA, and responsiveness to the BCUC's comments in this regard in the F2022 RRA decision, but has concerns about the progress of the NIA DSM program which has performed below plan since its introduction in F2020. Zone II RPG supports BC Hydro's ongoing work to develop a performance management framework for the NIA.[1492] Ongoing reporting from BC Hydro is required to evaluate whether increased and/or new DSM expenditures are adequately addressing the unique challenges faced by Indigenous communities in the NIA.[1493]

Zone II RPG requests that BC Hydro continue to report on DSM activities in the NIA in its annual report to the BCUC on DSM activities, and particularly:

a. whether increased expenditures are achieving planned energy savings;

b. the effectiveness of enabling support measures;

c. whether it is necessary to update the long-term avoided cost of diesel in the NIA due to the increased cost of diesel; and

d. whether the planned performance measurement framework, developed with Indigenous communities, is effectively being used to report on BC Hydro's initiatives to address community goals and barriers to DSM implementation.[1494]

Zone II RPG encourages BC Hydro to consider setting up additional coordinator roles in the NIA to support DSM work in the various communities to build on the apparent success of the Coastal First Nations Great Bear Initiative Climate Action Network. Zone II RPG stresses that BC Hydro's DSM program for the NIA needs a "multiyear, comprehensive, and flexible approach considering housing upgrades that incorporate DSM measures", and encourages BC Hydro to consider a coordinator working with various funders and communities to facilitate housing upgrades.[1495]

BCSEA supports increased DSM spending on NIAs during the Test Period.[1496]

BC Hydro commits to continue working with communities in the NIA to overcome the unique barriers to participation in DSM programs in the NIA.[1497]

[1488] Exhibit B-20, Zone II RPG IR 72.1
[1489] Exhibit B-31, Zone II RPG IR 77.1.
[1490] Exhibit B-31, Zone II RPG IR 77.2.2
[1491] ZoneII RPG Final Argument, p. 23
[1492] Zone II RPG, Final Argument, p. 26.
[1493] Zone II RPG, pp. 2-3; 23.
[1494] Zone II RPG Final Argument, p.23.
[1495] Zone II RPG, Final Argument, pp. 23–24.
[1496] BCSEA Final Argument, p. 44.
[1497] BC Hydro Reply Argument, p. 154.

Panel discussion

The Panel is satisfied with the evidence in support of the expansion of DSM in NIA communities. Zone II RPG and BCSEA also endorse BC Hydro's plans. In response to Zone II RPG's submission for NIA specific annual reporting, the Panel interprets those areas as already within the scope for BC Hydro reporting as part of the NIA performance measurement framework and DSM Annual Report.

4.9.3 Is the F2023 to F2025 DSM Expenditure Schedule in the public interest?

In reviewing whether the expenditure schedule is in the public interest, the Panel examines the evidence and submissions pertaining to each of the relevant considerations outlined in section 44.2(5.1) of the UCA in turn below. Following this, the Panel's overall determination on the acceptance of BC Hydro's F2023–F2025 DSM expenditure schedule is addressed in section 4.9.3.5.

4.9.3.1 Interests of Persons in British Columbia who Receive or may Receive Service from the Authority

The Panel must first consider whether the proposed DSM expenditure schedule is in the interests of persons in British Columbia who receive or may service from BC Hydro.

Following the submission of the DSM Plan during the proceeding, BC Hydro notes that the net impact to bills of the DSM Plan compared to the placeholder amounts in the original Application is $4.0 million inF2023, $6.6 million in F2024, and $9.2 million in F2025. This results in an estimated net bill increase (relative to those filed in the Application) of 0.07 per cent inF2023, 0.05 per cent in F2024, and 0.05 per cent in F2025. In other words, all else equal, this change results in net bill impacts of (1.32) per cent, 2.05 per cent, and 2.74 per cent in F2023, F2024 and F2025, respectively.[1498]

The allocation of DSM expenditures over the Test Period across customer classes is shown in the table below, relative to the F2022 RRA.

Table 69: DSM Program Spend by Sector[1499]

	Residential Including Low-Income (%)	Commercial and Light Industrial (%)	Large Industrial (%)
BC Hydro DSM program spend by sector			
F2022 RRA	36	35	29
Fiscal 2023 to F2025 Plan	44	34	22
BC Hydro Allocation of DSM costs in Cost of Service Study			
Allocation of DSM costs	40	36	24

BC Hydro noted in IRs that while these DSM cost allocation percentages are helpful as a rough gauge of the balance within the DSM portfolio, BC Hydro does not target a specific level of DSM Program spending for each sector. Instead, DSM expenditures are developed for each initiative considering several factors including, but not limited to cost effectiveness, market opportunities, government policy and regulation, the Integrated Resource Plan, and feedback from customers, the BCUC, stakeholders and interveners. BC Hydro provided the following reasons for the increased proportion of residential expenditures:

- A doubling of average annual expenditures in the NIA;

[1498] Exhibit B-10, p. 6.
[1499] Exhibit B-10, Table 9, p. 16

- The introduction of residential capacity-focused programs which will be introduced during the Test Period to support the proposed time-varying residential rates. Capacity focused programs for the commercial and industrial sectors are not expected to be needed until after the current Test Period;
- A continued focus on the Home Renovation Rebate program; and
- Other than the commercial new construction program, which is being phased out, average annual expenditures on all commercial and industrial programs increase in this Test Period relative to the previous test period.[1500]

BC Hydro states that the DSM Plan is developed and designed to maintain broad access across all sectors and begins with a consideration of the market opportunities and needs across its entire customer base. BC Hydro then develops programs from the bottom up so that they are broadly applicable to customer segments that experience similar barriers.[1501]

The DSM Regulatory Account was established in accordance with G-55-95, and the initial amortization period of 10 years was extended from 10 to 15 years in 2012. In the F2012-F2014 Amended RRA, BC Hydro requested the change from 10 to 15 years based on evidence that the average persistence of new energy savings had increased. An amortization change from 10 years to 15 years was requested and approved by BCUC Order No. G-77-12A, in accordance with Direction No. 3 to the BCUC. Subsequent to the F2012-F2014 Amended RRA, the issue of DSM amortization was reviewed in the F2020-F2021 RRA, and the DSM amortization was maintained at 15 years.[1502]

The following table shows the average measure life persistence for the DSM expenditures in the Test Period, which are deferred to the DSM Regulatory Account.

Table 70: DSM Average Measure Life (years)[1503]

	3-Year Period F2023-F2025	
	GWh Weighted	**$ Weighted**
DSM Portfolio	**15.3**	**12.8**

Positions of the Parties

BC Hydro submits that its DSM Plan provides numerous benefits and is in the interests of its current and future customers, including the projected energy savings and capacity benefits, and the opportunity provided to all customer classes to save electricity and lower their bills.[1504]

BCSEA agrees that the BC Hydro F2023-F2025 DSM Expenditure Schedule provides numerous benefits and is in the interests of its current and future customers. BCSEA provides detailed reasons for its support, including noting the broad range of cost-effective measures for all customer classes that will achieve significant energy savings and capacity benefits over the Test Period.[1505]

BCSEA cautiously supports BC Hydro's shift from DSM incentives to a codes and standards based strategy to support DSM in both residential and commercial new construction, noting that BC Hydro says new construction

[1500] Exhibit B-19, BCUC IR 229.1.
[1501] Exhibit B-31, CEC IR 81.4
[1502] Exhibit B-31, AMPC IR 6.1.
[1503] Exhibit B-20, BCSEA, IR 76.2.
[1504] BC Hydro Final Argument, pp. 186–187.
[1505] BCSEA Final Argument, pp. 47–52.

is a key component of BC Hydro's overall codes and standards approach.[1506] BCSEA comments that if future evaluation shows that the codes and standards approach to residential and commercial construction is leaving unacceptable amounts of lost opportunities, then BC Hydro could consider using section 4(1.1)(d) of the DSM Regulation to increase the cost-effectiveness of a new construction program.[1507]

BCSEA commends BC Hydro's active development of options for residential demand-response and time varying measures, noting that BC Hydro has conducted an "impressive" number of pilots.[1508]

BCOAPO submits the F2023-2025 Expenditure Schedule meets the interests of person in BC,[1509] but notes concerns with respect to low income DSM expenditures. While BCOAPO notes and supports the increased levels of activity and spending over the Test Period for the Energy Savings Kits (ESK) and Energy Conservation Assistance Program (ECAP),[1510] it again takes issue with the lack of new programs aimed at the Low Income ratepayers. BCOAPO submits the savings from ESKs are low, and "far from the adequate response needed" to assist low income customers.[1511] While ECAP provides more tangible energy and bill savings to recipients, target participation remains low at around 1 percent of eligible low income customers per year over the Test Period.[1512]

BCOAPO supports BC Hydro's initiative to study the viability of deep retrofit measures across a variety of housing types, including multifamily buildings. BCOAPO submits that in the absence of lifeline rates, DSM programs targeted to low income ratepayers should be an important affordability measure.[1513]

BC Hydro notes in reply that its low-income program is expanding. In addition to the ESK And ECAP offers, BC Hydro also has an Indigenous Communities Conservation Program, which together address the needs of low income customers. BC Hydro notes that expenditures in the Low Income area have more than doubled since F2016. In addition, BC Hydro notes it is: increasing support for Social Housing Retrofit Support Program under the Commercial program; studying the viability of future retrofit offers; and points to the anticipated income qualified CleanBC Better Homes programs which the BC Government expects to launch.[1514]

AMPC submits that "[a]pproving BC Hydro's DSM plan and implementation in rates as proposed will unfairly prioritize the potential longer-term benefits to future ratepayers over concrete current ratepayer costs in the F2023 – F2025 test years (and beyond). BC Hydro's failure to consider the cost implications of its proposals on ratepayers today does not proportionally serve the 'public interest' nor 'persons in British Columbia who receive or may receive service from the authority' in the test years. For the test years, the DSM plan only benefits the individual customers who participate in DSM programs, while imposing costs on other ratepayers who cannot take advantage of this programming."[1515]

BC Hydro argues that AMPC's desire to avoid short-term rate impacts prioritizes short-term benefits over longer-term benefits in a way that is not prudent or in the public interest. BC Hydro submits it must take a longer-term view and position itself to be able to meet customer needs not only over the Test Period, but in F2030 as well. It takes time to ramp up DSM savings levels, and rejecting BC Hydro's proposed ramp up in expenditures would prejudice BC Hydro's ability to meet its resource needs in the future, to the detriment of customers.[1516]

1506 BCSEA Final Argument, p. 52–56.
1507 BCSEA Final Argument, p. 56.
1508 BCSEA Final Argument, p. 56.
1509 BCOAPO Final Argument, pp. 83–84.
1510 BCOAPO Final Argument, p. 84.
1511 BCOAPO Final Argument, p. 85.
1512 BCOAPO Final Argument, p. 86.
1513 BCOAPO Final Argument, pp. 85–86.
1514 BC Hydro Reply Argument, p. 155–157.
1515 AMPC Final Argument, pp. 3-4 to 3-5..
1516 BC Hydro Reply Argument, p. 160.

AMPC submits that If the BCUC determines the DSM programs as proposed should be approved, it should look to amortize these DSM costs over a time period that better matches the costs of this programming with its benefits.[1517] BC Hydro submits that AMPC has not provided any reasonable basis for changing the current amortization period or method for the DSM Regulatory Account, and notes the amortization period of the DSM Regulatory Account was extended from 10 to 15 years in 2012 and was reviewed by the BCUC in the F2020-F2021 RRA. [1518] BC Hydro submits the current weighted average DSM measure persistence continues to support the 15-year amortization period, and therefore, an amortization period of 15 years continues to reasonably match the costs and benefits of DSM expenditures over the same period.[1519]

BCSEA accepts BC Hydro's evidence that the current weighted average DSM measure persistence figures support the 15-year amortization period for the DSM Regulatory Account.[1520]

BCOAPO agrees with BC Hydro's proposed approach to reflect adjustments flowing from the F2023-F2025 DSM Expenditure Schedule in a compliance filing.[1521]

Panel Discussion

The Panel considers that pursuant to section 44.2(5.1) of the UCA, the DSM Plan is in the interests of persons in British Columbia who receive or may receive service from the authority. This is supported by evidence about the breadth of opportunities for ratepayers to participate in DSM initiatives thereby supporting reduced energy bills, as indicated by the cost-effectiveness determinations above. The Panel is satisfied that the cost allocation is aligned with the opportunity for customers within each customer class to participate. With the exception of BCOAPO, the other interveners did not dispute this evidence.

In the case of BCOAPO, the Panel notes that a 1 percent participation rate of low-income households in the ECAP program is low. However, the Panel is satisfied with BC Hydro's reply on the expansion of the low-income program and in particular, the intent to extend programming into multifamily buildings and increasing support for the Social Housing Retrofit Support Program under the commercial customer class.

The other aspect of public interest is impact on rates. The Panel acknowledges AMPC's arguments regarding rate impacts and the BC Hydro evidence on the net impact to bills during the Test Period. However, this bill impact is of greatest concern for those customers that do not participate in DSM programs or see the resulting bill savings. Also, the DSM Plan builds upon a longstanding set of programs that has been in place for many years and was supported by previous BCUC decisions. Furthermore, the net bill increase from the placeholder expenditures submitted in the original Application is 0.07 percent in F2023 and 0.05 percent in the following two years. The Panel considers this bill impact to be immaterial.

The Panel further declines AMPC's recommendation to amortize DSM costs over a longer time period, noting that BC Hydro's evidence that the current weighted average DSM measure persistence figures support the 15-year amortization period.

4.9.3.2 British Columbia's Energy Objectives

Section 44.2 (5.1)(a) of the UCA requires the BCUC to consider BC's energy objectives in determining whether to accept an expenditure schedule filed by BC Hydro.

[1517] AMPC Final Argument, p. 3-6.
[1518] BC Hydro Reply Argument, pp. 161-–162; Exhibit B-31, AMPC IR 6.1.
[1519] BC Hydro Final Argument, p. 189.
[1520] BCSEA Final Argument, p. 58.
[1521] BCOAPO Final Argument, p. 17.

BC Hydro provides a summary of the DSM Plan alignment of the following BC energy objectives in Table 10 of the DSM Expenditure Schedule:

(a) To achieve electricity self-sufficiency,

(b) To take demand-side measures and to conserve energy,

(c) To use and foster the development of innovative technologies that support energy conservation,

(d) To ensure that BC Hydro's rates remain among the most competitive,

(e) To reduce B.C. GHG emissions,

(f) To encourage communities to reduce GHG emissions and use energy efficiently, and

(g) To encourage economic development and the creation and retention of jobs.[1522]

Positions of the parties

Regarding the objective to ensure competitive rates, BC Hydro submits that this issue was considered in the 2021 IRP through the inclusion of a "keeping costs down for customers" planning objective, and the DSM Plan is aligned with the Base Resource Plan of the IRP.[1523]

BCSEA agrees with BC Hydro that the F2023-F2025 DSM Expenditure Schedule supports the above-mentioned BC energy objectives. In support of competitive rates, BCSEA notes the Utility Cost Test value of 1.4 means the F2023-F2025 DSM Expenditure Schedule will reduce BC Hydro's revenue requirements, and accepts BC Hydro's description of the basis for this conclusion.[1524]

BCOAPO submits the F2023-2025 Expenditure Schedule adequately addresses how it supports BC's energy objectives.[1525]

Panel Discussion

The Panel is satisfied that BC Hydro's DSM expenditure schedule generally aligns with the current BC energy objectives in the *Clean Energy Act* as summarised in the Application, and further notes that no interveners have raised any concerns regarding misalignment. Accordingly, the Panel considers that pursuant to section 44.2 (5.1)(a) of the UCA, BC Hydro's DSM expenditure schedule is consistent with and supports the relevant energy objectives set out in the *Clean Energy Act*.

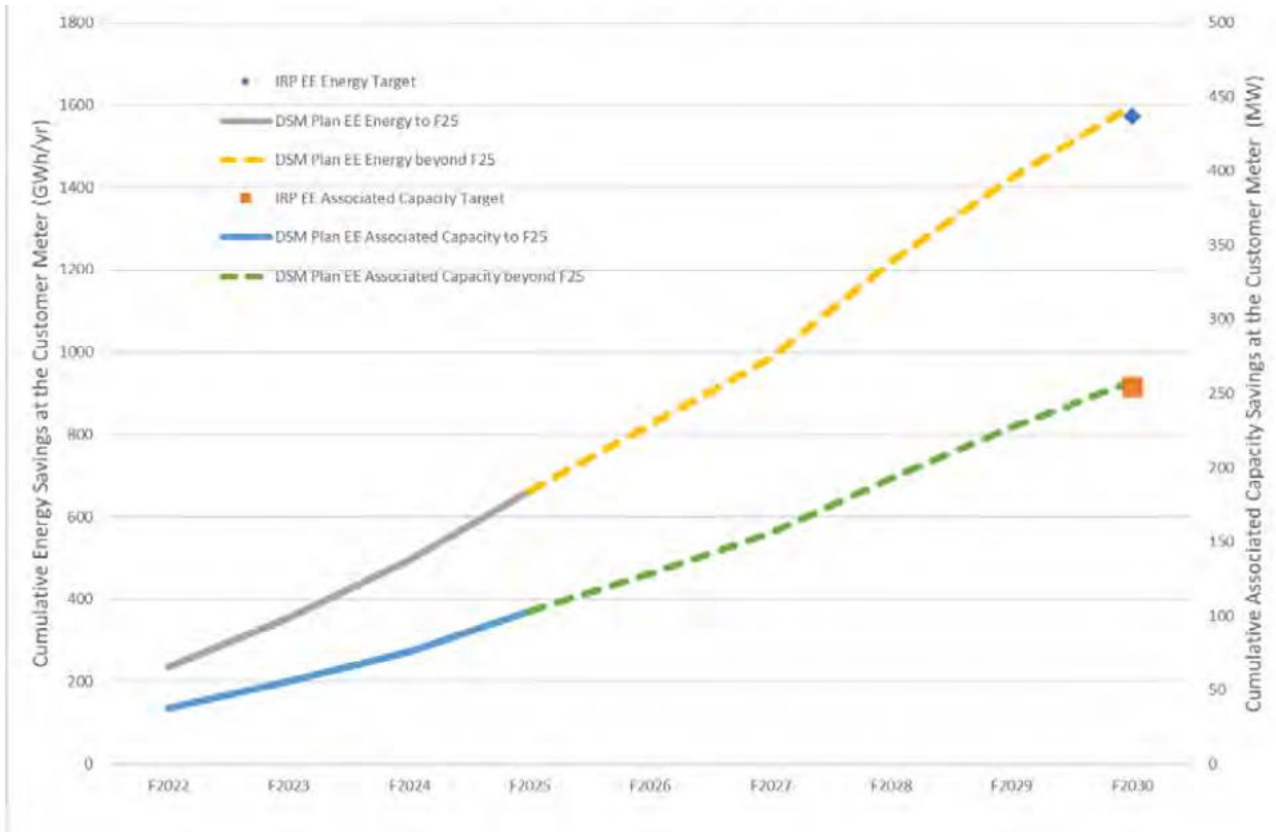
4.9.3.3 Most Recent Long-Term Resource Plan

Under Section 44.2 (5.1)(b)(ii), the BCUC must consider a long-term resource plan filed by the authority under section 44.1 of this Act. The BCUC's review of the IRP is ongoing and there has not yet been a determination under section 44.1(8)(c) regarding "whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures." Accordingly, BC Hydro submits that in this proceeding in respect of BC Hydro's DSM Expenditure Schedules, the BCUC and interveners should consider the guidance of the 2021 IRP as filed.[1526]

[1522] Exhibit B-10, Table 10, p. 25.
[1523] BC Hydro Final Argument, p. 186.
[1524] BCSEA Final Argument, p. 38.
[1525] BCOAPO Final Argument, pp. 83–84.
[1526] Exhibit B-10, cover letter, p. 2.

The DSM Plan has been developed in the context of the 2021 IRP's Base Resource Plan, and is based on the forecast transition from energy and capacity surplus to deficit by F2030.[1527] The ramp up to meet the energy savings and capacity savings levels identified in the Base Resource Plan of the 2021 IRP will mostly occur beyond F2025, as shown in Figure 8 below. BC Hydro states that the decision to start ramping up activities towards the end of the Test Period is supported by feedback from the Conservation and Energy Management Advisory Committee.[1528]

Figure 8: Energy and Associated Capacity Savings from Energy Efficiency Programs to achieve 2030 IRP Targets[1529]



Given the overlapping 2021 IRP and RRA proceedings, BC Hydro demonstrates in the Application how the DSM expenditure application aligns with the adequacy requirements set out in the DSM Regulation.[1530] BC Hydro also confirmed in this proceeding that the annual plan expenditures on its Codes and Standards Program of at least $5.5 million for each year of the Test Period, exceeds the minimum requirements set out in the DSM Regulation of an average of $2 million per year over the portfolio's period of expenditures.[1531] Cost-effectiveness is addressed in the following section.

According to section 4(1.1)(b) of the DSM Regulation:

> subject to subsection (1.3), the avoided electricity cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is (ii)… an amount that the commission is satisfied represents the

[1527] Exhibit B-10, pp. 16–17.
[1528] Exhibit B-10, p. 19.
[1529] Exhibit B-19, BCUC IR 232.2, p. 3 of 6.
[1530] Exhibit B-10, Table 11, pp. 29–30.
[1531] Exhibit B-20, BCSEA IR 83.2.

> authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia.

For the purposes of assessing cost-effectiveness as required by the DSM Regulation, BC Hydro is using an energy long run marginal cost (LRMC) of $65 per MWh and a capacity LRMC of $109 per kW-year based on the updated values presented in Appendix L of the ongoing 2021 IRP Application.[1532] Cost-effectiveness is addressed in the following section.

Positions of the Parties

BC Hydro submits that while the 2021 IRP is currently under review by the BCUC, section 44.2(5.1) requires the BCUC to consider BC Hydro's latest filed long-term resource plan. Therefore, consistent with the BCUC's request for BC Hydro to file its DSM Plan in this proceeding, it is not necessary for the 2021 IRP to be accepted for the BCUC to proceed with the review and acceptance of the DSM Plan.[1533]

BC Hydro states:

> The ramp up of expenditures in fiscal 2025 beyond the base level of DSM is well justified and supported by stakeholder feedback. The ramp up in expenditures in fiscal 2025 is needed to put BC Hydro on a path to meet the energy and capacity savings levels in the Base Resource Plan in the 2021 IRP. The ramp up will support energy studies for new projects and energy management activities in the commercial and industrial areas that require long lead times, and the development of an online marketplace for residential customers to support the future ramp up required in the residential sector. Feedback from BC Hydro's external advisory committee supported the ramping up of some DSM activities to ensure that customers and industry would be better prepared to support the increase in DSM activity over time.[1534]

MoveUP and BCSEA agree that BC Hydro's proposed DSM expenditure is consistent with its overall resource planning and the filed IRP. BCSEA agrees with BC Hydro that it is not necessary for the 2021 IRP to be accepted for the BCUC to proceed with the review and acceptance of the F2023-F2025 DSM Expenditure Schedule.[1535]

BCSEA agrees that the DSM Plan meets the adequacy requirements, noting it includes the following provisions: Demand side measures for low-income households and rental accommodations; education programs for schools and post-secondary institutions; resources to support development of, or compliance with, standards; and measures to support adoption of step codes by local governments and First Nations.[1536]

AMPC submits that until the 2021 IRP is accepted and approved by the BCUC, it should not be used as justification to increase DSM expenditures in F2022 – F2025.[1537]

In reply BC Hydro reiterates its view there there is no requirement that the BCUC accept the 2021 IRP before accepting the 2023-2025 DSM Plan, but "*must* consider the 2021 IRP, i.e. the BCUC cannot choose to ignore the 2021 IRP as AMPC suggests." BC Hydro also notes the ramp up of DSM savings to the F2030 savings levels outlined in the Base Resource Plan of the 2021 IRP must be considered as supporting evidence for the proposed

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[1532] Exhibit B-10, p. 31.
[1533] BC Hydro Final Argument, p. 184.
[1534] BC Hydro Final Argument, pp. 188–189.
[1535] MoveUp Final Argument, p. 3; BCSEA Final Argument, pp. 35–37.
[1536] BCSEA Final Argument, pp. 39–43.
[1537] AMPC Final Argument, p. 3-2.

ramp up of savings. BC Hydro submits that the alignment of the F2023-F2025 DSM Plan with the 2021 IRP supports the conclusion that it is in the public interest.[1538]

Panel Discussion

Section 44.2(5.1)(b)(ii) requires that the BCUC consider "(ii) a long-term resource plan filed by the authority under section 44.1 of this Act". The Panel agrees with BCSEA and BC Hydro that the BCUC must consider the filed 2021 IRP, irrespective of the fact that the IRP has not yet been accepted. The Panel disagrees with AMPC's submission that the filed 2021 IRP needs to be approved before considering the DSM expenditures over the Test Period. The filed 2021 IRP sets out the Base Resource Plan which has been used to inform the development of the DSM Plan.

The Panel is satisfied that the DSM Plan for the Test Period has been informed by the needs of the underlying long-term resource planning contained within the 2021 IRP. The filed 2021 IRP calls for ramping up DSM energy and capacity savings and expenditures over its 20 year planning horizon, thereby supporting the F2023-F2025 DSM Expenditure Schedule rather than the placeholder DSM savings and expenditures in the original Application.

Section 44.1 (8)(d) of the UCA regarding long term resource and conservation planning requires the BCUC to consider whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures. The BCUC has not yet made a finding regarding the adequacy of BC Hydro's DSM portfolio in the ongoing IRP Proceeding. BC Hydro has provided evidence to demonstrate how the DSM Plan meets the adequacy requirements. The Panel notes that BCSEA agrees with BC Hydro, and that no interveners dispute BC Hydro's claim that the DSM Plan meets the adequacy requirements as set out in the DSM Regulation.
The Panel's finding with respect to cost-effectiveness is addressed further below.

4.9.3.4 Cost Effectiveness of the DSM Plan

Section 44.2(5.1)(d) of the UCA requires that, for expenditure schedules including demand side measures, the BCUC must consider whether the demand-side measures are cost-effective within the meaning prescribed by regulation. section 4 of the DSM Regulation[1539] sets out the process for determining cost-effectiveness for the purposes of section 44.2(5)(d) of the UCA, including the specific application of the Total Resource Cost (TRC) and a modified TRC (mTRC) test to represent societal and non-energy benefits for DSM programs. Other than for specified measures or measures intended to address adequacy as defined in the DSM Regulation, the BCUC may determine that a measure is not cost-effective using the Utility Cost Test (UCT).[1540] For any of the tests, a ratio of 1.0 or more indicates that benefits exceed the costs and that the DSM program or portfolio is cost-effective under that particular test.

The TRC is the ratio that results when the value of the benefits of DSM activity, as measured by avoided energy and capacity costs as applicable, is divided by the sum of the utility and customer costs for that DSM activity. section 4(1.1)(b)ii) of the DSM Regulation requires that the "long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia" be used in the calculation of the TRC and associated mTRC. BC Hydro is using an energy LRMC of $65 per MWh and a capacity LRMC of $109 per kW-year based on the updated values presented in Appendix L of the 2021 IRP Application.[1541] The modified TRC requires a 40 percent increase to the benefits of programs aimed at low-Income and adequacy programs (such as the NIA and Social Housing Retrofit Support Offer) required under section 3 of the DSM Regulation.

[1538] BC Hydro Final Argument, p. 159.
[1539] OIC No. M138, B.C. Reg. 117/2017.
[1540] OIC No. M138, B.C. Reg. 117/2017, section 4 (1.8).
[1541] Exhibit B-10. p. 31

The UCT is used to assess the impact of a DSM investment on BC Hydro's revenue requirement. A positive UCT result using BC Hydro's market price forecast would provide assurance that even surplus energy resulting from DSM would have a positive impact on BC Hydro's revenue requirements.[1542] BC Hydro is using the energy reference price of $51 per MWh and generation capacity reference price of $38 per kW-yr derived in the 2021 IRP to value energy and capacity savings for the UCT. BC Hydro's reference price combines the market price of electricity during surplus periods with the LRMC of electricity during deficit periods.[1543]

The table below shows the results of the UCT and modified TRC[1544] for the proposed F2023-F2025 DSM Expenditures Schedule, as corrected by BC Hydro in the proceeding, alongside the total expenditures over the Test Period:

Table 71: Benefit Cost Ratios and Associated Expenditures[1545]

	Benefit Cost Ratios			**Total expenditures F2023 – F2025 ($millions)**
	Utility Cost Test (Reference Price)	**Total Resource Cost Test (excl non-energy benefits)**	**Modified Total Resource Cost Test (LRMC)**	
Energy Efficiency Rate Structures	35.4	**2.0**	2.0	1.6
Energy Efficiency Programs	2.1	**1.7**	2.3	208.8
Capacity focused Rate Structures	1.2	**2.6**	2.6	2.8
Capacity-focused Programs	1.2	**1.8**	1.8	11.7
Total DSM Portfolio (including supporting initiatives & codes & standards)	1.4	**1.3**	1.6	295.7

BC Hydro clarifies that no programs require the use of the mTRC non-energy benefits increase to be cost-effective and notes that the overall portfolio TRC is 1.3. BC Hydro states that the TRC values for the Low-Income, NIA and Social Housing Retrofit offers include a 40 percent adder to program benefits as required by section 4(2) of the DSM Regulation.[1546]

Certain measures, such as heat pumps in the Home Renovation Rebate program, are being provided by both the DSM and LCE programs under Electrification Plan. BC Hydro states that the LCE actions provide BC Hydro heat pump incentives to customers looking to fuel-switch from existing natural gas to electricity, resulting in the reduction of GHG emissions. The DSM Plan supports the implementation of BC Hydro's Home Renovation Rebate program, which targets customers with existing electric heat and high electric bills and provides incentives on heat pumps to achieve energy efficiency.[1547]

Positions of the Parties

BC Hydro submits the DSM plan is cost-effective and is accordance with the requirements of the DSM Regulation. BC Hydro notes the positive UCT result indicates the costs of DSM activities are lower than the

[1542] Exhibit B-10, pp. 30–31.
[1543] Exhibit B-10, p. 30.
[1544] BC Hydro provides a more detailed overview of benefit-cost ratios including TRC, mTRC and UCT results in Exhibit B-10-1 Attachment 1, Section B, Table 1-6
[1545] Exhibit B-10, Table 12, p. 312; updated in Exhibit B-10-2; Exhibit B-20, BCSEA IR 80.1
[1546] Exhibit B-19, BCUC IR 230.5
[1547] Exhibit B-7, BCUC IR 125.1

reference price of energy and capacity, indicating that the DSM Plan will reduce revenue requirements. The TRC of 1.6 means that BC Hydro's DSM initiatives are cheaper than new supply from a resource perspective.[1548]

BCSEA agrees that the DSM Plan is cost-effective and supports inclusion of measures which are not cost-effective at this time.[1549] BCSEA is satisfied that the Home Renovation Rebate DSM Program and the LCE heat pump program are complementary (integrated delivery) but appropriately separate (different legal bases).[1550]

BCOAPO submits the F2023-2025 Expenditure Schedule is cost-effective, noting the F2023-F2025 DSM Expenditures Schedule meets the TRC test at both the portfolio level as well as at the program level.[1551]

AMPC disputes the BC Hydro's application of cost-effectiveness, noting "BC Hydro relies entirely on the Government definition of 'cost-effectiveness' to justify the impacts of its DSM plan (by way of the Utility Cost Test 'UCT' and the modified Total Resource Cost 'mTRC' test).[1552]

In reply, BC Hydro submits that AMPC's characterization of the MTRC and TRC test as insufficient to protect ratepayer interests is misleading. The TRC test helps to determine whether DSM is cheaper or more expensive than new supply from a resource perspective and is widely used in the DSM industry to assess cost-effectiveness. Moreover, Section 4 of the DSM Regulation requires the use of the TRC and MTRC tests in the determination of cost effectiveness. Contrary to AMPC's suggestion, the MTRC and TRC reflect present value calculations which take into account the timing of costs and benefits over time, and consider the fact that financial impacts (costs or benefits) that occur in the future have less weight from today's perspective. As such, the MTRC and TRC reflect values that are appropriately discounted to provide a proper comparison of costs and benefits.

In addition, BC Hydro rejects AMPC's assertion that DSM results in increased costs to the utility, stating that a UCT result of 1.0 or greater indicates that DSM reduces a utility's costs. Contrary to AMPC's suggestion, 'lost revenues' are not a DSM cost; rather the term 'lost revenues' is a proxy for the impact of the reduction in GWh over which revenue requirement can be recovered.[1553]

AMPC also submits that BC Hydro should be required to provide details of its DSM plans at the "measure level"[1554] in future DSM plans, especially if plans include ramped up levels of activity. AMPC asserts that more granular information is necessary to ensure ratepayers' interests are protected and to understand which customers are benefitting from BC Hydro programming and which are not. AMPC states it is the only way to test BC Hydro's spending for cost control and efficient use of expenditures and activity prioritization.[1555]

In reply BC Hydro states that the level of detail requested by AMPC is either not available or would be misleading, noting that:

> While some information may be available by the more detailed key component level for some programs and initiatives, not all key components will have energy savings. As well, expenditures

[1548] BC Hydro Final Argument, p. 184–185.
[1549] BCSEA Final Argument, p. 37.
[1550] BCSEA Final Argument, p. 45.
[1551] BCOAPO Final Argument, p. 83.
[1552] AMPC Final Argument, p. 3-4.
[1553] BC Hydro Reply Argument, pp. 159–160.
[1554] While not defined in the Application, based on interpretation of Exhibit B-20, AMPC 2.34.1 and AMPC Final Argument, p. 39, "measure level" refers to key-components of BC Hydro's programs (e.g., activities which collectively make up the Leaders in Energy Management – Industrial program) within a customer sector (e.g., Industrial Sector Energy Efficiency Programs).
[1555] AMPC Final Argument, p. 3-7.

> and energy savings are not necessarily planned and tracked by all of the key component headings.
>
> We do not make arbitrary allocations of energy savings across key components because it would not lead to meaningful insights on the cost-effectiveness of the key components. The different program key components work together as a package and are not designed to be assessed separately.[1556]

BC Hydro further notes the BCUC has consistently considered cost-effectiveness at the portfolio level for all the largest utilities in the province, as permitted by Section 4(1) of the DSM Regulation which provides for the BCUC to review cost-effectiveness at the individual measure level, a group level, or at the portfolio level.[1557]

Panel Determination

The Panel has considered the extent to which the DSM Plan is cost-effective at the portfolio level. The Panel is satisfied that the DSM Plan meets the cost-effectiveness criteria set out in Section 4 of the DSM Regulation. This is supported by the evidence that the TRC, mTRC and UCT ratios are greater than 1. More specifically, the DSM Plan portfolio benefits exceed costs by a factor of 1.3, as indicated by the TRC. This is also supported by most interveners.

The Panel disagrees with AMPC's concern that BC Hydro relies entirely on the Government definition of 'cost-effectiveness' to justify the impacts of its DSM plan, as the DSM Regulation prescribes many aspects of the cost-effectiveness methodology. In other words, the BCUC is constrained in how it evaluates cost-effectiveness and by extension, BC Hydro is obligated to demonstrate how its DSM Plan aligns with those methodological aspects defined by the DSM Regulation. While the Panel considers the DSM Plan to be cost effective, the next section focuses on the public interest which overlaps with AMPC's comments.

The Panel has considered AMPC's argument that BC Hydro should be required to provide details at the "measure level" in future DSM plans. AMPC did not provide a definition of "measure", but in IRs referred to the key components which collectively constitute the Leaders in Energy Management – Industrial (LEM-I) Program. We agree that granular information is necessary to evaluate if ratepayers' interests are protected and to understand which customers are benefitting from DSM programming and which are not. We do not agree that financial and cost-effectiveness data is necessary at the key component level. However, we recommend that BC Hydro provide more granular descriptions of program components such as targeted customer participation rates and key technologies deployed in future DSM Plans. Furthermore, we recommend that BC Hydro report on key accomplishments at the measure level within its annual DSM reporting. As a representative example, we highlight the level of detail provided in the most recent FortisBC Energy Inc. Natural Gas Demand-Side Management Programs Annual Report.[1558]

The Panel supports the integrated delivery of complementary LCE Program and DSM initiatives. We recommend that costs and benefits of each be reported on separately. The Panel included a reporting directive for the Electrification Plan in Section 4.1 of this Decision.

