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May 4, 2020

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British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Your reference	Our reference
Project No. 1598990	1000385863

Dear Mr. Wruck:

BC Hydro F2020-F2021 Revenue Requirements Application (RRA)
Association of Major Power Customers of BC (AMPC)
AMPC Final Argument

We are legal counsel to AMPC in this matter and write on its behalf to file AMPC's final argument in the above-noted proceeding.

If you have any questions, please contact the writer.

Yours very truly,

(for) Matthew D. Keen

MDK/roe

Encl.

CAN_DMS: \133283856\1

BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

F2020 to F2021 REVENUE REQUIREMENTS APPLICATION

PROJECT NO. 1598990

ARGUMENT OF THE ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC

May 4, 2020

Association of Major Power Customers of BC ("AMPC")

BC Hydro Fiscal 2020 to Fiscal 2021 Revenue Requirements Application ("RRA")

FINAL ARGUMENT

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Association of Major Power Customers of BC ("AMPC")

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FINAL ARGUMENT

I. Overview

Context and structure

1. This is the Argument of the Association of Major Power Customers of BC ("AMPC"). AMPC is a long-standing industry association of large industrial customers of BC Hydro who take service at the transmission level. Electricity rates are important to members' ability to compete in their respective markets.

2. As it has since the early 1980s, AMPC has actively participated in this proceeding to identify areas where BC Hydro's rates can be made fairer and more competitive, and to propose further directions to BC Hydro to the Commission that will improve BC Hydro's regulation and service offerings.

3. This Argument is filed in an unprecedented time. The sudden effects of the COVID-19 pandemic that emerged immediately after the close of the record in this proceeding threaten the public and economic health of the province and the country.

4. Just as governments and their agents have taken measures to ensure public safety, plans are now under way to re-open the economy and take steps towards recovery. More competitive electricity rates will be an essential part of AMPC members' efforts to return their businesses to full output. The recommendations that follow are based on the hearing record, but are just as vital in the COVID-19 context as they were when the record closed. Some recommendations in particular offer a principled opportunity for near-term rate relief.

5. Importantly, BC Hydro's Application is the first step in implementing the return to full regulatory oversight, outlined in the Phase 1 Final Report of Government's Comprehensive Review of BC Hydro. That fact should be foremost in the Commission's assessment of BC Hydro's Application, and the relief this Argument seeks is designed to fit that scope.

6. AMPC's recommendations arise from two sources: general regulatory and rate-specific recommendations from InterGroup's written and oral evidence, and items pursued in cross-examination. All are grounded in uncontroversial regulatory principles. Some are not "one-to-one" changes to revenue requirement, but rather, "directional" findings that can provide critical guidance to all parties about priorities and how regulation will unfold. Customers, BC Hydro and future decision-makers will all benefit from stability and predictability.

7. Each of AMPC's main topics is the subject of an individual appendix. The main argument that follows immediately below provides a precis of AMPC's concerns and the relief sought, relying on the details that each appendix provides.

BC Hydro's Application must be evaluated in the context of the Phase 1 Review

8. BC Hydro's Application is grounded in the Phase 1 Final Report of Government's Comprehensive Review of BC Hydro. That process contemplates a phased return of BC Hydro to enhanced regulation by the Commission. Next steps comprise the Phase 2 Final Report and further BC Hydro rates applications to the Commission, including rate of return, integrated resource planning, cost of service, rate design, and post-F2021 revenue requirement.

9. As an independent, expert body, the Commission has obligations under its statutory mandate relative to this Application and BC Hydro's rates more generally, and can provide advice and guidance on rate-related matters that pertain to near term proceedings, as well as this Application.

10. The Commission's directions and conclusions from this proceeding should therefore be mindful of the larger context of BC Hydro's rate regulation, which has been designed to span multiple proceedings.

The Commission should apply standard regulatory principles to the present record

11. Amid a global pandemic, it may seem artificial to argue which historical costs are best for forecasting purposes. AMPC concurs with BC Hydro, however, that this proceeding must be brought to a close, and the record should not be reopened to consider uncertain effects and new inputs in real time. The Evidentiary Update – including information that was, or should have been, available at that time – is a reasonable basis for setting rates in the test period.[1]

12. Parties remain able to base their arguments on the record, and on standard regulatory principles. AMPC has done so. That context similarly allows the Commission to make its determinations firmly based on the record and circumstances of the oral hearing.

13. Yet, BC Hydro concludes its Final Argument by urging a result-oriented methodology to the selection of evidentiary inputs. BC Hydro adopts a conservative approach and implicitly focusses on a level of revenue, warning against future rate increases if accurate costs are selected for the test period. [2] This thinking must be rejected.

14. BC Hydro argues against particular evidentiary inputs based on effects (or results) rather than accuracy or consistency. It is not a principled approach and should not be endorsed. For example, the opportunity to net interest rate and pension cost forecasts against each other, or not, should not bias the choice of forecast methodology (e.g., five-year average, or not).[3].

[1] BC Hydro Final Argument, p. 248-251. See para. 578 re "offsetting impacts".
[2] BC Hydro Final Argument, p. 248, para. 578 and 587.
[3] BC Hydro Final Argument, p. 252-253, paras. 590-592.

II. InterGroup's Recommendations

15. AMPC retained InterGroup Consultants Ltd. to evaluate the Application and provide its views, in particular as it affects industrial customers. InterGroup's expert evidence is high-quality and credible, and AMPC adopts its recommendations in this Argument.

16. Mr. Bowman and Ms. Davies have experience advising customers, utilities, and governments alike. They engaged deeply with the Application and the Commission's history of regulating BC Hydro. InterGroup filed a comprehensive expert report and defended it across information requests and cross-examination from myriad Interveners, BC Hydro, Commission Staff, and Commissioners. These parties asked InterGroup important questions to test and clarify its evidence. AMPC commends the resulting transcript and responses to the Commission.

17. At the same time, the Commission has access to little expert evidence contrary to BC Hydro's positions. While AMPC sponsored expert evidence to provide contrasting views from those of BC Hydro, it is unfortunate no other party was in a position to do so. The Commission must exercise caution against overreliance on BC Hydro perspectives that have not been tested or challenged to the degree warranted for such a major regulatory process.

18. InterGroup's recommendations fall into two broad categories. First, timely recommendations that relate to the overall regulation of BC Hydro by the Commission, spanning this proceeding and forthcoming rate proceedings. Second, considerations specific to the test period rates.

To give effect to the Phase 1 Report directions, the Commission should issue general directions to BC Hydro to ensure efficient and effective processes

19. The Commission should direct BC Hydro to recognize industrial rate competitiveness as a high priority because of the *systemic risk* that lagging industrial competitiveness poses to *all* rate classes. While this does not generate any single revenue requirement change in the current Application, it can help provide directional guidance to BC Hydro and communicate the severity of the issue to all participants through the series of decisions that need to be made in this and future proceedings. Industrial rate competitiveness is addressed in **Appendix A**.

20. Consistent with InterGroup's evidence, and based on the record of this proceeding, AMPC submits that the Commission should provide directives to BC Hydro about information it should include in upcoming near-term proceedings, which include proceedings that address:

    i. Setting BC Hydro's return on equity;

    ii. The Integrated Resource Plan (IRP) proceeding;

    iii. BC Hydro's cost of service methodology and rate design; and

iv. The next RRA, as it relates to regulatory account complexity and interim rates.

21. The Commission is an independent, expert body that can exercise its statutory mandate be a "first mover" in providing advice and guidance to parties including BC Hydro and government.[4] Direction from the Commission can assist in setting the scope for these upcoming proceedings, identifying priorities and guideposts, and specifying information and studies that BC Hydro can begin to prepare now for future proceedings. As InterGroup elaborates in its Evidence, the current hearing panel "[s]taying silent in anticipation of potential future (but currently unknown) government direction risks policy choices made without the benefit of BCUC expertise, independence and process."[5] All of these factors contribute to an orderly process as BC Hydro returns to Commission regulation. These matters are discussed further in **Appendix B.**

Specific issues in the F2020-F2021 RRA

22. Concerning test period rates, the Commission should take the following steps, as described in InterGroup's Evidence:

    a. **Powerex Net Income:** The Commission should direct BC Hydro to adhere to its own methodology by updating its test year forecasts to include F2019 actuals in its Powerex Net Income forecast methodology, reducing each test year's revenue requirement by $56 million. Powerex Net Income is covered in **Appendix C**.

    b. **Finance Charges:** The Commission should direct BC Hydro to update its finance charge forecasts for relevant known conditions and values, and use data reasonably available at the time of BC Hydro's Evidentiary Update to set rates. This is addressed in more detail in **Appendix D**. Specifically:

        i. For **long-term debt**, BC Hydro should update its forecast to reflect interest rates at levels consistent with the debt locked in during the test years to date – the discrepancy in the Application is either gearing or a serendipitous internal oversight that BC Hydro is now reluctant to correct, and is unfair to ratepayers; and

        ii. For **short-term debt**, BC Hydro should update its forecast to reflect the BC Ministry of Finance's short-term interest rate forecast published in early September 2019 – there was no reason for BC Hydro not to avail itself of its "phone call" access to the identical information in August.

    c. **Pension Costs:** The Commission should direct BC Hydro to reject the new 3.33% pension discount rate for the purposes of rate setting. While AMPC does not challenge Morneau Shepell's credentials, the updated discount rate was provided without meeting the burden of proof to support such a marked change, in contrast to the updates BC Hydro *avoided* making above.