1556 BC Hydro Reply Argument, pp. 163–164.
1557 BC Hydro Reply Argument, p. 164.
1558 https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/230331-fei-2022-dsm-annual-report-ff.pdf?sfvrsn=92bf7ebd_1

4.9.3.5 Overall Determination on the F2023 to F2025 DSM Expenditure Schedule

Pursuant to section 44.2(3) of the UCA, the BCUC must accept the DSM expenditure schedule if it concludes after review that making the expenditures is in the public interest.

Positions of the Parties

BC Hydro submits that the DSM Plan for the Test Period provides broad customer access to conservation and energy management opportunities, will result in significant energy and capacity savings, has been developed in the context of the 2021 IRP, is adequate and cost effective in accordance with the DSM Regulation, and is in the interests of BC Hydro's customers. Accordingly, the BCUC should accept the DSM Plan for the Test Period as being in the public interest under section 44.2 of the UCA.[1559]

BCSEA and MoveUP support BCUC acceptance of the F2023-F2025 DSM Expenditure Schedule.[1560] Despite ongoing concerns regarding the DSM offerings for low-income customers (addressed above), BCOAPO does not object to accepting the proposed DSM Expenditure Schedule for F2023-F2025, as it supports BC's energy objectives, is cost-efffective, meets the interests of persons in BC who receive or may receive service from BC Hydro, and is consistent with the 2021 IRP.[1561]

AMPC is the only intervener to oppose a portion of the DSM expenditures, submitting that the BCUC should only approve BC Hydro's DSM expenditures included in its original Application, and not the "ramping up" spending from its supplemental DSM filing, until such time as the 2021 IRP is accepted as being in the public interest.[1562]

BC Hydro rejects this proposal on the basis that the initial expenditures were "placeholder" amounts and have not been tested in evidence. BC Hydro further notes that the BCUC must consider the latest filed resource plan, with no requirement for it to have been accepted before it may be considered. BC Hydro states that it would make adjustments after the BCUC's decision on the 2021 IRP, if needed.[1563]

BCSEA agrees with BC Hydro that the ramp-up of DSM expenditures in F2025 is consistent with the 2021 IRP and is supported by stakeholder feedback.[1564]

AMPC also notes three factors which may result in lower DSM expenditures, namely anticipated changes to the transmission rate; inflationary impacts on customer expenditure; and the need for customers to prioritise spending between electrification and DSM programs.[1565] In reply, BC Hydro submits that concerns with respect to a potential change to the transmission service rate structure are premature, as any change is subject to BCUC approval. With respect to the pressures on customer expenditures from either inflation or the Electrification Plan, BC Hydro notes there is no evidence to suggest these factors could cause customers to stop investing in DSM measures. Should participation in DSM be less than forecast, this will result in lower expenditures, and only actual expenditures are deferred to the DSM Regulatory Account.[1566]

1559 BC Hydro Final Argument, p. 181.
1560 BCSEA Final Argument, pp. 3, 35; MoveUP Final Argument, p. 3.
1561 BCOAPO Final Argument, pp, 83–84.
1562 AMPC Final Argument, p. 8-2.
1563 BC Hydro Reply Argument, pp. 158–160.
1564 BCSEA Final Argument, p. 36.
1565 AMPC Final Argument, p. 3-5.
1566 BC Hydro Reply Argument, pp. 160–161.

The CEC takes no position, suggesting that the 2021 IRP is the more appropriate proceeding in which to consider these expenditures. BC Hydro notes in reply that the BCUC requested[1567] that BC Hydro file its DSM expenditure schedule for F2023 (at a minimum) in this proceeding. BC Hydro notes that no party has objected to the scope of this proceeding including the DSM expenditures schedules, and that it would be extremely inefficient from a regulatory perspective to reverse course now.[1568]

Panel Determination

Based on the Panel's earlier discussion on the relevant factors set out in section 44.2(5.1) of the UCA, **the Panel finds BC Hydro's proposed DSM expenditure schedule for the Test Period to be in the public interest, and accepts the DSM expenditure schedule of $89.5 million in F2023, $96.1 million in F2024 and $110.1 million in F2025 under section 44.2 of the UCA**.

The net bill increase from the placeholder expenditures submitted in the original Application is very small; only 0.07 percent in fiscal 2023 and 0.05 percent in the following two years. The Panel considers this bill impact to be immaterial. Furthermore, participants in the DSM program will benefit from reduced bills. In addition, the Panel notes much of the increase in F2025 relates to capacity related expenditures that are identified in the Base Resource Plan in the IRP.

The Panel rejects AMPC's submission that the BCUC should only approve BC Hydro's DSM expenditures included in its original Application, and not the "ramping up" spending from its supplemental DSM filing, until such time as the 2021 IRP is accepted as being in the public interest.

4.9.4 Revised F2022 DSM Expenditure Schedule

BC Hydro is seeking acceptance of a Revised Fiscal 2022 DSM Expenditure Schedule (Revised F2022 Schedule) as it is forecasting F2022 DSM expenditures will exceed the F2022 DSM expenditure schedule previously accepted by the BCUC. The Revised F2022 Schedule totals $85.4 million, $3.2 million higher than the previously accepted DSM Schedule for F2022.

Table 72: Revised Fiscal 2022 DSM Expenditure Schedule[1569]

	Expenditure ($million)
F2022 Accepted DSM Expenditures	82.2
F2022 Additional DSM Expenditures	3.2
F2022 Revised DSM Expenditures	**85.4**

The following table outlines the plan and forecast expenditures along with new incremental energy and capacity savings in F2021 and F2022.

[1567] Exhibit A-3.
[1568] BC Reply Argument, p. 158.
[1569] Exhibit B-10, p. 4.

Table 73: DSM Incremental savings and expenditures for F2021 and F2022[1570]

	New Incremental Energy Savings (GWh/year)		New Incremental Associated Capacity Savings (MW)		Expenditures ($ million)	
	RRA Plan	Actual/ Forecast	RRA Plan	Actual/ Forecast	RRA Plan	Actual/ Forecast
F2021	753	780	136	135	89.1	77.0
F2022	588	615	93	97	82.2	85.4

BC Hydro attributes the increase to higher than anticipated participation in the Home Renovation Rebate program in F2022, due to time-limited increased incentives offered during the COVID-19 pandemic. BC Hydro states that the 'double the rebate' promotion which began in Q3 of F2021 (with work to be completed by June 30, 2021 for customers to qualify) was intended to support customers and industry partners and stimulate economic activity in the home energy retrofit sector which was lagging due to the pandemic.[1571] BC Hydro provided the following table comparing planned with actual participation for the Residential Home Renovation Rebate program, over the period when the incentives were doubled for parts of both fiscal years. BC Hydro notes that prior to the introduction of the increased incentive, participation in Q1 of F2021 was below plan.[1572]

Table 74: Planned and actual participation in the Home Renovation Rebate program in F2021 and F2022 (year-end forecast)

	F2021 Plan	F2021 Actual	F2022 Plan	F2022 Actual (YEF)
Participation	4,488	5,532	5,947	6,428

BC Hydro notes that participation in the Home Renovation Rebate Program has remained strong following the removal of the increased incentive following Q1 in 2022 and plans to allow the market to stabilize before determining if or when a higher rebate is warranted.[1573]

The pandemic also resulted in the delay of some commercial and capacity focused DSM expenditures in F2021, resulting in increased expenditures in F2022.[1574]

BC Hydro notes that participation in the Low Income Program has been lower than planned because the COVID-19 pandemic impacted its ability to perform in-premise work with some customers, resulting in less participation and savings than planned. While BC Hydro has taken additional steps to increase participation, total expenditures and savings from the Low Income Program are still forecast to be lower than those in the original F2022 DSM Plan.[1575]

BC Hydro considered whether the approved transfer rules[1576] could be utilized to cover the expenditures which were estimated to be 4 percent above plan. While the current transfer rules allow for a transfer between fiscal years of a test period to accommodate situations where a given fiscal year may be above the planned amount, BC Hydro's F2022 DSM expenditure schedule was only for one year, so there was no opportunity to transfer unspent amounts from the previous year. The current transfer rules do not provide another mechanism for BC Hydro to accommodate the $3.2 million variance in F2022.[1577]

[1570] Exhibit B-10, Table 5, p. 8.
[1571] Exhibit B-20, BCSEA IR 65.2.
[1572] Exhibit B-20, BCSEA IR 70.1.
[1573] Exhibit B-31, BCSEA IR 88.3.
[1574] Exhibit B-10, p. 9.
[1575] Exhibit B-20, BCOAPO IR 176.1; Exhibit B-8, BCSEA IR 4.2.
[1576] BC Hydro F2020-F2021 RRA Decision and Order G-246-20, p. 153.
[1577] Exhibit B-10. p. 10.

Positions of the Parties

BC Hydro submits that the revised F2022 DSM expenditure schedule of $85.4 million is in the public interest, noting the additional expenditures do not materially change the previously accepted F2022 expenditure schedule, will support BC's energy objectives in the *Clean Energy Act*, and result in a cost-effective DSM portfolio, with a benefit cost ratio of 1.6 under the modified Total Resource Cost ("TRC") Test. If accepted, BC Hydro will reflect the BCUC's acceptance of the revised F2022 DSM expenditure schedule in a compliance filing following the BCUC's decision on the Application.[1578]

BCSEA supports acceptance of BC Hydro's Revised F2022 DSM Expenditure Schedule under section 44.2 of the UCA, [1579] and agrees with BC Hydro that the revised F2022 DSM expenditure schedule is consistent with the previously accepted F2022 DSM expenditure schedule and that it remains a cost-effective portfolio of DSM initiatives. Both BCSEA and BCOAPO note the revised TRC ratio of 1.6.[1580]

BCOAPO notes that along with the 3.9 percent increase in expenditures for F2022 BC Hydro is forecasting new incremental energy savings in F2022 of 615 GWh (4.6 percent higher than originally planned).[1581]

Despite noting concerns with the apparent reduction in savings and expenditures related to the Low Income Program relative to the original F2022 DSM Expenditure Schedule, BCOAPO does not object to the revised F2022 Schedule.[1582]

Likewise, no interveners objected to the Revised F2022 Schedule.

Panel Determination

The Panel accepts BC Hydro's Revised F2022 DSM Expenditure Schedule and finds it to be in the public interest, pursuant to section 44.2 of the UCA. BC Hydro has demonstrated that the DSM portfolio remained cost-effective in F2022 on an overall portfolio basis, as noted by BCSEA and BCOAPO. The panel appreciates the unique circumstances of the COVID-19 pandemic, and that BC Hydro applied for approval during F2022, once it became clear that expenditures may exceed the approved F2022 amounts. Also, BC Hydro filed this variance proposal in the fiscal year for which it applies.

While the Panel has concerns regarding the doubling of incentives to stimulate investment, it notes that BC Hydro chose to do so only after observing that participation was lower than plan, and the incentive was time limited. In response to this concern, **the Panel directs BC Hydro to conduct an evaluation of the doubling of incentives in F2022 in its next DSM Expenditure Schedule, including analysis of the incremental electricity savings due to expanded incentives and the attribution of electricity savings from complementary measures such as additional incentives and tax policy by all levels of government. Within this evaluation, BC Hydro is directed to assess if the doubling of incentives resulted in additional demand-side savings in energy and reduced load in a defined peak period. The assessment should include regional inflation in the cost of related products and services, changes in free riders and free drivers and impacts on market transformation**.

The Panel observes that BC Hydro's current funding transfer rules[1583] do not apply to a one-year DSM plan and that an update to those rules is warranted. **The Panel directs BC Hydro to submit a proposal in its next RRA to update its DSM funding transfer rules to include provisions to address a funding shortfall in the final year of a DSM plan for no more than 5 percent, including a one-year DSM Expenditure Schedule, and any other changes**

[1578] BC Hydro Final Argument, p. 182.
[1579] BCSEA Final Argument, p. 3.
[1580] BCSEA Final Argument, p. 34; BCOAPO Final Argument, p. 78.
[1581] BCOAPO Final Argument, p. 77.
[1582] BCOAPO Final Argument, p. 79.
[1583] BC Hydro F2020 to F2021 RRA, Decision and Order G-246-20, p. 154.

to the DSM funding transfer rules it deems necessary. In doing so, the Panel recommends BC Hydro consider the guidelines for DSM funding transfer applications contained in the BCUC's Decision and Order G-371-22 to FBC's DSM Expenditures Plan application to enable consistency in applications for variances above the threshold levels set in the current DSM funding transfer rules.

4.10 Transmission Revenue Requirement and Open Access Transmission Tariff

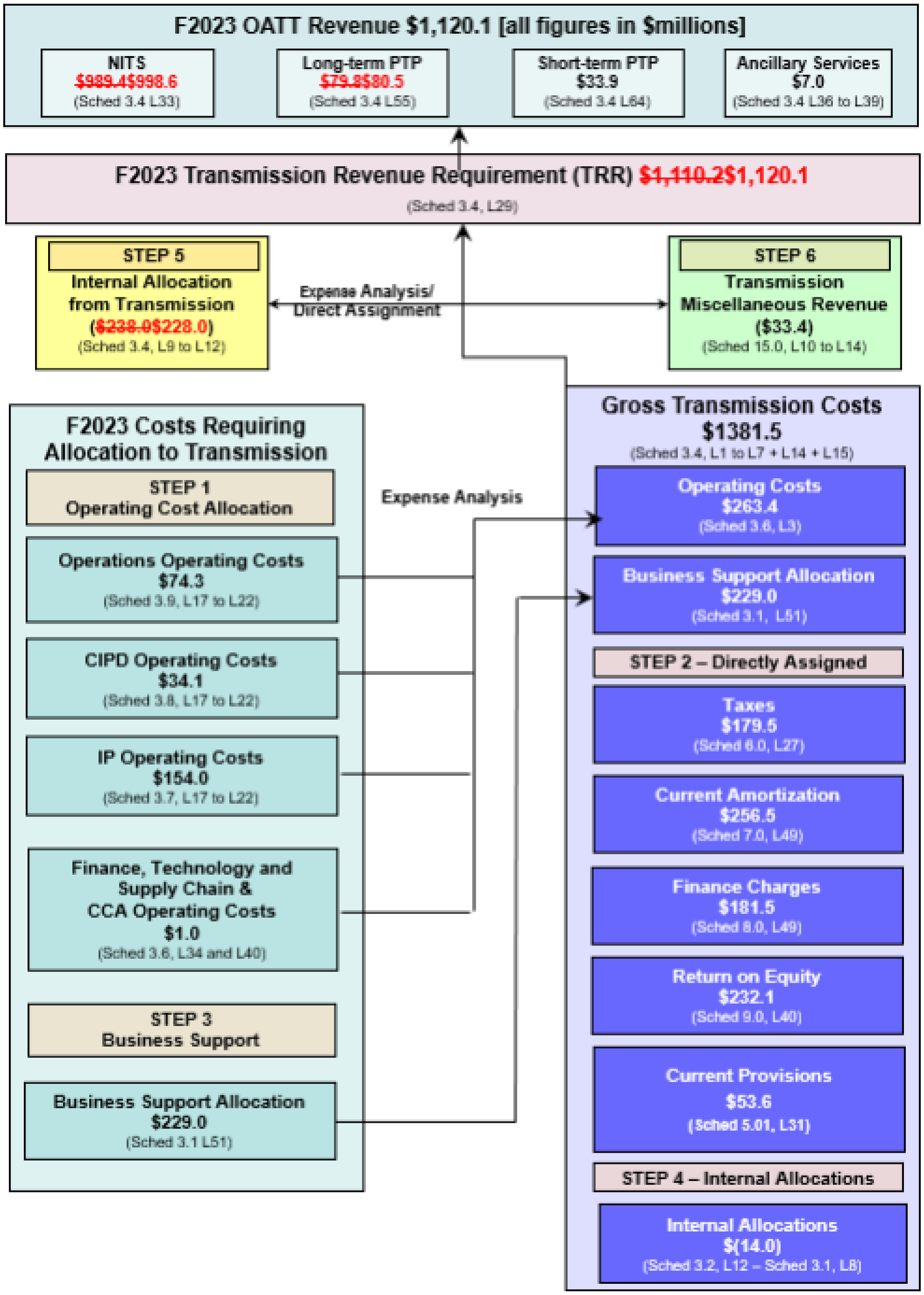
BC Hydro's Open Access Transmission Tariff (OATT) provides BCUC-approved terms through which OATT customers may access BC Hydro's transmission system "on a comparable basis to BC Hydro." The OATT rates apply to all usage of BC Hydro's transmission system, including usage by BC Hydro itself and by external OATT customers. The OATT considers only transmission capacity and not the sale of energy except for some ancillary services. The rates charged under the OATT are designed to collect the Transmission Revenue Requirement (TRR), which is the sum of all costs associated with the assets used to provide transmission service under the OATT.[1584]

Transmission Revenue Requirement

The TRR is comprised of the current costs associated with BC Hydro's transmission lines and high-voltage equipment used to provide transmission service pursuant to the OATT, which excludes both generation-related transmission assets and substation distribution assets.[1585] The allocations and direct assignments involved in calculating the F2023 TRR are set out in BC Hydro's figure below, as corrected in an errata filed by BC Hydro.

[1584] Exhibit B-2, p. 9-1.
[1585] Exhibit B-2, p. 9-2.

Figure 9: Fiscal 2023 TRR Components ($ million) with References to Appendix A Financial Schedules to the Application[1586]



Where possible, BC Hydro directly assigns costs to the TRR. Where direct assignment is not possible, costs are allocated using one or more of the following parameters:[1587]

i. Planned expenditures for maintenance and/or capital programs that are representative of the work a KBU [Key Business Unit] expects to undertake during the Test Period;

[1586] Exhibit B-2-6, Figure 9-1, p. 9-3.
[1587] Exhibit B-2, p. 9-7.

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.

As a result of the above analysis, BC Hydro allocates to the TRR the following operating costs from other business functions:[1588]

- 42 percent of the Integrated Planning Business Group operating costs;
- 29 percent of the Capital Infrastructure Project Delivery Business Group operating costs;
- 28 percent of the Operations Business Group operating costs;
- 19 percent of the Materials Management operating costs;
- 30 percent of the Fleet Services operating costs; and
- 50 percent of Customer Services for load attraction costs.

BC Hydro directly assigns to gross transmission costs certain costs such as provisions, taxes, amortization, finance charges, return on equity, and business support costs, as well as internal costs attributable to transmission.[1589]

To calculate the TRR, BC Hydro removes transmission related costs that are not related to providing service under the OATT from the TRR.[1590] BC Hydro also directly assigns miscellaneous revenues from external OATT customers and FortisBC, and certain other revenues, which offsets the TRR costs.[1591]

The cost components which make up the TRR in the Test Period are set out in the table below, as corrected in an errata filed by BC Hydro.

[1588] Exhibit B-2, p. 9-9.
[1589] Exhibit B-2, pp. 9-10 to 9-12.
[1590] Exhibit B-2, pp. 9-12 to 9-16.
[1591] Exhibit B-2, pp. 9-16 to 9-18.

Table 75: Transmission Revenue Requirement[1592]

	($ million)	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
		1	2	3	4	5	6
1	Operating Cost	242.0	247.2	~~209.4~~ 248.0	263.4	266.3	263.6
2	Provisions and Other	31.1	62.8	61.5	53.6	59.2	32.8
3	Taxes	164.7	167.0	172.6	179.5	187.9	193.2
4	Amortization	235.8	239.2	264.7	256.5	262.1	271.7
5	Finance Charges	227.9	148.3	149.1	181.5	174.9	172.9
6	Allowed Net Income	225.2	232.5	231.0	232.1	231.5	180.9
7	Business Support Cost	232.0	239.1	235.8	229.0	233.2	234.1
8	Internal Allocations to Transmission						
9	Generation Ancillary Services	2.8	2.5	2.6	2.6	2.6	2.6
10	Transmission Capitalized Overhead	(16.3)	(16.6)	(16.6)	(16.6)	(16.6)	(16.6)
11	Gross Transmission Costs	1,345.2	1,322.0	~~1,310.1~~ 1,348.9	1,381.5	1,401.0	1,335.0
12	Less Internal Allocations from Transmission						
13	Generation Related Transmission Assets	(43.3)	(43.3)	(43.3)	(54.0)	(54.7)	(52.1)
14	Generation Real Time Dispatch	(2.4)	(3.0)	(3.0)	(5.6)	(4.4)	(4.5)
15	Distribution Real Time Dispatch	(21.3)	(25.7)	(25.6)	(24.0)	(25.4)	(25.8)
16	Substation Distribution Assets	(129.0)	(149.3)	~~(156.7)~~ (139.4)	~~(154.4)~~ (144.5)	~~(155.9)~~ (146.4)	~~(148.1)~~ (138.2)
17	Less Miscellaneous Revenues						
18	FortisBC Inc. General Wheeling Agreement	(5.2)	(5.3)	(5.3)	(5.7)	(6.0)	(6.3)
19	Secondary Revenues	(7.3)	(7.1)	(6.7)	(6.8)	(6.8)	(6.9)
20	Interconnections	(8.3)	(4.6)	(6.1)	(6.1)	(4.2)	(3.3)
21	Amortization of Contributions	(15.3)	(11.0)	(12.0)	(12.4)	(11.9)	(12.5)
22	Northwest Transmission Line Supplemental Charges	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
23	Subtotal	(234.5)	(251.6)	~~(261.0)~~ (243.7)	~~(271.3)~~ (261.4)	~~(271.7)~~ (262.2)	~~(261.8)~~ (251.9)
24	Transmission Revenue Requirement	1,110.7	1,070.4	~~1,049.1~~ 1,105.1	~~1,110.2~~ 1,120.1	~~1,129.3~~ 1,138.8	~~1,073.2~~ 1,083.2

Generation Related Transmission Asset Allocation

BC Hydro's transmission assets related to the generation function are not used to provide service under the OATT and thus the related costs are removed from the TRR. By Letter L-92-07, the BCUC accepted that an annual fixed charge of $43.3 million was appropriate for Generation Related Transmission Asset (GRTA) costs noting that "it requires considerable effort to identify GRTA and non-GRTA assets in any given year."[1593] However, in light of increased costs associated with transmission lines, BC Hydro has proposed in the Application the GRTA allocation for each fiscal year be calculated using the following formula based on the most recent fiscal year for which end of year (latest actual) net book value (NBV) is available, as recorded in BC Hydro's corporate asset database:[1594]

$$(\text{GRTA})_{\text{fiscal}} = (\text{Gross Transmission})_{\text{fiscal}} \times \frac{(\text{GRTA NBV})_{\text{latest actual}}}{(\text{Gross Transmission NBV})_{\text{latest actual}}}$$

BC Hydro states that transmission infrastructure is stable and review of the GRTA facilities list should not be required unless there is construction of new remote generation and transmission lines to connect such generation to the grid. BC Hydro states that it will undertake a review of the GRTA facilities list for the next RRA to reflect the addition of new assets in the Peace region of B.C. associated with the Site-C generating station coming into service and will include the updated GRTA facilities as part of the next RRA. Following that review, BC Hydro expects the facilities list will only need to be reviewed every 10 years.[1595]

[1592] Exhibit B-2-6 Table 9-1, p. 9-5.
[1593] Exhibit B-2, p. 9-13.
[1594] Exhibit B-2, p. 9-14.
[1595] Exhibit B-2, p. 9-14; Exhibit B-19, BCUC IR 209.3.

The proposed method above results in internal allocation of GRTA costs of $54 million, $54.7 million and $52.1 million for F2023, F2024, and F2025, respectively.[1596] This results in a reduction to the TRR of approximately 1 percent and a corresponding 1 percent decrease in the Point-to-Point rate compared to using the previous fixed charge of $43.3 million. This results in an increase of approximately $0.1 million in the amount recovered from BC Hydro ratepayers through bundled service rates.[1597]

Open Access Transmission Tariff

BC Hydro's TRR is recovered through the OATT, which sets out the rates for the following services:[1598]

1. Network Integrated Transmission Service (NITS);
2. Point-to-point (PTP) Transmission Service; and
3. Ancillary Services.

As the main users of BC Hydro's transmission system, BC Hydro and Powerex account for approximately 99 percent of the revenue collected through the OATT, while external transmission customers account for approximately 1 percent of the revenue.[1599]

Once the TRR is known, the OATT rates are calculated using the following steps:[1600]

- 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.

The derivation of the ancillary services is shown in BC Hydro's table below, as corrected in an errata filed by BC Hydro.

[1596] Exhibit B-2, p. 9-14.
[1597] Exhibit B-2, p. 9-13, Footnote 504.
[1598] Exhibit B-2, p. 9-1.
[1599] Exhibit B-2, p. 9-1.
[1600] Exhibit B-2, p. 9-21.

Table 76: Calculation of Scheduling, System Control and Dispatch Rate[1601]

		Schedule Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	**PTP Volumes (MWh)**							
2	Long-Term PTP	Schedule 3.4 L52	9,302,776	8,453,400	8,453,400	8,453,400	8,453,400	8,453,400
3	Short-Term PTP	Schedule 3.4 L61	10,044,869	4,087,966	12,777,198	13,569,715	14,418,500	15,243,843
4	**Total PTP Volumes**		19,347,645	12,541,366	21,230,598	22,023,115	22,871,900	23,697,243
5	NITS and Secondary Transmission		9,848,363	12,954,763	~~9,848,363~~ 12,954,763	9,848,363	9,848,363	9,848,363
6	**Total Volumes**	**Schedule 3.4 L48**	29,196,008	25,496,129	~~31,078,961~~ 34,185,361	31,871,478	32,720,263	33,545,606
7	**Scheduling, Control and Dispatch Cost ($ million)**	Schedule 3.4 L47	4.2	3.9	4.6	4.4	4.6	4.7
8	**Scheduling Fee[511] ($/MWh)**	**(L47/L48) =Schedule 3.4 L49**	0.144	0.152	~~0.149~~ 0.135	0.138	0.141	0.140

The PTP rates are calculated as follows, as corrected in an errata filed by BC Hydro:

Table 77: Calculation of the PTP Transmission Service Rate[1602]

		Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	TRR ($ million)	Schedule 3.4 L29	1,110.7	1,070.4	~~1,049.1~~ 1,105.1	~~1,110.2~~ 1,120.1	~~1,129.3~~ 1,138.8	~~1,073.2~~ 1,083.2
2	Less Ancillary Services ($ million)	Schedule 3.4 L36 to L39	(7.7)	(6.4)	(7.3)	(7.0)	(7.3)	(7.3)
3	Net TRR ($ million)	Schedule 3.4 L40	1,103.0	1,064.0	~~1,041.8~~ 1,097.9	~~1,103.1~~ 1,113.1	~~1,122.0~~ 1,131.6	~~1,065.8~~ 1,075.8
4	Maximum Capacity Supply (MW)	Schedule 3.4 L.41	13,279	13,596	13,596	13,337	13,337	13,337
5	Annual Billing Determinants (MW month)	L4 x 12 months	159,348	163,152	163,152	160,044	160,044	160,044
6	PTP Rate ($/MW Month)	L3 X 1,000,000/L5 = Schedule 3.4 L43	6,832.35	6,521.81	~~6,385.65~~ 6,729.20	~~6,892.77~~ 6,955.00	~~7,010.73~~ 7,070.52	~~6,659.52~~ 6,722.00

The NITS rate is calculated as follows, as corrected in an errata filed by BC Hydro:

Table 78: Calculation of Monthly NITS Charge[1603]

		Reference	F2021 Actual	F2022 Decision	F2022 Forecast	F2023 Plan	F2024 Plan	F2025 Plan
			1	2	3	4	5	6
1	**TRR ($ million)**	Schedule 3.4 L29	1,110.7	1,070.4	~~1,049.1~~ 1,105.1	~~1,110.2~~ 1,120.1	~~1,129.3~~ 1,138.8	~~1,073.2~~ 1,083.2
2	**Less PTP and Ancillary Services Revenue:**							
3	PTP Revenue ($ million)	Schedule 3.4 L70	(120.5)	(85.7)	~~(105.9)~~ (109.9)	~~(113.7)~~ (114.5)	~~(117.2)~~ (117.9)	~~(115.2)~~ (116.0)
4	Ancillary Service ($ million)	Schedule 3.4 L36 to L39	(7.7)	(6.4)	(7.3)	(7.0)	(7.3)	(7.3)
5	**Total PTP and Ancillary Services Revenue ($ million)**	L3+L4	(128.4)	(92.1)	~~(113.2)~~ (117.1)	~~(120.8)~~ (121.5)	~~(124.5)~~ (125.2)	~~(122.6)~~ (123.3)
6	**NITS Revenue Requirement ($ million)**	Schedule 3.4 L33	982.9	978.3	~~935.9~~ 988.0	~~989.4~~ 998.6	~~1,004.8~~ 1,013.7	~~950.6~~ 959.9
7	**Monthly NITS Charge ($ million)**	Schedule 3.4 L34	81.9	81.5	~~78.0~~ 82.3	~~82.5~~ 83.2	~~83.7~~ 84.5	~~79.2~~ 80.0

[1601] Exhibit B-2-6, Table 9-5, p. 9-23.
[1602] Exhibit B-2-6, Table 9-6, p. 9-26.
[1603] Exhibit B-2-6, Table 9-8, p. 9-30.

In addition to the above errata, BC Hydro notes that it had incorrectly allocated approximately $200 million of Site C capital additions in fiscal 2021 to the Generation function instead of the Transmission function in the Application. Correcting the allocation results in a 0.9 percent increase in the F2023 OATT rates and a reduction to BC Hydro's revenue requirement in each year of the Test Period of less than $0.1 million. BC Hydro states that it will reflect this correction in a compliance filing following the BCUC's decision on the Application.[1604]

Positions of the Parties

BC Hydro submits that its proposed OATT rates are just and reasonable and should be approved.[1605]

Interveners, except for BCOAPO, either do not oppose or do not provide a position on BC Hydro's proposed TRR or OATT rates. Although not opposing, BCOAPO comments that the GRTA percentage only recognizes the extent to which the facilities are used to provide a local service function and as such, the GRTA percentage will not include any use of GRTA facilities by Powerex or third parties. BCOAPO submits that the BCUC should direct BC Hydro to address this issue in its next RRA.[1606]

In reply, BC Hydro submits that BCOAPO is not correct because the use by third party customers, including Powerex, is reflected in BC Hydro's assigned percentage use of GRTA. BC Hydro states that it had already clarified through IRs that BC Hydro would consider the use of a GRTA transmission line by Powerex or third parties when assigning the percentage GRTA of the transmission line in the facilities list.[1607]

Panel Determination

The Panel finds that the proposed OATT rates are just and reasonable and approves the OATT rates as applied for, subject to any adjustments resulting from the corrections identified by BC Hydro in the proceeding, the determinations and directives contained in this Decision, and any future determinations and directives made by the Panel with respect to the following two topics as noted in Section 1.3 of this Decision:

- **BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA; and**
- **BC Hydro's finance charges.**

The Panel is satisfied that BC Hydro has calculated the TRR based on allocations and direct assignment of costs consistent with prior BCUC decisions and approved rate designs.

The Panel is also satisfied with BC Hydro's response regarding its assigned percentage use of GRTA by third party customers and Powerex. Therefore, the Panel declines BCOAPO's request for a direction to BC Hydro to address this issue in its next RRA.

4.11 SRP Topics

An SRP on the following scope items was held on January 16, 2023:

1. The impact of the Account Credits Direction on the Application, including but not limited to the Cost of Energy Variance Accounts, the DARR, and the forecasts related to the Specified Costs defined in the Account Credits Direction; and

1604 Exhibit B-2-7, Cover Letter, p. 1.
1605 BC Hydro Final Argument, p. 180.
1606 BCOAPO Final Argument, pp. 74 – 75.
1607 BC Hydro Reply Argument, p. 152.

2. The cost of energy forecasts, load forecasts, and Trade Income forecasts, as impacted by the F2022 actual results and the Cryptocurrency Direction.

The Account Credits Direction and the Cryptocurrency Direction are discussed in Sections 2.4.3 and 2.4.4, respectively, of this Decision.

As part of the SRP, the Panel requested parties to make submissions on the following:[1608]

i) the DARR and the DARR table mechanism proposed in the Application;

ii) whether the forecasts in the Application, including cost of energy, load, Trade Income, labour costs, vegetation management costs, and fuel costs, should be updated for the purposes of setting rates for the F2023 to F2025 Test Period;

iii) whether BC Hydro should use a rate rider, separate from the DARR, to refund Trade Income directly to ratepayers as outlined in Panel IR No. 1, or some other alternative approach, commencing in the F2023 to F2025 Test Period;

iv) whether BC Hydro should forecast Trade Income as zero in its revenue requirements, and use a rate rider, separate from the DARR, to refund Trade Income directly to ratepayers as outlined in Panel IR No. 1, or some other alternative approach, commencing in the F2023 to F2025 Test Period;

v) whether BC Hydro should forecast Trade Income annually based on a rolling 5-year average of the most recent actuals available each year and the actual ending balance in the Trade Income Deferral Account (TIDA) is recovered or refunded to ratepayers annually by a new rate rider separate from the DARR; and

vi) any other relevant items.

During the SRP, AMPC provided evidence and made a proposal regarding the impact of the Account Credits Direction on BC Hydro's industrial customers, and BC Hydro provided its final argument on the SRP topics. Following the SRP, AMPC's proposal was formally provided as part of its final argument on the SRP topics. Interveners were provided an opportunity to provide their final arguments on the SRP topics, including AMPC's proposal, and BC Hydro provided its reply argument.

The cost of energy forecast is discussed in Section 4.3, the load forecast is discussed in Section 4.2, and labour costs, vegetation management, and fuel costs forecasts are discussed as part of operating costs in Section 4.4.1 of this Decision. The sections below discuss Trade Income, including whether a rate rider separate from the DARR should be used with respect to the Trade Income forecast and the TIDA, the DARR and the DARR table mechanism, AMPC's proposal raised at the SRP, the appropriateness of filing an evidentiary update in the proceeding, and the application of interest to the new regulatory accounts directed by the Account Credits Direction.

As mentioned in Section 1.3 of this Decision, subsequent to the filing of final and reply arguments on the SRP topics, including AMPC's proposal, BC Hydro filed a request to reinstate a $320 million regulatory liability in the TIDA. The reinstatement of the regulatory liability would have the effect of offsetting the transfer from the TIDA to the customer credit regulatory account that occurred pursuant to the Account Credits Direction. The review of BC Hydro's request to reinstate the $320 million regulatory liability in the TIDA is currently ongoing. Any determinations with respect to this request will be made by the Panel in due course after the issuance of this Decision.

[1608] Exhibit A-42; 2023-01-16 SRPTranscript Volume 6, p. 1311, lines 7 to 17.

4.11.1 The Cost of Energy Variance Accounts and the Deferral Account Rate Rider

BC Hydro has the following regulatory accounts, collectively referred to as the Cost of Energy (COE) Variance Accounts, which capture the differences between forecast and actual revenues and costs for future recovery or refund to ratepayers via the DARR:

- Heritage Deferral Account;
- Non-Heritage Deferral Account;
- Load Variance Regulatory Account;
- Biomass Energy Program Variance Regulatory Account;
- Low Carbon Fuel Credits Variance Regulatory Account; and
- Trade Income Deferral Account

As discussed in Section 4.11.1.3 of this Decision, BC Hydro is requesting approval to recover the balances in the COE Variance Accounts through the DARR using the DARR table mechanism. Specifically, starting in F2023 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 COE Variance Accounts at the end of the preceding fiscal year.

The sections below discuss Trade Income, whether a rate rider separate from the DARR should be used with respect to the Trade Income forecast and the TIDA, the mechanism for setting the DARR, and the impact of the F2022 actual results on the DARR.

4.11.1.1 Trade Income Forecast

BC Hydro forecasts the Test Period Trade Income at $224.2 million for each of F2023, F2024, and F2025 based on the average of actual Trade Income over the last five years at the time of preparing the Application (i.e. F2017 to F2021).[1609]

On August 31, 2022, BC Hydro's fiscal 2022 financial statements were publicly released, which showed F2022 actual Trade Income as $422.5 million. If the Test Period Trade Income was calculated based on an average of the latest 5 years of actuals that included F2022 (i.e. F2018 to F2022), it would result in a Trade Income forecast of $287.6 million for each year of the Test Period. This would result in a one-time rate and bill decrease of approximately 1.2 percent in F2023.[1610]

Although its F2022 financial statements were released to the public at the end of August 2022, BC Hydro confirmed that it had a draft of the F2022 ending TIDA balance in April 2022, which was then externally audited and received Board approval on June 9, 2022.[1611]

In the F2020 to F2021 RRA Decision, the BCUC directed BC Hydro to update its Trade Income forecast for that test period based on a 5-year average that includes the actual results from its evidentiary update that was filed during the proceeding. The BCUC also directed that in all future RRAs, BC Hydro update its forecasts that are based on a rolling average of historical actual results to include the most recently completed years' actuals that are reasonably available at the time an evidentiary update is prepared unless BC Hydro can demonstrate strong regulatory justification for not doing so.[1612]

[1609] Exhibit B-2, p. 8-41.
[1610] Exhibit B-2, Panel IR 1.1.
[1611] Exhibit B-51, AMPC IR 5.2.
[1612] BC Hydro F2020 to F2021 RRA, Decision and Order G-246-20, p. 163.

Subsequent to the issuance of the F2020 to F2021 RRA Decision, the Lieutenant Governor of B.C. issued Order in Council (OIC) No. 172, which amended Direction No. 8 to the BCUC to, among other things, provide a definition of Trade Income and to direct the following:

- section 4(3): "In setting rates for the authority for a fiscal year, the commission must subtract from the costs to be recovered in rates an amount equal to the net incomes, for the fiscal year, of Powerex Corp. and Powertech Labs Inc.";
- section 4(4): "For the purposes of subsection (3), (a) the net income of Powerex Corp. for the fiscal year is the amount equal to the trade income forecast by the authority for that fiscal year […]"
- section 9: "In regulating and setting rates for the authority, the commission must allow the authority to continue to defer to the trade income deferral account the variances between actual and forecast trade income."

BC Hydro states that section 4(4) of Direction No. 8 to the BCUC restricts the BCUC from directing adjustments to BC Hydro's Trade Income forecast for the purposes of setting rates in an RRA. This means that the BCUC cannot direct BC Hydro to reforecast its Trade Income as contemplated in the alternative approaches outlined above.[1613] In BC Hydro's view, the amendments to Direction No. 8 supersede any previous BCUC determinations with respect to the forecast methodology for Trade Income.[1614] However, BC Hydro does not consider there to be any restrictions on the BCUC from directing that the TIDA be recovered via a mechanism outside of the DARR.[1615]

Positions of the Parties

BC Hydro submits that it is not updating its Test Period Trade Income forecasts[1616] and that sections 4(3) and (4) of Direction No. 8 require the BCUC to set rates based on Trade Income as forecast by BC Hydro. It also points out that section 3 of the UCA states that Government Directions issued under that section of the UCA are not withstanding previous BCUC directions. Further, BC Hydro submits that it is not updating its Trade Income forecast because it is not appropriate to only update the Trade Income forecast to consider actual F2022 results and not any other areas of the Application. Also, providing a broader update will result in a significant delay, which would be contrary to the BCUC's stated desire to bring this proceeding to a timely resolution.[1617]

MoveUP, BCSEA, the CEC, and Zone II RPG support not updating the Trade Income forecasts.[1618]

BCOAPO submits that it is reasonable to update the Test Period Trade Income forecast to reflect $287.6 million annually given that it has a material rate impact and that actual amounts are likely to be substantially higher. However, BCOAPO acknowledges that Direction No. 8 may prohibit the BCUC from varying BC Hydro's forecast.[1619]

AMPC submits that BC Hydro should be directed to update its Test Period Trade Income forecast to account for F2022 actuals, but not any of its other forecasts.[1620] AMPC argues that the BCUC is not constrained by Direction

[1613] Exhibit B-50, BCUC IR 234.1.
[1614] 2023-01-16 SRP Transcript Volume 6, p. 1456, line 9 to p. 1457, line 10.
[1615] Exhibit B-50, BCUC IR 244.3.
[1616] 2023-01-16 SRP Transcript Volume 6, p. 1494, lines 23 to 24.
[1617] 2023-01-16 SRP Transcript Volume 6, p. 1504, line 5 to p. 1505, line 18.
[1618] MoveUP SRP Final Argument, p. 1; BCSEA SRP Final Argument, pp. 1-–2; CEC SRP Final Argument, pp. 3 – 4; Zone II RPG SRP Final Argument, p. 2.
[1619] BCOAPO SRP Final Argument, p. 8.
[1620] AMPC SRP Final Argument, pp. 3, 17 – 18.

No. 8 and that BC Hydro's interpretation of Direction No. 8 conflicts with the BCUC and BC Hydro's past practices. AMPC submits that there is "no express language removing the [BCUC's] authority over the content of those forecasts." AMPC also points out that the language in Direction No. 8 is similar to that of section 7(a) of the Heritage Special Direction No. HC2 to the BCUC and in response to a directive in the BCUC's decision on BC Hydro's F2009 to F2010 RRA, BC Hydro adjusted its forecast of Trade Income. Further, AMPC points out that BC Hydro adjusted its Trade Income in the current Application to remove low carbon fuel credit revenue as directed by the BCUC.[1621]

In reply, BC Hydro submits that the BCUC is required to accept the amount forecasted by BC Hydro in setting rates.[1622] It also submits that AMPC's interpretation of Direction No. 8 is inconsistent with the clear meaning of section 4(4), the context of Direction No. 8, the surrounding legislative history, and section 8 of the *Interpretation Act*. BC Hydro argues that the direction specifically refers to BC Hydro's forecast and thus different language would have been used if the direction intended for the BCUC to determine the forecast Trade Income.[1623]

BC Hydro submits that there is no past practice of the BCUC overriding Direction No. 8. It points out that while BC Hydro may have updated its Trade Income in the past, it is not required to given section 4(4) of Direction No. 8. BC Hydro also argues that the language in section 4(4) makes it clearer, than the language in the Heritage Special Direction No. HC2 to the British Columbia Utilities Commission, that the forecast is to be made solely by BC Hydro. In addition, BC Hydro notes that the F2022 RRA Decision did not include a directive regarding BC Hydro's Trade Income forecast. It did however contain a directive regarding the treatment of low carbon fuel credits, which BC Hydro responded to by removing low carbon fuel credit revenue from its Trade Income forecast.[1624]

Panel Determination

Although there is actual F2022 Trade Income data available to BC Hydro and to the parties in this proceeding, the Panel declines to order BC Hydro to update its Trade Income forecast. Direction No. 8 to the BCUC prohibits the BCUC from directing BC Hydro to reforecast Trade Income annually.

4.11.1.2 Trade Income Rate Rider

Through Panel IR no. 1, SRP IR no. 3, and at the SRP, alternative approaches to forecasting Trade Income and the recovery or repayment of the TIDA were explored. The alternative approaches included:

i) Continuing to forecast Trade Income based on the five-year average of previous actuals, but recovering or repaying the actual ending balance in the TIDA in a given year annually via a new Trade Income Rate Rider (TIRR), separate from the DARR, once actuals are known (Alternative Approach (i));

ii) Forecasting Trade Income at zero and the repaying the actual ending balance of the TIDA in a given year annually via the TIRR, separate from the DARR, once actuals are known (Alternative Approach (ii)); and

iii) Forecasting Trade Income annually based on a rolling five-year average of the most recent actuals available each year and recovering or repaying the actual ending balance in the TIDA in a given year annually via the TIRR, separate from the DARR, once actuals are known (Alternative Approach (iii)).

[1621] AMPC SRP Final Argument, p. 16.
[1622] BC Hydro SRP Reply Argument, p. 8.
[1623] BC Hydro SRP Reply Argument, pp. 4 – 7.
[1624] BC Hydro SRP Reply Argument, pp. 7 – 8.

BC Hydro modelled the estimated impact to rates, bills, the DARR, the TIRR, and the ending balances of the Cost of Energy Variance Accounts based on Alternative Approach (i). The impact on the Test Period is summarized in the following table:

Table 79: Test Period Impact of Alternative Approach (i) [1625]

Rate & Bill Impacts	Scenario			Application			Difference		
	F2023	F2024	F2025	F2023	F2024	F2025	F2023	F2024	F2025
Annual Rate Increase	0.6%	1.0%	2.2%	0.6%	1.0%	2.2%	0.0%	0.0%	0.0%
DARR	0.0%	0.0%	0.0%	(2.0%)	(1.0%)	(0.5%)	2.0%	1.0%	0.5%
TIRR	(1.9%)	0.0%	0.0%	0.0%	0.0%	0.0%	(1.9%)	0.0%	0.0%
Annual Bill Impact	(1.4%)	3.0%	2.2%	(1.4%)	2.0%	2.7%	(0.0%)	1.0%	(0.5%)
Cumulative Bill Impact	(1.4%)	1.6%	3.8%	(1.4%)	0.6%	3.3%	(0.0%)	1.0%	0.5%
Cost of Energy Variance Account Balance*	11.7	8.3	6.1	4.7	(1.1)	(3.1)	6.9	9.3	9.2
Trade Income Deferral Account Balance	-	-	-	(125.5)	(71.0)	(44.2)	125.5	71.0	44.2

* Cost of Energy Variance Account Balance excludes Trade Income Deferral Account Balance

The table above shows that under Alternative Approach (i), if the entire ($103.6) million actual F2022 ending TIDA balance (net of the $400 million transfer from the TIDA in F2023) is returned to ratepayers via the TIRR, there would be no impact to rates, but the DARR would be reduced to zero in each year of the Test Period. The TIRR would result in a refund of 1.9 percent in F2023, and the TIRR for fiscal 2024 and 2025 would not be known until the actual F2023 and F2024 results, respectively, are finalized in August of each year.[1626]

The following tables summarize the impact to F2012 to F2022 if Alternative Approach (i) was in place during those years, a "base case" that includes actual historical information under approved rate increases and DARR percentages, and the difference between Alternative Approach (i) and the "base case:"[1627]

Table 80: Alternative Approach (i) in F2012 to F2022

Rate & Bill Impacts	Scenario										
	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022
Annual Rate Increase	8.0%	3.9%	1.4%	9.0%	6.0%	4.0%	3.5%	3.0%	15.1%	(4.5%)	4.0%
DARR*	2.5%	5.0%	5.0%	3.0%	2.0%	5.0%	5.0%	4.5%	(5.0%)	(2.5%)	(3.5%)
TIRR	5.3%	(0.0%)	1.2%	4.4%	(0.2%)	1.2%	(0.3%)	(0.5%)	(6.4%)	(1.4%)	(4.0%)
Annual Bill Impact	13.4%	1.2%	2.6%	10.2%	0.4%	8.5%	2.0%	2.4%	(2.0%)	3.6%	0.1%
Cumulative Bill Impact	13.4%	14.7%	17.7%	29.8%	30.3%	41.4%	44.3%	47.7%	44.8%	50.0%	50.1%
Cost of Energy Variance Account Balance*	590.2	476.8	356.8	577.2	852.1	613.0	219.4	(587.9)	(258.2)	(378.8)	(317.6)
Trade Income Deferral Account Balance	(0.0)	46.0	175.1	(10.3)	52.3	(15.4)	(21.8)	(326.9)	(69.9)	(213.7)	(268.0)

* Cost of Energy Variance Account Balance excludes Trade Income Deferral Account Balance

Table 81: Base Case in F2012 to F2022

Rate & Bill Impacts	Base										
	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022
Annual Rate Increase	8.0%	3.9%	1.4%	9.0%	6.0%	4.0%	3.5%	3.0%	6.8%	(1.6%)	1.0%
DARR*	2.5%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	0.0%	0.0%	0.0%
Annual Bill Impact	7.8%	6.4%	1.4%	9.0%	6.0%	4.0%	3.5%	3.0%	1.8%	(1.6%)	1.0%
Cumulative Bill Impact	7.8%	14.7%	16.4%	26.9%	34.5%	39.9%	44.7%	49.1%	51.7%	49.3%	50.7%
Cost of Energy Variance Account Balance*	610.9	537.4	466.4	688.8	892.9	702.7	359.7	(409.0)	(95.3)	6.7	(117.9)
Trade Income Deferral Account Balance	174.7	190.2	324.7	244.6	250.0	194.2	126.8	(258.8)	(173.7)	(226.7)	(503.6)

* Cost of Energy Variance Account Balance excludes Trade Income Deferral Account Balance

[1625] Exhibit B-49, Panel IR 1.4.i.
[1626] Exhibit B-49, Panel IR 1.4.i.
[1627] Exhibit B-49, Panel IR 1.4.i.

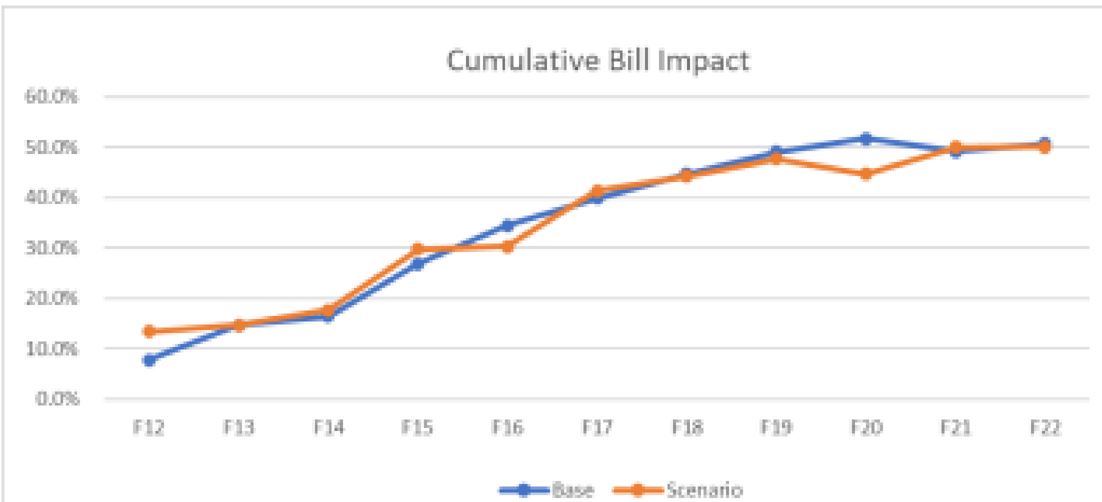
Table 82: Difference Between Alternative Approach (i) and the Base Case

Rate & Bill Impacts	Difference										
	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022
Annual Rate Increase	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.2%	(2.8%)	3.0%
DARR*	(0.0%)	(0.0%)	0.0%	(2.0%)	(3.0%)	0.0%	0.0%	(0.5%)	(5.0%)	(2.5%)	(3.5%)
TIRR	5.3%	(0.0%)	1.2%	4.4%	(0.2%)	1.2%	(0.3%)	(0.5%)	(6.4%)	(1.4%)	(4.0%)
Annual Bill Impact	5.6%	(5.3%)	1.2%	1.2%	(5.6%)	4.5%	(1.5%)	(0.6%)	(3.8%)	5.2%	(0.9%)
Cumulative Bill Impact	5.6%	(0.0%)	1.4%	2.9%	(4.2%)	1.6%	(0.5%)	(1.4%)	(7.0%)	0.7%	(0.6%)
Cost of Energy Variance Account Balance*	(20.6)	(60.6)	(109.6)	(111.6)	(40.8)	(89.7)	(140.2)	(178.9)	(162.9)	(385.4)	(199.7)
Trade Income Deferral Account Balance	(174.8)	(144.2)	(149.6)	(254.9)	(197.7)	(209.6)	(148.7)	(68.1)	103.8	12.9	235.6

* Cost of Energy Variance Account Balance excludes Trade Income Deferral Account Balance

The following chart shows the cumulative bill impacts of Alternative Approach (i) and the "base case:"[1628]

Figure 10: Cumulative Bill Impact of Alternative Approach and the Base Case



The above tables and chart show that if the TIRR was used during F2012 to F2022, it would have resulted in different annual bills compared to the "base case," including 2 years where the annual bill impacts exceed 10 percent. BC Hydro notes that the above is modelled based on the calculated TIRR percentage being in place for the entire year, and therefore understates the bill increases and decreases and the associated volatility. BC Hydro states that under the most likely assumption that the TIRR could only be implemented part way through the year (beginning in September), there would need to be a "catch-up" amount for April to August on the next customer bill after August, so the annual and cumulative bill impacts would be even more pronounced during that portion of the year.[1629]

Alternative Approach (i) would increase the frequency of clearing the balance in the TIDA (i.e. annually) compared to if the TIDA was recovered or repaid using the DARR via the DARR table mechanism. For the remaining Cost of Energy Variance Accounts, the range of the net balance of these accounts excluding the TIDA, would be $219.4 million to $852.1 million based on the above tables. The recovery or refund period for this range of balance is 3 to 6 years, which is slightly less than the typical 4 to 6 years associated with the Cost of Energy Variance Accounts balances inclusive of the TIDA balances.[1630]

With respect to Alternative Approach (ii), BC Hydro estimates that forecasting Trade Income as zero would result in approximately a 4 percent rate increase in the year of implementation (i.e. F2023). BC Hydro states that this

[1628] Exhibit B-49, Panel IR 1.4.i.
[1629] Exhibit B-49, Panel IR 1.4.i.
[1630] Exhibit B-49, Panel IR 1.4.i.

alternative approach would result in even higher bill volatility than Alternative Approach (i) because the variance between actual Trade Income and zero would be higher.[1631]

With respect to Alternative Approach (iii), BC Hydro states that if the Trade Income forecast was updated annually, then the rates in the Application cannot be finalized and would need to change annually as the previous years actuals becomes available.[1632]

During the SRP, a further alternative approach was discussed where both the TIDA balance and the Trade Income forecast are recovered or refunded to ratepayers via a rate rider. Currently, the Trade Income forecast is included in BC Hydro's revenue requirement and refunded to ratepayers via BC Hydro's general rates. Under this proposed approach, the Trade Income forecast could be updated annually without impacting BC Hydro's revenue requirement and rates. Removing the Trade Income forecast from the Test Period revenue requirement would result in an increase in the Test Period rates, which would then be offset by the rate rider. However, BC Hydro explains that this could potentially result in large bill volatility, which could be mitigated if the Trade Income was forecast on the same basis as it is currently and implemented on April 1st every year and then further mitigated using a smoothing mechanism, such as recovering the previous year's variances over a period longer than a year. BC Hydro states that it needs to understand all the mechanics of the approach to properly assess it against the current methodology.[1633]

Positions of the Parties

BC Hydro submits that Alternative Approach (i) is not appropriate because the significant downsides of this approach outweigh any potential benefits. BC Hydro submits that this approach creates less rate stability and predictability for customers and is administratively more complex than the DARR table mechanism. It argues that the only potential benefit is that Trade Income variances would be returned to or recovered from customers more quickly than under the DARR table mechanism, which is not a significant benefit since the DARR table mechanism returns or recovers variances over a relatively short period of time without material intergenerational equity and maintains rate stability.[1634]

BC Hydro points out that a recovery period of one year for the TIDA balance is inconsistent with the recovery periods of its other Cost of Energy Variance Accounts and most of its other variance accounts. In BC Hydro's view, there is no principle basis for a unique recovery period for the TIDA balance and if the BCUC were inclined to return variances to ratepayers more quickly, it should apply to all the Cost of Energy Variance Accounts. BC Hydro also argues that introducing a new rate rider with complex implementation midway through the fiscal year which increases bill volatility would not be well accepted or understood by customers, which is contrary to the Bonbright rate design principles.[1635]

For similar reasons, BC Hydro does not consider Alternative Approach (ii) and Alternative Approach (iii) appropriate either.[1636]

With respect to the alternative approach raised at the SRP where BC Hydro's forecast of Trade Income is also recovered through a separate TIRR outside of rates, BC Hydro submits that it does not offer any appreciable benefits and it would increase complexity and administration. Further, if one tries to smooth the potential bill volatility and rate stability of this approach by designing the rate rider to recover the variances over more than one year, then one would end up in the same place and the same considerations of the DARR table mechanism.

[1631] Exhibit B-49, Panel IR 1.4.ii.
[1632] Exhibit B-50, BCUC IR 244.1; 2023-01-16 SRP Transcript Volume 6, p. 1344, lines 13 to 22.
[1633] 2023-01-16 SRP Transcript Volume 6, p. 1447, line 8 to p. 1454, line 3.
[1634] 2023-01-16 SRP Transcript Volume 6, p. 1506, line 15 to p. 1508, line 16.
[1635] 2023-01-16 SRP Transcript Volume 6, p. 1508, line 17 to p. 1510,line 7.
[1636] 2023-01-16 SRP Transcript Volume 6, p. 1510, lines 8 to 22.

However, BC Hydro submits that if the BCUC determines that a TIRR approach is just and reasonable, then it requests that the BCUC provide a direction to BC Hydro to design a mechanism with two rate riders that would balance the relevant rate design principles. BC Hydro argues that it has not had the time to prepare the analysis that was done with the DARR table mechanism in this proceeding and in the F2022 RRA proceeding.[1637]

Zone II RPG supports BC Hydro's request for direction from the BCUC to develop a mechanism for the next test period to ensure sufficient time for analysis, design, and consultation.[1638]

With the exception of RCIA, interveners are not in favour of a new rate rider to address the TIDA balance or the Trade Income forecast.[1639] RCIA recommends using Alternative Approach (ii) to refund Trade Income to ratepayers because it would provide some rate relief during the winter period when residential ratepayer bills are typically highest.[1640]

In reply, BC Hydro submits that RCIA has not offered any rationale for its support of Alternative Approach (ii) or responded to the drawbacks highlighted by BC Hydro. In BC Hydro's view, forecasting Trade Income at zero and clearing the TIDA balance through a separate rate rider is not reasonable or appropriate. This is because it would result in an approximately 4 percent incremental rate increase in the year of implementation and a forecast of zero would lead to significant volatility in bills due to changes in rate rider being implemented in September of each year. BC Hydro also points out that RCIA's proposal is not feasible given Direction No. 8.[1641]

The CEC and NTC, on the other hand, provide alternative approaches to addressing the balance in the TIDA.

The CEC suggests an approach where "any Trade Income should first go to ensuring that the account has collected sufficient funds to support the Trade Income forecast included in rates for a given year, and second be distributed as a [direct bill] refund to customers to the extent it is surplus to the requirement to meet the forecast amount of Trade Income to be included in rates."[1642]

In reply, BC Hydro submits that the CEC's approach has significant drawbacks compared to the use of the DARR table mechanism and should not be accepted. BC Hydro notes that the CEC's approach makes an incorrect assumption that variances from forecast will always result in a refund to customers. BC Hydro argues that the CEC's approach would create significant bill volatility and increase complexity, administrative costs, and customer complaints.[1643]

NTC offers the following approach for discussion:[1644]

1. Set the Trade Income forecast at a fixed number (e.g. $100 million per year) adjusted for inflation, either annually or with each new RRA.
2. Place the variances between forecast and actual Trade Income in the TIDA and allow them to "even out" over time subject to the accumulated TIDA balance remaining within a reasonable range. For example, take no action unless the TIDA surges above $150 million, adjusted for inflation. If the threshold is reached, then the entire TIDA balance should be refunded to ratepayers as soon as possible (e.g. a retroactive bill refund in September or October) with a provision for lowest-income customers.

[1637] 2023-01-16 SRP Transcript Volume 6, p. 1510, line 23 to p. 1514, line 9.
[1638] Zone II RPG SRP Final Argument, p. 3.
[1639] MoveUP SRP Final Argument, p. 1; BCSEA SRP Final Argument, pp. 1-2; BCOAPO SRP Final Argument, p. 10; Zone II RPG SRP Final Argument, p. 3.
[1640] RCIA SRP Final Argument, pp. 6 – 7.
[1641] BC Hydro SRP Reply Argument, pp. 14 – 15.
[1642] CEC SRP Final Argument, pp. 2 – 3, 4 – 6.
[1643] BC Hydro SRP Reply Argument, pp. 15 – 16.
[1644] NTC SRP Final Argument, pp. 3 – 4.

3. In the event that the accumulated TIDA is at a significant negative threshold amount (e.g. -$100 million), the forecast should be reduced on a going forward basis (e.g. $75 million instead of $100 million), which would allow the variance to "cure itself" or if not, trigger a reevaluation of the entire process.

In reply, BC Hydro submits that NTC's approach is not feasible, it would increase bill instability and complexity, and it would cause bill volatility compared to the DARR table mechanism. BC Hydro submits that it is not amenable to changing its forecast Trade Income as suggested by NTC and the BCUC does not have the jurisdiction to approve a low income rate[1645]

AMPC's preference is its proposal raised at the SRP, which is described below in Section 4.11.2 of this Decision. However, with respect to the alternative approaches raised by the BCUC, it supports an approach where Trade Income forecasts are updated annually, and variances refunded over a 2 to 3 year period. It does not support forecasting Trade Income at zero or having annual Trade Income variances refunded or recovered annually[1646] AMPC submits that if the BCUC wants to explore such an approach, then it should be explored in BC Hydro's next RRA where the issues can be issues can be thoroughly canvassed and the mechanism scrutinized.[1647]

In reply, BC Hydro submits that AMPC makes the incorrect assumption that variances from forecast Trade Income will always result in a refund to customers, recovering Trade Income variances over a 2-to-3 year period would result in greater bill volatility compared to the DARR table mechanism, and BC Hydro is not amenable to reforecasting Trade Income annually over the Test Period.[1648]

In addition, the CEC, NTC, and RCIA argue that Trade Income should not be treated as a cost of energy account and that the TIDA should not be recovered or refunded as part of the DARR.[1649]

In reply, BC Hydro submits that the balance in the TIDA should remain grouped with the other COE Variance Accounts and recovered through the DARR using the DARR table mechanism. BC Hydro submits that the increased rate instability and complexity of separating the TIDA outweigh any nominal benefit of returning to, or recovering from, ratepayers the forecast Trade Income variances quicker.[1650] BC Hydro submits that it is generally opposed to the creation of second rate rider because it would cause rate instability, increase complexity and would likely be poorly received by customers. BC Hydro submits that speeding up the recovery of the COE Variance Account balances could be achieved through a single rate rider by adjusting the DARR table mechanism.[1651]

BC Hydro argues that interveners' position that Trade Income is different than the other COE Variance Account is not relevant to the treatment of the balances. BC Hydro submits that "the grouping of the TIDA with the other COE Variance Accounts is just and reasonable because all these accounts experience large variances from forecast due to factors beyond BC Hydro's control, such as weather."[1652] BC Hydro also argues that there is a relationship between Trade Income and the COE Variance Accounts due to the intercompany transactions between BC Hydro and Powerex. Therefore, differing treatment of the COE Variance Accounts risks misalignment in the realization and recovery of these intercompany transactions.[1653]

[1645] BC Hydro SRP Reply Argument, pp. 16 – 17.
[1646] AMPC SRP Final Argument, p. 3.
[1647] AMPC Reply Argument on AMPC's Proposal, p. 12.
[1648] BC Hydro SRP Reply Argument, p. 18.
[1649] CEC SRP Final Argument, pp. 2 – 3; NTC SRP Final Argument, pp. 3 – 4; RCIA SRP Final Argument, p. 3.
[1650] BC Hydro SRP Reply Argument, pp. 11, 13.
[1651] BC Hydro SRP Reply Argument, p. 14.
[1652] BC Hydro SRP Reply Argument, pp. 11 – 12.
[1653] BC Hydro SRP Reply Argument, p. 12.

BC Hydro recommends that if the BCUC is inclined to take a different approach to recovering the TIDA balance, then the BCUC should issue directives in the decision on the parameters for an alternative approach, so that BC Hydro can design and bring forward a proposal for review. BC Hydro's preference is to bring the proposal forward in a future application for implementation in the next test period. However, if the BCUC determines that it should be implemented in the current Test Period, then BC Hydro recommends implementation in the last year of the Test Period to allow sufficient time to complete any necessary regulatory reviewsand to avoid retroactive adjustments to the DARR for F2023 and F2024.[1654]

<u>Additional DARR Submissions</u>

After the filing of final arguments and submissions related to topics canvassed at the SRP, the Panel invited parties to provide submissions on setting the DARR annually, commencing in F2025, at the beginning of each fiscal year based on the most recently available actual results.[1655] The following is a summary of those submissions, which includes parties' positions regarding the mechanism to recover or refund Trade Income forecasts and the TIDA, as included in those submissions. The Panel's determination on the DARR is in Section 4.11.1.3 of this Decision.

In BC Hydro's submission, it assumes that the DARR would be set to recover the balance in all the COE Variance Accounts using the DARR table mechanism proposed in the Application. Although this scenario is preferable compared to the scenarios explored in the SRP which involved a second rate rider for the TIDA, BC Hydro submits that it prefers its proposed approach in the Application where the DARR is set for the three-year test period. BC Hydro argues that recovering the balance in all the COE Variance Accounts together through the DARR will result in less rate volatility, be less complex, and be better received by customers compared to a separate approach for the TIDA.[1656]

BC Hydro argues that its proposed approach in the Application produces the following favourable results compared to the scenario presented by the Panel where the DARR is set annually:[1657]

1) Customers will have advanced notice of the proposed DARR for the entire test period;
2) The balances in the COE Variance Accounts would have the opportunity to offset and balance out over the test period, which reduces the potential for volatility in the DARR year over year;
3) The balances in the COE Variance Accounts would be recovered over four to six years, which balances maintaining rate stability, avoiding potential rate shock, and minimizes intergenerational inequity. In contrast, setting the DARR annually could potentially recover the balances in the COE Variance Accounts faster which would result in increased DARR amounts and bill volatility; and
4) The DARR would reflect the forecast amortization from the COE Variance Accounts. In contrast, setting the DARR based on the most recently available audited actual results, would not include forecast amortization of the COE Variance Accounts.

BC Hydro points out that despite recent history, the DARR can be negative or positive and a mechanism that results in a faster recovery of the balances would lead to increased rate volatility and higher customer bills when there is a large balance to recover. Since the net balance of the COE Variance Accounts could switch suddenly from a positive to a negative, BC Hydro submits that the new scenario presented by the Panel increases the likelihood of a swing of up to 10 percent in the DARR in addition to any general rate changes. BC Hydro submits

[1654] BC Hydro SRP Reply Argument, pp. 18 – 19.
[1655] Exhibit A-46.
[1656] BC Hydro DARR Submission, pp. 1 - 2.
[1657] BC Hydro DARR Submission, p. 2.

that the scenario presented by the Panel would allow such a swing to occur automatically without the opportunity for customers and interveners to provide submission on the impact.[1658]

Of the interveners that provided a submission, Zone II RPG, BCOAPO, BCSEA, and MoveUP agree with BC Hydro's submissions, which is to set the DARR for the three-year test period based on the forecast net balance of the COE Variance Accounts at the end of the preceding fiscal year using the DARR table mechanism, as proposed in the Application.[1659] On the other hand, the CEC, RCIA, AMPC, and NTC primarily reiterated their positions described in their submissions on the SRP topics. Of these four interveners, only RCIA supports recovering or refunding the TIDA using a rate rider separate from the DARR.

The CEC submits that the amortization of the TIDA should be treated differently than the other COE Variance Accounts and that a quicker return of excess Trade Income surplus to customers is more equitable when combined with smoothing in rates based on BC Hydro's forecast of Trade Income.[1660] The CEC recommends:[1661]

- a two-tiered amortization mechanism for the DARR, where the COE Variance Accounts, excluding the TIDA, are amortized over four to six (or five to seven) years, and an annual setting of the TIDA amortization.
- annually setting the TIDA amortization at five years for any cumulative forecast used in rates for which actual Trade Income is less than forecast, but amortize in the following year the full amount of any excess of actual Trade Income over forecast.
- A "lag year" approach be applied to the Trade Income results to calculate the DARR annually. For example, calculate the Trade Income balances and amortizations for F2025 based on the actual ending F2023 balances.

In reply, BC Hydro submits that the CEC's proposal should be rejected because it is unprincipled, asymmetric, and would increase bill volatility. BC Hydro argues that the CEC's approach does not reflect a fair balancing of customer and utility interests. BC Hydro also points out that the conclusions reached by the CEC are based on Trade Income variances that are not accurate because the CEC was not using Trade Income as defined by Direction No. 8.[1662]

RCIA submits that the COE Variance Accounts should be recovered or refunded within a year because this would better serve customers since the COE Variance Accounts are forecast to have a credit balance through F2030. RCIA submits that longer amortization periods can be considered, if and when necessary, as part of the annual filing proceeding for the rate rider or as part of a RRA.[1663]

In reply, BC Hydro submits that RCIA's submissions should be rejected based they are based on a flawed understanding of the balances in the COE Variance Accounts presented in Table 7-5 of the Application, which do not include any forecast additions after F2022.[1664]

AMPC submits that the DARR mechanism should be fully re-evaluated in BC Hydro's next RRA, rather than "on-the-fly", due to the importance of the issues. AMPC argues that the scenarios canvassed at the SRP, including the current DARR scenario presented by the Panel, raise complex ratemaking issues that could not be fully

[1658] BC Hydro DARR Submission, pp. 3 – 4.
[1659] Zone II RPG DARR Submission; BCOAPO DARR Submission; BCSEA DARR Submission; MoveUP DARR Submission.
[1660] CEC DARR Submission, pp. 2 – 3.
[1661] CEC DARR Submission, pp. 3 – 4.
[1662] BC Hydro Reply DARR Submission, pp. 2, 8 – 9.
[1663] RCIA DARR Submission, pp. 3 – 4.
[1664] BC Hydro Reply DARR Submission, pp. 2, 7.

considered due to the timing in the proceeding that they were raised.[1665] Nonetheless, AMPC submits that setting the DARR annually based on the balances in all of the COE Variance Account may be preferable to the other options raised and the status quo if the following safeguards were also implemented:[1666]

1) "Rate volatility should be managed." AMPC suggests smoothing the annual DARR recoveries and refunds over two or three years and increasing the dead band from the current $50 million to $200 million.
2) Implement general rate changes and the DARR in the fall when the preceding fiscal year's actual results are available. AMPC argues that this would reduce confiscation risk and avoids having two rate changes per year.
3) "Trade income forecasts should not be removed from revenue requirement." AMPC argues that the Trade Income forecasts act as a natural hedge against other COE variances and "starting from the status quo approach to forecasting would be simpler than having to revert back" should the BCUC decide to re-evaluate the approach adopted in this proceeding in the future.

In reply, BC Hydro agrees with AMPC that it would be preferrable to determine an alternative approach for the recovery of the COE Variance Account balances in the next RRA when there is an appropriate process for modelling and analysis. BC Hydro submits that the BCUC should accept the proposed DARR amounts for this Test Period, but issue directions for how BC Hydro should redesign the approach to the DARR for future test periods.[1667]

However, contrary to AMPC's submission, BC Hydro submits that seeking to thwart future government directions is an improper consideration for the BCUC because it is inconsistent with the BCUC's statutory mandate.[1668] BC Hydro submits that AMPC's proposed safeguards would increase bill volatility and setting rates in the fall would be a material change that is not within the scope of the submissions and it would not be procedurally fair for the BCUC to direct such a change without further process. However, with respect to AMPC's third safeguard, BC Hydro submits that if AMPC means that "the Trade Income forecast should not be reduced to zero," then it agrees with AMPC on that safeguard.BC Hydro also notes that its "forecast of trade income must be removed from the revenue requirement pursuant to section 4(3) and (4) of Direction No. 8."[1669]

NTC submits that with thoughtful design, the alternative approach it suggested in its submission on the SRP topics can form the basis of a sound methodology going forward. NTC reiterates that the essence of its alternative approach is to separate the TIDA from the other COE Variance Accounts and refund any large Trade Income surpluses to customers as quickly as possible.[1670] NTC also provides arguments in response to BC Hydro's previous reply submissions regarding NTC's alternative approach and submits that any necessary refinements to the approach could be further worked out by BC Hydro.[1671]

In reply, BC Hydro submits that NTC's alternative approach to the DARR remains not feasible. [1672]

Panel Determination

For the reasons set out below, commencing in F2025, the Panel directs BC Hydro to:

- **Recover the Test Period Trade Income forecast from a rate rider rather than through the general revenue requirement (i.e. a Trade Income Rate Rider or TIRR).**

[1665] AMPC DARR Submission, p. 2.
[1666] AMPC DARR Submission, p. 2.
[1667] BC Hydro Reply DARR Submission, pp. 2, 3.
[1668] BC Hydro Reply DARR Submission, p. 2, 3 – 4.
[1669] BC Hydro Reply DARR Submission, p. 2, 5 – 6.
[1670] NTC DARR Submission, p. 2.
[1671] NTC DARR Submission, pp. 2 – 5.
[1672] BC Hydro Reply DARR Submission, pp. 2, 9.