[4] Transcript Volume 11, p. 2005, pdf p. 181, ll. 14-20.
[5] Exhibit C11-14, BCUC IR 2.1, p. 8, pdf p. 9.

Concerning the test period:

i. InterGroup's Evidence recommended the Commission retain the 3.83% pension discount rate from its original RRA Application to apply to test year pension costs (both non-current and current), and this remains an acceptable approach for rate setting at this time.

ii. However, a preferable and longer-term solution is for the Commission to adopt the approach of using a five-year average of discount rates as previously proposed by BC Hydro, which it appears would address both BC Hydro's and AMPC's concerns. Indeed, a five-year average can be used to stabilize various volatile revenue requirement inputs, including pension costs, storm restoration costs, and Powerex Net Income.

iii. For either change, test year rates should be adjusted accordingly. The financial impacts should not be ignored in the current rate period and instead captured within deferral accounts, as suggested by BC Hydro.

The impacts of BC Hydro's discount rate change are $67.3 million for F2020 and $67.7 million for F2021. This issue is covered further in **Appendix E**.

d. **Medical Service Plan (MSP) Premiums**: The Commission should direct BC Hydro to incorporate the $70 million gain from the elimination of MSP premiums into revenue requirement, rather than defer this *known* amount to deferral accounts to be settled *years* into the future.

AMPC takes no issue with the accounting rules that BC Hydro's Rebuttal Evidence cites regarding limits on recognizing these amounts in March 31, 2019 balances for financial reporting purposes, does take issue with uncritically applying such rules for ratemaking purposes. The *regulatory account mechanics* are within the Commission's control, and AMPC submits those mechanics should be varied here to address a known cost within the test period under review. Doing so also lowers rates sooner and on a fair basis – a step that would give effect to prioritizing industrial rate competitiveness.

e. **Depreciation:** AMPC currently has no alternative but to accept BC Hydro's late-arriving commitment to complete and file a depreciation study in the coming years. This matter is vital to fair rates, and there is ample evidence that BC Hydro's costs for depreciation may be well over-stated, causing adverse impacts on customers today. Further, BC Hydro's practice is well outside the mainstream of accepted practices and the advice of its own depreciation consultant. As with other types of filings, BC Hydro has committed to a depreciation study in the past and then decided not to proceed, which underlines the need for clear direction from the Commission on this matter now. This topic is addressed in **Appendix F**.

The above matters should be included in rates at the earliest possible opportunity, and not simply adjusted through deferral accounts or any new form of balancing. The BCUC has a clear opportunity to improve industrial rate competitiveness and help accelerate rate relief at a crucial time for the economy.

III. Further Orders Based on the Evidence from the Oral Hearing

23. Based on the elements of BC Hydro's Application that were addressed in parties' cross-examinations at the oral hearing, AMPC makes the following submissions:

    a. **Hedging:** BC Hydro appears to have overvalued the risk of increasing interest rates without fully assessing the market conditions and potential benefits of a sustained low interest rate environment. BC Hydro's hedging strategy increased from 50% to 75% of long-term debt issuances during a time of sustained low interest rates, without justification on the record. BC Hydro appears to be overly focused on cost certainty, rather than protecting ratepayers from the risk of higher interest rates. The Commission should assess the performance of BC Hydro's current debt hedging strategy to date and make findings about its relative success and impact on rates . The Commission should also direct BC Hydro to identify and report, at the next RRA, on its hedging strategies and outcomes, including how successfully BC Hydro has minimized its cost of debt. This is addressed in **Appendix G**.

    b. **Interconnections:** Interconnections have been a longstanding industrial competitiveness concern, and BC Hydro has not made meaningful improvement with respect to staff numbers, timelines and results. This needs to change, particularly given BC Hydro's stated desire to grow and attract load. The Application and BC Hydro's testimony do not provide sufficient evidence that BC Hydro is prepared to significantly improve its practices. This is covered further in **Appendix H**.

    c. **Capital Projects (Geotechnical Concerns):** BC Hydro has changed its processes regarding geotechnical investigations, but it has failed to provide adequate information on the record of this proceeding regarding the costs associated with its prior practice. The Commission should direct BC Hydro to identify the costs associated with foreseeable geotechnical-related delay and redundancies on certain capital projects, and disallow those amounts from the capitalized project costs. This is covered further in **Appendix I**.

    d. **Project Write-offs:** The Commission should not approve BC Hydro's proposed recovery of forecast project write-off expenses. It would require the Commission to assume that BC Hydro project practices are prudent, inconsistent with the general onus BC Hydro bears to justify specific costs. BC Hydro could offer no examples of comparable practices in other jurisdictions. Further, the proposed change to BC Hydro's practices regarding project write-offs alters the framework through which the government earns a rate of return, which is premature given that the rate of return proceeding remains in the future. This is covered further in **Appendix J**.

    e. **General Concern about the Commission's ability to review BC Hydro's assets**: The Commission cannot disallow costs related to many large BC Hydro projects – for example, the Interior to Lower Mainland transmission line ("ILM") and Site C Clean Energy Project. Nonetheless, the Commission should not assume all of the associated costs were prudent – many may not have been. This is significant in both the context of future rate of return consideration (the utility faces little risk and a fair return is therefore conservative), as well as project write-offs, because BC Hydro's rationale for these amounts assumes that all write-offs are prudent.

There are clear *prima facie* facts on the record for both major projects that merit the scrutiny of a regulator. While the Commission has no legal authority to stop those costs from entering rates, and while BC Hydro's Final Argument endeavors to provide assurance, the Commission's reasons in this proceeding should be clear that it has not been able to assess the prudence of these project costs. This is also covered in **Appendix J.**

f. **Early Acquisition of Vancouver Properties for Substation Projects:** The $110M of property assets should not be in rate base if and when BC Hydro's net income is calculated based on a rate of return on rate base (i.e., rather than the present prescribed amount). Because there is currently a legislated net income, there is no quantifiable harm to ratepayers in the test period arising from the rate of return, but, if it were otherwise, ratepayers should not pay a return on these assets. This is covered further in **Appendix K**.

g. **DSM and Load Curtailment:** BC Hydro needs to better integrate load curtailment options (and perhaps other DSM) into its resource planning. It should be using industrial load curtailment to a greater degree. This is covered further in **Appendix L**.

IV. Responses to Commission Questions

24. The Commission has requested parties to respond to three legal questions.[6] AMPC quotes the questions and provides its brief responses immediately below.

> **1.** ***Whether the Peace Region Electric Supply*** **[PRES]** ***project meets the requirements to be considered a prescribed undertaking under section 18 of the Clean Energy Act, pursuant to section 4(2) of the Greenhouse Gas Reduction (Clean Energy) Regulation;***
>
> **2.** ***Whether the Minette Station to LNG Canada Interconnection*** **[MIN to LNGC]** ***project meets the requirements of the Transmission Upgrade Exemption Regulation, as amended by B.C. Reg. 160/2018, to exempt the project from Part 3 of the Utilities Commission Act;***

25. AMPC has reviewed the legislation and the project descriptions on the record of this proceeding. AMPC accepts that the PRES and MIN to LNGC projects satisfy the quoted sections, as the legislation appears to be drafted in contemplation of these projects.

26. AMPC notes that during the oral hearing, Chairperson Morton inquired further about how the Commission ought to assess the prudence of BC Hydro's spending on these projects.[7] Consistent with AMPC's submissions during the oral hearing concerning the Commission's continuing supervisory jurisdiction, and the importance of interveners' ability to inquire after

[6] Exhibit A-31.
[7] Transcript Volume 8, p. 1239, pdf p. 165, l. 20 - p. 1240, pdf p. 166, l. 12.

other exempt project costs (e.g., the ILM transmission line and Site C Clean Energy Project), AMPC agrees that Commission efforts to assess BC Hydro's cost prudence are important.

27. Where BC Hydro has not met its onus of demonstrating prudence, or where the Commission has not had the benefit of contending views or contrasting evidence, the Commission should say as much. Its reasons should be simple: recovering the cost of exempt facilities in rates is mandated by regulation but, despite Commission efforts, those costs should not be assumed to be prudent given the limitations on parties' ability to test and understand them.

3. Whether British Columbia Hydro and Power Authority's investments in electric vehicle charging infrastructure should be included in rate base during the current test period and recovered from ratepayers or be separately tracked and excluded from rate base until the British Columbia Utilities Commission directs otherwise, given the developing landscape of the electric vehicle charging stations market in BC.

28. In response to this question, BC Hydro submits that Direction No. 8 requires EV charging infrastructure to be added to BC Hydro's rate base.[8] That interpretation is not self-evident to AMPC. Direction No. 8 requires the Commission to establish BC Hydro's rate base as, broadly speaking, its assets in service, subject to adjustments.[9] Those adjustments may exclude post-F2012 expenditures that the Commission determines should not be recovered in rates. As para. 331 of BC Hydro's Final Argument intimates, under Direction No. 8 the Commission may consider if EV charging expenditures should be excluded from rates.

29. For these reasons, AMPC submits that the Commission ought to simply apply a "first principles" approach: has BC Hydro satisfied its onus to show that the investment is necessary for utility service, reflects the lowest cost alternative that will meet the identified need safely, and will be used and useful? If not, potentially as with the downtown substation properties, for example, the investments should be held outside rate base and revenue requirement. BC Hydro explains that the charging stations support CleanBC. Its Service Plan suggests the same.[10]

30. BC Hydro also argues that the forthcoming legislation is likely to deal with the issue, and so any adjustment to rate base would be inappropriate. Also, because net income is prescribed by legislation, BC Hydro suggests retaining the investments in rate base does not harm ratepayers. AMPC submits that these reasons cut both ways. If the legislation changes, the Commission can respond. Likewise, if ratepayers are unharmed by the Commission taking steps in the normal course, there is no reason to deviate from that course.

[8] BC Hydro Final Argument, p. 145, para. 329, pdf p. 155.
[9] Direction No. 8 to the British Columbia Utilities Commission, BC Reg. 24/2019, s. 1, "rate base", Note 1.
[10] Exhibit B-5, BCUC 1.122.4, pdf p. 1388; Exhibit B-1, Appendix E, pp. 6 and 15, pdf pp. 1346 and 1355.

V. Conclusion

31. This proceeding has been lengthy, and generated an extensive record. It features tens of thousands of pages of evidence and an eleven-day oral hearing that filled nearly all of the time allocated. AMPC appreciates the diligence and participation displayed by the Commission, BC Hydro, other interveners, and participants in the proceeding. This appreciation extends to steps taken before and after the onset of the COVID-19 pandemic.

32. This proceeding is important to AMPC because access to safe and reliable electricity at fair, competitive and predictable rates are critical to AMPC members' businesses. Those businesses are a key part of the provincial economy and fabric of BC, and will play an important role as the province begins its recovery.

33. For these reasons, AMPC submits the Commission should grant the recommendations and orders outlined by AMPC in **Sections II and III** of this Argument and elaborated in **Appendices A to L** of this submission.

All of which is respectfully submitted this 4th day of May, 2020.

Norton Rose Fulbright Canada LLP



Matthew D. Keen | Emily Chan | Alexander Baer

Counsel to the Association of Major Power Customers of British Columbia

APPENDIX A: INDUSTRIAL RATE COMPETITIVENESS

ISSUE

34. Industrial rate competitiveness is a longstanding concern in BC and a significant issue in this proceeding. Industrial customers are unique in their profile and price sensitivity relative to other ratepayers, as uncompetitive rates have distinct, wide-ranging, and long-term implications for their operations.

35. Load reductions or permanent load loss harm BC Hydro's ability to recover its costs, resulting in higher rates for all ratepayers. The slowdown or shut down of industrial operations also affects jobs, communities, and investment in the province. Uncompetitive rates constitute a systemic risk because all ratepayers, not only industrial customers, face potential harm from uncompetitive industrial rates. As a result, addressing industrial rate competitiveness should be a high priority for the Commission.

AMPC SUMMARY AND/OR RECOMMENDATION:

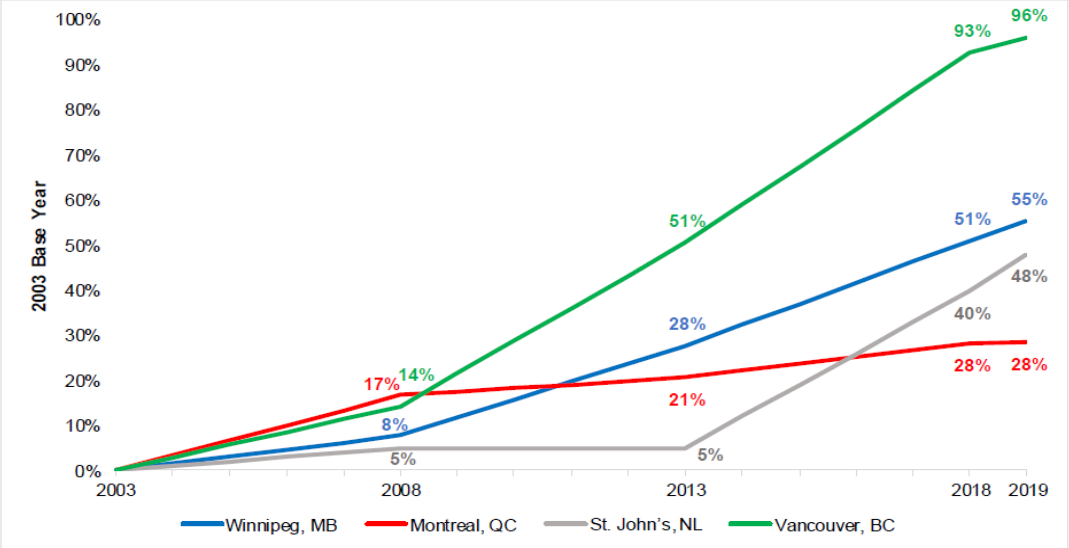
36. As many industrial customers and AMPC members compete in global markets, they are "price-takers" who are typically unable to directly pass escalating power costs on to their customers. Electricity intensive industrial operations facing increasingly uncompetitive rates may feel economic pressure to shift or migrate production to other jurisdictions, or relocate facilities. The larger size of industrial loads means that when such shifts happen, the broader system is more readily affected.

37. Over the past decade, BC Hydro's industrial customers have faced significant rate increases. As InterGroup explains in its Evidence, BC Hydro's industrial electricity rates have increased by 96% since 2003.[11] Whether these industrial rate increases are assessed on a percentage increase basis or in absolute dollars, they represent a significant erosion of competitiveness in BC that is only worsening over time. BC Hydro itself recognizes this loss of competitiveness – its CEO, Mr. O'Riley acknowledged in the oral hearing that BC Hydro is "not as deep into that top quartile [of industrial competitiveness] as we were in the past."[12]

38. When compared against its peers – i.e., other hydropower dominated, Crown-owned Canadian utilities, BC Hydro's industrial rate increases considerably exceed and outpace these other utilities.[13] Over the same time period, these comparator utilities have had much smaller electricity cost increases, in the range of 28% to 55%.[14]

[11] Exhibit C11-11, p. 17, pdf p. 21.
[12] Transcript Volume 5, p. 412, pdf p. 92, ll. 11-18.
[13] Exhibit C11-11, p. 17, pdf p. 21.
[14] Exhibit C11-11, p. 17, pdf p. 21, for a hypothetical 50 MW load.

Figure 4-2: Comparison of average electricity prices growth in Vancouver for Large-Power Customers to other Canadian cities where the power source is predominantly from hydro[21]



39. On this basis, AMPC makes the following recommendations:

    a. The Commission should make addressing industrial rate competitiveness a priority. The issue is important and extends beyond industrial customers.

    b. The Commission should make a clear finding that addressing industrial rate competitiveness should be a goal across the BC Hydro proceedings expected in the near-term (e.g., rate of return and rate design), to facilitate a consistent approach. Otherwise, there is a risk that issues arising in this Application will not be resolved and will repeat in the future.

DISCUSSION AND SUPPORT:

A. Introduction

40. In this Appendix, AMPC addresses the following topics:

    a. The unique impacts of uncompetitive rates on industrial customers;

    b. The detrimental effects of uncompetitive industrial rates on all ratepayers, BC Hydro, and the Province of British Columbia; and

    c. Material increases in BC Hydro's industrial electricity rates since 2003, which are increasingly uncompetitive compared its peer utilities in Canada.

B. Industrial Customers are Uniquely Affected by Uncompetitive Rates

41. Large industrial customers are a sizable and important component of BC Hydro's total load – they represent approximately 26% of total sales or approximately 14,000 GWh/year to BC Hydro.[15]

42. There is no serious dispute that competitiveness, and more specifically, industrial rate competitiveness is important. BC Hydro itself agreed in its Rebuttal Evidence[16] and in the oral hearing[17] that industrial rate competitiveness is important.