- **Recover or repay the TIDA balance from/to customers via the TIRR, instead of the DARR, over a 3-year amortization period, and limit the amortization of a deficit in the TIDA balance to the amount of forecast Trade Income that year. As a result, the TIRR rate rider will not be less than zero.**
- **Set the TIRR annually at the beginning of each fiscal year based on the most recently available actual results.**
- **File for approval of the TIRR annually in a filing separate from its RRA filings.**

The Panel notes that determinations have not been made in this Decision regarding BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA, as mentioned in Section 1.3 of this Decision. Further directions, if any, regarding the mechanism set out above as a result of the Panel's review of BC Hydro's request will be made in due course after the issuance of this Decision.

We appreciate that these directives may increase bill volatility and we share BC Hydro and certain Interveners' concerns regarding bill volatility. However, rate stability is *only one* Bonbright principle. Equally important are that rates are not unduly discriminatory and are economically efficient. It is the role of the regulator to balance these principles and that balance is a key principle in our determination.

That said, it is important to have mechanisms in place to monitor bill volatility and, when possible, take steps to mitigate it.

TIDA and the COE Accounts

We agree with CEC, NTC, and RCIA that the Trade Income deferral account should not be treated as a cost of energy account. We are not persuaded that there is sufficient similarity between Trade Income and the Cost of Energy to group these variance accounts together for recovery/refund to customers. This is because Trade Income is not directly related to the BC Hydro's cost to provide service and further, Trade Income is from an unregulated subsidiary. Generally speaking, regulatory practice is to exclude both net income from, and costs incurred by, an unregulated subsidiary from a regulated utility's revenue requirement.

Further, we do not agree with BC Hydro that grouping the TIDA with the other COE Variance Accounts is just and reasonable because all these accounts experience large variances from forecast due to factors beyond BC Hydro's control, such as weather. Powerex is involved in a number of energy related activities across North America, of which sales and purchases on behalf of BC Hydro are only a portion. Therefore, we do not agree that Trade Income is necessarily tightly coupled with the same environmental factors that drive volatility in BC and Pacific Northwest prices.

The fact that only positive Trade Income is included does not change the significance of this principle. It is included in BC Hydro's revenue requirement due to government direction. Trade Income belongs to the shareholder and to the extent it is included in BC Hydro's rates is a "gift" of the government.

Trade Income Rate Rider

As noted in Section 4.11.1.1 of this Decision, the Panel accepts that, because of Direction No. 8, the BCUC cannot direct BC Hydro to reforecast Trade Income annually. However, directing BC Hydro to recover the Test Period Trade Income forecast via a separate rate rider rather than through the general revenue requirement does not compel BC Hydro to actually forecast the Trade Income annually. Recovering Trade Income through a rate rider provides necessary transparency. Trade Income is neither a cost of, nor income from, any of BC Hydro's regulated operations.

Including forecast Trade Income as a rate rider may result in increased bill volatility, but when the rate rider is added to the base rate the result is, all else equal, no less volatile than including Trade Income in rates. Reforecasting Trade Income annually can increase rate volatility compared to a fixed forecast for the test period, but this must be balanced against the need to ensure that forecasts are as accurate as possible. Given the nature of the forecast mechanism, the five-year historical average, fixing the forecast for the term of the test period hampers the effectiveness of the forecasting mechanism. The best tool to manage bill volatility regarding forecast Trade Income overall while balancing intergenerational equity is to forecast Trade Income annually using a five-year average of past actuals, which helps to reduce variances between forecast and actuals. We encourage BC Hydro to reforecast Trade Income annually. Doing so could be an important tool to further manage rate volatility.

With regard to NTC's proposal to set the Trade Income forecast at a fixed amount, we note BC Hydro's position that it is not "amenable" to doing so. Given Direction No. 8, NTC's proposal is therefore unworkable.

<u>Grouping Trade Income and the recovery of the TIDA - Bill Transparency</u>

While the TIDA recovery isn't related sufficiently to Cost of Energy variance recovery, it is directly related to the Trade Income forecast. Therefore, we direct that forecast Trade Income and the recovery/refund of TIDA balance be combined into a common rate rider. Combining these two elements of a "Powerex Dividend" into a rate rider provides transparency into the source of these amounts. Further, since these amounts are not effective price signals to the actual cost of providing electricity services it provides customers access to a more accurate price signal – the core rate and the portion of the DARR remaining after the TIDA is removed.

<u>Recovery of the TIDA and Bill Volatility</u>

Several parties commented on removing TIDA recovery out of the DARR and recovering the TIDA amortization in a separate rate rider. Both the CEC and NTC offered alternatives to both approaches.

BC Hydro is correct that grouping the balances of these accounts together and recovering them through the DARR allows variances to be offset and smoothed out over time to increase rate stability. However, that is neither sufficient justification to group the accounts, nor is it the only way to smooth TIDA recovery variances. In the Panel's view, amortizing the TIDA over three years and limiting the amortization of a deficit in the TIDA balance to the amount of forecast Trade Income that year will mitigate volatility and result in a rate that is just, reasonable and not unduly discriminatory.

Ultimately, bill volatility must be balanced against transparency and issues of intergenerational equity.

The Panel appreciates BC Hydro's offer to provide an alternative approach for review after the issuance of this Decision. However, submissions on the matter have been canvassed in this proceeding and we are satisfied with the approach as set out above in the Panel's determination.

The Panel's determination regarding the DARR is discussed in the following section.

4.11.1.3 The Deferral Account Rate Rider

BC Hydro is requesting approval to:[1673]

- Recover the balances in the COE Variance Accounts through the DARR using the DARR table mechanism as described in Section 7.3.3.3 of the Application, specifically, starting in F2023 and on an ongoing basis, set the DARR percentage effective April 1 of a given year based on the percentage in the DARR table

[1673] Exhibit B-2, p. 7-20.

mechanism corresponding to the forecast net balance of the COE Variance Accounts at the end of the preceding fiscal year; and

- Refund the balances in the COE Variance Accounts through the DARR using the DARR table mechanism and set the DARR at:
  - (2.0) percent for F2023;
  - (1.0) percent for F2024; and
  - (0.5) percent for F2025.

The requested Test Period DARR is based on BC Hydro's forecast of the net balance of the COE Variance Accounts of ($220) million at the end of F2022, ($121) million at the end of F2023, and ($72) million at the end of F2024.[1674]

Starting in F2023 and on an ongoing basis, BC Hydro is proposing to use the DARR table mechanism to determine the DARR percentage for a given year. Specifically, the DARR percentage would be effective April 1 of a given year based on the percentage in the DARR table mechanism corresponding to the forecast net balance of the COE Variance Accounts at the end of the preceding fiscal year.[1675] BC Hydro's proposed DARR table mechanism is as follows:

[1674] Exhibit B-2, Table 7-5, p. 7-35.
[1675] Exhibit B-2, p. 7-20.

Table 83: Deferral Account Rate Rider Table Mechanism[1676]

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 BCUC approved the DARR table mechanism in BC Hydro's F2009 to F2010 RRA and stated:[1677]

> The [BCUC] 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.

Subsequently, the DARR was set as follows, which deviated from the DARR table mechanism:[1678]

- For F2011, the DARR was set through a negotiated settlement agreement;
- For F2012 to F2014, the DARR was set pursuant to Government Direction No. 3 to the BCUC;
- For F2015 to F2019, the DARR was set pursuant to Government Direction No. 7 to the BCUC; and
- For F2020 to F2021, the DARR was set at 0 percent and the BCUC approved the amortization of the entire COE Variance Account balances into rates over that test period.

[1676] Exhibit B-2, Table 7-2, p. 7-19.
[1677] 2022-09-21 Oral Hearing Transcript Volume 3 PM, p. 800, line 26 to p. 801, line 11; BC Hydro F2009 to F2010 RRA, Decision to Order G-134-08, p. 172.
[1678] 2022-09-21 Oral Hearing Transcript Volume 3 PM, p. 801, line 12 to p. 802, line 21; 2022-09-21 Oral Hearing Transcript Volume 3 PM-Special Errata, p. 803B, line 5 to p. 803E, line 8.

In BC Hydro's F2022 RRA, BC Hydro proposed to return to the DARR table mechanism to recover the balances in the COE Variance Accounts going forward and to determine the level of the DARR based on the forecast net balance of the COE Variance Accounts at the end of the preceding fiscal year. The BCUC approved this method for F2022 only and deferred ruling on the continued use of the DARR methodology until the current Application because the streamlined way the F2022 RRA was reviewed meant that not all the significant issues related to the mechanism could be examined fully.[1679]

BC Hydro's modelling presented in the F2022 RRA proceeding showed that the proposed DARR table mechanism clears balances of $250 million, $500 million, and $750 million within 4 to 6 years and clears a balance of $1 billion in 7 years.[1680] In the last 15 years (F2007 to F2021), the actual net ending balance of the COE Variance Accounts has been over $1 billion once.[1681]

During the current proceeding, several alternative methods to the proposed DARR table mechanism were explored, such as amortizing the balance over 3 and 5 years, increasing the DARR table cap by +/-$100 million to +/-$600 million and correspondingly increasing the maximum rate rider percentage to +/-6 percent, and having no DARR table cap.[1682] The following table shows the end of year net balance of the COE Variance Accounts and the bill impacts for F2012 to F2022 under the scenario that BC Hydro's proposed DARR table mechanism or these alternative methods were used in those years.

Table 84: Proposed and Alternative COE Variance Accounts Recovery Mechanisms[1683]

	F12-F14 RRA			F15-F16 RRA		F17-F19 RRA			F20-F21 RRA		F22 RRA
$ million	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022
Scenario 1: Proposed Mechanism											
End of Year Balances	694.5	631.2	689.2	830.7	1,040.0	787.9	373.5	(712.8)	(446.2)	(230.1)	(142.3)
Annual Bill Impact	9.5%	3.9%	1.5%	9.0%	6.0%	4.0%	3.5%	1.5%	4.2%	(1.9%)	(1.6%)
Scenario 2: Recover over 3 years											
End of Year Balances	602.6	447.8	418.6	609.6	882.1	552.6	66.8	(1,159.3)	(796.9)	(408.7)	(298.5)
Annual Bill Impact	12.2%	3.7%	1.2%	5.4%	5.8%	7.3%	3.3%	2.8%	(1.7%)	(2.2%)	1.7%
Scenario 3: Recover over 5 years											
End of Year Balances	711.4	670.4	759.3	951.8	1,225.8	959.8	540.0	(617.4)	(502.7)	(372.1)	(323.5)
Annual Bill Impact	9.0%	3.8%	1.3%	8.6%	5.8%	5.9%	3.3%	2.8%	4.3%	(1.9%)	(2.6%)
Scenario 4: DARR Mechanism capped at +/- $600 million and +/- 6%											
End of Year Balances	658.5	556.6	592.2	709.4	870.7	566.1	119.2	(854.1)	(536.6)	(271.2)	(157.0)
Annual Bill Impact	10.6%	3.9%	1.0%	9.0%	6.5%	4.0%	3.0%	(1.4%)	5.7%	(1.9%)	(1.1%)
Scenario 5: DARR Mechanism, not capped											
End of Year Balances	604.4	500.0	552.4	668.0	806.1	407.5	25.6	(902.2)	(417.8)	(200.7)	(112.0)
Annual Bill Impact	12.1%	2.4%	0.5%	9.5%	7.0%	5.5%	(0.3%)	(1.0%)	3.3%	2.4%	(1.6%)

The above table shows that amortizing the balance over 3 years (i.e., scenario 2), increasing the DARR table cap to +/-$600 million and correspondingly increasing the maximum rate rider percentage to +/-6 percent (i.e., scenario 4), and having no DARR table cap (i.e. scenario 5) would have resulted in bill increases greater than 10 percent inF2012 and larger swings between bill decreases and bill increases inF2019 and F2020.

1679 BC Hydro F2022 RRA, Decisionto Order G-187-21, p. 67.
1680 Exhibit B-2, p. 7-17.
1681 Exhibit B-7, BCUC IR 97.3.
1682 Exhibit B-7, BCUC IRs 97.1, 97.2.
1683 Exhibit B-7, BCUC IR 97.1.

Further modelling done by BC Hydro showed that using the DARR table mechanism where the cap is at +/- $600 million and +/-6 percent, balances of $250 million, $500 million, $750 million, and $1 billion would clear within 3 to 6 years. Alternatively, using the DARR table mechanism where there is no cap would result in these balances being cleared within 3 to 5 years.[1684] Under BC Hydro's proposed DARR table mechanism, these balances would typically clear within 4 to 6 years, except for a $1 billion balance, which would clear in 7 years.[1685]

Positions of the Parties

BC Hydro states that the proposed DARR table mechanism continues to provide a principled, symmetrical, and structured approach to clearing the net balances in the COE Variance Accounts in a reasonable and transparent manner, and it continues to meet the following objectives set out for the DARR in the F2009 to F2010 RRA which BC Hydro considers remain valid:[1686]

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.

BC Hydro submits that the proposed DARR table mechanism achieves a reasonable balance between maintaining rate stability (i.e. avoiding rate shock) and intergenerational equity (i.e. clearing the net balance from the COE Variance Accounts over a reasonable amount of time). BC Hydro submits that these objectives should be prioritized over minimizing the use of the DARR.[1687]

BC Hydro submits that the BCUC will still retain oversight even with the approval of the DARR table mechanism because BC Hydro will require BCUC approval for its proposed DARR percentages in its RRAs.[1688]

In addition, BC Hydro submits that although the DARR table mechanism has been seldom used as designed since it was first approved, no other superior approach has been identified despite repeated consideration over the past decade.

MoveUP does not oppose BC Hydro's proposed DARR table mechanism.[1689]

BCOAPO submits that it is reasonable to use the DARR table mechanism as the "starting point" in determining the basis for refunding or recovering the balances in the COE variance accounts. However, the BCUC should make it clear that it can and may approve, deny, or alter a future BC Hydro proposal based on the DARR.[1690]

The CEC recommends the BCUC approve the proposed DARR rates subject to the BCUC setting the DARR table mechanism such that a balance of $750 million in the COE variance accounts clears in seven years.[1691]

In reply, BC Hydro submits that the CEC has not provided rationale for the request. Under BC Hydro's proposed DARR table mechanism, balances would typically clear within 4 to 6 years or in 7 years for a $1 billion balance.

[1684] Exhibit B-7, BCUC IR 97.2.
[1685] Exhibit B-2, p. 7-17.
[1686] BC Hydro Final Argument, pp. 138 – 139.
[1687] BC Hydro Final Argument, p. 140.
[1688] BC Hydro Final Argument, pp. 139 – 140.
[1689] MoveUP Final Argument, p. 4.
[1690] BCOAPO Final Argument, p. 59.
[1691] CEC Final Argument, p. 96.

While BC Hydro acknowledges that there may be little difference between 6 and 7 years, it submits that adjusting the DARR table mechanism solely to delay the recovery of the account balances is not warranted.[1692]

AMPC submits that $50 million threshold in BC Hydro's proposed DARR table mechanism will result in "considerable use of the rider for customers on an ongoing basis" leading to rate instability and confusion for customers regarding their electricity bills and the true cost of energy. AMPC suggests that the use of the DARR be minimized and thus recommends the BCUC direct BC Hydro to establish a larger "deadband" of values under the table mechanism, within which the DARR would be set at 0 percent (i.e. +/- $200 million). AMPC suggests that this approach would allow the cost of energy amounts to partially offset each other year over year. AMPC recommends this approach be implemented in BC Hydro's next RRA and for BC Hydro to work on COE forecasting improvements over this time.[1693]

In addition, AMPC argues that allowing the Cost of Energy Variance Accounts to accrue large balances due to forecast variances would cause these funds to continually be used on an ad-hoc basis in the future by the Government of B.C. for other than its intended purpose.[1694]

In reply, BC Hydro submits that it does not endorse the principle of trying to minimize the use of the DARR and it does not support AMPC's proposed change to the table mechanism. Attempting to minimize the use of the DARR would not increase rate stability or intergenerational equity because it could lead to higher balances in the COE Variance Accounts that would take longer to clear. BC Hydro considers a +/- $200 million deadband to be too wide.[1695]

Further, BC Hydro submits that the balances in the COE Variance Account accumulate for reasons beyond its control and AMPC's proposal to increase the deadband would allow balances to accumulate to a greater degree compared to BC Hydro's proposed DARR table mechanism. BC Hydro also points out that government has the power to legislate regardless of regulatory account balances.[1696]

After the filing of final arguments and submissions related to topics canvassed at the SRP, the Panel invited parties to provide submissions on setting the DARR annually, commencing in F2025, at the beginning of each fiscal year based on the most recently available actual results.[1697] Those submissions, which includes parties' positions regarding the mechanism to recover or refund Trade Income forecasts and the TIDA, are summarized in Section 4.11.2 of this Decision.

Panel Determination

The Panel approves the F2023 and F2024 DARR, as applied for, subject to any adjustments resulting from the corrections identified by BC Hydro in the proceeding, the determinations and directives contained in this Decision, and any future determinations and directives made by the Panel with respect to the following two topics as noted in Section 1.3 of this Decision:

- **BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA; and**
- **BC Hydro's finance charges.**

The Panel denies BC Hydro's requested DARR for F2025, instead commencing in F2025, the Panel directs BC Hydro to:

[1692] BC Hydro Reply Argument, p. 83.
[1693] AMPC Final Argument, pp. 7-2 – 7-3.
[1694] AMPC Final Argument, pp. 7-1 – 7-2.
[1695] BC Hydro Reply Argument, pp. 80 – 81.
[1696] BC Hydro Reply Argument, pp. 81 – 82.
[1697] Exhibit A-46.

- **Set the DARR annually, using BC Hydro's proposed DARR table mechanism, at the beginning of each fiscal year, based on the most recently available actual net COE Variance Account balances without the TIDA balance.** For example, commencing April 1, 2024, set the DARR based on the actual ending F2023 balances, with the same process to follow for each subsequent fiscal year; and
- **File for approval of the DARR annually in a filing separate from its RRA filings.**

The Panel notes that determinations have not been made in this Decision regarding BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA, as mentioned in Section 1.3 of this Decision. Further directions, if any, regarding the mechanism set out above as a result of the Panel's review of BC Hydro's request will be made in due course after the issuance of this Decision.

In Section 4.11.1.2 of this Decision, the Panel directed BC Hydro to recover or repay the TIDA balance from/to customers via the TIRR, instead of the DARR, commencing in F2025.

Setting the DARR annually allows the DARR to be more responsive to changes in the COE Variance Account balances compared to BC Hydro's proposed approach of setting the DARR over a given test period using the forecast COE Variance Account balances available at the time the RRA is developed. BC Hydro's proposed approach does not consider additions to the COE Variance Accounts, which could result in large account balances and a larger DARR in the subsequent test period compared to setting the DARR annually.

The Panel is not persuaded by the CEC's and AMPC's respective arguments to adjust the DARR table mechanism. The CEC has not provided sufficient regulatory justification regarding how adjusting the DARR table mechanism such that a balance of $750 million in the COE Variance Accounts is cleared in 7 years would be an improvement to BC Hydro's proposed table mechanism. With respect to AMPC's suggestion to increase the $50 million deadband in the DARR table mechanism to $200 million, this approach could lead to higher balances in the COE Variance Accounts, resulting in greater intergenerational inequity.

4.11.1.4 Updating the DARR with F2022 Actual Results

As mentioned in Section 2.4.3 of this Decision, the Account Credits Direction required the BCUC to allow BC Hydro to, among other things, transfer amounts totalling $400 million from the TIDA to various regulatory accounts in F2023. The TIDA is classified as one of BC Hydro's COE Variance Accounts, which is recovered or refunded to ratepayers via the DARR.

If the $400 million was not transferred out of the TIDA pursuant to the Account Credits Direction, it would have been refunded to BC Hydro's ratepayers through the DARR over a period of time commencing in F2026.[1698] The amount that would have been refunded to each customer group is shown in column A of the following table:[1699]

[1698] Exhibit B-51, BCSEA IR 100.3.
[1699] Exhibit B-51, BCSEA IR 100.4.

Table 85: Allocation of Funds Transferred out of the TIDA

$ millions	Refund through the DARR (A)	Allocation of the funds following the Accounts Credits Direction: Customer Credit Regulatory Account (B)	Crisis Fund Regulatory Account (C)	Inflationary Pressures Regulatory Account (D)	Total (E = B+C+D)	Change (F = E-A)
Residential	170.4	176.1	6.0	31.5	213.7	43.3
Light Industrial & Commercial	140.0	115.1		25.9	141.0	1.0
Large Industrial	80.9	-		15.0	15.0	(66.0)
Fortis BC	3.0	23.8		0.6	24.4	21.4
New Westminster	2.5	4.9		0.5	5.4	2.9
Other	3.2			0.6	0.6	(2.6)
Total BC Hydro Customers	**400.0**	**320.0**	**6.0**	**74.0**	**400.0**	**-**

The following table provides the net balance of the COE Variance Accounts after taking into account the actual ending F2022 balances and the $400 million transfer from the TIDA. It shows that the updated net balance of the COE Variance Accounts is $2.0 million more than the forecast balance in the Application.

Table 86: Cost of Energy Variance Account Balances Reflecting F2022 Actuals and F2023 Transfer[1700]

Cost of Energy Variance Accounts ($ million)	F2022: Forecast per the Application (A)	F2022: Actual (B)	F2022: Variance (C = B - A)	Transfer (D)	Net Balance (E = B - D)
Heritage Deferral	90.1	105.4	15.3		105.4
Non-Heritage Deferral	(189.6)	(185.6)	4.0		(185.6)
Trade Income Deferral	(233.6)	(503.6)	(270.0)	400.0	(103.6)
Load Variance	134.2	32.9	(101.3)		32.9
Biomass Energy Program Variance	(20.6)	(40.4)	(19.8)		(40.4)
Low Carbon Fuel Credits Variance	-	(30.2)	(30.2)		(30.2)
Total	**(219.5)**	**(621.5)**	**(402.0)**	**400.0**	**(221.5)**

Similarly, the updated net balance of the COE Variance Accounts at the end of each year of the Test Period is approximately $2.0 million more than the forecast balances in the Application as shown in the following table.

Table 87: Updated F2023 to F2025 Cost of Energy Variance Account Balances[1701]

Cost of Energy Variance Accounts	Forecast per the Application			Updated Forecast			Variance		
($ million)	F2023	F2024	F2025	F2023	F2024	F2025	F2023	F2024	F2025
Heritage Deferral	48.4	27.4	17.1	57.1	32.7	20.8	8.7	5.3	3.7
Non-Heritage Deferral	(104.7)	(62.9)	(41.7)	(103.3)	(62.9)	(42.4)	1.4	(0.0)	(0.7)
Trade Income Deferral	(125.5)	(71.0)	(44.2)	(56.1)	(32.1)	(20.4)	69.4	38.8	23.8
Load Variance	72.1	40.8	25.4	17.8	10.2	6.5	(54.3)	(30.5)	(18.9)
Biomass Energy Program Variance	(11.1)	(6.3)	(3.9)	(21.9)	(12.5)	(8.0)	(10.8)	(6.3)	(4.1)
Low Carbon Fuel Credits Variance	-	-	-	(16.4)	(9.4)	(6.0)	(16.4)	(9.4)	(6.0)
Total	**(120.8)**	**(72.0)**	**(47.4)**	**(122.8)**	**(74.1)**	**(49.5)**	**(2.0)**	**(2.1)**	**(2.1)**

Based on the updated forecast balances in the above tables, BC Hydro states that the DARR would remain the same as requested in the Application using BC Hydro's proposed DARR table mechanism.[1702]

[1700] Exhibit B-48, p. 2.
[1701] Exhibit B-48, p. 2.
[1702] Exhibit B-48, p. 2.

Positions of the Parties

BC Hydro submits that it is not proposing any changes to its proposals with respect to the DARR or the DARR table mechanism in the Application. This is because the Account Credits Direction has no impact on its proposed DARR and BC Hydro continues to believe that the DARR table mechanism is the best available approach to the treatment of the balances in the COE Variance Accounts. In BC Hydro's view, the DARR table mechanism offers a better balance of the objectives of minimizing intergenerational equity, maintaining rate stability, and administrative simplicity and transparency.[1703]

MoveUP and BCSEA agree with BC Hydro's submissions.[1704] Zone II RPG supports the DARR proposed by BC Hydro.[1705]

The CEC submits that the DARR, "at this point in time, is acceptable for treatment of energy cost deferred balances."[1706] BCOAPO submits that the updated COE Variance Account balances and the Account Credits Direction do not have a material impact on the DARR recovery percentages that result from the application of the DARR table mechanism.[1707]

In reply, although BC Hydro does not directly address the DARR rates applied for in the Application, it submits that no update to the Application is required for the Account Credits Direction or F2022 actual amounts.[1708]

AMPC recommends the BCUC adopt AMPC's recommendations for the DARR in AMPC's Final Argument (described in Section 4.11.1.3 of this Decision), but in the meantime, consider having Trade Income variances accrue to the Site C Regulatory Account, so that the balances can help offset future rate pressures and provides the BCUC with time to reform the DARR mechanism.[1709]

AMPC submits that the Account Credits Direction further supports its submission in Final Argument that the BCUC should re-evaluate and overhaul BC Hydro's DARR mechanism and incent BC Hydro to improve its forecast accuracy. AMPC argues that the large negative balances accruing in the COE Variance Accounts means that customers are substantially overpaying in current rates, which will be refunded "many years down the road." Since refining the DARR mechanism will take time, AMPC suggests that in the interim, the BCUC could consider earmarking any balance that occurs over the Test Period in COE Variance Accounts for the purpose of offsetting future rate impacts associated with Site C, by directing the funds be moved to the Site C Regulatory Account. AMPC argues that this would address ratepayers' risk of having these large balances accrue and it would refund the amounts to ratepayers quicker.[1710]

With respect to AMPC's proposal to put Trade Income surpluses into the Site C Regulatory Account, the CEC submits that there are alternatives in the future for proposing rate smoothing, these future issues can be considered in future RRAs, and there is greater customer value to distribute Trade Income earlier than to retain them in regulatory accounts. The CEC also submits that AMPC's proposal creates intergenerational inequities and contribute to "unnecessary confusion and complexity."[1711]

In reply, BC Hydro submits that AMPC's proposal to have Trade Income variances accrue to the Site C Regulatory Account has no benefits and has significant drawbacks and should be rejected. BC Hydro argues that AMPC's

1703 2023-01-16 SRP Transcript Volume 6, p. 1492, line 24 to p. 1494, line 2.
1704 MoveUP Final Argument on SRP Topics, p. 1; BCSEA Final Argument on SRP Topics, pp. 1–2.
1705 Zone II RPG Final Argument on SRP Topics, p. 1.
1706 CEC Final Argument on SRP Topics, p. 2.
1707 BCOAPO Final Argument on SRP Topics, p. 2.
1708 BC Hydro SRP Reply Argument, pp. 1, 30.
1709 AMPC Final Argument on SRP Topics, pp. 2, 11 – 12.
1710 AMPC Final Argument on SRP Topics, pp. 12 – 13.
1711 CEC Argument on AMPC's Proposal, p. 3.

approach would result in the Trade Income variance amounts being effectively amortized over 84 years, which would result in material intergenerational inequity concerns and an effective rate increase over the Test Period.[1712]

Panel Determination

The Panel notes that the evidence shows that the DARR would remain the same as requested in the Application, using BC Hydro's proposed DARR table mechanism, when both the actual ending fiscal 2022 net balance of the COE Variance Accounts and the $400 million transfer from the TIDA are taken into account. **Therefore, the Panel determines that no changes to the DARR are required to reflect the actual ending fiscal 2022 balances and the $400 million transfer from the TIDA.**

With respect to AMPC's suggestion to transfer funds from the COE Variance Accounts to the Site C Regulatory Account, the Panel is not convinced that this would result in quicker refunds to ratepayers considering that BC Hydro has proposed an 84-year amortization period for the Site C Regulatory Account. In our view, this would result in significant intergenerational inequity.

4.11.2 AMPC's Proposal

During the SRP, AMPC presented evidence and testimony from its members to show that high energy prices are hard on its members' businesses and that there have been "unprecedented" energy market prices for both electricity and natural gas. AMPC states that when BC Hydro's transmission customers are exposed to high electricity and natural gas prices, they typically must either curtail their load or purchase the expensive energy. In AMPC's view, the high market prices have benefited BC Hydro given its surplus position. However, when the market prices were lower, AMPC's members bore the cost of the surplus. Therefore, it is unfair and unreasonable to credit the benefits to only some of BC Hydro's customers given the high market prices.[1713]

AMPC proposes the BCUC direct BC Hydro to establish a new temporary deferral account, transfer available funds from the TIDA to the deferral account, refund these funds to customers that were excluded from the credits in the Account Credits Direction (Excluded Customers), either in this Test Period (e.g. fiscal 2024 or fiscal 2025) or the next, and then close the deferral account.[1714]

Positions of the Parties

AMPC submits that its proposal satisfies the BCUC's obligations under both the Account Credits Direction and its governing legislation.[1715]

AMPC submits that refunding the Cost of Energy Variance Accounts in any manner other than a pro rata basis to customers would reflect "an unduly discriminatory or preferential cross-subsidy." AMPC argues that the Account Credits Direction doesn't require the BCUC to abdicate its obligations under the UCA to set just and reasonable rates and that the BCUC should keep the Excluded Customers "whole." AMPC states that if Cabinet intended to override the BCUC's statutory obligations, then Cabinet must provide "clear language directing the Commission to exercise a power or perform a duty in a specified manner to achieve that outcome," which it did not.[1716] AMPC argues that the BCUC must consider the extent to which the Account Credits Direction displaces its other legal obligations.[1717] AMPC suggests that the only question now is "how" the BCUC should treat the Excluded Customers.[1718]

[1712] BC Hydro SRP Reply, pp. 17 – 18.
[1713] 2023-01-16 SRP Transcript Volume 6, p. 1461, line 12 to p. 1466, line 4.
[1714] AMPC SRP Final Argument, p. 2.
[1715] AMPC SRP Final Argument, p. 2.
[1716] AMPC SRP Final Argument, pp. 1 – 2, 10.
[1717] AMPC SRP Final Argument, p. 8.
[1718] AMPC SRP Final Argument, pp. 1 – 2.

AMPC cites the BCUC's review of BC Hydro's EV Fast Charging Rate Application as an example where "implicit policy interests do not override the Commission's overarching ratemaking obligations." AMPC argues that in rejecting BC Hydro's proposed rate in that decision, the BCUC dismissed parties' submissions that allowing BC Hydro's customers to cross-subsidize EV charging was in the public interest, and instead found that the proposed cross-subsidy failed to meet the BCUC's other obligations under the UCA. AMPC submits that the current situation with respect to the Account Credits Direction is directly analogous to that in BC Hydro's EV Fast Charging Rate Application.[1719]

In addition, AMPC argues that the Account Credits Direction is intended to only change the timing of refunds to manage financial challenges some customers face regarding inflationary pressures.[1720] To support this, AMPC cites a Government of B.C. news release that characterizes the account credits as a "cost-of-living credit" for residential and commercial customers to help offset expenses "during the months ahead" and as a measure "to get money into the pockets of people who need it most right now." AMPC submits that the Account Credits Direction does not foreclose "equitable rates" for industrial customers, who also face inflationary pressures.[1721]

Further, AMPC argues that its proposal is justified and necessary because the negative balances accrued in the COE Variance Accounts in fiscal 2022 reflect overpayment of all customers, which would have been refunded to all customers, absent of the Account Credits Direction. AMPC submits that large industrial customers would have been refunded approximately $80.9 million of the $400 million actual fiscal 2022 ending balance.[1722]

BC Hydro, MoveUP, BCSEA, the CEC, and BCOAPO oppose AMPC's proposal, while Zone II RPG and NTC take no position.[1723] RCIA, on the other hand, does not object to AMPC's proposal on the condition that it does not materially increase residential ratepayers' rates over the Test Period.

RCIA agrees in principle with AMPC that "all ratepayers who have contributed to paying for…assets that enable BC Hydro to generate trade income should share in the benefits of that trade income." However, RCIA submits that AMPC benefits from a portion of the Account Credits Direction that transfers $74 million from the TIDA into the inflationary pressures regulatory account.[1724]

In reply, AMPC does not disagree with RCIA, but submits that there is a difference in timing and risk. Therefore, AMPC recommends that $80.9 million be earmarked for industrial customers now and any necessary adjustments to account for ratepayers' proportionate "benefit" of the $74 million be determined later based on the amounts BC Hydro is allowed to recover from the inflationary pressures regulatory account.[1725]

BCSEA submits that "the BCUC has no legal authority to attempt to reverse the distributional impact of the Account Credits Direction on the excluded customers." BCSEA argues that AMPC's request would "force" residential and commercial customers to cross-subsize transmission service customers, which would be contrary to the BCUC's rate setting obligations under the UCA.[1726]

[1719] AMPC SRP Final Argument, pp. 5 – 6, 8.
[1720] AMPC SRP Final Argument, p. 2.
[1721] AMPC SRP Final Argument, pp. 10 – 11.
[1722] AMPC SRP Final Argument, pp. 4, 6 – 7; AMPC Reply Argument on AMPC's Proposal, Footnote 40, p. 9.
[1723] BC Hydro SRP Reply Argument, p. 22; MoveUP Argument on AMPC's Proposal, p. 5; CEC Argument on AMPC's Proposal, p. 2; BCSEA Argument on AMPC's Proposal, p. 1; BCOAPO Argument on AMPC's Proposal, p. 2; Zone II RPG Argument on AMPC's Proposal; NTC Argument on AMPC's Proposal.
[1724] RCIA Argument on AMPC's Proposal, pp. 2 – 3.
[1725] AMPC Reply Argument on AMPC's Proposal, p. 10.
[1726] BCSEA Argument on AMPC's Proposal.

In reply, AMPC submits that BCSEA is not accurate because the Account Credits Direction "does not prescribe any rate or distributional impact."[1727]

The CEC submits that the BCUC "must act on the Credit Directions [sic] explicitly and should not interpret or insert undirected intents." In the CEC's view, AMPC is asking the BCUC "to violate its statutory responsibilities by unduly favouring a single customer class." The CEC further submits that AMPC's proposal is not an available option for the BCUC because it could be seen as solely for the purpose of explicitly adjusting the revenue to cost ratios of the customer classes.[1728]

In reply, AMPC submits that the CEC's submission is misguided and backwards. AMPC argues that the revenue to cost ratios are not implicated with AMPC's proposal and, if they are implicated, by not exercising the BCUC's powers in response to the Direction, the result would be effectively adjusting the revenue to cost ratios."[1729]

MoveUP disagrees with AMPC's interpretation of the UCA. MoveUP states:[1730]

> The unambiguous purpose of section 3 is to authorize Cabinet to override the normal operation of the UCA and of the Commission's jurisdiction and process, including by imposing Government's preferred rules or outcomes. It places no limits on the scope of this power, except that Cabinet cannot "specifically and expressly" nullify an existing Commission order or decision, or direct the Commission to rescind it.
>
> A section 3 Direction reverses the usual statute/regulation hierarchy discussed in AMPC's argument, such that an Order in Council will prevail over its parent statute. Parliamentary supremacy enables arrangements of this kind: the legislature can delegate whatever it chooses.