43. Uncompetitive rates are a concern for any customer class, but industrial customers are disproportionately affected. Mr. Bowman was repeatedly confronted on this point in cross-examination, and provided the following clarification:

> "It's <u>not to say that one customer is more important than the other</u>, it's to say that there's a <u>systemic risk</u> associated with industrial customers that is <u>different at this point in time</u>, to my understanding, than other causes.'[18] [emphasis added]

44. He explained that other customer classes can also present systemic risks in other circumstances, such as solar panel-using residential customers in Jamaica. On BC Hydro's system, these systemic risks arise from reasons unique to the profile of industrial customers:

    a. Electricity is one of the largest cost inputs in industrial sectors like natural gas production, pulp and paper, mining, and forestry.[19] Energy costs can range from 10 to 60% or more of total operating costs for large industrial customers.[20]

    b. As "price takers",[21] industrial customers do not have the ability to pass escalating electricity costs onto customers. BC Hydro acknowledged the "challenging economic circumstances" and "highly competitive markets" that large industrial customers face.[22]

45. Mr. Bowman explained that BC Hydro's rates for residential customers are "not in that range"[23] where "all the customers are going to go drop off the system".[24] However, he provided his opinion that some industrial customers can be expected to respond to present rate pressure by curtailing production at times:

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[15] Exhibit C11-11, p. B-1, pdf p. 74.
[16] Exhibit B-28, p. 3, pdf p. 6, Q/A 2, l. 8; Transcript Volume 5, p. 412, pdf p. 92, ll. 25-26.
[17] Transcript Volume 5, p. 411, pdf p. 91, ll. 25-26 and p. 412, pdf p. 92, ll. 5-6.
[18] Transcript Volume 11, p. 1986, pdf p. 162, ll. 15-19.
[19] Transcript Volume 5, p. 409, pdf p. 89, ll. 13-15 and 18-26.
[20] Exhibit C11-13, AMPC Response to MoveUP IR 3.3, pp. 6-7, pdf pp. 7-8.
[21] Transcript Volume 5, p. 409, pdf p. 89, ll. 18-26.
[22] Exhibit B-28, BC Hydro Rebuttal Evidence, p. 4, pdf p. 5, ll. 4-5; Transcript Volume 5, p. 357, pdf p. 37, l. 24 - p. 358, pdf p. 38, l. 1.
[23] Transcript Volume 11, p. 1986, pdf p. 162, ll. 4-5.
[24] Transcript Volume 11, p. 1985, pdf p. 161, ll. 20-21.

> MR. BOWMAN: A … BC Hydro's rates are not in that range for residential customers, but they are in a range for industrial customers where given market conditions and given the challenges faced by some of them there is a risk of having firms responding to electricity price increases or electricity price pressures in general with, you know, shutting shifts, perhaps closures, and affecting BC Hydro's loads in towns. And I don't think -- like I say, I don't think that's a secret. I think everyone who reads the newspapers will know of some of those pressures.[25]

C. Uncompetitive Industrial Rates are Detrimental to All

46. The loss of residential or commercial load is an unfortunate scenario that should be avoided. But, as InterGroup noted, the loss of a single residential or commercial customer does not have the same far-reaching impact as the slowdown, shutdown or departure of a single industrial customer.[26] InterGroup explained this point directly in an IR response:

> In the large industrial sector, particularly the energy intensive sector, electricity can make up a very substantial part of a firm's costs. As such, uneconomic rates threaten the very operations of the firm's plant and can lead to load migration or outright loss. This undermines BC Hydro's industrial loads, as well as the related downstream residential loads of workers and commercial loads of suppliers. It can be very difficult for BC Hydro to replace this revenue from domestic sources, and therefore the same power may be exported. This threatens to make other jurisdictions more competitive at the very time BC Hydro is becoming less competitive, and may cause further cost increases to other classes, along with obvious economic and social concerns for the region."[27]

47. If industrial customers reduce consumption or new loads do not materialize, then BC Hydro's ability to recover its costs is affected, and all of BC Hydro's customers' rate must rise to compensate.[28] Mr. Bowman summarized this point in his opening statement:

> MR. BOWMAN: … BC Hydro was a cost leader among low cost jurisdictions in Canada through to 2008, which is no longer maintained. Industrial customers established themselves and the size of their operations in B.C. based in part on low cost power. Energy makes up a large percent of their total operating costs because rate competitiveness affects industrial customers differently than other customer groups, the Commission panel should flag industrial competitiveness as a priority for BC Hydro.
>
> If industrial customers reduce consumption or new loads do not arise then all of BC Hydro's customers rate must rise.[29]

[25] Transcript Volume 11, p. 1986, pdf p. 162, ll. 4-14.
[26] Exhibit C11-14, CEC IR 1.1, p. 2, pdf p. 65.
[27] Exhibit C11-13, AMPC Response to MoveUP IR 3.1 and 3.2, p. 6, pdf p. 7.
[28] Transcript Volume 11, p. 1965, pdf p. 141, ll. 11-14.

48. For these reasons, it is in the interests of BC Hydro, all ratepayers, and the Province of BC to mitigate the risk of industrial load migration through more competitive rates. Again, Mr. Bowman addressed this point repeatedly in cross-examination:

> MR. ANDREWS: Q So in terms of your recommendations, would you say that your recommendations are based on the interests of these high load factor industrial customers, and the transmission service class? Or all of the members of the transmission service class? Or maybe as a third alternative, all industrial customers, whether they are in transmission service or in large general service?
>
> …
>
> MR. BOWMAN: A Well, our recommendations are in regard to regulating BC Hydro generally that in a manner that will benefit all customers. Our retainer was from a group of industrial customers, and they relayed to us the types of things that they see as concerns, and we have some understanding from working with industrial customers in different places the types of concerns that industrial customers have.
>
> But I think in regards to things like industrial competitiveness, <u>even if I am a residential customer, losing an industrial customer or risking their competitiveness and their ability to operate and continue to even buy power from BC Hydro is a type of systemic risk that I am not interested in either. So, I think the interests are there broadly for the jurisdiction, the utility and all the customers</u>.[30] [emphasis added]

49. Mr. O'Riley's comments are instructive in terms of the broader significance of declining industrial rate competitiveness:

> MR. KEEN: Q But you agree with -- again, at the policy level, declining industrial rate competitiveness is a problem, yes?
>
> MR. O'RILEY: A Well, we would like to maintain our industrial rate competitiveness. We would like these customers to carry on and continue and provide jobs and employments and support for communities, so we are a hundred percent in agreement with you that creating conditions that cause these companies to continue is important.[31]

[29] Transcript Volume 11, p. 1965, pdf p. 141, ll. 1-14.
[30] Transcript Volume 11, p. 1978, pdf p.154, l. 18 - p. 1979, pdf p.155, l. 15.
[31] Transcript Volume 5, p. 412, pdf p.92, ll. 19 - p. 413, pdf p. 93, l. 2.

D. BC Hydro's Industrial Rates are Increasingly Uncompetitive Relative to its Peers

50. The evidence and data before the Commission is clear about where BC Hydro's rates are situated. Notwithstanding BC Hydro's insistence that its costs ought to be compared to non-peer jurisdictions, InterGroup's Evidence presents a straightforward and fair comparison:

    a. "BC Hydro is presently the highest cost Canadian jurisdiction of the hydro-dominated provinces, including Manitoba, Quebec, and Newfoundland, typically treated as peer jurisdictions. This is a significant change from each of 2003 and 2008 when BC Hydro was second lowest, behind only Manitoba and only to a small degree."[32]

    b. "Over the period since 2003, BC Hydro's rates, as reported in the Hydro-Quebec survey, have increased 96%, compared to 55% for Manitoba, 48% for Newfoundland and 28% for Quebec."[33]

    c. "[F]rom 2008 to 2019, the average rate increases across North American jurisdictions was 30% … The most prominent increases have occurred in western states and provinces, including in BC (Vancouver has increased 72% …). When adjusting for exchange, BC electricity prices have seen the highest overall growth in this timeframe. Comparatively over this timeframe, other Canadian hydro jurisdictions (where generation is over 90% hydroelectric) have seen growth between 10 – 44%."[34]

    d. "Where BC used to rank 2nd in average rates about 10 years ago, rate growth over the past decade has dropped BC's competitiveness to fourth as of April 2019. Notably, the other three Canadian hydro-focused jurisdictions [i.e., Manitoba, Newfoundland, and Quebec] rank higher than BC in 2019."[35]

    e. "On a broader scale, the rate impacts experienced by BC Hydro industrial customers over 16 years exceed all North American jurisdictions studied by Hydro Quebec."[36]

51. InterGroup's deliberate choice to emphasize BC Hydro's rates relative to those of Crown-owned hydro-dominated utilities reflects an "apples to apples" comparison that the Commission should prefer to BC Hydro's approach of treating the 22 disparate jurisdictions across North America as equally relevant comparators.[37]

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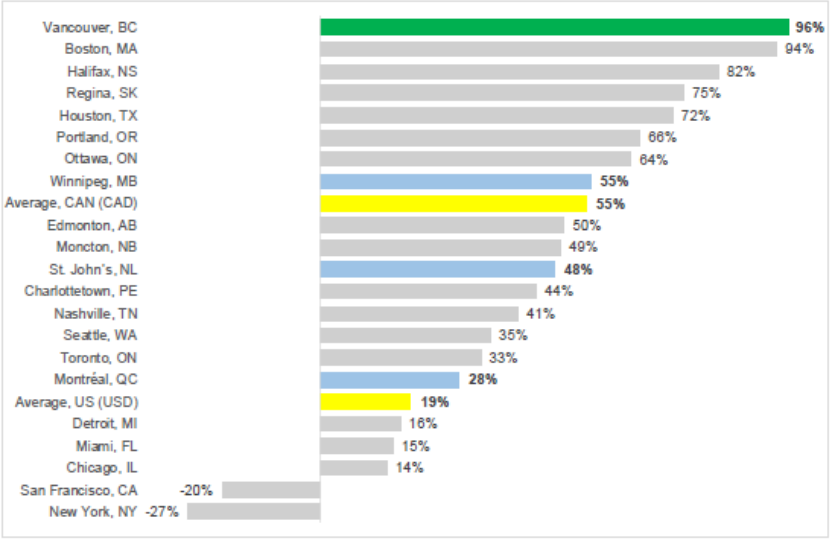
[32] Exhibit C11-11, p. 15, pdf p. 19.
[33] Exhibit C11-11, p. 17, pdf p. 21, and p. B-4, pdf p. 77.
[34] Exhibit C11-11, p. B-2, pdf p. 75.
[35] Exhibit C11-11, p. B-9, pdf p. 82.
[36] Exhibit C11-11, p. 18, pdf p. 22.
[37] Exhibit B-28, Appendix A, "Electricity Rate Comparison Annual Report No. 12", pdf pp. 23-44.

52. Any suggestions from BC Hydro that InterGroup hid comparisons favourable to BC Hydro or used an unduly narrow peer group (i.e., that it "cherry-picked" the three lowest average prices[38]) should be rejected.

53. Appendix "B" of InterGroup's Evidence directly compares BC Hydro's electricity prices with those of the entire Hydro-Quebec survey group across multiple years. Rather than omitting any data, InterGroup's analysis required significant tabulation and presentation, including with and without foreign exchange effects. It clearly shows that the pace of BC Hydro's rate increases exceeds that of any comparator:

Figure B-4: Electricity Prices Growth in Major North American Cities in last 16 years where in CAD for Canadian Cities and USD for US Cities (from April 1, 2003 to April 1, 2019)[6]



54. The three main comparators that InterGroup selected are an uncontroversial peer group:

> MR. GHIKAS: Q And Hydro Quebec doesn't present the data the way that you have done in figure 4.1, does it?
>
> MR. BOWMAN: A The Hydro Quebec report is just a snapshot of one year, it doesn't do anything over time.
>
> MR. GHIKAS: Q Right, but it also doesn't single out those four utilities -- four jurisdictions and present data like that, does it?
>
> MR. BOWMAN: A No, it wouldn't because the Hydro Quebec report is just a data dump of a number of cities. <u>The reason for focusing that way is because there is, you know, generally understood to be a series of jurisdictions in Canada that are</u>

[38] Exhibit B-28, p. 3, pdf p. 6, ll. 13-19 and p. 4, pdf p.7, Figure 1.

> pretty similar, Manitoba, Quebec and B.C. being the traditional ones, that have a large hydro. That have the resources to build that way, that have Crown owned utilities that dominate the sector. So they're, you know, typically thought of as peers.[39] [emphasis added]

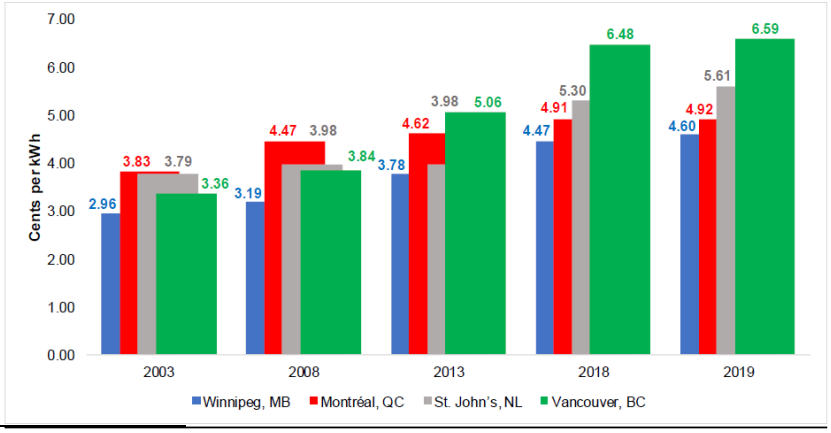
55. BC Hydro itself has used Manitoba and Quebec as its peers. In assessing its operating costs against other jurisdictions, BC Hydro conducted its comparison against "three other major Canadian hydroelectric utilities".[40] The associated footnote contains a reference to BC Hydro's response to CEC IR 1.34.1, in which BC Hydro stated its reasons for selecting Manitoba Hydro and Hydro Quebec as comparative Canadian utilities, which include that these utilities are "closely aligned with BC Hydro's operations", "would provide for a reasonable comparison", and have a "similar profile to BC Hydro":

56. Mr. Bowman explained under cross-examination why using the three hydro provinces for primary comparison purposes made sense from a customer perspective too. In response to a line of questioning from counsel about whether the Hydro Quebec survey excluded certain hydro based utilities, Mr. Bowman confirmed that multiple jurisdictions have hydro, but may nonetheless have uncompetitive rates, citing Ontario as one example:

> Ontario has a fair bit of hydro, in fact Ontario actually has more hydro than Manitoba does as an absolute value, but Ontario's rate are not competitive and they've long since driven out any sort of industrial firm that's sensitive to rates, that's the issue for competitiveness.[41]

57. More powerful yet is Figure 4.1 in the InterGroup Evidence, which compares the absolute costs per kWh of peer utilities for five different years, spanning 2003 to 2019:

Figure 4-1: Comparison of average electricity prices in Vancouver for Large-Power Customers to other Canadian cities where the power source is predominantly from hydro[20]



[39] Transcript Volume 11, p. 2033, pdf p. 209, ll. 2-20. Also see Transcript Volume 11, p. 2034, pdf p. 210, l. 24 - p. 2035, pdf p. 211, l. 4.
[40] BC Hydro Final Argument, para. 235, pdf p. 115.
[41] Transcript Volume 11, p. 2038, pdf p. 214, ll. 12-19.

58. As Mr. Bowman explained, the purpose of Figure 4.1 was to show not only absolute cost but electricity cost changes over time (emphasis added):

> MR. BOWMAN: A … I want to emphasis the change over time, we didn't just do this to do a snapshot. <u>The point about change over time is if you're an industrial customer established in a jurisdiction you have a given cost structure where it sort of doesn't matter if another jurisdiction is a little bit cheaper than you or somewhat more expensive. What really matters is how your costs change over time</u>, because you're going to face other types of costs that are different, transportation, labour, climate, all this things change…. So the change is way more important than the absolute level.[42]
> …
> It is the pressures that people have seen from the increases we are talking about is, the fact that you are seeing a doubling over the period here where other jurisdictions who have similar type of asset base haven't required that.[43] [emphasis added]

59. At the coarsest level, it may simply be that other jurisdictions have done a better job at managing their costs over time to keep rate increases small than has BC Hydro.

60. In cross-examination, BC Hydro also suggested that looking at absolute percentage increases of prices obscures overall competitiveness.[44] The Evidence filed by InterGroup provides *both* price increases in absolute dollars as well as percentages. Figure 4.1 alone from InterGroup's Evidence proves that BC Hydro rates are becoming less and less competitive, in material fashion:[45]

61. Additional factors that cause and compound industrial rate competitiveness are discussed in **Appendix B.** Ultimately, industrial uncompetitiveness creates a systemic risk to all rate classes, and has broader implications for BC Hydro and the province. The recommendation from AMPC for the Commission, to find that industrial rate competitiveness is a high priority in this and future proceedings, is intended to provide directional guidance to BC Hydro and communicate the severity of this issue to all participants in this and upcoming proceedings.

[42] Transcript Volume 11, p. 2036, pdf p. 212, l. 6 - p. 2037, pdf p. 213, l. 1.
[43] Transcript Volume 11, p. 2043, pdf p. 219, ll. 15-19.
[44] Transcript Volume 11, p. 2049, pdf p. 225, ll. 7-10.
[45] Exhibit C11-11, p. 16, pdf p. 20.

APPENDIX B: COMMISSION DIRECTIVES TO ENABLE INCREASED REGULATORY OVERSIGHT

ISSUE

62. Under the Phase 1 Final Report of Government's Comprehensive Review of BC Hydro, BC Hydro's Application is the first step in implementing full resumed regulatory oversight by the Commission. A series of other rate proceedings will come before the BCUC in the near-term, most conspicuously the rate of return review.

63. At this juncture, the current Commission hearing panel has the opportunity, powers, and statutory mandate, to provide directives to BC Hydro about information it should include in upcoming proceedings, and the scope that the Commission anticipates for these processes. Commission guidance about how it expects regulation will unfold would benefit BC Hydro, future decision-makers, customers, and government alike.

64. Any directives made by the Commission at this time regarding future proceedings do not bind the Commission to future decisions, but will help avoid critical information gaps, inefficiencies and delays, and provide all participants with orderly processes.

SUMMARY AND RECOMMENDATION:

65. AMPC adopts the recommendations of InterGroup, which are for the Commission to set priorities for future rate applications and use the current proceeding to explicitly set out important guideposts to permit an orderly, efficient, and successful process to unfold. AMPC submits the Commission should make the following findings to help guide next steps:

    a. **Deferral Accounts:** BC Hydro's overall deferral account structure is excessively complicated and broad, serving to reduce transparency in rate setting and transfer risk to ratepayers from BC Hydro's shareholder. BC Hydro should be directed to, over time, continue reducing the scale and scope of regulatory accounts where feasible. This will ensure that BC Hydro's costs are fully regulated and are transparent to the regulator and impacted parties. Using existing deferral accounts as a "catch-all" should be discouraged. The Commission should utilize its authority to require rates based on the best information about test year costs and appropriate forecasting methodologies, rather than allowing BC Hydro to rely on deferral accounts to postpone addressing forecast inaccuracies.

    b. **Scale of Cost Increase and Threshold for Review of RRA:** Absent the use of a favourable DARR balance to fund a government-directed ROE, customers would have seen a material rate reduction in F2020, all else being equal. Factors outside of BC Hydro's control that resulted in swings in the DARR should not be allowed to obscure material cost increases at BC Hydro – that is, potential shortfalls that would otherwise require rate increases of between 10 to 15 percent.