MoveUP argues that AMPC is essentially asking the BCUC to overrule the Account Credits Direction, which MoveUP submits is not the role of a regulatory tribunal. MoveUP suggests that the "political" realm is the proper place for AMPC's grievance.[1731]

In reply, AMPC submits that MoveUP and the CEC inaccurately portray AMPC's submission and wrongly assume that the Account Credits Direction requires cross-subsidization. AMPC submits that it is not asking the BCUC to disregard the Account Credits Direction and its proposal does not reverse the impacts of the Direction. This is because residential and commercial ratepayers will still receive immediate refunds and BC Hydro will still transfer funds from the TIDA into new and existing regulatory accounts.[1732] AMPC submits that if the Account Credits Direction does not explicitly dictate a cross-subsidy at the expense of industrial customers and if it does not limit the BCUC's rate setting obligation, then the BCUC must exercise its powers consistently with the UCA's scheme.[1733]

MoveUP submits that "[n]one of the authorities cited by AMPC involve grants of regulation-making authority to a federal or provincial Cabinet or Minister to override statues enacted by Parliament or a legislature, comparable to section 3."[1734] In reply, AMPC submits that it cited a recent Supreme Court of Canada decision that "specifically considered this form of delegated decision-making."[1735]

[1727] AMPC Reply Argument on AMPC's Proposal, p. 3.
[1728] CEC Argument on AMPC's Proposal, p. 2.
[1729] AMPC Reply Argument on AMPC's Proposal, p. 8.
[1730] MoveUP Argument on AMPC's Proposal, p. 3.
[1731] MoveUP Argument on AMPC's Proposal, p. 5.
[1732] AMPC Reply Argument on AMPC's Proposal, pp. 2 – 3.
[1733] AMPC Reply Argument on AMPC's Proposal, p. 3.
[1734] MoveUP Argument on AMPC's Proposal, p. 3.
[1735] AMPC Reply Argument on AMPC's Proposal, p. 4.

MoveUP submits that AMPC has not cited any provision of the UCA that requires a Direction to include a recital that confirms Cabinet intends to displace UCA provisions. In reply, AMPC submits that "this idea is embedded within the language of section 3."[1736] [Emphasis in original]

BC Hydro submits that AMPC's requested relief must be rejected. BC Hydro generally agrees with MoveUP, the CEC, BCOAPO, and BCSEA's submissions, which oppose AMPC's proposal. BC Hydro disagrees with AMPC's interpretation of the Account Credits Direction and states that "AMPC's proposal asks the BCUC to undermine Government's direction, which would be contrary to section 3(2) of the UCA, and set rates in a manner that would be unduly discriminatory and preferential."[1737]

In addition, BC Hydro submits that AMPC mischaracterizes the impact of the Account Credits Direction when it suggests that the amounts in the regulatory account are a prior overpayment. BC Hydro argues that the amounts are not overpayments, but rather "the TIDA ensures that, over time, customers receive the benefit of actual Trade Income." BC Hydro explains that Trade Income is not a cost that customers have paid for, but rather it reflects profits from Powerex's trading activities, which is a revenue credit against BC Hydro's revenue requirements. BC Hydro notes that customers benefit from Trade Income by virtue of government direction, namely Direction No. 8.[1738]

Panel Determination

The Panel rejects AMPC's request for a direction to establish a new temporary deferral account, transfer available funds from the TIDA to the deferral account, and refund these amounts to the Excluded Customers. The Panel does not agree with AMPC's interpretation of the relationship between the BCUC's obligations under the UCA and Cabinet's directions under section 3 of the UCA. As mentioned by interveners, a statutory provision must not be read in isolation, but instead must be interpreted in the context of the UCA as a whole and in light of the provision's legislative purpose. In the context of the UCA as a whole, the legislative purpose of section 3 is to give the legislature the ability to override any part of the UCA. The language of section 3(2) is clear that the BCUC must comply with a direction of the Lieutenant Governor in Council despite any other provision of the UCA (with certain exceptions noted in section 3(3), which do not apply in this case). By the enabling statute, directions from Cabinet under section 3 trump all other provisions in the statute, and such directions therefore cannot be subsidiary, subordinate or subservient to other provisions of the UCA.

Because industrial customers were not included in the Direction establishing account credits for residential and commercial customers, it is reasonable to infer that the legislature did not intend industrial customers to benefit from an account credit. Contrary to AMPC's argument, this is clear language directing the BCUC to perform a duty in a specified manner, which does disturb the BCUC's mandate. This "undue discrimination" is coming from Cabinet, which overrides the usual regulatory principles of the UCA regarding prohibiting undue discrimination.

We do not agree with AMPC that the only question is "how the Commission should treat customers excluded from the account credits provided by the Direction." There is no requirement for the BCUC to apply the usual regulatory principles to industrial customers, to balance out Cabinet's intentions. Simply put, the BCUC must comply with directions given under section 3, as the BCUC can only do what the UCA enables it to do. It is not the BCUC's duty, nor does the BCUC have the power, to re-balance or override actions the legislature has taken under section 3.

AMPC argues that the current situation with respect to the Account Credits Direction is directly analogous to that in BC Hydro's EV Fast Charging Rate Application and that in that circumstance, by denying BC Hydro's rate application which it characterizes as being in the public interest, the BCUC considered its "other obligations under the UCA". We disagree that the two circumstances are analogous. The EV Fast Charging Rate Application was

[1736] AMPC Reply Argument on AMPC's Proposal, p. 5.
[1737] BC Hydro SRP Reply Argument, pp. 22, 28 – 29.
[1738] BC Hydro SRP Reply Argument, pp. 22 – 23.

brought under the GGRR. In denying that application, the BCUC made no decision that was inconsistent with, or overrode, the applicable provisions of the GGRR.

Our view is also consistent with the BCUC's prior determination that when rates have been set by a direction issued under section 3 of the UCA, the BCUC is not authorized to engage in reviews under sections 58 to 60 about whether that direction or the result thereof is unjust or unreasonable or unduly discriminatory or unduly preferential.[1739]

Further, the Panel is not persuaded by AMPC's argument that the negative balances accrued in the COE Variance Account reflect the overpayment by all customers, at least not for the TIDA. As noted by the Panel in Section 4.11.1.2 of this Decision, Trade Income arises from the activities of an unregulated subsidiary of BC Hydro and is not directly related to the cost to provide a regulated service. Trade Income belongs to the unregulated subsidiary and its shareholder, BC Hydro. The shareholder of BC Hydro, the provincial government, has chosen through Direction No. 8 to transfer Trade Income to BC Hydro's ratepayers. Therefore, customers' share of the benefits of Trade Income is limited to the amount set by government.

4.11.3 Evidentiary Update

During the SRP, questions were raised regarding why BC Hydro did not file an evidentiary update to the Application once its actual F2022 results were publicly released considering that certain actual results may have an impact on the Test Period forecasts.

BC Hydro states that it cannot provide actual fiscal year results until the Government of B.C. issues its actual financial results and BC Hydro's financial statements are released, which most recently occurred on August 31, 2022. Therefore, it could not file an evidentiary update with actual F2022 results until after this date.[1740]

BC Hydro states that it would not be appropriate to only update one area of the Application, such as Trade Income, and updating all areas of the Application would have significantly extended the current proceeding. BC Hydro explains that the regulatory timetable for this current proceeding did not contemplate an evidentiary update and BC Hydro notes that the BCUC had indicated a desire to complete the proceeding in a reasonable amount of time. BC Hydro points out that there are regulatory accounts in place to capture variances for future rate setting purposes.[1741]

Due to the timing of the public release of BC Hydro's F2022 financial statements, the timing of the oral hearing, and the Government of B.C.'s announcement of potential affordability measures, BC Hydro did not consider an evidentiary update to be feasible.[1742] Although BC Hydro would consider doing an evidentiary update when it is possible to and if it would add value to the process, BC Hydro did not consider the F2022 actual results warranted an evidentiary update.[1743]

In the proceeding to review its F2020 to F2021 RRA, BC Hydro provided an evidentiary update which added approximately three months to the regulatory timetable, excluding the time required to prepare the evidentiary update and the time required for potential follow-up process, such as an oral hearing, argument, etc.[1744] BC Hydro considers that a comprehensive evidentiary update could add about six or seven months to the current proceeding.[1745] BC Hydro indicates that it could do a targeted evidentiary update up to the end of F2022, as an example, but many of the factors would not result in a change in the Application and there are other factors

[1739] BC Hydro Application for Approval of Charges Related to Meter Choices Program, Decision and Order G-59-14, pp. 61, 66.
[1740] Exhibit B-51, AMPC IR 7.3.
[1741] Exhibit B-49, Panel IR 1.2.
[1742] 2023-01-16 SRP Transcript Volume 6, p. 1359, line 16 to p. 1360, line 19.
[1743] 2023-01-16 SRP Transcript Volume 6, p. 1370, line 21 to p. 1371, line 6.
[1744] Exhibit B-51, AMPC IR 7.2.
[1745] 2023-01-16 SRP Transcript Volume 6, p. 1362, line 3 to p. 1363, line 3.

beyond F2022 that could be worth updating, such as the fact that interest rates have continued to increase since the end of F2022. BC Hydro considers that a targeted evidentiary update would still add months to the process.[1746]

BC Hydro also clarified that an evidentiary update, as opposed to updated evidence, is usually filed more formally and separate from an IR response, and would represent almost a "reapplication" or a "modified application." The evidentiary update would also potentially request a new set of rates because of new information.[1747]

Positions of the Parties

BC Hydro submits that the Application does not need to be updated at this time for the Account Credits Direction, the Cryptocurrency Direction, or any other reason. Any major update to the Application would result in a material delay to the proceeding and would derail the efforts to get the timing of BC Hydro's RRAs back on track.[1748] BC Hydro argues that the delay would impact other filings, such as BC Hydro's PBR plan application that has been directed to be filed by the end of the calendar year, as it would draw on its resources and having a decision late in the year would complicate those efforts. BC Hydro submits that there will always be more-up-to-date information and "at some point a line just has to be drawn, and a decision made on the evidence."[1749]

Zone II RPG requests that the BCUC provide direction to BC Hydro on how and when future applications should or should not be amended based on material changes in circumstances.[1750]

AMPC recommends the BCUC reject BC Hydro's reasons for not filing an evidentiary update. AMPC argues that BC Hydro had time to provide an evidentiary update without undermining the timing of the proceeding. AMPC provides examples of past BC Hydro RRA proceedings where evidentiary updates were provided, but only delayed the proceeding by approximately one to six weeks.[1751]

In reply, BC Hydro submits that it was reasonable and appropriate to not file an evidentiary update in September of 2022 after its F2022 actual results became publicly available. BC Hydro argues that it was not feasible to file an evidentiary update considering the BCUC's reiterated desire to bring the proceeding to a timely close and the government's active consideration of affordability measures related to BC Hydro at that time. BC Hydro also argues the following three points. First, the broad consensus among parties that there is no need to update the Application for F2022 actual results confirms that it was reasonable to not file an evidentiary update in the fall. Second, updating only the Trade Income forecast, as requested by AMPC, is not a reasonable approach because there may be compounding or offsetting impacts from other components of the revenue requirement. Third, the circumstances in the current proceeding are different from the past proceedings cited by AMPC.[1752]

Panel Discussion

The Panel accepts BC Hydro's rationale for not filing an evidentiary update regarding the F2022 actual results. The Panel notes that aside from AMPC, no other party requested BC Hydro to file an evidentiary update. The Panel declines Zone II RPG's request for a BCUC direction on amendments to future applications. In the Panel's view, BC Hydro should take the lead on how and when future applications should be amended based on the circumstances at that time. The BCUC can also direct an evidentiary update when the circumstances warrant it. However, even in the absence of a formal evidentiary update, there is nothing that prevents BC Hydro from updating evidence in a proceeding at any time. It does so through its responses to IRs and filing of various

[1746] 2023-01-16 SRP Transcript Volume 6, p. 1363, line 22 to p. 1364, line 23.
[1747] 2023-01-16 SRP Transcript Volume 6, p. 1383, line 18 to p. 1386, line 1.
[1748] 2023-01-16 SRP Transcript Volume 6, p. 1492, lines 1 to 14.
[1749] 2023-01-16 SRP Transcript Volume 6, p. 1494, line 26 to p. 1497, line 11.
[1750] Zone II RPG SRP Final Argument, p. 2.
[1751] AMPC SRP Final Argument, pp. 16 – 17.
[1752] BC Hydro SRP Reply Argument, pp. 8 – 11.

documents. In this case, for example, it has provided updated information on Powerex's actual income for F2022.

4.11.4 Interest on the Customer Credit Regulatory Account and the Inflationary Pressures Regulatory Account

As mentioned in Section 2.4.3 of this Decision, although the Account Credits Direction enabled BC Hydro to establish a customer credit regulatory account and an inflationary pressures regulatory account, and transfer funds from the TIDA to these regulatory accounts, it was silent on the application of interest to either of these regulatory accounts.

Both the customer credit regulatory account and the inflationary pressures regulatory account are variance accounts. Since BC Hydro's practice is to apply interest to variance regulatory accounts based on its weighted average cost of debt, it would not be opposed to a direction from the BCUC to apply interest on these accounts.[1753]

Assuming that BC Hydro incurs the estimated $120 million of inflationary cost pressures during the Test Period, BC Hydro estimates the following interest attracted to the customer credit regulatory account and the inflationary pressures regulatory account during the Test Period:

Table 88: Estimated Interest[1754]

Estimated Interest ($ million)	F2023	F2024	F2025
Customer Credit Regulatory Account	-	-	-
Inflationary Pressures Regulatory Account	(0.3)	(0.2)	0.7

Positions of the Parties

BCOAPO submits that it would be reasonable to apply interest to the customer credit regulatory account and the inflationary pressures regulatory account given the nature of the accounts and the fact that the funds transferred to these accounts originated in the TIDA.[1755] Other interveners did not comment on this topic.
In reply, BC Hydro submits that it is not opposed to interest being applied to this regulatory account.[1756]

Panel Determination

The Panel directs BC Hydro to apply interest to the customer credit regulatory account and the inflationary pressures regulatory account based on its current weighted average cost of debt. This is consistent with the application of interest to BC Hydro's other variance regulatory accounts that attract interest. However, the Panel notes that the application of interest to the account does not guarantee that the interest will be recoverable from ratepayers. For example, if the BCUC later determines that there are amounts recorded in the inflationary pressures regulatory account that should not be recovered from ratepayers, then any related interest should also not be recoverable.

1753 Exhibit B-48, p. 5; Exhibit B-51, NTC IR 62.1.
1754 Exhibit B-51, MoveUP IR 1.2.
1755 BCOAPO SRP Final Argument, p. 11.
1756 BC Hydro SRP Reply Argument, p. 19.

5.0 Other Items

5.1 Cost Control

In Final Argument, AMPC submits that the Application doesn't demonstrate effective cost control and efficient prioritization of expenditures and activity in key areas by BC Hydro.[1757] AMPC recommends that the BCUC issue a general direction to BC Hydro "to better control its costs through forecasting, budgeting, and prioritizing and pacing projects, and recommend that it provide information on how it has done so as part of its rate applications (or face the risk of an adverse inference should it fail to do so)." AMPC also recommends that the BCUC scrutinize the individual elements of the Application through a "cost control lens."[1758]

AMPC submits that BC Hydro's controllable costs are substantially increasing and makes specific comments on the increases in the following cost categories:[1759]

- Amortization of property, plan, and equipment;
- Vegetation management;
- Labour;
- Other reliability investment;
- Electrification;
- DSM; and
- Site C.

AMPC submits that careful regulatory oversight is immediately required because of information asymmetry and BC Hydro's "failure to provide transparent insight into these forecast increases."[1760]

AMPC also stresses the importance for BC Hydro to demonstrate effective cost control and "least cost budgeting" in light of the erosion of B.C.'s competitiveness for businesses due to high electricity rates, the current inflationary environment, and the funding of "priorities that extend beyond least cost power from both past and recent government and external policy direction."[1761] AMPC also argues that reducing the use of the DARR mechanism would be a way to better incentivize cost control.[1762]

In Reply, BC Hydro submits that AMPC's arguments do not take into consideration relevant historical context from prior proceedings and are inconsistent with the evidence. BC Hydro argues that managing costs has been a key priority, evidenced by several years of bill impacts below the inflation rate.[1763]

BC Hydro notes that the BCUC had previously acknowledged BC Hydro's efforts to minimize increases in base operating costs, had endorsed BC Hydro's budgeting approaches for both operating costs and capital, and rejected a "least cost" approach that may lead to detrimental effects from cost cutting. BC Hydro also points out that two areas singled out by AMPC as requiring additional cost control, cybersecurity and vegetation management, are areas that the BCUC has specifically identified in previous decisions as areas of potential under-investment.[1764]

[1757] AMPC Final Argument, p. 2.
[1758] AMPC Final Argument, p. 1-1.
[1759] AMPC Final Argument, pp. 1-2 – 1-4.
[1760] AMPC Final Argument, p. 1-4.
[1761] AMPC Final Argument, p. 1-5 – 1-7.
[1762] AMPC Final Argument, p. 1-7.
[1763] BC Hydro Reply Argument, pp. 2 – 3.
[1764] BC Hydro Reply Argument, pp. 2 – 3.

BC Hydro submits that the BCUC should endorse BC Hydro's approach, which balances fiscal discipline and appropriate investments, and aligns with BC Hydro's Five-Year Strategy.[1765]

Panel Determination

The Panel declines AMPC's recommendation to issue a general direction to BC Hydro regarding cost control and the provision of information on its activities in this regard.

The Test Period costs related to each of the cost categories identified by AMPC as substantially increasing have been reviewed in this proceeding and any costs that the Panel finds to be unjust or unreasonable have not been included in BC Hydro's revenue requirement for recovery from ratepayers.

The Panel notes that in the BCUC's decision on BC Hydro's PBR Report, the BCUC directed BC Hydro to file a proposal for its next RRA that includes several PBR elements (PBR Application). The review of the PBR Application is the appropriate forum to address cost control matters more holistically.

With respect to AMPC's comments regarding information asymmetry, the Panel notes that the BCUC has previously found that an index-based formula can mitigate information asymmetry problems and BC Hydro has been directed to include in its PBR Application a proposed formula to capture as much as possible of its controllable O&M and capital expenditures.[1766] With respect to AMPC's comments regarding incentivizing cost control, the Panel notes that the BCUC has previously found that a longer test period would provide incentives for BC Hydro to contain costs and achieve regulatory efficiency. BC Hydro has also been directed to include a test period of at least 5 years in its PBR Application.[1767] Therefore, no further BCUC directions are required to address the matters raised by AMPC until BC Hydro's PBR Application is filed.

5.2 Recovery of Project Write-off Costs

BC Hydro's actual project write-offs in F2021 were $9.6 million, of which BC Hydro is seeking approval to defer $7.3 million to the Project Write-off Costs Regulatory Account for recovery from ratepayers over the Test Period. BC Hydro is not seeking approval to recover the remaining $2.3 million.

In Table P-1 in Appendix P to the Application, BC Hydro provides the itemized project write-offs deferred to the Project Write-off Costs Regulatory Account in F2021, along with the rationale for the write-offs.

Included in the project write-offs is $0.5 million for the Asset Investment Planning (AIP) Tool project. BC Hydro cancelled this project due to increases in expected total project cost and to align the project with the implementation of an Enterprise Asset Management (EAM) software platform. BC Hydro determined that the full benefits of the project could only be realized if an EAM software platform was implemented first. BC Hydro explains that it is initiating the Stations Work Management project in F2022, which will form the foundation for the EAM software platform, and is expected to be completed in F2025. BC Hydro states that it may initiate a new project after the implementation of the EAM software platform.[1768]

[1765] BC Hydro Reply Argument, p. 4.
[1766] BCUC Review of BC Hydro's PBR Report, Decision and Order G-388-21, pp. iii, 58.
[1767] BCUC Review of BC Hydro's PBR Report, Decision and Order G-388-21, pp. ii, 58.
[1768] Exhibit B-2-1, Appendix P, Table P-1, pp. 7 – 8.

Positions of Parties

The CEC recommends that the BCUC disallow the recovery of $0.5 million related to the cancellation of the AIP Tool project. The CEC submits that it does not accept BC Hydro's rationale for the recovery of costs related to the cancellation of the project.[1769]

In reply, BC Hydro submits that it has provided a detailed description of the reasons for writing off the costs related to the AIP Tool in Appendix P to the Application. BC Hydro also submits that its explanation is sound, the CEC has provided no evidence or argument that contradicts BC Hydro's evidence, and the $0.5 million in costs was prudently incurred and should be recovered in rates.[1770]

The CEC also recommends that the BCUC disallow the recovery of $0.5 million related to 13 miscellaneous projects with write-offs equal to or less than $200,000 in each case. The CEC submits that BC Hydro has not provided sufficient justification for the recovery of these costs.
In reply, BC Hydro submits that it has provided sufficient evidence to justify the recovery of write-off costs totaling $0.5 million for the 13 miscellaneous projects. BC Hydro argues that for practicality and regulatory efficiency, it is reasonable and customary to provide less detail on smaller amounts in each category of costs. BC Hydro also points out that no party asked questions about the $0.5 million amount.[1771]

Panel Determination

The Panel declines the CEC's request to disallow the recovery of project write-off costs of $0.5 million related to the AIP Tool project and $0.5 million related to the 13 miscellaneous projects with write-offs equal to or less than $200,000 each.

The Panel is satisfied with BC Hydro's rationale for writing off the costs related to the AIP Tool project and finds that it is reasonable to recover the costs from ratepayers and no intervener, including the CEC, has provided any evidence to the contrary.

The Panel is also satisfied with the amount of detail provided for the rationale to write-off the costs related to the 13 miscellaneous projects considering the immateriality of the expenditures. On average each of the write-offs would be less than $38,500. There is no evidence in this proceeding to indicate that these costs should not be recovered from ratepayers. The CEC had the opportunity to request additional information on these miscellaneous projects during this proceeding but did not do so.

5.3 Interim Rates Proposal – Site C Project Capital Costs and Deferred Costs

A portion of the Site C project is expected to be in-service during fiscal 2025, including the first generating unit. As shown in Table 89 below, this results in the inclusion of costs related to the Site C project starting in the fiscal 2025 revenue requirement. The remaining Site C generating units are anticipated to be in-service during fiscal 2026.[1772] BC Hydro expects substantially all of the Site C project costs will be incurred by approximately May 2026 (i.e. six months after the last unit goes into service).

BC Hydro recognizes that the BCUC and interveners will likely be interested in reviewing BC Hydro's execution of the Site C project and thus anticipates that the BCUC will assess the extent to which Site C project capital and deferred costs[1773] are recoverable in rates once the entire project is complete. Although BC Hydro believes that

[1769] CEC Final Argument, p. 93.
[1770] BC Hydro Reply Argument, p. 79.
[1771] BC Hydro Reply Argument, pp. 78 – 79.
[1772] Exhibit B-2, p. 6-125.
[1773] Deferred costs in relation to Site C are the costs that have been or are being deferred to the Site C Regulatory Account, as explained in Exhibit B-7, BCUC IR 112.2.

its forecast Site C project costs for F2025 are reasonable and should be recovered in full, it recognizes that the BCUC's review could result in the disallowance of recovery of costs related to the project that have been included in the F2025 revenue requirement.[1774] Based on BC Hydro's anticipated completion date of the Site C project, it estimates that the BCUC's review could start in June 2026 and take 12 months, which is approximately 38 months after the start of F2025.[1775]

The following table shows the estimated annual revenue requirements related to the capital additions and deferred costs of the Site C project from the expected in-service date of the first generating unit until the estimated completion date for a BCUC review of the project (i.e. December 2024 (F2025) to June 2027 (F2028)).

Table 89: Estimated Site C Revenue Requirements Until Completion of a BCUC Review of the Project[1776]

Estimated Site C Revenue Requirements ($ million)	F2025	F2026	F2027	F2028	Total
PP&E Amortization	34	188	197	49	468
Regulatory Account Amortization	1	7	7	2	17
Finance Charges	120	471	481	119	1,191
Estimated Site C Revenue Requirements	154	665	685	170	1,675

In addition to the assets that are expected to come into service starting in fiscal 2025, there are Site C transmission related assets that went into service in fiscal 2021, which have been included in rates since then. The impact of these transmission assets on the fiscal 2023 and fiscal 2024 revenue requirements is $12.4 million and $12.9 million, respectively, of which $0.4 million and $1.2 million, respectively, are operating costs. The remaining costs are related to depreciation and finance costs.[1777]

During the proceeding, AMPC submitted evidence prepared by its expert Ms. Davies, where she states that the Site C project expenditures have not been determined to be used and useful and that it is realistic for first power to not occur until F2026, and therefore, all Site C costs (capital and operating) should not be included in the F2025 revenue requirement.[1778]

Two approaches are discussed below that allow this current proceeding to conclude without the BCUC having to assess or make any determinations regarding the reasonableness of the F2025 Site C project depreciation and deferred costs: (i) keep fiscal 2025 rates interim at the conclusion of this proceeding or (ii) use a regulatory account to capture cost variances.

(i) Keep Fiscal 2025 Rates Interim

In the Application, BC Hydro proposes that F2025 rates remain interim at the conclusion of this proceeding pending the outcome of the BCUC's future assessment of the recoverable amount of total Site C project costs. Any variances between F2025 interim rates (set at the conclusion of the current proceeding) and permanent rates (set following the review of the recoverable amount of total Site C capital and deferred costs), could be refunded to customers when F2025 rates are made permanent.[1779] However, BC Hydro is not proposing to keep F2023 and F2024 rates interim given the limited impact of the capital and finance costs on rates in those years related to the transmission assets discussed above that are already in-service.[1780]

[1774] Exhibit B-2, p. 1-54.
[1775] Exhibit B-7, BCUC IR 3.4.
[1776] Exhibit B-7, BCUC IR 3.5.
[1777] Exhibit B-8, BCOAPO IR 39.2.
[1778] Exhibit C7-12, p. 49.
[1779] Exhibit B-2, p. 1-54.
[1780] Exhibit B-8, BCOAPO IR 39.2.

BC Hydro estimates that this approach would result in the F2025 rates being held interim until approximately June 2027, which is approximately 38 months after the start of F2025.[1781] BC Hydro states that the BCUC has previously held rates interim for extended periods to address the potential for future determinations that affect revenue requirements in a test period. BC Hydro cites the BCUC's Generic Cost of Capital Phase 1 proceeding as an example, whereby the rates for the affected utilities were held interim for approximately 18 months.[1782] Although BC Hydro is not aware of instances where interim rates have been used to address the implementation of a specific capital project, it states that the logic of doing so in the case of the Site C project is similar to that in the Generic Cost of Capital Phase 1 proceeding. Further, BC Hydro states that Site C is not a typical capital project since it is much larger than other capital projects previously undertaken by utilities under BCUC regulation, and it is being operationalized over multiple test periods.[1783]

BC Hydro states that it had successfully managed interim rates in the past. As an example, BC Hydro's F2020 rates were held interim for approximately 19 months. However, BC Hydro also acknowledges that there would be challenges and costs associated with holding rates interim, such as tracking and rebilling affected customers and sending refund cheques, which would be exacerbated the longer the period that rates are held interim.[1784]

(ii) Use of a Regulatory Account

In response to BCUC IRs, BC Hydro addressed an alternative to BC Hydro's proposed approach of holding F2025 rates interim. Under the alternative approach, the F2025 rates would be set as permanent based on the forecast revenue requirement impact of the Site C capital and deferred costs, and a regulatory account would be established to capture any variances between the forecast and the actual revenue requirement impact, resulting from the BCUC review of Site C capital and deferred costs at the completion of the project.

This approach would create certainty for customers regarding F2025 rates and allow for the rates in the Test Period to be finalized at the conclusion of the current proceeding. It would also have lower administrative burden and would eliminate the need for individual refunds to specific ratepayers because any refunds would be included in a regulatory account and returned to all ratepayers as part of future rates. However, this approach would result in some intergenerational inequity issues because any resulting refunds would be to the benefit of the ratepayers at that time rather than to the benefit of ratepayers in F2025. In addition, since any refunds would be included in the test period after the BCUC completes the review of the Site C capital and deferred costs, the timing of the benefit of any refund would be delayed compared to the approach proposed by BC Hydro in the Application. However, given that the time period involved is only a few years, BC Hydro suggests that these shortcomings would not be significant. [1785]

Positions of Parties

BC Hydro submits that the use of a regulatory account to capture variances between the forecast and approved revenue requirement impact of the Site C capital and deferred costs is preferable compared to the approach originally proposed in the Application. BC Hydro clarifies that the new regulatory account would "capture <u>any future variances</u> between the forecast and actual revenue requirement impact resulting from any BCUC review of Site C costs after the completion of the project."[1786] [Emphasis in original]

1781 Exhibit B-7, BCUC IR 3.3.
1782 Order G-187-12; Exhibit B-2, p. 1-55; Exhibit B-7, BCUC IR 3.1.
1783 Exhibit B-7, BCUC IR 3.2.
1784 Exhibit B-7, BCUC IR 3.3.
1785 Exhibit B-7, BCUC IR 3.6.
1786 BC Hydro Final Argument, pp. 202 – 204.

BC Hydro also emphasizes the importance of the regulatory account being a variance account, rather than an account that defers recovery of all capital and deferred Site C costs starting in F2025 until the completion of the BCUC's review of Site C capital and deferred costs. BC Hydro submits that the latter would lead to a significant rate impact upon recovery of the regulatory account.[1787]

MoveUP, however, submits that leaving the F2025 rates interim is preferable.[1788]

BCSEA, the CEC, and BCOAPO support BC Hydro's preference for using a regulatory account.[1789] In BCOAPO's view, having certainty of F2025 rates and avoiding the costs and complexity of tracking customers and adjusting bills more than three years after the fact outweigh potential inter-generational equity concerns. However, BCOAPO adds that the regulatory account should also capture the variances for F2023 and F2024.[1790]

AMPC supports BC Hydro's preferred approach but adds that the regulatory account should be used until Site C has been reviewed for prudence and that this account should include all Site-C related capital and deferred costs as well as revenue. In AMPC's view, a BCUC review of Site C costs could begin earlier than suggested by BC Hydro, which would minimize any cumulative rate impacts. Alternatively, AMPC suggests that the BCUC should reject the inclusion of Site-C related costs in the fiscal 2025 rates "unless and until BC Hydro provides an update on project timing confirming that the project will be in-service in F2025."[1791]

In reply, BC Hydro submits that AMPC's approach is likely to prejudice customers by introducing significant volatility in rates. Further, it would be unrealistic to expect a BCUC review of Site C capital and deferred costs could follow shortly upon the in-service date, which would result in a very large balance in AMPC's proposed regulatory account. Also, AMPC's proposal to include revenues in the regulatory account would shift revenues from the cost of energy accounts to this account, but it would not resolve the rate volatility issue.[1792]

BC Hydro did not reply to BCOAPO's or MoveUP's respective submissions on this topic.

Panel Determination

The Panel directs BC Hydro to establish a new regulatory account to capture the variances between the following, commencing in F2023:

a) **The revenue requirement impact of the Site C capital costs and costs deferred to the Site C Regulatory Account, based on the forecast costs approved for recovery in rates in this Decision, and**

b) **The revenue requirement impact of the Site C capital costs and costs deferred to the Site C Regulatory Account approved for recovery in rates, as determined by the BCUC following any BCUC prudency review of the Site C project.**

The Panel notes that any variances between the forecast and actual capital additions and finance charges as it relates to the Site C project would be captured in the new regulatory account directed above, instead of in the Amortization of Capital Assets Regulatory Account and Total Finance Charges Regulatory Account, respectively.

BC Hydro estimates it could take approximately 38 months from the commencement of F2025 for the completion of a BCUC review of the prudency of the Site C capital and deferred costs. Regardless of the start date of any BCUC review, the use of a regulatory account for 38 months or more is preferable to holding rates

1787 BC Hydro Final Argument, p. 204.
1788 MoveUP Final Argument, p. 3.
1789 BCSEA Final Argument, p. 69; CEC Final Argument, p. 12; BCOAPO Final Argument, pp. 7 – 8.
1790 BCOAPO Final Argument, pp. 7 – 8.
1791 AMPC Final Argument, pp. 6-3, 8-4.
1792 BC Hydro Reply Argument, pp 172 – 173.

interim. In this circumstance, the certainty of F2025 rates and lower administrative burden outweigh the intergenerational inequity issues and delay in potential customer refunds that come from the use of a regulatory account.

The Panel agrees with BCOAPO's submission that F2023 and F2024 variances should also be captured in a deferral account. Considering that the use of a regulatory account means that none of the rates in the Test Period will need to be held interim pending the results of the BCUC's review of the Site C capital and deferred costs, the Panel sees no strong reason to not include any related variances for F2023 and F2024 in the regulatory account.

With respect to AMPC's comments, no compelling reason has been presented in this proceeding to suggest that a BCUC prudency review would result in the disallowance in rates of all (as opposed to a fraction) of Site C's capital and deferred costs. Therefore, the inclusion of all of Site C related capital and deferred costs and revenues in the regulatory account until any BCUC prudency review is concluded could result in significant rate impacts and intergenerational equity issues. Although the Panel agrees with AMPC that a review of the Site C capital and deferred costs could commence earlier than estimated by BC Hydro, such as prior to the completion of the Site C project, the review would still take a significant amount of time to complete given the size and complexity of the project. In addition, the Panel is not persuaded by the evidence in this proceeding that Site C will not be in-service in F2025 and therefore it would not be reasonable to reject the inclusion of Site C related costs in the F2025 rates.

5.4 UNDRIP and Steps to Advance Reconciliation

In July 2021, BC Hydro finalized a new Five-Year Strategy that identifies four goals, one of which is advancing reconciliation with Indigenous Peoples.[1793] The strategy sets out BC Hydro's plans to achieve this goal, which include developing an UNDRIP implementation plan and advancing BC Hydro's diesel reduction strategy in the NIA.[1794]

The total increase in BC Hydro's planned operating costs related to UNDRIP is $5.6 million which includes five additional FTEs over the Test Period, comprising of increases of $1.6 million in F2023 and $2.0 million in each of F2024 and F2025. Of the $5.6 million increase in operating costs, approximately $0.4 million in each year relates to labour and the remaining amounts relate to non-labour costs, such as consulting resources and capacity funding.[1795]

The total increase in BC Hydro's planned operating costs related to advancing its diesel reduction strategy in the NIA is $2.7 million and three FTEs over the Test Period, comprising of increases of $0.7 million in F2023 and $1.0 million in each of F2024 and F2025.[1796] The increased costs are to support and develop a strategy to pursue new renewable generation opportunities to reduce diesel use in remote communities.[1797]

BC Hydro sets out the following performance measures and targets with respect to its goal of advancing reconciliation with Indigenous Peoples:[1798]

[1793] Exhibit B-2, p. 1-5.
[1794] Exhibit B-2, p. 1-9.
[1795] Exhibit B-44, Cover Letter, p. 2.
[1796] Exhibit B-8, Zone II RPG IR 15.1.
[1797] Exhibit B-2, p. 5-31.
[1798] Exhibit B-2-1, Appendix D, p. 19.

Table 90: Advancing Reconciliation with Indigenous Peoples – Performance Measures and Targets

Performance measures supporting five-year strategy	Targets
Indigenous procurement	$1 billion by the end of F26 (cumulative since 2015)
Non-integrated areas (NIA) diesel reduction	TBD
Indigenous employment at BC Hydro	25% increase from F21 baseline by end of F26
Indigenous awareness training at BC Hydro	80% of employees trained in INDIG-101 and/or INDIG-201 by end of F26
Progressive Aboriginal Relations Certification	Gold level

Of the measures above, BC Hydro states that some of them are newer initiatives. In particular, BC Hydro previously did not have a metric associated with procurement and employment, and the Indigenous awareness training was implemented in 2017 and 2019.[1799]

With respect to Indigenous procurement, BC Hydro states that as of the first quarter of F2023, it has reached approximately $1.02 billion worth of Indigenous direct procurement, which exceeds its goal of $1 billion.[1800] Approximately 65 percent of the $1.02 billion is related to procurement opportunities related to the Site C project, leaving approximately $380 million related to non-Site C work that has been awarded to other Indigenous Nations.[1801] Although BC Hydro has met its target, it plans to continue providing economic opportunities through procurement to Indigenous Nations in the province.[1802]

With respect to its diesel reduction strategy in the NIA, BC Hydro is developing a strategy to pursue new renewable generation opportunities in remote communities. It is working with governments, clean energy industry partners and with Indigenous communities to identify and pursue mutually beneficial projects.[1803]

With respect to Indigenous employment at BC Hydro, it is currently at 4 percent, which exceeds the 3.6 percent of Indigenous representation in the available workforce in B.C. BC Hydro targets representation of 5 percent by F2026, which is a 25 percent increase of its current representation.[1804] In addition, BC Hydro has been making efforts to increase the presence of Indigenous peoples in leadership positions, as well as supporting Indigenous employment through its contractors.[1805]

With respect to Indigenous awareness training, the foundation of BC Hydro's approach to working with Indigenous communities is BC Hydro's Statement of Indigenous Principles, which is a set of 10 principles designed to support BC Hydro's move towards true and lasting reconciliation with all Indigenous Nations in B.C.