Transparency is important. The Commission should take into account the significant scale of cost increases when reviewing BC Hydro's proposed cost levels in this and subsequent RRAs. The Commission should also indicate that BC Hydro must remain attentive in preparing future RRAs to bringing the cost pressure on rates down, with limited exceptions (such as interconnections, which are addressed in **Appendix H**).

c. **Rate of Return Review:** BC Hydro should be provided further direction clarifying matters that will be in scope in the upcoming rate of return review, and that should be addressed in BC Hydro's submission. These include issues relevant to determining a fair level of return, including funding sources, financial and other risk and who bears it, and shareholder policy issues.

d. **Additional Factors Affecting Competitiveness of Rates:** The Commission should direct BC Hydro to identify and, where possible, quantify contributors to the uncompetitiveness of rates arising from government actions (such as ill-advised IPP policy, or ILM project issues that have been removed from regulation). In time, these costs should be scrutinized to determine whether they are used, useful and prudently acquired assets that provide service at the lowest reasonable cost. The cost impact of projects that the Commission cannot review is relevant to the risk BC Hydro's shareholder assumes, and in turn, the level of return that is fair.

e. **Cost of Service:** BC Hydro should be directed to bring forward, for open and transparent testing, a cost of service methodology review and rate design application as soon as practicable, before 2023. This is a normal and required part of fulfilling the legislative requirement for just and reasonable rates, and was committed to by BC Hydro multiple times. BC Hydro's current cost of service methodology arose only out of a truncated process that did not fully and properly address many important issues, and is therefore deficient for go-forward purposes. This issue is further urgently required given the degree of adverse effect experienced by industrial customers from the failure to properly reflect the purposes of Tier 2 (marginal cost) and Tier 1 (below average cost) rates in the cost of service study. Currently, industrial customers are failing to receive the benefits that should have arisen from the Tier 2 framework, as the Tier 1 energy is effectively now priced at average price and not a price that is below average.[46] This issue is part of the reason why industrial competitiveness has eroded, and it cannot be fully addressed without a proper cost of service review.

66. These items are addressed in turn in the following sections.

[46] Exhibit C11-11, p. 32, pdf p. 36.

DISCUSSION AND SUPPORT

A. Complex Deferral Accounts Undermine Transparency, Discipline and Fairness

67. In response to AMPC and InterGroup's concern about BC Hydro's use of deferral accounts, Mr. O'Riley conceded that BC Hydro has been criticized over the last decade by a variety of parties for the number of regulatory accounts it maintains,[47] and expressed mild frustration that parties did not appreciate the role of each account.[48]

68. AMPC's concern, and InterGroup's Evidence, is more nuanced. It is not the simple number of regulatory accounts or the magnitude of balances within the accounts (although both stand out), but the overall complexity of BC Hydro's regulatory accounts. Their use collectively, over time, undermines transparency, utility discipline, and effective ratemaking.[49] BC Hydro's Final Argument "misses the forest for the trees" in its response, and fails to address this larger concern.

69. As InterGroup noted, the primary purpose of regulatory/deferral accounts is to match costs to benefits, which current practices undermine.[50] And as explained in response to BCSEA IR 6.1, the accounts dampen shareholder risk and cloud utility transparency and discipline:

> The scope of deferral accounts means that BC Hydro's shareholder is at very little risk from normal business functions and variances. If the accounts are not simplified and narrowed (both in scope and number), the justification for a ROE is significantly undermined (i.e., the justification for reward based on assumed risk diminishes as the risk assumed diminishes). Further, the accounts are excessively broad which makes transparent regulation difficult. For these reasons the accounts should ideally be narrowed in scope (not just collapsed into fewer accounts). Absent such steps, the ROE should be adjusted materially downwards.[51]

70. No government owned Canadian utility appears to maintain regulatory accounts with as broad a scope and function as BC Hydro.[52] Compared to its Canadian peer utilities, BC Hydro's regulatory accounts are markedly broader and more complex.[53]

71. As a consequence, deciphering year-to-year changes and cost drivers is difficult,[54] and complicated filings and extensive information requests are required to unpack BC Hydro's rate case.[55] BC Hydro states that because it provides the information required in the BCUC's Deferral Account Checklist, information on the history, cost and recoveries of each

[47] Transcript Volume 5, p. 431, pdf p. 111, ll. 12-21.
[48] Transcript Volume 5, p. 431, pdf p. 111, ll. 6-11.
[49] Exhibit C11-11, pp. 23-24, pdf pp. 27-28.
[50] C11-13, AMPC response to BCSEA 6.2, p. 16, pdf p. 42.
[51] Exhibit C11-13, pp. 15-16, pdf pp. 41-42.
[52] Exhibit C11-11, p. 24, pdf p. 28.
[53] Exhibit C11-11, p. 24, pdf p. 28.
[54] Exhibit C11-11, p. 24, pdf p. 28.
[55] Exhibit C11-11, p. 24, pdf p. 28.

account, and eight years of actual and forecast balances, it has been "transparent". BC Hydro's Final Argument also undertakes an exhaustive defence of each individual deferral account.[56] None of these facts alleviate the core concern above: the deferral accounts unduly complicate regulation, leading to a loss of utility discipline and accountability. The need for such extensive documentation in this proceeding underscores the point that regulatory account mechanics add significant complexity to rate reviews.

72. Mr. Bowman elaborated on this point in cross-examination when asked if InterGroup supported less use of deferral accounts:

> MR. BOWMAN: A Directionally, I am suggesting that as these series of proceedings occur, towards reregulation of BC Hydro, that it would be appropriate if at this juncture the Commission provided direction that we are trying to narrow or limit or reduce the scope of things covered by deferral accounts or alternatively that if it's as many things are going to be covered by deferral accounts as there are today, that we take that into account on anything that's trying to assess the shareholder returns to the owner because it affects the extent to which the shareholder is taking any risk at all.
>
> …
>
> I'm suggesting at this point we've definitely swung much farther towards the "let's just charge ratepayers actuals" and stabilize everything we can or most of the things that we can, and as a result there's very little risk remaining in the system, very little swings that will affect BC Hydro and ratepayers pay their actuals at the end of the day.
>
> The downside of that approach is that you can lose a lot of discipline and you can have a mindset, if you like, that the utility is not on the hook and therefore need not manage those things in the same way. That's the downside of that type of approach.
>
> …
>
> [T]<u>he deferral account tool perhaps has been the hammer that makes every problem look like a nail. A bit over used</u>.[57] [emphasis added]

73. The relief AMPC seeks from the Commission is simple: a general direction for BC Hydro to simplify its regulatory and deferral accounts regulatory account structure over time as a long-term priority, to improve accuracy and transparency in regulation. [58]

B. Cost Pressures on BC Hydro are Obscured

74. InterGroup's written Evidence identified favourable events that have permitted setting the 5% DARR collection for F2020 down to 0%, allowing BC Hydro to propose moderate rate increases but with a limited net effect on customer bills.[59] These included IFRS changes

[56] BC Hydro Final Argument paras. 408-428, pdf pp. 187-196.
[57] Transcript Volume 11, p. 2008, pdf p. 184, ll. 15-26, p. 2009, pdf p. 185, l. 18 – p. 2010, pdf p. 186, l. 5, p. 2013, pdf p. 186, ll. 10-12.
[58] Exhibit C11-11, p. 24, pdf p. 28.
[59] Exhibit C11-11, pp. 19-20, pdf pp. 23-24.

that permitted a one-time adjustment to the Heritage Deferral Account balances and conditions like decreased water rentals, IPP purchases from dry conditions, and increased Powerex Net Income that were materially improved compared to forecasts.[60]

75. Rate reductions that would have been possible under the initial DARR methodology due to declining balances in the deferral accounts will not be seen by customers.[61]

76. Both Ms. Davies and Mr. Bowman explained the larger issue, that BC Hydro has obscured cost increases that it otherwise would have had to justify more strenuously. InterGroup provided detailed calculations in response to BCUC IR 1.1 of how BC Hydro's shortfalls of $738.7 and $511.5 million for each of F2020 and F2021 would require rate increases of 15.1% and 10.4% respectively.[62] Annual shortfalls in the range of $500 to 700+ million, with necessary rate increases in the range of 10 to 15 percent, present a stark contrast to BC Hydro's pronouncements regarding its "culture of cost containment."[63]

77. Mr. Bowman likewise explained that cost pressures can "get lost" owing to "other good news item[s]":

> If we didn't have that favourable variance. <u>And that $700 million shortfall I guarantee before it would make it into this room would have gone through some serious sharp pencil analysis, and some significant cost review inside the building</u>.
> …
> It's not about whether the DARR should be different, it's not about rewriting some history or changing, we wish the government hadn't changed it in regulation, and <u>there is no specific recommendations except about recognizing how much cost pressures are actually built into BC Hydro's application that if you are not careful, get lost by the fact that there is this other good news item</u>.[64] [emphasis added]

78. But for the DARR swing, BC Hydro would have had to impose major rate increases to achieve a distributable surplus of $712 million.[65] BC Hydro would have faced significant pressures to reduce costs and find efficiencies, rather than burden customers to that extent. AMPC's recommendations in this area are intended to ensure that context is recognized and some of that pressure is felt.