[1799] 2022-09-21 Oral Hearing Transcript, Volume 3PM, p. 775, lines 3 to 12.
[1800] 2022-09-21 Oral Hearing Transcript, Volume 3AM, p. 618, lines 17 to 25; p. 620, lines 17 to 24.
[1801] 2022-09-21 Oral Hearing Transcript, Volume 3PM, p. 695, line 19 to 24.
[1802] 2022-09-21 Oral Hearing Transcript, Volume 3AM, p. 621, lines 4 to 9.

[1803] Exhibit B-2, pp. 5-31– 5-32.
[1804] Exhibit B-8, NTC IR 4.2.
[1805] 2022-09-21 Oral Hearing Transcript, Volume 3 AM, p. 624,lLines 1 to 17; 2022-09-21 Oral Hearing Transcript Volume 3 PM, p. 749, line 10 to p. 751, line 3.

To help employees understand how to apply these principles, BC Hydro launched its Indigenous Awareness 101 and 201 courses with more than 2100 and 1300 employees completing each course, respectively.[1806]

BC Hydro has achieved four gold levels since 2012 after initially achieving silver in 2009 in the Progressive Aboriginal Relations (PAR) Certification program. PAR is a certification program that provides independent third-party verification of corporate performance in Indigenous relations in four categories: leadership actions, employment, business development, and community relationships.[1807]

In addition, to date BC Hydro has entered into 13 Relationship Agreements, three historic grievance settlements, and other opportunities related to procurement and employment.[1808] The purpose of the Relationship Agreements is to build mutually respectful relationships. The agreements set out how BC Hydro and Indigenous Nations will work together, their priorities, and how to effectively engage with the Nations on BC Hydro's work.[1809] BC Hydro's Relationship Agreements are with Indigenous Nations in areas where BC Hydro has a significant infrastructure presence.[1810]

With respect to its diesel reduction strategy in the NIA, BC Hydro is developing a strategy to pursue new renewable generation opportunities in remote communities. It is working with governments, clean energy industry partners and with Indigenous Communities to identify and pursue mutually beneficial projects.[1811]

Positions of Parties

BC Hydro submits that its planned operating cost and FTE increases in the Test Period are necessary to support the development and implementation of its UNDRIP implementation plan. Implementing the principles of UNDRIP in BC Hydro's business is a long-term effort and the work will continue beyond the Test Period and its Five-Year Strategy.[1812]

Regarding its NIA Diesel Reduction Strategy, BC Hydro submits that its work on the related activities is progressing, and that work is also underway on documenting a Diesel Reduction Strategy. BC Hydro submits that it is actively engaged with many of the 14 NIA communities regarding their community needs. BC Hydro also notes that in the proceeding to review its 2021 Integrated Resource Plan, it has committed to providing a submission to the BCUC that sets out a proposal for a modified framework for the regulatory review of resource plans for the NIAs.[1813]

Zone II RPG and NTC are the only interveners to provide their positions on this topic in final argument.

Zone II RPG

Zone II RPG supports the $5.6M incremental spending with respect to UNDRIP but submits that it may not be sufficient. It also requests the BCUC direct BC Hydro to report annually on activities, performance metrics, and expenditures associated with UNDRIP implementation.[1814]

[1806] Exhibit B-2, p. 1-8.
[1807] 2022-09-21 Oral Hearing Transcript Volume 3 PM, p. 774, lines 5 to 21; Exhibit B-44, Cover Letter, p. 2; Exhibit B-8, Zone II RPG IR 20.2.2.
[1808] Exhibit B-2-1, Appendix D, p. 17.
[1809] 2022-09-21 Oral Hearing Transcript Volume 3 AM, p. 647, line 20 to p. 648, line 6.
[1810] Exhibit B-8, NTC IR 9.2.
[1811] Exhibit B-2, p. 5-32.
[1812] BC Hydro Final Argument, p. 95.
[1813] BC Hydro Final Argument, p. 94.
[1814] Zone II RPG Final Argument, pp. 10 – 14.

In reply, BC Hydro submits that there is no need for the direction sought by Zone II RPG because BC Hydro intends to report on its UNDRIP implementation plan on an annual basis. Further, BC Hydro submits that the BCUC should avoid providing directions as to how it should advance reconciliation and implement the principles of UNDRIP in its business, particularly in the context of an RRA. Consultation on the draft UNDRIP implementation plan is the appropriate venue for BC Hydro to consider suggestions of this nature.[1815]

Zone II RPG supports the $2.7M incremental spending in operating costs regarding BC Hydro's diesel reduction strategy, but raises concerns with missed opportunities in the interim, work not being done in a timely manner, and lack of information on forthcoming diesel reduction measures.[1816] Zone II RPG also notes BC Hydro provides little in terms of its efforts to reduce diesel reduction in the NIA. It recommends BC Hydro include detailed information on the development and implementation of the NIA Diesel Reduction Strategy, including specific action items, deadlines and measurable targets and expenditures as well as summaries of consultation with Indigenous Nations.[1817]

In reply, BC Hydro submits that Zone II RPG's comments are more appropriately addressed in a future regulatory process and notes that it has committed in the IRP proceeding to file a submission by spring 2023, setting out a proposal for a modified framework for the regulatory review of long-term resource plans for the NIA. BC Hydro submits that the future regulatory process established to review long-term resource plans for the NIA is the appropriate forum for further consideration of BC Hydro's Diesel Reduction Strategy in the NIA. Further, BC Hydro agrees with Zone II RPG's submission that targets for the NIA Diesel Reduction Strategy should be developed through external engagement with NIA's Indigenous communities. BC Hydro submits that it meets weekly with Tsay Keh Dene Nation on the co-development of a clean energy project, and BC Hydro and Kwadacha Nation have been working to advance clean energy opportunities in the community.[1818]

Zone II RPG encourages BC Hydro, in conjunction with the Low Income Advisory Council (LIAC) to consider new affordability metrics in its next test period that better measure affordability for all BC Hydro customers, including those in the NIA, based on local circumstances.[1819] It submits that if BC Hydro were to adopt affordability metrics that reflect the true impact of rate increases in B.C., BC Hydro would improve regulatory oversight and the transparency of future rate applications.[1820]

In reply, BC Hydro states that it is open to and interested in considering any opportunities to measure affordability in the NIA, and submits that the LIAC will remain the key avenue to advance the work on metrics for affordability.[1821]

<u>NTC</u>

NTC submits that BC Hydro's approach to UNDRIP and reconciliation is "very disjointed,"[1822] and that there are limited economic/procurement opportunities for Indigenous Nations from the ongoing operation and maintenance of the BC Hydro system. NTC submits that "non-Section 35 [of the *Constitution Act*] reconciliation and UNDRIP should provide economic opportunities irrespective of BC Hydro's existing or new infrastructure footprint in the territory of a First Nation."[1823] NTC requests BC Hydro be directed to co-develop non-section 35 rights economic opportunities with First Nations and to publicly track the "Cumulative Dollar Value Metric" to

[1815] BC Hydro Reply Argument, p. 56.
[1816] Zone II RPG Final Argument, pp. 2, 7, 9 – 10.
[1817] Zone II Final Argument, para. 28-30, p. 9.
[1818] BC Hydro Reply Argument, p. 54.
[1819] Zone II RPG Final Argument, p. 2; para. 44, pp. 14–15.
[1820] Zone II RPG Final Argument, para. 44, pp. 14–15.
[1821] BC Hydro Reply, Part 5, Section I, para. 154, pp. 54–55.
[1822] NTC Final Argument, p. 2.
[1823] NTC Final Argument, p. 6.

show the section 35 and non-section 35 economic opportunities separately, and annually as well as cumulatively. NTC also requests the BCUC direct BC Hydro to "correct" the way Indigenous procurements are recorded because the cumulative dollar value of contracts does not accurately reflect the First Nation's share of the economic benefits of the contracts.[1824]

In reply, BC Hydro submits that the intent of its UNDRIP implementation plan is to consolidate its goals with respect to reconciliation and UNDRIP.[1825] BC Hydro also submits that its reconciliation with First Nations cannot be separated from the impacts of its business on First Nations, nor can reconciliation be separated from consultation and section 35 of the *Constitution Act*. BC Hydro argues that to advance reconciliation, it must do more with those First Nations on whom its business has had a disproportionate impact. However, BC Hydro submits that it also meets with First Nations and/or Indigenous groups with whom it does not have Relationship Agreements. It further submits that it is in the process of seeking feedback on its draft UNDRIP implementation plan through province-wide engagement and that consultation on the draft plan is the appropriate venue to consider suggestions such as NTC's.[1826]

Regarding NTC's request for a BCUC direction to BC Hydro to "correct" the reporting of its Indigenous procurement metric. BC Hydro submits that NTC's suggested change is neither possible, nor necessarily supported by some First Nations. It submits that it cannot report on what it does not know and requiring disclosure of the economic benefits First Nations receive from their contracts with BC Hydro would be contrary to the stated interests of First Nations.[1827]

NTC requests the BCUC to make public copies of all Relationship, Impact Benefit and like agreements.[1828]

In reply, BC Hydro submits that the NTC's request should be rejected because no sound rationale has been provided for why NTC needs this information. Also, disclosure of such information could violate confidentiality provisions and risks damaging its relationships with First Nations and could undermine its efforts to renew or enter into new Relationship Agreements. BC Hydro submits that it would be unfair to the affected First Nations, who have not been provided the opportunity to make submissions on the matter.[1829]

NTC requests BC Hydro be directed to consolidate, rewrite, and expand the Statement of Indigenous Principles as described in Sections 2.1 to 2.6 of NTC's Final Argument.[1830]

In reply, BC Hydro submits that the BCUC should not accede to NTC's request because it would extend beyond the BCUC's jurisdiction and into the role of management. Further, a direction is not required as BC Hydro is already seeking feedback on its Statement of Indigenous Principles, which is referenced in BC Hydro's draft UNDRIP implementation plan. BC Hydro submits that it will consider the feedback when determining potential changes to its Statement of Indigenous Principles and its UNDRIP implementation plan.[1831]

NTC suggests that the indefinite suspension of the Standing Offer Program and renewals of First Nations-related EPAs conflicts with reconciliation. In this regard, NTC requests BC Hydro be directed to co-develop with First Nations the answers to the following questions:[1832]

1. What economic opportunities are available to First Nations as part of reconciliation and UNDRIP including in this instance section 35 Rights?
2. Who makes the decisions and on what basis?

[1824] NTC Final Argument, p. 13.
[1825] BC Hydro Reply Argument, p. 57.
[1826] BC Hydro Reply Argument, pp. 57 – 59.
[1827] BC Hydro Reply Argument, p. 61.
[1828] NTC Final Argument, p. 15.
[1829] BC Hydro Reply Argument, pp. 61 – 63.
[1830] NTC Final Argument, p. 9.
[1831] BC Hydro Reply Argument, p. 59.
[1832] NTC Final Argument, pp. 17 – 18.

3. Are the decisions reviewable and by whom?

In reply, BC Hydro submits that the BCUC should decline making such direction because these are primarily legal questions, and it is open to NTC to seek legal advice on its questions. Further, BC Hydro submits that the Government of B.C. has committed to engage with Indigenous Nations to explore how the indefinite suspension of the Standing Offer Program may affect individual Nations' economic interests and to explore alternate opportunities to meet those interests.[1833]

NTC requests BC Hydro be directed to co-develop with First Nations a set of terms and conditions for the acquisition of vegetation management services.[1834]

In reply, BC Hydro submits NTC's requested direction would exceed the BCUC's jurisdiction by extending into the management of the utility. Providing First Nations contracting opportunities is part of BC Hydro's efforts to advance reconciliation and those opportunities are provided on a commercial basis.[1835]

NTC submits that if reconciliation and UNDRIP become enshrined in PBR, the ability of the BCUC to objectively measure and assess BC Hydro's progress must be made abundantly clear and the progress be publicly reported on an annual basis.[1836]

Panel Determination

The topic of UNDRIP and reconciliation was canvassed during the oral hearing. With respect to the various recommendations and requests for BCUC directions made by Zone II RPG and NTC as summarized above, we make the following findings:

<u>Zone II RPG</u>

Request for a BCUC direction to BC Hydro to report annually on activities, performance metrics, and expenditures associated with UNDRIP implementation:

We note BC Hydro's submission that it is developing an UNDRIP implementation plan. Further, BC Hydro submits that the BCUC should avoid providing directions as to how it should advance reconciliation and implement the principles of UNDRIP in its business, particularly in the context of an RRA, and that consultation on the draft UNDRIP implementation plan is the appropriate venue for BC Hydro to consider suggestions of this nature. At the same time, however, BC Hydro has indicated that it intends to report on its UNDRIP implementation plan on an annual basis. In light of that commitment, we see no reason not to direct BC Hydro to provide annual reporting on its progress on the UNDRIP implementation plan. Accordingly, **the Panel directs BC Hydro to include as part of its Annual Report filing to the BCUC a report on its progress on its UNDRIP implementation plan.** In doing so, we acknowledge that we are not prescribing the framework of that report, which may be crafted as BC Hydro sees fit, nor directing it to undertake specific activities in pursuit of its UNDRIP implementation. We view such matters are properly within the purview of BC Hydro's management rather than that of the BCUC.

Recommendation that BC Hydro include detailed information on the development and implementation of the NIA Diesel Reduction Strategy, including specific action items, deadlines and measurable targets and expenditures as well as summaries of consultation with Indigenous Nations:

We note that there is not much divergence between the submissions of Zone II RPG and those of BC Hydro about the need to advance its work on the NIA Diesel Reduction Strategy. We also note that BC Hydro committed during the IRP proceeding to file a submission by spring 2023 that sets out a proposal for a modified

[1833] BC Hydro Reply Argument, p. 64.
[1834] NTC Final Argument, p. 21.
[1835] BC Hydro Reply Argument, p. 65.
[1836] NTC Final Argument, p. 3.

framework for the regulatory review of long-term resource plans for the NIA. While BC Hydro states that a separate regulatory proceeding is the appropriate forum for further consideration of that strategy along with Zone II RPG's comments, it agrees with the latter's submission that targets for the strategy should be developed through external engagement with NIA Indigenous communities. It also acknowledges it already meets weekly with Tsay Keh Dene Nation on the co-development of a clean energy project, and along with the Kwadacha Nation, it has been working to advance clean energy opportunities in the community.[1837] In light of these acknowledgements, **the Panel directs BC Hydro to file its long term resource plan for the NIA by March 31, 2024 and to include as part of that plan details of its NIA Diesel Reduction Strategy including proposed performance metrics for review and approval by the BCUC.**

Encouragement to BC Hydro, in conjunction with the Low Income Advisory Council (LIAC) to consider new affordability metrics in its next test period that better measure affordability for all BC Hydro customers, including NIA customers, based on local circumstances:

The Panel is satisfied with BC Hydro's response that it is open to and interested in considering any opportunities to measure affordability in the NIA, and agrees that the LIAC will remain the key avenue to advance the work on development of affordability metrics.[1838]

Lastly, the Panel notes that Zone II RPG supports BC Hydro's $5.6M incremental spending with respect to UNDRIP during the Test Period despite the intervener's concerns that the amount may not be sufficient, along with the $2.7M incremental operating costs regarding BC Hydro's NIA Diesel Reduction Strategy. The Panel finds those operating costs to be reasonable for the Test Period given the need for BC Hydro to control its costs in the current economic environment. The Panel notes that Zone II RPG has not proposed any additional expenditures that it considers necessary for BC Hydro to incorporate for its UNDRIP implementation plan or the NIA Diesel Reduction Strategy.

We now review NTC's recommendations and requests for BCUC directions in respect of UNDRIP and reconciliation.

NTC

Direction to BC Hydro to co-develop non section 35 rights economic opportunities with First Nations [under the Constitution Act 1984] and to publicly track the "Cumulative Dollar Value Metric" to show the section 35 and non-section 35 economic opportunities separately, and annually as well as cumulatively, along with a direction to BC Hydro to "correct" the way Indigenous procurements are recorded because the cumulative dollar value of contracts does not accurately reflect the First Nation's share of the economic benefits of the contracts.

The Panel rejects NTC's first request. We do not consider it appropriate to direct BC Hydro to provide economic opportunities to specific groups or individuals as that is a matter that is within management's prerogative, not that of the BCUC. Furthermore, it is not evident how one can segregate section 35 rights with non-section 35 rights (whatever these may be) and attribute specific economic opportunities to one or the other in a meaningful manner, nor has NTC provided any evidence to that effect in this proceeding. Neither BC Hydro nor NTC has proposed any specific expenditures that may be required to support the development of these opportunities. Accordingly, we see little merit to requiring the tracking of such opportunities. Moreover, we accept BC Hydro's submission that reconciliation cannot be separated from consultation and section 35 of the *Constitution Act 1984.*

With respect to the second direction sought by NTC, we accept BC Hydro's submission that the suggested change is neither possible, nor necessarily supported by all First Nations. BC Hydro cannot report on what it does not know and requiring disclosure of the economic benefits First Nations receive from their contracts with BC Hydro, without the consent of the First Nations in question, would be inappropriate and may be contrary to their interests.

[1837] BC Hydro Reply Argument, p. 54.
[1838] BC Hydro Reply, Part 5, Section I, para. 154, pp. 54–55.

Request for the BCUC to make public copies of all Relationship, Impact Benefit and like agreements:

The Panel rejects this request. The BCUC has not required BC Hydro to file copies of all of its Relationship, Impact Benefit and like agreements with the BCUC to date, and we do not consider it necessary or appropriate for BC Hydro to do so without the consent of those specific First Nations who are counterparties to these agreements. If NTC wants to request copies of these agreements directly from BC Hydro or the relevant First Nations, it is at liberty to do so at any time, and the BCUC need not be involved in that process. Furthermore, NTC has not provided any sound rationale as to why NTC needs this information. We accept that disclosure of such information could violate confidentiality provisions and risks damaging BC Hydro's relationships with First Nations and could undermine its efforts to renew or enter into new or similar agreements. Lastly, we agree with BC Hydro that it would be unfair to the affected First Nations, who have not been provided the opportunity to make submissions on the matter, to require such disclosure.

Direction to BC Hydro to consolidate, rewrite, and expand the Statement of Indigenous Principles as described in sections 2.1 to 2.6 of NTC's Final Argument:

We reject this request on the basis that such direction would encroach beyond utility regulation into general business management. Further, we agree with BC Hydro that such a direction is not required as it is already seeking feedback on its Statement of Indigenous Principles which it will consider when determining potential changes to that statement and its UNDRIP implementation plan. We see no reason to doubt that commitment on the part of BC Hydro and encourage NTC to provide its feedback directly to BC Hydro.

In conjunction with a direction to BC Hydro to co-develop with First Nations a set of terms and conditions for the acquisition of vegetation management services, a direction to co-develop with First Nations the answers to the following questions:

1. *What economic opportunities are available to First Nations as part of reconciliation and UNDRIP including in this instance section 35 Rights?*
2. *Who makes the decisions and on what basis?*
3. *Are the decisions reviewable and by whom?*

For the same reason as our rejection of NTC's request above, we find that such directions reach beyond the jurisdiction and authority of the BCUC as regulator and encroach onto the prerogative of BC Hydro management. Furthermore, notwithstanding the motives for doing so, it is not the role of the BCUC to direct BC Hydro to provide economic opportunities to specific groups or individuals or to stray from its procurement policies as established by management. As BC Hydro notes, providing First Nations contracting opportunities is part of its efforts to advance reconciliation and those opportunities are provided on a commercial basis. In short, this precludes BC Hydro from preferring or discriminating against specific service providers.

If reconciliation and UNDRIP become enshrined in PBR, the ability of the BCUC to objectively measure and assess BC Hydro's progress must be made abundantly clear and the progress be publicly reported on an annual basis:

As the elements of the PBR proposal to be filed by BC Hydro will be reviewed by another panel yet to be appointed, we find it premature and inappropriate to opine on whether reconciliation and UNDRIP must be enshrined in any such proposal. To the extent that these matters are mandated by law, we expect BC Hydro to comply with all legal requirements applicable to its operations and the provision of its services. We also expect that to the extent BC Hydro chooses to enshrine reconciliation and UNDRIP in its PBR proposal, it would also incorporate appropriate metrics to measure its annual progress towards achieving those goals to justify any related expenditures.

5.5 Confidentiality Request

BC Hydro requests that certain information in the Application be held on a confidential basis primarily because (i) aspects relate to matters deemed to be confidential by the BCUC's Rules of Practice and Procedure, and (ii) the remainder is security-sensitive information relating to the protection of critical infrastructure, the release of which could compromise the safety and reliability of the BES by exposing it to malicious attacks.[1839]

By Order G-263-21, the BCUC granted BC Hydro's request to hold certain information in the Application confidential until further notice. During the course of the proceeding, BC Hydro filed additional confidential information onto the evidentiary record.

Panel Determination

The Panel approves BC Hydro's request to hold confidential the information filed confidentially during the course of the proceeding. The information will be held confidential until further order of the BCUC. The Panel directs BC Hydro to suggest in its Compliance Filing a reasonable time limit on confidentiality and the rationale therefor.

6.0 Summary of Directives

This summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page No.
1.	The Panel approves the requested rates, subject to the adjustments resulting from the corrections identified by BC Hydro in the proceeding, the determinations and directives contained in this Decision, and any future determinations and directives made by the Panel with respect to the following two topics as noted in Section 1.3 of this Decision: • BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA; and • BC Hydro's finance charges.	9
2.	The Panel directs that the requested general rate increases, OATT rates, and DARR for F2023 and F2024 approved by the BCUC on an interim basis by Order G-47-22 and Order G-60-23, respectively, remain unchanged until further order of the Panel.	10
3.	BC Hydro is directed to re-calculate its revenue requirements in a compliance filing based on the corrections it identified in the proceeding, the Panel's determinations in this Decision, and any future Panel determinations and directives issued in the proceeding (Compliance Filing). The Compliance Filing is to be filed with the BCUC within 30 days of	10

[1839] Exhibit B-2-1, Appendix B, Recital C, pp. 4 – 5.

	Directive	Page No.
	the issuance of an order approving the Test Period rates on a permanent basis. BC Hydro is directed to include in its Compliance Filing, a revised Appendix A to the Application and updated rate schedules, reflecting the corrections identified by BC Hydro in the proceeding, the BCUC's Decision and accompanying Order, and the future order approving Test Period rates on a permanent basis.	
4.	Considering that Direction No. 8 only prescribes BC Hydro's net income up to and including F2025, the Panel directs BC Hydro to file a cost of capital application, effective April 1, 2025, by no later than April 1, 2024.	10
5.	The Panel directs BC Hydro to deduct from its revenue requirement the $2.1 million in forecast labour costs for incremental FTEs associated with Connecting Customers in delivering the Electrification Plan. The Panel directs BC Hydro to record its actual operating labour costs associated with Connecting Customers pursuant to the Electrification Plan in a new regulatory account, accruing interest at BC Hydro's current weighted average cost of debt, to a maximum of $2.1 million for the period F2023 to F2025, with the amortization and disposition of this account to be decided by a future BCUC panel.	18
6.	The Panel directs BC Hydro to report on the following aspects of the Electrification Plan in its next RRA: • A count of completed customer interconnection studies by rate schedule and the extent to which the subject customers of those completed studies actually connected new electrical loads. • The actual expenditures, the electricity load increase, and the carbon emission reduction results, for each year of the Test Period and for each component of the Electrification Plan. This must include a clear delineation between government and BC Hydro expenditures and results where dual funding sources are combined. The results should be informed by measurement and verification studies for a sample of the projects, where possible. • Forecast expenditures, electricity load increase and carbon emission reduction results, as a point of comparison against actuals in the previous bullet. • Revenue versus cost impact analysis within this Test Period, as a basis for informing cost-effectiveness assessments for programming that may extend past	19

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	the duration of the Electrification Plan Direction (i.e., in F2027 and beyond). • Forecast and actual revenue requirement and rate impacts of the Electrification Plan.	
7.	The Panel directs BC Hydro to integrate all future electrification forecasts into its normal load forecasting efforts with its established and evolving methodology as a means of reducing the possibility of duplication.	27
8.	The Panel directs BC Hydro to continue producing both the binary and probability-weighted methods for forecasting industrial loads and to report on the results including a comprehensive load forecast in the next RRA.	29
9.	The Panel directs BC Hydro to remove 783 GWh of forecast [Electrification Plan] load in F2025 and to remove the related forecast loads in F2023 and F2024. The Panel also directs BC Hydro to remove the cost of energy forecast to serve these loads from the Test Period revenue requirements.	35
10.	The Panel directs BC Hydro to update, in its Compliance Filing, the F2023 to F2025 revenue requirements with the costs related to the Island Generation EPA.	41
11.	BC Hydro uses the Energy Studies Manager decision support tool when making short term operational decisions and the Panel understands the following improvements are planned from F2022 to F2027: • Increase Automation of the Energy Studies Manager: Efficiency Improvements; and • Improve Data Transfer management in the Energy Studies Manager. BC Hydro is directed to include the impact of these improvements on its short term	45

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	decision making in the next RRA.	
12.	BC Hydro is directed in its next RRA to provide a progress report on its commitment to increase its capabilities to understand and model increases in the intensity and frequency of extreme weather events, and report on any consequent modifications to the Energy Studies models.	45
13.	BC Hydro is directed, in its next RRA filing, to report on the materiality and effects on CNRO of including 2020 TPA price and volume terms in the Energy Studies models.	47
14.	The Panel directs BC Hydro to file, in its next RRA, an analysis of the variance in cost of energy for the past five years, including the controllability of the circumstances leading to those variances and whether all the items deferred to the Cost of Energy variance accounts should continue to receive variance account treatment and if so under what circumstances.	51
15.	The Panel directs BC Hydro, as part of its Compliance Filing, to deduct $3.9 million from its original budget of MRS operating costs over the Test Period related to the implementation of the new Planning Coordinator function.	67
16.	The Panel directs BC Hydro to include results on the distribution forced outages due to vegetation in both percentage terms and actual hours in future RRAs.	74
17.	The Panel directs BC Hydro to provide information in the next RRA with respect to the performance of the Vegetation Management Strategy when measured against the metrics set out in Table 5-31 of the Application.	74

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18.	The Panel directs BC Hydro to file a report of actual cybersecurity costs incurred and FTEs deployed during the Test Period, with a detailed breakdown referencing the specific recommendations in its confidential Cyber Threat and Risk Assessment and the projects in the Cyber Security Plan (CSP) where the costs were incurred, and FTEs deployed. BC Hydro must file this report with the BCUC, on a confidential basis if needed, within three months of the date of issuance of this Decision and thereafter, within three months of the end of each remaining fiscal year in the Test Period.	76

19.	The Panel directs BC Hydro to include the following information, separated by asset class, as part of its next RRA:
	
	• Mean life data set in Microsoft Excel format; and
	• Asset age demographics and Asset condition demographics as follows:
	    o For all Appendix M Asset Classes – Data equivalent to the table of “Transmission Wood Pole Structures Asset Health” (Table 28) with an additional column for “Number of Assets” which is shown in the associated Figure 5 of Appendix M; and
	    o For all Appendix L Asset Classes – Graphical data in a Microsoft Excel format along with the Asset Ages. BC Hydro can choose if it wants to continue to also provide its current visual representation of the data.
		102

20.	The Panel directs BC Hydro to file in its Compliance Filing a proposal for how best to implement RCIA’s recommendations for incorporating both pre-capital investment risk scores and post-capital investment risk scores into Appendices I & J and the timing for same in future RRAs.	102
21.	The Panel directs BC Hydro to report on the NIA customer satisfaction index on reliability as part of its next RRA.	109
22.	The Panel directs BC Hydro to include in its next depreciation study consideration of its operational records of asset retirements and asset mean lives to estimate or verify the	122

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	average service lives of its assets.	
23.	The Panel directs BC Hydro to consider a more expansive set of peer comparisons in its next depreciation study, and to endeavour to use peers for which publicly available data can be provided and detailed comparisons made.	126
24.	The Panel directs BC Hydro to provide more comprehensive explanations of recommended changes to average service lives in its next depreciation study.	129
25.	The Panel approves the positive salvage percentages as set out in the Depreciation Study.	139
26.	The Panel approves the adoption of changes to vehicle asset classes as set out in the Depreciation Study.	140
27.	The Panel approves the creation of a new asset class for EV charging station assets and the average service life, as recommended by Concentric.	142
28.	The Panel determines that the appropriate average service life for depreciation purposes for account C25203, "Tower, Lattice / Aesthetic" should be increased from 65 to 75 years, and not remain unchanged as proposed by Concentric.	148
29.	The Panel determines that the appropriate average service life for depreciation purposes for account C25202, "Pole Structures > or = 60Kv" should remain at 50 years, as proposed by Concentric.	152

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30.	The Panel determines that the appropriate average service life for depreciation purposes for account C55101, “Conductor, Overhead > or = 60kV” should be reduced from 60 to 55 years, as proposed by Concentric.	156
31.	The Panel determines that the appropriate average service life for depreciation purposes for account C55102, “Conductor, Overhead < 60 kV” should be increased from 45 to 50 years, as proposed by Concentric.	159
32.	The Panel determines that the appropriate average service life for depreciation purposes for account C55303, “Cable, Submarine > or = 60 kV” should remain at 45 years, as proposed by Concentric.	163
33.	The Panel directs BC Hydro to explain in its Compliance Filing why the submarine HVDC assets that have been “decommissioned but have not been removed or fully retired” (and also related substation and other assets) have not been removed from rate base.	164
34.	The Panel determines that the appropriate average service life for depreciation purposes for account C55304, “Cable, Submarine < 60 kV” should remain at 35 years, and not be reduced to 30 years as proposed by Concentric.	164
35.	The Panel determines that the appropriate average service life for depreciation purposes for account C55301, “Cable, Underground < 60 kV” should remain at 40 years, as proposed by Concentric.	166

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36.	The Panel determines that the appropriate average service life for depreciation purposes for account C55302, "Cable, Underground > or = 60 kV" should remain at 40 years, as proposed by Concentric.	166
37.	The Panel determines that the appropriate average service lives for depreciation purposes for accounts C52101, 52102, 52103, 52104, 52105 and C52501, 52502, 52503, 52504, 52505 should remain unchanged, as proposed by Concentric.	171
38.	The Panel determines that the average service live for depreciation purposes for account C52106, "Transformer, Power, Comp Pool" should remain at 45 years, and not reduced to 40 years as proposed by Concentric.	172
39.	The Panel determines that the appropriate average service lives for depreciation purposes for accounts C54101, 54103, 54104, 54105 should remain unchanged, as proposed by Concentric.	175
40.	The Panel determines that the appropriate average service life for depreciation purposes for account C54102 should increase from 30 to 35 years, as proposed by Concentric.	176
41.	The Panel determines that the appropriate average service life for depreciation purposes for account C55401, "Buswork & Station Conductor" should remain at 60 years, rather than reduced to 55 years as proposed by Concentric.	178
42.	The Panel determines that the appropriate average service life for depreciation purposes for account C21001, "Dam, Embankment / Concrete" should remain at 100 years, as	183

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	proposed by Concentric.	
43.	The Panel determines that the appropriate average service life for depreciation purposes for account C22003, “Powerhouse, Integral With Dam” should remain at 100 years, as proposed by Concentric.	184
44.	The Panel directs BC Hydro to provide, in its next depreciation study, a more comprehensive analysis of the age of its current dams and of the dams it has decommissioned.	184
45.	The Panel determines that the appropriate average service life for depreciation purposes for account C41002, “Governor System, Turbine” should remain at 50 years, and not increase to 55 years as proposed by Concentric.	189
46.	The Panel determines that the appropriate average service life for depreciation purposes for accounts C41001 and C41007 and C42001 should increase by 5 years, as proposed by Concentric, and the appropriate average service life for depreciation purposes for accounts C41003, C41004, C41005, C41006, C41008, C42002, C42003, C42004 should remain unchanged, also as proposed by Concentric.	189
47.	The Panel determines that the appropriate average service life for depreciation purposes for account C23604, “Gate” should increase from 40 years to 45 years, as proposed by Concentric.	192
48.	The Panel determines that the appropriate average service life for depreciation purposes for account C80302, “Software, Enterprise Systems” should remain at 10 years, as	195

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	proposed by Concentric.	
49.	The Panel directs BC Hydro to file with the BCUC as a compliance filing, within 3 months of the date of this Decision, an analysis of the following: • The feasibility, effort and cost of reconstructing BC Hydro's historical asset retirement data prior to 2011. • The value of using reconstructed historical asset retirement data compared to using BC Hydro's operational records of asset retirements and their mean lives to estimate or verify the average service lives of its assets.	197
50.	The Panel directs BC Hydro to submit an analysis on the use of group accounting by December 31, 2023.	199
51.	The Panel approves BC Hydro's use of the traditional method of accounting for net salvage.	215
52.	The Panel directs BC Hydro to address in its next RRA whether collecting interest on collected net salvage amounts to offset the impact of inflation is just and reasonable.	217
53.	The Panel approves the net salvage rates proposed by BC Hydro, contained in the Concentric report in Exhibit B-2, Appendix T, pp. 28 to 33, for use in the next test period.	218
54.	The Panel directs BC Hydro, in its next depreciation study, to explain in detail why the recommended net salvage percentages differ from what would be suggested by the actual asset retirement evidence.	218
55.	The Panel approves BC Hydro's exclusion of specified asset classes from net salvage, as	220

<table>
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<tr><td></td><td>identified above in Table 61 of this Decision.</td><td></td></tr>
<tr><td>56.</td><td>The Panel approves BC Hydro’s request to implement net salvage rates effective F2026.</td><td>222</td></tr>
<tr><td>57.</td><td>The Panel directs BC Hydro to submit a proposal in its next RRA to explain how the net salvage rates should be phased in.</td><td>222</td></tr>
<tr><td>58.</td><td>The Panel approves for BC Hydro to defer the following actual costs to the MRS Costs Regulatory Account, commencing in F2023 and on an ongoing basis:

• Unplanned costs related to the implementation of new or revised MRS adopted as a result of a future Assessment Report filed with the BCUC where the BCUC’s adoption of such new or revised MRS occurred too late to be reflected in the forecast for the test period; and
• Unplanned costs, excluding assessed penalties, incurred in a test period to address possible non-compliance with MRS, if and as required, where the work related to such possible non-compliance was identified too late to be reflected in the forecast for the test period.

The Panel also approves BC Hydro to:

• Recover amounts deferred to the account in respect of completed fiscal years, including any under/over recovered balance from F2022, over the next test period, starting in F2026 and on an ongoing basis, subject to BCUC review and approval of these amounts; and
• Apply interest to the balance of the MRS Costs Regulatory Account based on BC Hydro’s weighted average cost of debt

The Panel does not approve BC Hydro’s request regarding the recovery of interest charges. Instead, the Panel authorizes BC Hydro to recover the actual interest charged to the account for amounts related to any completed fiscal years over the next test period, subject to BCUC review and approval of these amounts.</td><td>225</td></tr>
<tr><td>59.</td><td>The Panel directs BC Hydro to provide, in all future RRAs, the total actual MRS costs deferred, including supporting details, to enable the BCUC to determine the amount that</td><td>226</td></tr>
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	should be recovered from ratepayers.	
60.	The Panel approves BC Hydro to: • Commence recovery of the forecast balance of the Site C Regulatory Account as at December 31, 2024 over the forecast weighted average life of the Site C assets, commencing January 1, 2025. • On an ongoing basis commencing in the test period beginning in F2026, amortize the forecast balance in the Site C Regulatory Account at the end of the prior test period over the remaining weighted average useful life.	228
61.	The Panel directs BC Hydro to recalculate the forecast weighted average life of the Site C assets in its Compliance Filing based on any adjustments resulting from the determinations and directives contained in this Decision regarding the service lives of the Site C assets.	228
62.	The Panel denies BC Hydro’s request to recover the forecast March 31, 2022 balance of the EV Costs Regulatory Account over the Test Period and the request to recover any balance remaining at the end of the Test Period over the next test period.	231
63.	The Panel directs BC Hydro to: • Transfer the F2022 EV fast charging service revenue from the Load Variance Regulatory Account to the EV Costs Regulatory Account; • Remove the Test Period forecast revenue, including the Low Carbon Fuel Credits revenue, and costs related to its EV fast charging service, including finance costs associated with the EV fast charging capital assets, from the revenue requirement; • Commencing in F2023, and until directed otherwise by the BCUC, defer the actual revenue, including the Low Carbon Fuel Credits revenue, and costs related to its EV fast charging service, including finance costs associated with the EV fast charging capital assets, to the EV Costs Regulatory Account; and • Change the name of the EV Costs Regulatory Account to the EV Fast Charging Regulatory Account.	232

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64.	The Panel approves BC Hydro's request to continue to apply interest to the balance of the EV Costs Regulatory Account (or EV Fast Charging Regulatory Account) each year based on its current weighted average cost of debt. However, the Panel denies BC Hydro's request to recover the forecast interest charged to the account each year beginning in F2023.	232
65.	Pursuant to the Electrification Plan Direction, the Panel approves BC Hydro's requests related to the Load Attraction Costs Regulatory Account, as set-out in Section 7.3.1 Application, and approves BC Hydro's request to not change the recovery of the LCE Program component of the DSM Regulatory Account	241
66.	Purcsuant to the Electrification Plan Direction, the Panel authorizes BC Hydro to defer to the DSM Regulatory Account up to $193.7 million in costs incurred in F2022 to F2027 to provide the LCE Program.	241
67.	The Panel authorizes BC Hydro to amortize from the DSM Regulatory Account each fiscal year, the forecast annual LCE amortization amount, calculated on the assumption that the costs to provide its LCE Program for the fiscal year will be amortized over a period of 15 years.	241
68.	The Panel approves BC Hydro's requests related to the CCF Regulatory Account and the MCPP Regulatory Account, as set-out in Section 7.3.3.5 and Section 7.3.3.6 of the Application, respectively.	241
69.	Pursuant to the amended CCF Direction, the Panel authorizes BC Hydro to defer up to a maximum of $11 million to the CCF Regulatory Account for the amounts incurred by BC Hydro to administer the CCF Pilot Program and the grants provided to residential	242

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	customers under the CCF Pilot Program.	
70.	The Panel approves BC Hydro's requests related to the following regulatory accounts: • Dismantling Cost Regulatory Account, as set out in Section 7.3.2.2 of the Application; • Low Carbon Fuel Credits Regulatory Account, as set out in Section 7.3.3.1 of the Application; • Real Property Sales Regulatory Account, as set out in Section 7.3.3.7 of the Application; • Fiscal 2022 Depreciation Study Impact Regulatory Account, as set out in Section 7.3.3.2 of the Application, with the exception that BC Hydro is directed to recover the actual (instead of the forecast) F2022 ending balance of the account, based on the depreciation rates approved by the BCUC in this Decision, over the Test Period.	242
71.	With respect to the Fiscal 2022 Depreciation Study Impact Regulatory Account, the Panel directs BC Hydro to update the F2022 ending regulatory account balance with the actual balance in its Compliance Filing and to close the account once the account balance is zero.	242
72.	The Panel finds BC Hydro's proposed DSM expenditure schedule for the Test Period to be in the public interest, and accepts the DSM expenditure schedule of $89.5 million in F2023, $96.1 million in F2024 and $110.1 million in F2025 under section 44.2 of the UCA.	259
73.	The Panel accepts BC Hydro's Revised F2022 DSM Expenditure Schedule and finds it to be in the public interest, pursuant to section 44.2 of the UCA.	262
74.	The Panel directs BC Hydro to conduct an evaluation of the doubling of incentives in F2022 in its next DSM Expenditure Schedule, including analysis of the incremental electricity savings due to expanded incentives and the attribution of electricity savings from complementary measures such as additional incentives and tax policy by all levels of government. Within this evaluation, BC Hydro is directed to assess if the doubling of	262

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	incentives resulted in additional demand-side savings in energy and reduced load in a defined peak period. The assessment should include regional inflation in the cost of related products and services, changes in free riders and free drivers and impacts on market transformation.	
75.	The Panel directs BC Hydro to submit a proposal in its next RRA to update its DSM funding transfer rules to include provisions to address a funding shortfall in the final year of a DSM plan for no more than 5 percent, including a one-year DSM Expenditure Schedule, and any other changes to the DSM funding transfer rules it deems necessary.	262
76.	The Panel finds that the proposed OATT rates are just and reasonable and approves the OATT rates as applied for, subject to any adjustments resulting from the corrections identified by BC Hydro in the proceeding, the determinations and directives contained in this Decision, and any future determinations and directives made by the Panel with respect to the following two topics as noted in Section 1.3 of this Decision: • BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA; and • BC Hydro's finance charges.	268
77.	Commencing in F2025, the Panel directs BC Hydro to: • Recover the Test Period Trade Income forecast from a rate rider rather than through the general revenue requirement (i.e. a Trade Income Rate Rider or TIRR). • Recover or repay the TIDA balance from/to customers via the TIRR, instead of the DARR, over a 3-year amortization period, and limit the amortization of a deficit in the TIDA balance to the amount of forecast Trade Income that year. As a result, the TIRR rate rider will not be less than zero. • Set the TIRR annually at the beginning of each fiscal year based on the most recently available actual results. • File for approval of the TIRR annually in a filing separate from its RRA filings.	280

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78.	The Panel approves the F2023 and F2024 DARR, as applied for, subject to any adjustments resulting from the corrections identified by BC Hydro in the proceeding, the determinations and directives contained in this Decision, and any future determinations and directives made by the Panel with respect to the following two topics as noted in Section 1.3 of this Decision: • BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA; and • BC Hydro's finance charges.	286
79.	The Panel denies BC Hydro's requested DARR for F2025, instead commencing in F2025, the Panel directs BC Hydro to: • Set the DARR annually, using BC Hydro's proposed DARR table mechanism, at the beginning of each fiscal year, based on the most recently available actual net COE Variance Account balances without the TIDA balance. For example, commencing April 1, 2024, set the DARR based on the actual ending F2023 balances, with the same process to follow for each subsequent fiscal year; and • File for approval of the DARR annually in a filing separate from its RRA filings.	287
80.	The Panel determines that no changes to the DARR are required to reflect the actual ending fiscal 2022 balances and the $400 million transfer from the TIDA.	290
81.	The Panel rejects AMPC's request for a direction to establish a new temporary deferral account, transfer available funds from the TIDA to the deferral account, and refund these amounts to the Excluded Customers.	293
82.	The Panel directs BC Hydro to apply interest to the customer credit regulatory account and the inflationary pressures regulatory account based on its current weighted average cost of debt.	296

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83.	The Panel directs BC Hydro to establish a new regulatory account to capture the variances between the following, commencing in F2023: c) The revenue requirement impact of the Site C capital costs and costs deferred to the Site C Regulatory Account, based on the forecast costs approved for recovery in rates in this Decision, and d) The revenue requirement impact of the Site C capital costs and costs deferred to the Site C Regulatory Account approved for recovery in rates, as determined by the BCUC following any BCUC prudency review of the Site C project.	302
84.	The Panel directs BC Hydro to include as part of its Annual Report filing to the BCUC a report on its progress on its UNDRIP implementation plan.	308
85.	The Panel directs BC Hydro to file its long term resource plan for the NIA by March 31, 2024 and to include as part of that plan details of its NIA Diesel Reduction Strategy including proposed performance metrics for review and approval by the BCUC.	309
86.	The Panel approves BC Hydro's request to hold confidential the information filed confidentially during the course of the proceeding. The information will be held confidential until further order of the BCUC.	311
87.	The Panel directs BC Hydro to suggest in its Compliance Filing a reasonable time limit on confidentiality and the rationale therefor.	311

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of April 2023.

Original signed by:

D. M. Morton
Panel Chair / Commissioner

Original signed by:

A. K. Fung, KC
Commissioner

Original signed by:

R. I. Mason
Commissioner

Original signed by:

A. Pape-Salmon
Commissioner

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ORDER NUMBER
G-91-23

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority
Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

BEFORE:
D. M. Morton, Panel Chair
A. K. Fung, KC, Commissioner
R. I. Mason, Commissioner
A. Pape-Salmon, Commissioner

on April 21, 2023

ORDER

WHEREAS:

A. On August 31, 2021, the British Columbia Hydro and Power Authority (BC Hydro) filed its Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 44.2, and 58 to 61 of the *Utilities Commission Act* requesting, among other things, interim and, after certain future determinations in other proceedings, permanent approval of the following:

   (i) Increase in rates by 0.62 percent, effective April 1, 2022, by 0.97 percent, effective April 1, 2023 and by 2.18 percent, effective April 1, 2024; and

   (ii) The fiscal 2023, fiscal 2024, and fiscal 2025 Open Access Transmission Tariff (OATT) rates as set out in Table 9-4 of the Application;

B. In the Application, BC Hydro also requested to set the Deferral Account Rate Rider (DARR) on an interim and permanent basis at (2.0) percent, effective April 1, 2022 for fiscal 2023; and, on a permanent basis at (1.0) percent, effective April 1, 2023 for fiscal 2024 and (0.5) percent, effective April 1, 2024 for fiscal 2025;

C. On December 22, 2021, BC Hydro filed its demand side management (DSM) expenditure schedule for fiscal 2023 to fiscal 2025 and a revised DSM expenditure schedule for fiscal 2022;

D. On January 19, 2022, January 31, 2022, April 14, 2022 and August 8, 2022, BC Hydro filed errata to the Application;

E. BC Hydro requests that certain portions of the Application and certain information filed during the course of the proceeding be held confidential in accordance with Part IV of the BCUC's Rules of Practice and Procedure;

F. By Order G-263-21, the BCUC established the regulatory timetable for the review of the Application. By Orders G-72-22, G-136-22, G-166-22, G-189-22, G-239-22, G-284-22, G-344-22, G-386-22, and G-10-23, the BCUC subsequently furthered and amended the regulatory timetable;

G. By Order G-47-22, the BCUC approved, on an interim and refundable basis, the requested fiscal 2023 rate increase of 0.62 percent, the requested OATT rates, and the requested DARR, effective April 1, 2022. By Order G-60-23, the BCUC approved, on an interim and refundable basis, the requested fiscal 2024 rate increase of 0.97 percent, the requested OATT rates, and the requested DARR, effective April 1, 2023;

H. On November 18, 2022, the Lieutenant governor in Council approved Order in Council (OIC) No. 571, which enacted the Direction to the British Columbia Utilities Commission Respecting Residential and Commercial Customer Account Credits (Direction);

I. The Direction requires the BCUC to, among other things, order BC Hydro to provide bill credits to its residential and commercial customers, to FortisBC Inc., and to New Westminster. The Direction also requires the BCUC to issue orders so that BC Hydro may make certain changes to its regulatory accounts, including transfers from the Trade Income Deferral Account (TIDA) of $320 million, $6 million, and $74 million to a customer credit regulatory account, the Customer Crisis Fund regulatory account, and an inflationary pressures regulatory account, respectively. The BCUC issued Order G-341-22 in response to the Direction;

J. Subsequent to the enactment of the Direction and the issuance of Order G-341-22, and in accordance with Orders G-344-22, G-386-22, and G10-23, parties provided submissions regarding, among other things, the effect of the Direction and how the balances in the Cost of Energy Variance Accounts and in particular, the TIDA, should be recovered from or refunded to ratepayers;

K. By Order G-66-23, the BCUC reopened the evidentiary record to accommodate Panel IRs regarding BC Hydro's finance charges ;

L. On March 31, 2023, BC Hydro filed a letter with the BCUC seeking approval, as part of the proceeding to review the Application, to reinstate a $320 million regulatory liability in the TIDA, which would effectively offset the transfer from the TIDA to the customer credit regulatory account that occurred pursuant to the Direction and Order G-341-22;

M. By Order G-74-23, the BCUC established a regulatory timetable to allow an opportunity for parties' submissions with respect to BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA, with further process to be determined;

N. By Order G-90-23, the BCUC established a regulatory timetable to allow for Panel IR no. 3 regarding BC Hydro's finance charges, with further process to be determined; and

O. The BCUC has considered the Application and the evidence and submissions filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 44.2, 56, 58 to 61 and 89 of the UCA, and for the reasons outlined in the decision issued concurrently with this order, the BCUC orders as follows:

1. The following are approved subject to the adjustments resulting from the corrections to the Application identified in the errata filed in the proceeding, the determinations and directives contained in the decision issued concurrently with this order, and any future determinations and directives made by the BCUC with

respect to BC Hydro's request to reinstate a $320 million regulatory liability in the TIDA and BC Hydro's finance charges:

(i) The requested rate increases of 0.62 percent, 0.97 percent, and 2.18 percent as applied for in the Application, effective April 1, 2022, April 1, 2023, and April 1, 2024, respectively;

(ii) The requested OATT rates as set out in Appendix II, Table II-2 of the Application, effective April 1, 2022, April 1, 2023 and April 1, 2024, respectively;

(iii) The requested DARR of (2.0) percent, effective April 1, 2022 for fiscal 2023 and (1.0) percent, effective April 1, 2023 for fiscal 2024.

2. The request to set the DARR at (0.5) percent, effective April 1, 2024 for fiscal 2025 is denied. Commencing in fiscal 2025, BC Hydro is to set the DARR as directed in the decision issued concurrently with this order.

3. The requested rate increases, OATT rates, and the DARR for fiscal 2023 and fiscal 2024 approved by the BCUC on an interim basis by Order G-47-22 and Order G-60-23, respectively, will remain unchanged until further order of the BCUC.

4. With respect to the following requests related to deferral and regulatory accounts:

(i) Load Attraction Costs Regulatory Account

The request to establish a Load Attraction Costs Regulatory Account to defer actual load attraction operating costs to this account each year beginning in fiscal 2023 and ending in fiscal 2027 is approved. The interest applied to the balance of the account is to be based on BC Hydro's current weighted average cost of debt and the forecast interest charged to the account each year is to be amortized each year. The forecast annual operating cost amount in the account will be amortized into rates starting the fiscal year following the expenditures over the benefit period of 20 years. The forecast balance at the end of a test period related to the difference between the amortization of the forecast annual load attraction operating cost amount and the calculation of the amortization based on the actual annual load attraction operating cost amounts is to be recovered over the next test period. The forecast balance at the end of a test period related to the difference between the forecast interest recovered and the actual interest charged to the account during that test period is to be recovered over the next test period.

(ii) Mandatory Reliability Standards (MRS) Costs Regulatory Account

The request to defer the following actual unplanned MRS costs to the MRS Costs Regulatory Account, effective in fiscal 2023 and on an ongoing basis, is approved:

- Costs related to the implementation of new or revised MRS adopted as a result of a future assessment report filed with the BCUC where the BCUC's adoption of such new or revised MRS occurred too late to be reflected in the forecast for the test period; and
- Costs, excluding assessed penalties, incurred in a test period to address possible non-compliance with MRS, if and as required, where the work related to such possible non-compliances was identified too late to be reflected in the forecast for the test period.

BC Hydro will recover amounts deferred to the MRS Costs Regulatory Account in respect of completed fiscal years, including any under/over recovered balance from fiscal 2022, over the next test period, starting in fiscal 2026 and on an ongoing basis, subject to BCUC review and approval of these amounts. BC Hydro will apply interest to the balance of the account based on BC Hydro's weighted average cost of debt. BC Hydro will recover actual interest charged to the account for amounts related to any completed fiscal years over the next test period, subject to BCUC review and approval of these amounts.

(iii) Dismantling Cost Regulatory Account

The request to continue to defer any variances between forecast and actual dismantling costs in fiscal 2023 to fiscal 2025 to the Dismantling Cost Regulatory Account is approved. The interest applied to the balance of the account each year is to be based on BC Hydro's current weighted average cost of debt, and the forecast interest charged to the account each year is to be recovered from the account each year. The forecast account balance at the end of a test period is to be recovered over the next test period.

(iv) Low Carbon Fuel Credits Account

The request to recover the balance of the Low Carbon Fuel Credits Regulatory Account through the DARR mechanism is approved.

(v) Depreciation Study Impact Regulatory Account

The request to recover the forecast March 31, 2022 balance in the Depreciation Study Impact Regulatory Account over this test period is denied. BC Hydro will recover the actual March 31, 2022 balance in the Depreciation Study Impact Regulatory Account over this test period, based on the depreciation rates approved by the BCUC in the decision issued concurrently with this order. BC Hydro will apply interest to the balance of the account each year based on BC Hydro's current weighted average cost of debt. BC Hydro will recover the forecast interest charged to the account each year beginning in fiscal 2023. BC Hydro will update the fiscal 2022 ending balance of the account with the actual balance in its compliance filing and close the account once the account balance is zero.

(vi) Cost of Energy Variance Accounts

Until further order of the BCUC, the request to recover or refund the balances in the Cost of Energy Variance Accounts through the DARR using the DARR table mechanism as described in Chapter 7, section 7.3.3.3 is approved for fiscal 2023 and fiscal 2024. Specifically, in fiscal 2023 and fiscal 2024, the DARR percentage effective April 1 of a given year will be set 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. Until further order of the BCUC, the mechanism to recover or refund the balances in the Cost of Energy Variance Accounts, commencing in fiscal 2025, is as directed in the decision issued concurrently with this order.

(vii) Site C Regulatory Account

The request to commence recovery of the forecast balance in the Site C Regulatory Account as at December 31, 2024 on January 1, 2025 over the forecast weighted average life of the Site C assets is approved, subject to any adjustments to the forecast weighted average life of the Site C assets resulting from the determinations and directives contained in the decision issued concurrently with this order. The request to, on an ongoing basis beginning in fiscal 2026, amortize the forecast balance in the Site C Regulatory Account at the end of the prior test period over the remaining weighted average useful life is approved.

(viii) Customer Crisis Fund Regulatory Account

The request to recover the forecast March 31, 2022 balance for the COVID Relief Fund for Residential Customers in the Customer Crisis Fund Regulatory Account over this test period is approved. The interest applied to the balance of the account in each year is to be based on BC Hydro's current weighted average cost of debt. The forecast interest charged to the account attributable to the COVID Relief Fund for Residential Customers balance each year is to be recovered from the account each year beginning in fiscal 2023.

(ix) Mining Customer Payment Plan Regulatory Account

The request to recover the forecast March 31, 2022 balance for COVID-19 Relief measures for commercial customers in the Mining Customer Payment Plan Regulatory Account over this test period is approved. The interest applied to the balance of the account each year is to be based on BC Hydro's current weighted average cost of debt. The forecast interest charged to the account attributable to COVID-19 Relief measures for commercial customers each year is to be recovered from the account each year beginning in fiscal 2023.

(x) Real Property Sales Regulatory Account

The request to continue to defer actual net gains realized on the sale of properties to the Real Property Sales Regulatory Account is approved. The interest applied to the balance of the account will continue to be based on BC Hydro's current weighted average cost of debt. The remaining balance of the account at the end of this test period will be refunded or recovered from ratepayers over the next test period.

(xi) Electric Vehicle Costs Regulatory Account

The request to recover the forecast March 31, 2022 balance of the Electric Vehicle Costs Regulatory Account over this test period and recover any balance remaining at the end of this test period over the next test period is denied. The interest applied to the balance of the account each year is to be based on BC Hydro's current weighted average cost of debt. The request to recover from the account each year the forecast interest charged to the account each year beginning in fiscal 2023 is denied.

(xii) DSM Regulatory Account

The request to not change the recovery of the Low Carbon Electrification component of the DSM Regulatory Account is approved.

5. With respect to the following requests related to depreciation and net salvage rates:

   (i) The request to implement for ratemaking purposes the updated useful lives and positive salvage rates and changes in asset classes, effective fiscal 2022, as set out in Chapter 8, section 8.3, is approved, with the exception of certain useful lives as identified in the determinations and directives contained in the decision issued concurrently with this order.

   (ii) The request to implement for ratemaking purposes the net salvage rates beginning in the next test period is approved. BC Hydro is directed to submit a proposal in its next revenue requirements application to explain how the net salvage rates should be phased in.

6. The BCUC accepts BC Hydro's DSM expenditures schedule of $89.5 million for fiscal 2023, $96.1 million for fiscal 2024, and $110.1 million for fiscal 2025.

7. The BCUC accepts BC Hydro's revised DSM expenditures schedule of $85.4 million for fiscal 2022.

8. Within 30 days of the issuance of a BCUC order approving rates for fiscal 2023 to fiscal 2025 on a permanent basis, BC Hydro is directed to re-calculate its revenue requirements and file a revised Appendix A to the Application and updated rate schedules, reflecting the corrections to the Application identified in the errata filed in the proceeding, the terms of this order, the determinations and directives contained in the decision issued concurrently with this order, and any future BCUC determinations and directives issued in the proceeding.

9. The request to hold confidential certain portions of the Application and certain information filed confidentially during the course of the proceeding is approved until further order of the BCUC.

10. BC Hydro is directed to comply with all other directives contained in the decision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of April 2023.

BY ORDER

Original signed by:

D. M. Morton
Commissioner

Glossary of Terms

Acronym	Description
Account Credits Direction	Direction to the BCUC Respecting Residential and Commercial Customer Account Credits
AMPC	Association of Major Power Customers of British Columbia
AIP	Asset Investment Planning
Application	BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application
B.C.	British Columbia
BC Hydro or the Authority	British Columbia Hydro and Power Authority
BCOAPO	British Columbia Old Age Pensioners’ Organization, Disability Alliance BC, Council of Senior Citizens’ Organizations of BC, and the Tenant Resource and Advisory Centre (BCOAPO et al.)
BCSEA	BC Sustainable Energy Association
BCUC	British Columbia Utilities Commission
BES	Bulk Electric System
Bowman	Patrick Bowman
Capital Power	Capital Power Corporation
CBOC	The Conference Board of Canada
CCF Regulatory Account	Customer Crisis Fund Regulatory Account
CDP	Certified Depreciation Professional
CEA	*Clean Energy Ac*t
CEBC	Clean Energy B.C.
CEC	Commercial Energy Consumers Association of British Columbia
CGAAP	The Canadian Generally Accepted Accounting Principles
CIP	Critical Infrastructure Protection
CM&E	Canadian Manufacturers and Exporters
CNRO	Consolidated Net Revenue from Operations
Compliance Filing	BC Hydro compliance filing due within 30 days of the issuance of an order approving the Test Period rates on a permanent basis
Concentric	Concentric Advisors, ULC
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
Cryptocurrency Direction	Direction to the BCUC Respecting Cryptocurrency Mining Projects

CSP	Cyber Security Plan
DARR	Deferral Account Rate Rider
Direction No. 8	Direction No. 8 to the British Columbia Utilities Commission, OIC 051/2019
DSM	Demand-Side Management
DSM Regulation	Demand-Side Measures Regulation, BC Reg. 326/2008
Electrification Plan Direction	The Direction to the BCUC Respecting Load Attraction and Low-Carbon Electrification (OIC 355)
Energy Outlook Report	The United States Energy Information Administration's Annual Energy Outlook report
EOL	End of Life
EPA	electricity purchase agreement
EV	electric vehicle
"F"	fiscal
F2020 to F2021 RRA Decision	British Columbia Hydro and Power Authority F2020 to F2021 Revenue Requirements Application – Decision and Order G-246-20 dated October 2, 2020
F2022 RRA Decision	British Columbia Hydro and Power Authority F2022 Revenue Requirements Application – Decision and Order G-187-21 dated June 17, 2021
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.
FERC	Federal Energy Regulatory Commission
FortisBC	FortisBC Energy Inc. and FortisBC Inc. (Collectively)
FTE	full-time equivalent
GHG	greenhouse gas
GGRR	Greenhouse Gas Reduction (Clean Energy) Regulation
Gjoshe	Edlira Gjoshe
GRA	General Rate Application
Guidelines	BC Hydro's 2018 Capital Filing Guidelines
GWh	Gigawatt hour
HC2	Heritage Special Direction No. HC2 to the BCUC issued by OIC 1123 in 2003
HDA	Heritage Deferral Account
Hydro One	Hydro One Networks Inc.
HPO	Heritage Payment Obligation
HVAC	Heating, ventilation, and air conditioning

IFRS	International Financial Reporting Standards
IPP	Independent Power Producer
IR	information request
IRP	integrated resource plan
Island Generation Application	BC Hydro Island Generation Electricity Purchase Agreement Renewal Application dated July 29, 2022
KBU	Key Business Unit
kV	Kilovolt
LCE	Low Carbon Electrification
LCE Program	Refers to programs that BC Hydro considers as LCE actions under section 4 of the GGRR.
LNG	Liquified Natural Gas
LiDAR	Light Detection and Ranging
LRMC	long-run marginal cost
Manitoba Hydro	Manitoba Hydro Electric Board
McCandless	Richard McCandless
MoveUP	Movement of United Professionals
MRS	Mandatory Reliability Standards
mTRC	Modified Total Resource Cost
MW	Megawatts
NARUC	National Association of Regulatory Utility Commissioners
NBV	Net Book Value
NERC CIP	The North American Electric Reliability Corporation Critical Infrastructure Protection
NHDA	Non-Heritage Deferral account
NIA	Non-Integrated Area
NITS	Network Integrated Transmission Service
NTC	Nuu-chah-nulth Tribal Council
O&M	operations and maintenance
OAG	Office of the Auditor General
OATT	Open Access Transmission Tariff
OIC	Order in Council
PBR	Performance Based Regulation

PBR Report Decision	British Columbia Utilities Commission Review of British Columbia Hydro and Power Authority's Performance Based Regulation Report, Decision and Order G-388-21 dated December 21, 2021
Powerex	Powerex Corp.
PTP	Point-to-point
RCIA	Residential Customer Intervener Association
RFP	Request for Proposal
RRA	Revenue Requirements Application
SAE	Statistically Adjusted End Use
SAIDI	System Average Interruption Duration Index- a measure of the amount of time, in hours, an average distribution customer is without power in a year
SAIFI	System Average Interruption Frequency Index - a measure of the number of sustained interruptions (longer than one minute) an average distribution customer will experience in one year
SRP	Streamlined Review Process
Test Period	Fiscal 2023 to fiscal 2025 test period
TIDA	Trade Income Deferral Account
TIRR	Trade Income Rate Rider
TMP	Thermal Mechanical Pulp
TPA	Transfer Pricing Agreement
TRC	Total Resource Cost
TRR	Transmission Revenue Requirement
TS	Tariff Supplements
UCA	*Utilities Commission Act*
UCT	Utility Cost Test
UNDRIP	United Nations Declaration on the Rights of Indigenous Peoples
VMS	Vegetation Management Strategy
Z1BRG	Zone 1B Ratepayers Group
Zone II RPG	Kwadacha Nation and Tsay Keh Dene Nation, together the Zone II Ratepayers Group

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Hydro and Power Authority

Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated August 20, 2021 – Appointing the Panel for the review of British Columbia Hydro and Power Authority Fiscal 2023 to Fiscal 2025 Revenue Requirements Application
A-2	Letter dated September 7, 2021 - BCUC Order G-263-21 establishing the regulatory timetable
A-3	Letter dated October 4, 2021 – the scope of the BCUC's review of Demand-Side Management expenditures and Site C costs as part of the current proceeding
A-4	Letter dated October 28, 2021 – BCUC Information Request No. 1
A-5	**CONFIDENTIAL** – Letter dated October 28, 2021 – BCUC Confidential Information Request No. 1
A-6	Letter dated December 10, 2021 – BCUC approving BC Hydro's extension request to file Information Request No. 1 responses
A-7	Letter dated December 22, 2021 – BCUC response to late request to intervene from E. Gjoshe
A-8	Letter dated December 23, 2021 – BCUC response to BC Hydro extension request
A-9	Letter dated February 4, 2022 – BCUC Request to BC Hydro regarding access to Confidential Materials
A-10	Letter dated February 8, 2022-- BCUC Information Request No. 2 to BCH
A-11	**CONFIDENTIAL** – Letter dated February 8, 2022 – BCUC Confidential Information Request No. 2 to BCH
A-12	Letter dated February 9, 2022 – BCUC approving extension to file Information Requests on BC Hydro's supplemental Response to BCOAPO IR 1.87.2
A-13	Letter dated February 22, 2022 -- BCUC Order G-44-22 regarding AMPC's request to access Confidential Materials

A-14	Letter dated February 22, 2022 – BCUC Order G-47-22 approving interim rates for fiscal 2023
A-15	Letter dated March 11, 2022 – BCUC Order G-72-22 amending the regulatory timetable
A-16	Letter dated March 18, 2022 – BCUC response to BCH's submission in compliance with Directives 2 and 3 of Order G-44-22
A-17	Letter dated April 19, 2022 – BCUC submitting procedural conference information
A-18	Letter dated May 18, 2022 – BCUC Order G-136-33 establishing a further regulatory timetable with Reasons for Decision
A-19	Letter dated June 16, 2022 – BCUC Order G-166-22 amending the regulatory timetable
A-20	Letter dated June 23, 2022 – BCUC submitting Information Request No. 3 to BC Hydro
A-21	Letter dated July 8, 2022 – BCUC requesting submissions on OIC 355 Direction regarding BCUC Respecting Load Attraction and Low-Carbon Electrification
A-22	Letter dated July 13, 2022 – BCUC Order G-189-22 amending the regulatory timetable with Reasons for Decision
A-23	Letter dated July 14, 2022 – BCUC Information Request No. 1 to AMPC on Intervener Evidence of Mr. Bowman
A-24	Letter dated July 14, 2022 – BCUC Information Request No. 1 to AMPC on Intervener Evidence of Ms. Davies
A-25	Letter dated July 14, 2022 – BCUC Information Request No. 1 to RCIA on Intervener Evidence
A-26	Letter dated July 14, 2022 – BCUC Information Request No. 1 to Zone II RPG on Intervener Evidence
A-27	Letter dated July 15, 2022 – BCUC response to CEC extension request to file Information Request No. 1 on Intervener Evidence
A-28	**CONFIDENTIAL** – Letter dated July 29, 2022 – BCUC response to BCH Submissions on Confidential Documents
A-29	Letter dated August 4, 2022 – BCUC response to BC Hydro regarding Confidential Order R-10-22
A-30	Letter dated August 19, 2022 – BCUC Order G-239-22 amending the regulatory timetable with Reasons for Decision
A-31	Letter dated August 26, 2022 – BCUC response to AMPC's Comments on Order G-239-22
A-32	Letter dated September 1, 2022 – BCUC clarification regarding oral hearing topics

A-33 Letter dated September 7, 2022 – BCUC Order G-248-22 on oral hearing scope with Reasons for Decision

A-34 Letter dated September 7, 2022 – BCUC issuing Oral Hearing Information

A-35 Letter dated September 13, 2022 – BCUC clarification regarding September 19 federal holiday

A-36 Letter dated September 16, 2022 – BCUC providing further information on oral hearing

A-37 Letter dated October 12, 2022 – BCUC Order G-284-22 amending the regulatory timetable

A-38 Letter dated October 18, 2022 – BCUC clarification regarding oral hearing transcript amendments

A-39 Letter dated October 28, 2022 – BCUC response to AMPC Request for Access to Confidential Information

A-40 Letter dated November 29, 2022 – BCUC Order G-344-22 amending the regulatory timetable

A-41 Letter dated December 23, 2022 – BCUC Order G-386-22 with amended timetable and Panel IR No. 1

A-42 Letter dated December 23, 2022 – BCUC issuing Streamlined Review Process (SRP) Information

A-43 Letter dated January 12, 2023 – BCUC submitting Information Request No. 3 on SRP topics to BC Hydro

A-44 Letter dated January 18, 2023 – BCUC Order G-10-23 with amended regulatory timetable

A-45 Letter dated January 30, 2023 – Commissioner Andrew Pape-Salmon Notice to Parties

A-46 Letter dated February 10, 2023 – BCUC requesting submissions regarding the DARR

A-47 Letter dated March 21, 2023 – BCUC Order G-60-23 approving interim rates for Fiscal 2024

A-48 Letter dated March 28, 2023 – BCUC Order G-66-23 with amended timetable

A-49 Letter dated March 28, 2023 – BCUC submitting Panel IR No. 2 to BC Hydro

A-50 Letter dated April 4, 2023 – BCUC Order G-74-23 establishing further regulatory timetable

A-51 Letter dated April 20, 2023 – BCUC Order G-90-23 establishing further regulatory timetable

A-52 Letter dated April 20, 2023 – BCUC submitting Panel IR No. 3 to BC Hydro

COMMISSION STAFF DOCUMENTS

A2-1	**CONFIDENTIAL** – Letter dated October 27, 2021 – BCUC staff submitting confidential BC Hydro Compliance Report Pursuant to Directive 8 of the BCUC Decision on the Fiscal 2022 Revenue Requirements Application, September 17, 2021
A2-2	Letter dated May 2, 2022 – BCUC staff submitting draft regulatory timetable
A2-3	Letter dated July 21, 2022 – BCUC Staff Seek Submission from BC Hydro on Confidential Documents for the Record
A2-3-1	Letter dated July 21, 2022 – BCUC Staff submitting Order R-18-19 Notice of Compliance Violation Investigation Pertaining to FAC-003 dated September 9, 2019
A2-3-2	Exhibit Withdrawn
A2-3-3	**Exhibit Withdrawn**
A2-3-4	**CONFIDENTIAL** – Letter dated July 21, 2022 – BCUC staff submitting confidential Order R-10-22 dated March 22, 2022
A2-3-4-1	**CONFIDENTIAL**– Letter dated August 8 2022 – BCUC staff submitting redacted confidential Order R-10-22 dated March 22, 2022
A2-4	Letter dated July 29, 2022 – BCUC Staff submitting Order R-28-21 Application for Acceptance of a Mitigation Plan (Version 1) required for Compliance with Mandatory Reliability Standards FAC-003-4 Requirement 2 – Violation ID: BCUC2020000733 FAC-003-4 Requirement 2 – Violation ID: BCUC2020000734 FAC-003-4 Requirement 2 – Violation ID: BCUC2020000735 dated November 4, 2021
A2-5	Letter dated July 29, 2022 – BCUC Staff submitting Order R-30-21 Application for Acceptance of a Mitigation Plan (Version 2) required for Compliance with Mandatory Reliability Standard: FAC-003-4 Requirement 4 – Violation ID: BCUC2020000727 dated November 18, 2021
A2-6	Letter dated July 29, 2022 – BCUC Staff submitting Order R-26-21 Application for Acceptance of a Mitigation Plan (Version 1) required for Compliance with Mandatory Reliability Standard: FAC-003-3 Requirement 6 – Violation ID: BCUC2020000728 dated November 3, 2021
A2-7	Letter dated July 29, 2022 – BCUC Staff submitting Order R-27-21 Application for Acceptance of a Mitigation Plan (Version 1) required for Compliance with Mandatory Reliability Standard: FAC-003-4 Requirement 7 – Violation ID: BCUC2020000729 dated November 3, 2021
A2-8	Letter dated July 29, 2022 – BCUC Staff submitting Order R-13-22 Application for Acceptance of a Mitigation Plan (Version 2) required for Compliance with Mandatory Reliability Standard: FAC-003-4 Requirement 2 – Violation ID: BCUC2019000681 dated March 25, 2022
A2-9	Letter dated July 29, 2022 – BCUC Staff submitting Fiscal 2022 Revenue Requirements Application Decision and Order G-187-21, pp. 38 and 42 dated June 17, 2021