79. In its Rebuttal Evidence, BC Hydro failed to meaningfully respond to InterGroup's recommendation, largely because it responded to an imagined preference for the earlier 10-year rates plan instead. BC Hydro's only relevant response was that net bills would remain

[60] Exhibit C11-11, pp. 19-20, pdf pp. 23-24.
[61] Exhibit C11-11, pp. 19-20, pdf pp. 23-24.
[62] Exhibit C11-14, BCUC IR 1.1, pp. 2-4, pdf 3-5; Transcript Vol. 11, p. 1988, pdf p. 164, ll. 9-18.
[63] BC Hydro Final Argument, para. 118, pdf p. 68; Transcript Vol.5, p. 337, pdf p. 17, l. 3 and p. 368, pdf p. 48, l. 10.
[64] Transcript Vol. 11, p. 1994, l. 23 - p. 1995 ll. 1 and 11-18; pdf pp. 170-171.
[65] Direction No. 8 to the BC Utilities Commission, B.C. Reg. 24/2019.

the same if the DARR had remained at 5%.[66] This misses the point, as InterGroup's analysis was predicated on the initial DARR methodology, given the context of declining deferral account balances, and not the 5% imposed later in the face of growing deferral account balances.

80. These facts support InterGroup's recommendation for the Commission to find that, absent the redirection of DARR funds into a government-directed ROE, customers would have seen a material rate reduction in F2020, all else equal.[67] AMPC adopts this recommendation.

C. Benefits and Recommendations for BCUC Guidance for Future Proceedings

81. AMPC addresses these issues here, although it recognizes that the Commission is not ruling on them directly in this proceeding, because the current proceeding is the best opportunity for the Commission to gather information and make critical findings on rate-related issues that will arise or be examined in greater detail in upcoming proceedings.

82. The Commission's guidance and recommendations to BC Hydro and government alike will be invaluable in setting "goalposts", allowing the utility to have adequate information to do the work it needs to do, and making significant progress in the phased return of BC Hydro to full regulation. BC Hydro's contention that "it would not be appropriate for the BCUC to make determinations on matters related to rate design and return on equity in future test periods"[68] is misplaced and should be ignored. AMPC seeks for the Commission to issue guidance about the scope and timing of processes that will establish BC Hydro rates. It is highly appropriate for the Commission to structure and manage its own processes.

83. The Commission is an independent expert body that can be a "first mover" to provide advice and guidance to BC Hydro and government alike. Mr. Bowman elaborated on this point:

> [T]his Commission is an expert body who can provide advice and scoping to BC Hydro on what would be filed in that review can say this would be within the scope. If that's not what government wants to happen, they still have the ability to apply direction and react to that long before that review occurs.[69]

84. A clear example of the need for BCUC advice and guidance to BC Hydro arises with regard to the upcoming rate of return proceeding. BC Hydro is currently operating in a model that does not mimic competitive forces,[70] and yet the Commission has its hands tied from doing the work that regulators typically do to independently establish a fair return on equity until F2022.[71]

[66] Exhibit B-28, pp. 5-6, pdf pp. 8-9.
[67] Exhibit C11-11, pp. 19-20, pdf pp. 23-24.
[68] Exhibit B-28, p. 2, pdf p. 5, ll. 7-8.
[69] Transcript Volume 11, p. 2005, pdf p. 181, ll. 14-20.
[70] Exhibit C11-13, BCSEA IR 5.7, p. 14, pdf p. 40.
[71] Exhibit C11-11, p. 21, pdf p. 25, citing Exhibit B-1, Appendix V, p. 17, pdf p. 2111.

85. There are compelling reasons to support the current BCUC Panel issuing directives to BC Hydro *now* that relate to the upcoming rate of return review.

86. In response to BCUC IR 2.1, in which Commission Staff inquired about the "advantages and potential risks" of the BCUC doing so, considering that government may provide policy guidance in the rate of return review for F2022, InterGroup provided multiple reasons for this BCUC Panel to issue findings and directions:

> Staying silent in anticipation of potential future (but currently unknown) government direction risks policy choices made without the benefit of BCUC expertise, independence and process. Recommendations made to BC Hydro in the normal course are important and part of the BCUC's current legislative mandate to exercise general supervision over public utilities and set just and reasonable rates. Government can issue directions to both BC Hydro and the BCUC notwithstanding BCUC direction to BC Hydro, but the BCUC should not shrink from its mandate in anticipation of Government direction.
>
> Further, in the event the BCUC provides direction on topics that require preparation of information or studies in support of a future BC Hydro filing, it is important to identify these early so BC Hydro can get the necessary materials prepared. Leaving these aspects of scope setting until after a filing is too late.
>
> There is a "risk" that Government policy direction, if any, overrides or reverses BCUC direction – as is the prerogative of government under the *UCA*. That "risk" is not a reason for the BCUC to avoid directing the most reasonable orderly process consistent with today's information. The only issue in this instance is whether or not, prior to any policy direction it might make, the Government of B.C. will have the benefit of the BCUC's independent advice and expertise as to priority issues and principles.[72] [emphasis added]

87. Similar to the Depreciation issue raised in this proceeding and discussed in further detail in **Appendix F**, it would be unfortunate if the rate of return review occurs with BC Hydro unable to produce important information to support the review, because it had not started the groundwork early enough, did not properly understand the Commission's views on the proper scope of the proceeding, or took an unduly narrow view of the scope of the proceeding.

88. For this reason, AMPC submits that the Commission should clarify the scope for the rate of return hearing within this proceeding's decision. Specifically, the Commission should direct BC to address the following matters in its submission:

    a. **The basis for justifying a return to the Government shareholder** (i.e., is it compensation for capital provided, or some other test)? In other Canadian jurisdictions, the Crown-owned utility shareholder has received no return because they have made no investment in the first place.[73] Arguably, having driven rates to uncompetitive levels

[72] Exhibit C11-14, BCUC IR 2.1, p. 8, pdf p. 9.
[73] Exhibit C11-13, BCSEA IR 5.6, p. 14, pdf p. 40.

through policy, the BC Government should not *further* drive rates higher to secure excessive returns on investment or earn a return on imprudent decisions that have driven up costs.[74]

b. **Whether BC Hydro in fact has any material "equity" investment by the Province**, including a tracking of the evolution of BC Hydro's existing equity and whether that fairly represents an investment by the BC Government as shareholder (as opposed to the establishment of reserves by ratepayers paying above-cost for power). As InterGroup points out, "[i]t should not be taken as a given that balances that BC Hydro's financial statement reports as "retained earnings" or "equity" represent actual shareholder investments on which it is appropriate to earn a return. It would be beneficial for the BCUC to clarify this point as being part of the ROE assessment earlier rather than later."[75]

c. **The extent of risk borne by BC Hydro's shareholder** on which to earn risk-based equity compensation. In addition, the impact of excessive deferral accounts and other "stabilization" mechanisms that serve to mute this risk exposure.

d. **The extent of benefits already provided to the BC Government** (in the form of policy directive responses which lead to above-cost energy delivery). This should include a summary of BC Hydro's retained earnings (historically and to the present day) with specific reference to equity injections or share purchases by Government, previous dividends to Government, charges other than dividends paid to the Government (historically and to the present day), the contribution to equity made by ratepayers paying rates-above-cost, and costs incurred relating to BC Government directions to BC Hydro that represent above-cost impacts on ratepayers (e.g., IPP policy).

   It is clear that the BC Government can direct BC Hydro to undertake many activities, similar to a Government department. The difference is that Government departments are funded through Government revenues – while BC Hydro is funded by energy ratepayers buying a service. The types of initiatives noted are specific to BC Hydro and not general purpose spending.[76] By issuing such directives, the Commission should make clear that this is a form of "return" or "dividend" to the BC Government (the implementation of adverse-cost policy objectives), and this may be best netted out of the return otherwise made available to the shareholder (if any).

[74] Exhibit C11-13, BCSEA IR 5.9, p. 14, pdf p. 40.
[75] Exhibit C11-13, BCSEA IR 5.5, p. 13, pdf p. 39.
[76] Note the exchange between Mr. Bowman and Mr. Andrews (counsel for the BCSEA) at Transcript Volume 11, pp. 2006-2007, pdf pp. 182-283 where an example of broad legislation on PCBs was used as a straw-man example, which was rejected by Mr. Bowman – he noted the type of benefit-tapping of concern by the BC Government related to "BC Hydro specific directives" like the need to use IPPs.