A2-10	Letter dated September 7, 2022 – BCUC Staff submitting Redacted BC Hydro Island Generation EPA Renewal excerpt dated July 29, 2022
A2-10-1	**CONFIDENTIAL** – Letter dated September 7, 2022 – BCUC Staff submitting confidential BC Hydro Island Generation EPA Renewal excerpt dated July 29, 2022
A2-11	**CONFIDENTIAL** – Letter dated September 23, 2022 – BCUC Staff submitting confidential staff calculations

APPLICANT DOCUMENTS

B-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO)** – Letter dated August 13, 2021 submitting proposed timetable for the review of the Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (F2023-F2025 RRA)
B-2	**PUBLIC** - Letter dated August 31, 2021 – BC Hydro submitting Fiscal 2023 to Fiscal 2025 Revenue Requirements Application (F2023-F2025 RRA)
B-2-1	**PUBLIC** - Letter dated August 31, 2021 – BC Hydro submitting F2023-F2025 RRA Appendix
B-2-1-1	**PUBLIC** - Letter dated September 9, 2021 – BC Hydro submitting correction to F2023-F2025 RRA Appendix II
B-2-1-2	Letter dated January 19, 2022 – BC Hydro submitting Errata to F2023-F2025 RRA Appendices
B-2-1-3	Letter dated January 31, 2022 – BC Hydro submitting Errata to F2023-F2025 RRA Appendix Q
B-2-2	**CONFIDENTIAL** - Letter dated August 31, 2021 – BC Hydro submitting F2023-F2025 RRA Confidential Chapter 6
B-2-2-1	**CONFIDENTIAL** - Letter dated January 19, 2022 – BC Hydro submitting confidential Errata to F2023-F2025 RRA Confidential Chapter 6
B-2-2-2	**CONFIDENTIAL** - Letter dated April 14, 2022 – BC Hydro submitting confidential Errata No. 4 to F2023-F2025 RRA
B-2-3	**CONFIDENTIA**L - Letter dated August 31, 2021 – BC Hydro submitting F2023-F2025 RRA Confidential Chapter 10 Appendices U, V and W
B-2-3-1	**REDACTED** - Letter dated September 28, 2021 – BC Hydro submitting F2023-F2025 RRA Redacted Confidential Chapter 10 Appendices U, V and W
B-2-4	**CONFIDENTIAL** - Letter dated August 31, 2021 – BC Hydro submitting F2023-F2025 RRA Confidential Appendices I and V
B-2-5	**CONFIDENTIAL** - Letter dated August 31, 2021 – BC Hydro submitting F2023-F2025 RRA Confidential Appendix JJ
B-2-6	Letter dated January 19, 2022 – BC Hydro submitting Errata to F2023-F2025 RRA

B-2-7	Letter dated April 14, 2022 – BC Hydro submitting Errata No. 4 to F2023-F2025 RRA
B-3	Letter dated September 21, 2021 – BC Hydro submitting Submarine Cable Update
B-4	Letter dated October 8, 2021 – BC Hydro submitting public notice filing in compliance with G-263-21
B-5	Letter dated October 8, 2021 – BC Hydro submitting update on DSM schedule
B-6	Letter dated December 9, 2021 – BC Hydro submitting extension request to file Information Request No. 1 responses
B-7	Letter dated December 16, 2021 – BC Hydro submitting responses to BCUC Information Request No. 1
B-7-1	**CONFIDENTIAL -** Letter dated December 16, 2021 – BC Hydro submitting confidential responses to BCUC Information Request No. 1
B-7-1-1	**CONFIDENTIAL** - Letter dated January 17, 2022 – BC Hydro submitting confidential response to BCUC Information Request No. 1.69.5.1
B-7-2	**PUBLIC** - Letter dated January 17, 2022 – BC Hydro submitting public response to BCUC Information Request No. 1.69.5.1
B-7-3	Letter dated April 14, 2022 – BC Hydro submitting revised response to BCUC Information Request No. 1 Questions
B-7-4	Letter dated August 8, 2022 – BC Hydro submitting revised response to BCUC Information Request No. 1 Question 1.13.2
B-8	Letter dated December 16, 2021 – BC Hydro submitting responses to Interveners Information Request No. 1
B-8-1	**CONFIDENTIAL -** Letter dated December 16, 2021 – BC Hydro submitting confidential revised response to RCIA Information Request No. 1.97.1
B-8-2	Letter dated January 31, 2022 – BC Hydro submitting revised response to RCIA Information Request No. 1.97.1
B-8-3	Letter dated February 4, 2022 – BC Hydro submitting supplemental response to BCOAPO Information Request No. 1.87.2
B-8-4	Letter dated April 14, 2022 – BC Hydro submitting revised responses to Intervener Information Request No. 1 Questions
B-8-5	Letter dated September 13, 2022 – BC Hydro submitting revised responses to Intervener Information Request No. 1
B-9	**CONFIDENTIAL -** Letter dated December 16, 2021 – BC Hydro submitting confidential responses to BCUC Confidential Information Request No. 1

B-10	Letter dated December 22, 2021 – BC Hydro submitting Fiscal 2023 to 2025 Demand-Side Measures expenditure schedule
B-10-1	Letter dated April 14, 2022 – BC Hydro submitting Errata to Fiscal 2023 to 2025 Demand-Side Measures expenditure schedule
B-10-2	Letter dated August 8, 2022 – BC Hydro submitting Errata No. 2 to Fiscal 2023 to 2025 Demand-Side Measures expenditure schedule
B-11	Letter dated February 1, 2022 – BC Hydro submitting Order G-187-21 Directive 2 compliance
B-12	Letter dated February 7, 2022 – BC Hydro submitting request for Fiscal 2023 interim rates
B-13	**CONFIDENTIAL** - Letter dated February 9, 2022 – BC Hydro submitting confidential response regarding access to Confidential Materials
B-14	**CONFIDENTIAL** - Letter dated February 9, 2022 – BC Hydro submitting confidential response to AMPC request
B-15	Letter dated March 8, 2022 – BC Hydro submitting extension request to file responses to Information Requests No. 2
B-16	**CONFIDENTIAL** – Letter dated March 10, 2022 – BC Hydro submitting G-44-22 compliance regarding market information
B-17	Letter dated March 10, 2022 – BC Hydro submission regarding OIC 123 Amendment to Direction No. 8 compliance
B-18	**CONFIDENTIAL** – Letter dated March 31, 2022 – BC Hydro submitting G-44-22 Directive 1 compliance regarding market information
B-19	Letter dated April 14, 2022 – BC Hydro submitting responses to BCUC Information Request No. 2
B-19-1	**CONFIDENTIAL** - Letter dated April 14, 2022 – BC Hydro submitting confidential responses to BCUC Information Request No. 2
B-19-2	Letter dated May 5, 2022 – BC Hydro submitting revised response to BCUC Information Requests No. 2
B-20	Letter dated April 14, 2022 – BC Hydro submitting responses to Intervener Information Request No. 2
B-20-1	**CONFIDENTIAL** - Letter dated April 14, 2022 – BC Hydro submitting confidential responses to Intervener Information Request No. 2
B-20-2	Letter dated May 5, 2022 – BC Hydro submitting revised responses to Intervener Information Request No. 2

B-20-3	Letter dated August 8, 2022 – BC Hydro submitting revised responses to ZoneII RPG Information Request No. 2 Question 2.63.3
B-20-4	Letter dated September 13, 2022 – BC Hydro submitting revised responses to Intervener Information Request No. 2
B-21	**CONFIDENTIAL** - Letter dated April 14, 2022 – BC Hydro submitting responses to BCUC Confidential Information Request No. 2
B-22	**CONFIDENTIAL** - Letter dated April 14, 2022 – BC Hydro submitting responses to Intervener Confidential Information Request No. 2
B-23	Letter dated April 14, 2022 – BC Hydro submitting Transfer Pricing Agreement (Low Carbon Fuel Credits)
B-24	Letter dated June 16, 2022 – BC Hydro submitting response to RCIA and AMPC extension requests
B-25	Letter dated July 6, 2022 – BC Hydro submitting response to Order in Council (OIC) No. 355 Direction
B-26	Letter dated July 8, 2022 – BC Hydro submitting extension request to file Intervener Information Request No. 3 responses
B-27	Letter dated July 14, 2022 – BC Hydro submitting Information Request No. 1 to AMPC Evidence
B-28	Letter dated July 14, 2022 – BC Hydro submitting Information Request No. 1 to RCIA Evidence
B-29	**CONFIDENTIAL** - Letter dated July 27, 2022 – BC Hydro submitting response to BCUC's request in Exhibit A2-3
B-30	Letter dated July 29, 2022 – BC Hydro submitting responses to BCUC Information Requests No. 3
B-30-1	Letter dated August 8, 2022 – BC Hydro submitting revised response to BCUC Information Requests No. 3 Question 3.242.1
B-31	Letter dated July 29, 2022 – BC Hydro submitting responses to Interveners Information Requests
B-31-1	Letter dated August 8, 2022 – BC Hydro submitting revised response to AMP Information Request No. 3 Question 3.1.1
B-32	**CONFIDENTIAL** - Letter dated August 3, 2022 – BC Hydro submitting response to BCUC's request in Exhibit A-28
B-33	Letter dated August 10, 2022 – BC Hydro submission on Oral Hearing Scope
B-34	Letter dated August 12, 2022 – BC Hydro reply submission on Oral Hearing Scope

B-35	Letter dated August 23, 2022 – BC Hydro submission on Connecting Customers Component of the Electrification Plan
B-36	Letter dated August 29, 2022 – BC Hydro submitting rebuttal to evidence from AMPC and RCIA - Depreciation and Net Salvage
B-36-1	Letter dated August 29, 2022 – BC Hydro submitting rebuttal to evidence from RCIA - Expected Asset Lives in Asset Management
B-36-2	Letter dated August 29, 2022 – BC Hydro submitting rebuttal to evidence from AMPC and RCIA - Vegetation Management
B-36-3	Letter dated September 1, 2022 – BC Hydro submitting rebuttal to evidence addendum
B-37	Letter dated August 29, 2022 – BC Hydro reply submission on the Connecting Customers Component of the Electrification Plan
B-38	Letter dated September 12, 2022 – BC Hydro providing Oral Hearing Opening Statement
B-39	Submitting at Oral Hearing Sept 20, 2022 - Transcripts from Manitoba Hydro GRA 2012/13 and 2013/14
B-40	Submitted at Oral Hearing Sept 20, 2022 - Transcript from Manitoba Hydro GRA 2014/15 and 2015/16
B-41	Submitted at Oral Hearing Sept 20, 2022 – Alliance Consulting Group – letter re: Proposed Depreciation Rates Hydro One, April 26, 2021
B-42	Submitted by BCH at Oral Hearing September 22, 2022 – BCUC IR and Response from BCH's Mainwaring Substation Upgrade Project
B-43	Letter dated October 4, 2022 – BC Hydro submitting response regarding Oral Hearing Transcript Amendments
B-44	Letter dated October 6, 2022 – BC Hydro submitting responses regarding the Undertakings resulting from the Oral Hearing
B-44-1	**CONFIDENTIAL -** Letter dated October 6, 2022 – BC Hydro submitting confidential responses regarding the Undertakings resulting from the Oral Hearing
B-44-2	Letter dated November 9, 2022 – BC Hydro submitting supplemental response to Undertaking 13
B-45	**CONFIDENTIAL -** Letter dated October 6, 2022 – BC Hydro submitting confidential responses regarding the In-Camera Undertakings resulting from the Oral Hearing
B-46	Letter dated October 27, 2022 – BC Hydro submitting response to Exhibit C7-42
B-47	Letter dated November 9, 2022 – BC Hydro submitting confirmation to respond to RCIA Undertaking 13 clarification request

B-48 Letter dated December 15, 2022 – BC Hydro submitting Residential and Commercial Customer Account Credits Direction

B-49 Letter dated January 10, 2023 – BC Hydro submitting responses to BCUC Panel Information Request No. 1

B-49-1 Letter dated January 16, 2023 – BC Hydro submitting revision to response to BCUC Panel Information Request No. 1

B-50 Letter dated January 16, 2023 – BC Hydro submitting responses to BCUC Information Request No. 3 on SRP Topics

B-51 Letter dated January 16, 2023 – BC Hydro submitting responses to Intervener Information Request No. 3 on SRP Topics

B-52 Letter dated January 19, 2023 – BC Hydro submitting Volume 6 Transcript Corrections for SRP on January 16, 2023

B-53 Letter dated February 13, 2023 - BC Hydro submitting request for interim F2024 rates

B-53-1 Letter dated March 9, 2023 - BC Hydro submitting request for interim F2024 rates - Updated

B-54 Letter dated March 31, 2023 - BC Hydro submitting Application to Reinstate a Regulatory Liability to the Trade Income Deferral Account

B-55 Letter dated April 4, 2023 – BC Hydro submitting responses to BCUC Panel Information Request No. 2

B-56 Letter dated April 13, 2023 – BC Hydro reply submission on Exhibit B-54

INTERVENER DOCUMENTS

C1-1 **BC SUSTAINABLE ENERGY ASSOCIATION (BCSEA)** - Letter dated September 9, 2021 Request to Intervene by T. Hackney and W.J. Andrews

C1-2 Letter dated August 27, 2021 – BCSEA submitting Confidentiality Declaration and Undertaking

C1-3 Letter dated November 4, 2021 – BCSEA submitting Information Request No. 1 to BC Hydro

C1-4 Letter dated February 15, 2022 – BCSEA submitting Information Request No. 2 to BC Hydro

C1-4-1 Letter dated February 22, 2022 – BCSEA submitting supplementary Information Request No. 2 to BC Hydro

C1-5 Letter dated April 26, 2022 – BCSEA submitting no Intervener Evidence

C1-6 Letter dated June 23, 2022 – BCSEA submitting Information Request No. 3 to BC Hydro

C1-7	Letter dated July 14, 2022 – BCSEA submitting Information Request No. 1 to ZoneII RPG Evidence
C1-8	Letter dated July 14, 2022 – BCSEA submitting Information Request No. 1 to AMPC Evidence
C1-9	Letter dated July 14, 2022 – BCSEA submitting Information Request No. 1 to RCIA Evidence
C1-10	Letter dated August 11, 2022 – BCSEA submission on Oral Hearing Scope
C1-11	Letter dated August 25, 2022 – BCSEA submission on connecting customers component on Electrification Plan
C1-12	Letter dated January 11, 2023 – BCSEA submitting Information Request No. 3 to BC Hydro on SRP Topics
C1-13	Letter dated April 6, 2023 – BCSEA submission on Exhibit B-54
C2-1	**MOVEMENT OF UNITED PROFESSIONALS (MOVEUP)** – Letter dated September 9, 2021 submitting request to intervene by Jim Quail
C2-2	Letter dated August 30, 2021 –MoveUP submitting Confidentiality Declaration and Undertaking
C2-3	Letter dated November 2, 2021 – MoveUP submitting Information Request No. 1 to BC Hydro
C2-4	Letter dated April 26, 2022 – MoveUP submitting Confidentiality Declaration and Undertaking
C2-5	Letter dated July 9, 2022 – MoveUP submitting Information Request No. 1 to AMPC Evidence
C2-6	Letter dated July 9, 2022 – MoveUP submitting Information Request No. 1 to RCIA Evidence
C2-7	Letter dated August 11, 2022 – MoveUP submission on Oral Hearing Scope
C2-8	Submitted by MoveUP at Oral Hearing September 23, 2022 –Witness Aid for RCIA Panel on Topic No. 5 Vegetation Management
C2-9	Letter dated January 10, 2023 – MoveUP submitting Information Request No. 3 to BC Hydro on SRP Topics
C2-9-1	Letter dated January 11, 2023 – MoveUP submitting Supplemental Information Request No. 3 to BC Hydro on SRP Topics
C2-10	Letter dated April 10, 2023 – MoveUP submission on Exhibit B-54
C3-1	**FORTISBC ENERGY INC. AND FORTISBC INC. (FORTISBC)** – Letter dated September 10, 2021 submitting request to intervene by Diane Roy

C3-2 Letter dated September 9, 2021 – FortisBC submitting Confidentiality Declaration and Undertaking

C3-3 Letter dated November 4, 2021 – FortisBC submitting Information Request No. 1 to BC Hydro

C3-4 Letter dated February 15, 2022 – FortisBC submitting Information Request No. 2 to BC Hydro

C3-5 Letter dated August 11, 2022 – FortisBC submission on Oral Hearing Scope

C3-6 Letter submitted August 12, 2022 – FortisBC submitting Confidentiality Declaration and Undertaking

C4-1 **CLEAN ENERGY BC (CEBC)** – Letter dated September 16, 2021 submitting request to intervene by Laureen Whyte

C4-2 Letter dated August 31, 2021 – CEBC submitting Confidentiality Declaration and Undertaking

C4-3 Letter dated November 4, 2021 – CEBC submitting Information Request No. 1 to BC Hydro

C4-4 Letter dated February 15, 2022 – CEBC submitting Information Request No. 2 to BC Hydro

C5-1 **KWADACHA NATION AND TSAY KEH DENE NATION, TOGETHER THE ZONE II RATEPAYERS GROUP (ZONEII-RPG)** – Letter dated September 20, 2021 submitting request to intervene by Jana McLean

C5-2 Letter dated September 13, 2021 – ZoneII-RPG submitting Confidentiality Declaration and Undertaking

C5-3 Letter dated September 3, 2021 – ZoneII-RPG submitting Additional Confidentiality Declaration and Undertaking

C5-4 Letter dated November 4, 2021 – ZoneII-RPG submitting Information Request No. 1 to BC Hydro

C5-5 Letter dated February 15, 2022 – ZoneII RPG submitting Information Request No. 2 to BC Hydro

C5-6 Letter dated April 28, 2022 – ZoneII RPG submitting Notice of Intention to file Intervener Evidence

C5-7 Letter dated June 20, 2022 – ZoneII RPG submitting Intervener Evidence

C5-8 Letter dated June 23, 2022 – ZoneII RPG submitting Information Request No. 3 to BC Hydro

C5-9 Letter dated July 14, 2022 – ZoneII RPG submitting Information Request No. 1 to AMPC Evidence

C5-10	Letter dated July 14, 2022 – ZoneII RPG submitting Information Request No. 1 to RCIA Evidence
C5-11	Letter dated August 8, 2022 – ZoneII RPG submitting responses to BCUC Information Request No. 1
C5-12	Letter dated August 8, 2022 – ZoneII RPG submitting responses to CEC Information Request No. 1
C5-13	Letter dated August 8, 2022 – ZoneII RPG submitting responses to BCSEA Information Request No. 1
C5-14	Letter dated August 8, 2022 – ZoneII RPG submitting responses to RCIA Information Request No. 1
C5-15	Letter dated August 11, 2022 – ZoneII RPG submission on Oral Hearing Scope
C5-16	Letter dated August 25, 2022 – ZoneII RPG submission on connecting customers component Electrification Plan
C5-17	Letter dated September 23, 2022 – ZoneII RPG submission on further process
C5-18	Letter dated November 3, 2022 – ZoneII RPG submission of representative contact information
C5-19	Letter dated January 12, 2023 – ZoneII RPG submitting Information Request No. 3 on SRP topics to BC Hydro
C5-20	Letter dated April 11, 2023 – ZoneII RPG submission on Exhibit B-54
C6-1	**CAPITAL POWER CORPORATION (CAPITAL POWER)** – Letter dated September 20, 2021 submitting request to intervene by Simon Kupi
C7-1	**ASSOCIATION OF MAJOR POWER CUSTOMERS (AMPC)** – Letter dated September 24, 2021 submitting request to intervene by Matthew Keen
C7-2	Letter dated August 27, 2021 – AMPC submitting Confidentiality Declaration and Undertaking
C7-3	Letter dated November 4, 2021 – AMPC submitting Information Request No. 1 to BC Hydro
C7-4	Letter dated December 17, 2021 – AMPC submitting Confidentiality Declaration and Undertaking
C7-5	Letter dated February 2, 2022 – AMPC submitting request to access BC Hydro Confidential Information Request responses
C7-6	Letter dated February 7, 2022 – AMPC submitting Confidentiality Declaration and Undertaking
C7-7	Letter dated February 15, 2022 – AMPC submitting Information Request No. 2 to BC Hydro

C7-8	**CONFIDENTIAL** - Letter dated February 15, 2022 – AMPC submitting confidential Information Request No. 2 to BC Hydro
C7-9	Letter dated April 28, 2022 – AMPC submitting Notice of Intention to file Intervener Evidence
C7-10	Letter dated June 15, 2022 – AMPC submitting extension request to file Intervener Evidence
C7-11	Letter dated June 20, 2022 – AMPC submitting Intervener Evidence of P. Bowman
C7-12	Letter dated June 20, 2022 – AMPC submitting Intervener Evidence of M. Davies
C7-13	Letter dated June 23, 2022 – AMPC submitting Information Request No. 3 to BC Hydro
C7-14	Letter dated July 14, 2022 – AMPC submitting Information Request No. 1 to RCIA Evidence
C7-15	Letter dated August 8, 2022 – AMPC submitting responses to BCUC Information Request No. 1 on Bowman Evidence
C7-16	Letter dated August 8, 2022 – AMPC submitting responses to CEC Information Request No. 1
C7-17	Letter dated August 8, 2022 – AMPC submitting responses to MoveUP Information Request No. 1 on Davies Evidence
C7-18	Letter dated August 8, 2022 – AMPC submitting responses to NTC Information Request No. 1
C7-19	Letter dated August 8, 2022 – AMPC submitting responses to RCIA Information Request No. 1
C7-20	Letter dated August 8, 2022 – AMPC submitting responses to ZoneII-RPG Information Request No. 1
C7-21	Letter dated August 8, 2022 – AMPC submitting responses to BC Hydro Information Request No. 1 on AMPC Evidence
C7-22	Letter dated August 8, 2022 – AMPC submitting responses to BCOAPO Information Request No. 1
C7-23	Letter dated August 8, 2022 – AMPC submitting responses to BCSEA Information Request No. 1 on AMPC Evidence
C7-24	Letter dated August 8, 2022 – AMPC submitting responses to BCUC Information Request No. 1 on AMPC Evidence

C7-25	Letter dated August 9, 2022 – AMPC submitting Confidentiality Declaration and Undertaking
C7-26	Letter dated August 11, 2022 – AMPC submission on Oral Hearing Scope
C7-27	Letter dated August 25, 2022 – AMPC submission on connecting customers component Electrification Plan
C7-28	Letter dated August 22, 2022 - AMPC submitting comments on BCUC Order G-239-22
C7-29	Submitted by AMPC at Oral Hearing September 20, 2022 - Excerpt from AUC Decision on AltaLink 2015-16 GRA, May 9, 2016
C7-30	Submitted by AMPC at Oral Hearing September 20, 2022 - Certification for Society of Depreciation Professionals
C7-31	Submitted by AMPC at Oral Hearing September 20, 2022 - Excerpt from AUC Decision on AltaLink 2019-20 GRA, NSA, April 16, 2020
C7-32	Submitted by AMPC at Oral Hearing September 20, 2022 - Rebuttal Evidence of L. Kennedy submitted in Manitoba Hydro 2015/16 & 2016/17 GRA, May 20, 2015
C7-33	Submitted by AMPC at Oral Hearing September 20, 2022 - Excerpt from AUC Decision on AltaLink Stage 2 Review and Variance of Decision 23848-D01-2020 in 2019-2021 GRA, November 19, 2020
C7-34	Letter dated September 19, 2022 – AMPC submitting Opening Statement of Patrick Bowman
C7-35	Submitted by AMPC at Oral Hearing September 21, 2022 – Excerpts from BCH F12-F14 RRA
C7-36	Submitted by AMPC at Oral Hearing September 22, 2022 – Excerpt BCH 2017 Waneta Transaction Application
C7-37	Submitted by AMPC at Oral Hearing September 22, 2022 – Opening Statement of Melissa Davies
C7-38	Submitted by AMPC at Oral Hearing September 22, 2022 – Excerpt from BCH 2022 RRA
C7-39	Submitted by AMPC at Oral Hearing September 22, 2022 – Excerpt from BCH RFP No. 10649
C7-40	Submitted by AMPC at Oral Hearing September 22, 2022 – Excerpt from BCH RFP No. 7089

C7-41	Letter dated October 7, 2022 – AMPC submitting request for Transcript corrections
C7-42	Letter dated October 26, 2022 – AMPC submitting request for access to confidential information
C7-43	Letter dated January 12, 2023 – AMPC submitting Information Request No. 3 on SRP topics to BC Hydro
C7-44	Letter dated January 13, 2023 – AMPC submitting new evidence at SRP
C7-45	Letter submitted February 28, 2023 – AMPC SRP Power Point Presentation
C7-46	Letter dated April 11, 2023 – AMPC submission on Exhibit B-54
C8-1	**Residential Consumer Intervener Association (RCIA)** – Letter dated September 27, 2021 submitting request to intervene by Fredrik Ambrosson
C8-2	Letter dated September 9th, 2021 – RCIA submitting Confidentiality Declaration and Undertaking
C8-2-1	Letter dated June 10, 2022 – RCIA submitting revised Confidentiality Declaration and Undertaking
C8-2-2	Letter dated June 14, 2022 – RCIA submitting second revised Confidentiality Declaration and Undertaking
C8-3	Letter dated November 4, 2021 – RCIA submitting Information Request No. 1 to BC Hydro
C8-4	Letter dated February 15, 2022 – RCIA submitting Information Request No. 2 to BC Hydro
C8-5	Letter dated April 28, 2022 – RCIA submitting Notice of Intention to file Intervener Evidence
C8-6	Letter dated June 15, 2022 – RCIA submitting extension request to file Intervener Evidence
C8-7	Letter dated June 20, 2022 – RCIA submitting Intervener Evidence on Expected Lives and Depreciation Lives of Selected Assets
C8-8	Letter dated June 20, 2022 – RCIA submitting Intervener Evidence on Expected Asset Lives in Asset Management
C8-9	Letter dated June 20, 2022 – RCIA submitting Intervener Evidence on Vegetation Management
C8-10	Letter dated June 23, 2022 – RCIA will not be submitting Information Request No. 3
C8-11	Letter dated July 12, 2022 – RCIA submitting Information Request No. 1 to ZoneII RPG Evidence
C8-12	Letter dated July 12, 2022 – RCIA submitting Information Request No. 1 to AMPC Evidence

C8-13	Letter dated August 8, 2022 – RCIA submitting responses to BCUC Information Request No. 1 on RCIA Evidence
C8-14	Letter dated August 8, 2022 – RCIA submitting responses to BC Hydro Information Request No. 1 on RCIA Evidence
C8-15	Letter dated August 8, 2022 – RCIA submitting responses to AMPC Information Request No. 1 on RCIA Evidence
C8-16	Letter dated August 8, 2022 – RCIA submitting responses to BCOAPO Information Request No. 1 on RCIA Evidence
C8-17	Letter dated August 8, 2022 – RCIA submitting responses to BCSEA Information Request No. 1 on RCIA Evidence
C8-18	Letter dated August 8, 2022 – RCIA submitting responses to CEC Information Request No. 1 on RCIA Evidence
C8-19	Letter dated August 8, 2022 – RCIA submitting responses to MoveUP Information Request No. 1 on RCIA Evidence
C8-20	Letter dated August 8, 2022 – RCIA submitting responses to NTC Information Request No. 1 on RCIA Evidence
C8-21	Letter dated August 8, 2022 – RCIA submitting responses to ZoneII-RPG Information Request No. 1 on RCIA Evidence
C8-22	Letter dated August 11, 2022 – RCIA submitting Confidentiality Declaration and Undertaking
C8-23	Letter dated August 11, 2022 – RCIA submission on Oral Hearing Scope
C8-24	Letter dated August 25, 2022 – RCIA submission on connecting customers component Electrification Plan
C8-25	Letter dated September 12, 2022 – RCIA submitting Addendums to Exhibits C8-13 and C8-14 respectively, responses to Information Requests No. 1 on RCIA Evidence
C8-26	Submitted by RCIA at Oral Hearing September 20, 2022 – Excerpt of slide deck, Society of Depreciation Professionals Annual Conference & Meeting September 2019 by Rick Fisher
C8-27	Letter dated September 19, 2022 –RCIA submitting Opening Statements for Oral Hearing
C8-28	**REVISED** - Submitted by RCIA at Oral Hearing September 22, 2022 – Revised Confidentiality Declaration and Undertaking Form
C8-29	Letter dated November 1, 2022 – RCIA submitting clarification request regarding Undertaking No. 13
C8-30	Letter dated January 11, 2022 – RCIA submitting change of primary contact to M. Matusiak

C8-31	Letter dated January 12, 2023 – RCIA submitting Information Request No. 3 on SRP topics to BC Hydro
C8-32	Letter dated April 11, 2023 – RCIA submission on Exhibit B-54
C9-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** – Letter dated September 28, 2021 submitting request to intervene by Chris Weafer
C9-2	Letter dated August 31, 2021 – CEC submitting Confidentiality Declaration and Undertaking
C9-3	Letter dated November 2, 2021 – CEC submitting Confidentiality Declaration and Undertakings
C9-4	Letter dated November 4, 2021 – CEC submitting Information Request No. 1 to BC Hydro
C9-5	Letter dated February 15, 2022 – CEC submitting Information Request No. 2 to BC Hydro
C9-5-1	Letter dated February 22, 2022 – CEC submitting supplementary Information Request No. 2 to BC Hydro
C9-6	Letter dated June 23, 2022 – CEC submitting Information Request No. 3 to BC Hydro
C9-7	Letter dated July 14, 2022 – CEC submitting extension request to file Information Requests on Intervener Evidence
C9-8	Letter dated July 15, 2022 – CEC submitting Information Request No. 1 to ZoneII RPG Evidence
C9-9	Letter dated July 14, 2022 – CEC submitting Information Request No. 1 to RCIA Evidence
C9-10	Letter dated July 14, 2022 – CEC submitting Information Request No. 1 to AMPC Evidence
C9-11	Letter dated August 11, 2022 – CEC submission on Oral Hearing Scope
C9-12	Letter dated August 25, 2022 – CEC submission on connecting customers component Electrification Plan
C9-13	Letter dated January 12, 2023 – CEC submitting Information Request No. 3 to BC Hydro on SRP Topics
C9-14	Letter dated April 11, 2023 – CEC submission on Exhibit B-54
C10-1	**NUU-CHAH-NULTH TRIBAL COUNCIL (NTC)** – Letter dated September 28, 2021 submitting request to intervene by David Austin
C10-2	Letter dated November 4, 2021 – NTC submitting Information Request No. 1 to BC Hydro
C10-3	Letter dated February 15, 2022 – NTC submitting Information Request No. 2 to BC Hydro
C10-3-1	Letter dated February 22, 2022 – NTC submitting supplementary Information Request No. 2 to BC Hydro

C10-4	Letter dated June 23, 2022 – NTC submitting Information Request No. 3 to BC Hydro
C10-5	Letter dated July 14, 2022 – NTC submitting Information Request No. 1 to AMPC Evidence
C10-6	Letter dated July 14, 2022 – NTC submitting Information Request No. 1 to RCIA Evidence
C10-7	Letter dated August 11, 2022 – NTC submission on Oral Hearing Scope
C10-8	Submitted by NTC at Oral Hearing September 21, 2022 – Roadmap
C10-9	Submitted by NTC at Oral Hearing September 21, 2022 – Truth and Reconciliation Commission of Canada – Calls to Action
C10-10	Submitted by NTC at Oral Hearing September 21, 2022 – Declaration on the Rights of Indigenous Peoples Act, [SBC 2019] Chapter 44
C10-11	Submitted by NTC at Oral Hearing September 21, 2022 - BC Hydro Mandate letter Aug 17, 2017
C10-12	Submitted by NTC at Oral Hearing September 21, 2022 - BC Hydro Statement of Indigenous Principles
C10-13	Submitted by NTC at Oral Hearing September 21, 2022 – BCH Financial Information Act Return for the Year Ended March 31, 2021
C10-14	Submitted by NTC at Oral Hearing September 21, 2022 – Extract from BC Hydro Site C Quarterly Progress Report No. 25 to the BCUC
C10-15	Submitted by NTC at Oral Hearing September 21, 2022 – Extract from BC Hydro Site C Quarterly Progress Report No. 1 to the BCUC
C10-16	Letter dated January 12, 2023 – NTC submitting Information Request No. 3 to BC Hydro on SRP Topics
C10-17	Letter dated April 11, 2023 – NTC submission on Exhibit B-54
C11-1	**British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Tenants Resource and Advisory Centre, and Together Against Poverty Society (BCOAPO**) – Letter dated September 28, 2021 submitting request to intervene by Leigha Worth, Kristin Barham and Bill Harper
C11-2	Letter dated November 4, 2021 – BCOAPO submitting Information Request No. 1 to BC Hydro
C11-3	Letter dated November 5, 2021 – BCOAPO submitting Confidentiality Declaration and Undertakings
C11-4	Letter dated February 15, 2022 – BCOAPO submitting Information Request No. 2 to BC Hydro

C11-4-1 Letter dated February 22, 2022 – BCOAPO submitting supplementary Information Request No. 2 to BC Hydro

C11-5 Letter dated June 23, 2022 – BCOAPO submitting Information Request No. 3 to BC Hydro

C11-6 Letter dated July 14, 2022 – BCOAPO submitting Information Request No. 1 to AMPC Evidence

C11-7 Letter dated July 14, 2022 – BCOAPO submitting Information Request No. 1 to RCIA Evidence

C11-8 Letter dated August 11, 2022 – BCOAPO submission on Oral Hearing Scope

C11-9 Letter dated August 25, 2022 – BCOAPO submission on connecting customers component on Electrification Plan

C11-10 Submitted by BCOAPO at Oral Hearing September 22, 2022 – IR and Response from BCH's Application Peace to Kelly Lake

C11-11 Letter dated January 12, 2023 – BCOAPO submitting Information Request No. 3 on SRP topics to BC Hydro

C11-12 Letter dated April 11, 2023 – BCOAPO submission on Exhibit B-54

C12-1 **ZONE 1B RATEPAYERS GROUP (Zone IB RPG)** – Letter dated September 29, 2021 submitting request to intervene by Fred J. Weisberg

C13-1 **RICHARD MCCANDLESS (MCCANDLESS)** – Letter dated September 21, 2021 submitting request to intervene

C13-2 Letter dated November 3, 2021 – McCandless submitting Information Request No. 1 to BC Hydro

C13-3 Letter dated February 14, 2022 – McCandless submitting Information Request No. 2 to BC Hydro

C13-4 Letter dated April 7, 2023 – McCandless submission on Exhibit B-54

C14-1 **CANADIAN MANUFACTURERS AND EXPORTERS (CME)** – Letter dated October 05, 2021 submitting late request to intervene by Paul Willis

C14-2 Letter dated November 4, 2021 – CME submitting Information Request No. 1 to BC Hydro

C14-3 Letter dated February 14, 2022 – CME submitting Information Request No. 2 to BC Hydro

C15-1 **EDLIRA GJOSHE (GJOSHE)** – Letter dated December 19, 2021 submitting late request to intervene

C15-2 Letter dated February 15, 2022 – Gjoshe submitting Information Request No. 2 to BC Hydro

C15-3 Letter dated September 11, 2022 – Gjoshe submitting status change requesting withdrawal from Intervener Status

INTERESTED PARTY DOCUMENTS

D-1 **BROWNLOW, H. (BROWNLOW)** – Submission dated September 22, 2021 Request for Interested Party Status

D-2 **UNIVERSITY OF BRITISH COLUMBIA (UBC) -** Submission dated November 3, 2021 Request for Interested Party Status by Joshua Wauthy

D-3 **BRUDY, S. (BRUDY)** – Submission dated December 28, 2022 Request for Interested Party Status

D-4 **CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS (CAPP) -** Submission dated January 13, 2023 Request for Interested Party Status by Geoff Morrison

D-5 **BRYENTON, R. (BRYENTON)** – Submission dated March 31, 2023 Request for Interested Party Status

LETTERS OF COMMENT

E-1 GARTSHORE, I. (GARTSHORE) – Letter of Comment dated September 17, 2021

E-2 BARROW, W. (BARROW) – Letter of Comment dated September 22, 2021

E-3 TAYLOR, D. (TAYLOR) – Letter of Comment dated January 27, 2022

E-4 MINISTER OF ENERGY, MINES AND LOW CARBON INNOVATION (EMLI) – Letter of Comment dated April 11, 2023