D. Identification of Additional Material Costs

89. Throughout its expert Evidence, InterGroup has identified additional contributors to uncompetitive rates. To summarize, these include, among others:

    a. **Cost pressures arising from government policy on IPPs**.[77] The "Zapped" report published by the Minister of Energy, Mines, and Petroleum resources drew three conclusions: that BC Hydro bought too much energy and energy with the wrong profile, BC Hydro paid too much for the energy it bought, and BC Hydro undertook these actions at the direction of government.[78] InterGroup's additional analysis of the cost of energy across multiple revenue requirement applications shows small changes to Heritage Energy and Market Energy, but significant growth in Non-Heritage Energy.[79]

    b. **Capital costs, including capital projects with costs significantly over budget**, such as the Northwest Transmission Line and the Interior to Lower Mainland transmission line.[80] As one prominent example, the Commission is barred from scrutinizing the ILM project and the unjustified costs that have been imposed on ratepayers, including a confidential adverse arbitration award that has added $96.7 million to the project cost.[81] The ILM, other capital projects, and project write-offs are discussed in greater detail in **Appendices I and J** of this Argument.

    c. Water rental charges. Government has already recognized that BC Hydro pays more for water use than other utilities across Canada, and even after the reduction in 2018, water rental rates are high compared to previous water rate structures and other jurisdictions.[82]

90. All of these issues are discussed in greater detail in Section 4 of InterGroup's Evidence. They have also been canvassed by AMPC and other interveners in the hearing room.

91. InterGroup has made two recommendations in response to these problems, both of which AMPC now adopts: for the Commission to clearly identify certain costs that materially contribute to uncompetitive rates (even if the BCUC cannot direct changes at this time), and for the Commission to ensure that future rate reviews consider and test the prudence and least cost nature of all costs that continue to be included in BC Hydro's revenue requirement (even costs committed in previous periods, which have to date not been properly tested or adjusted in rates).[83]

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[77] Exhibit C11-11, p. 25, pdf p. 29.
[78] Exhibit C11-11, p. 25, pdf p. 29, citing "Zapped: A Review of BC Hydro's Purchase of Power from Independent Power Producers" conducted for the Minister of Energy, Mines and Petroleum Resources, by Ken Davidson, February 2019.
[79] Exhibit C11-11, p. 26, pdf p. 30, Table 4-2.
[80] Exhibit C11-11, p. 28, pdf p. 32.
[81] Exhibit C11-11, pp. 28-29, pdf pp. 32-33.
[82] Exhibit C11-11, p. 29, pdf p. 33. Further details are contained in Exhibit C11-11, Appendix C, pdf pp. 86-88.
[83] Exhibit C11-11, p. 30, pdf p. 34.

E. Need for Directions to BC Hydro on Cost of Service and Rate Design

92. AMPC adopts InterGroup's recommendations that Rate Schedule 1823 be examined in the near-term, including the design of Tier 1 and 2 rates, and that the BCUC direct BC Hydro to bring forward the cost of service study methodology for an open and transparent review.[84]

93. AMPC acknowledges that the BCUC is prevented by statute from requiring BC Hydro to rebalance rates, but BC Hydro's industrial rates are less competitive in part because the industrial revenue to cost ratio is calculated according to disputed methods and based on premises that no longer exist. The Commission is not precluded from finding in its reasons that BC Hydro's rates would benefit from scrutiny of its cost of service methodology.

94. InterGroup has explained the challenges industrial customers currently face in this domain:

> 1. Customers did not receive the benefits that should have arisen from the Tier 2 framework, as the Tier 1 energy is effectively now priced at average price and not a price that is below average.
>
> 2. Customers have had their investment in efficiency deemed stale and Tier 2 credits either expire or approach expiry.
>
> 3. At the same time, the financial impacts of the other policy the Government put in place to incent private sector energy supply, providing access to marginal pricing for IPP supplies to BC Hydro (via EPAs), remain in place and are driving the average cost of energy materially higher for industrials.[85]

95. Specifically, for customers under Rate Schedule 1823, the concern noted by InterGroup in response to BCSEA IR 7.1 is as follows:

> [T]he Tier 1 rate should be lower than the average or embedded cost of power on BC Hydro's system. At present, the rate is only slightly below the average cost, as evidenced by the revenue-cost ratio measured by the last performed (and problematic) FACOS. A two-tier rate likely remains justified on economic efficiency grounds. However, there needs to be appropriate credits for long-term activities which affect the customer baseline and would ensure the Tier 1 rate is appropriately set.[86]

96. Affordability issues cannot be fully addressed without Commission review of BC Hydro's cost of service methodology. As InterGroup explains, accurate cost of service studies are "an "integral mechanism for setting just and reasonable rates."[87] Ms. Fraser agreed that cost of study outputs have value beyond informing rate rebalancing, including in matters relevant to revenue requirement.[88] Furthermore, cost of service studies (under accepted methods) are "normal and appropriate" for utilities to conduct at regular intervals. They are

[84] Exhibit C11-11, p. 33, pdf p. 37.
[85] Exhibit C11-11, p. 32, pdf p. 36.
[86] Exhibit C11-13, BCSEA IR 7.1, p. 17, pdf p. 43.
[87] Exhibit C11-13, Zone II RPG IR 1.1 and 1.1.1, p. 2, pdf p. 3.
[88] Transcript Volume 6, p. 808, pdf p. 235, ll. 9-10.

not a material cost, and it is an anomaly that BC Hydro is likely to see a 15-year gap between a normal assessment of its methodologies (2008 to 2022 or later).[89]

97. Despite BC Hydro generating a cost of service study annually,[90] Mr. Wong confirmed that BC Hydro has “no current plans” to file an application to deal with the cost of service methodology within the 2020 calendar year.[91] BC Hydro's current cost of service study is based on a negotiated settlement, which parties agreed to with the expectation that BC Hydro would conduct a fulsome cost of service review and file a rate design application in F2019.[92] As Ms. Fraser acceded on cross-examination, BC Hydro filed a modified cost of service study, but did not and has not filed a full cost of service study or rate design application for Commission review, despite its earlier commitments.[93] As a result, the revenue to cost ratios contained in BC Hydro's annual cost of service studies, which have not been scrutinized by the regulator, are of limited value.

98. Again, while the Commission is unable to require rate rebalancing to remedy any problems identified in revenue to cost ratios, ensuring revenue to cost ratios are transparently identified as well as defensibly calculated is critical. Proper cost of service information provides correct information to government and is a better basis for setting policy:

> [T]he policy determination that revenue-cost ratios should not be addressed by the Commission may reflect incomplete or incorrect information available to policy makers. Up-to-date and correct information (as provided by a Cost of Service study) may be the basis for reconsidering the policy.[94]

99. Otherwise, BC Hydro does not face a standard level of scrutiny and cross-subsidies may go undetected, or allowed to linger based on a mistaken appreciation of their severity.

100. Ms. Fraser confirmed on behalf of BC Hydro that it will file a comprehensive rate design application "no matter what the result of the Phase 2 [Comprehensive] Review" is.[95] Ms. Fraser also described the stakeholder and customer engagement efforts that BC Hydro intends to undertake to inform a future rate design application.[96] While welcome, the basis for the negotiated settlement was the promise of a F2019 filing that has not happened yet.

101. The Commission should therefore impose timelines on BC Hydro to file applications for approval of both its cost of service methodology and rate design as soon as practicable, and in any case, by the end of calendar 2022.

[89] Exhibit C11-13, MoveUP IR 1.1, p. 2, pdf p. 3.
[90] Exhibit B-28, p. 2, pdf p. 5, ll. 11-16.
[91] Transcript Volume 5, p. 427, pdf p. 107, l. 17.
[92] Transcript Volume 6, p. 804, pdf p. 231, l. 24 – p. 805, pdf p.232, l. 20.
[93] Transcript Volume 6, p. 805, pdf p. 232, ll. 7-20.
[94] Exhibit C11-13, MoveUP IR 1.1, p. 2, pdf p. 3.
[95] Transcript Volume 6, p. 807, pdf p. 234, ll. 20-24.
[96] Transcript Volume 6, p. 807, pdf p. 234, ll. 4-6.

APPENDIX C: FORECAST POWEREX NET INCOME

ISSUE

102. BC Hydro's Evidentiary Update changed its forecast methodology for Powerex Net Income (also referred to as "Trade Income" for the purposes of the discussion below),[97] in a discretionary manner that will increase each test year's revenue requirement by $56 million.[98] That discretionary step is inconsistent with the principles of the underpinning methodology and should be rejected.

103. BC Hydro's methodology is to average the five most recent actual years. This approach was undertaken in past applications, protecting ratepayers from year-to-year volatility from market conditions and avoiding the need for speculative or complicated forecasting approaches. In its original Application in this proceeding, BC Hydro used the actual years F2014 – F2018, with the average income being $120.6 million, to determine the F2020 and F2021 test year forecasts.[99]

104. For the August 2019 Evidentiary Update, BC Hydro updated its Cost of Energy forecasts for F2019 actuals, including actual 2019 Powerex Net Income. Despite using the actual figure generally, BC Hydro omitted it when it came to the Powerex Net Income forecast. Instead it retained the original calculation and test year forecasts.[100]

AMPC SUMMARY AND/OR RECOMMENDATION:

105. The Commission should direct BC Hydro to update its test year forecasts to include F2019 actuals in its Powerex Net Income forecast methodology and adjust rates accordingly. This should result in forecast Powerex Net Income for F2020 and F2021 equal to $176.3 million in each year.

106. As BC Hydro uses the same method for the storm restoration forecast costs,[101] as a matter of consistency, the five-year average used for F2020 and F2021 test years should also be updated to include F2019 actuals.

[97] Trade Income is "the greater of (a) the amount that is equal to BC Hydro's consolidated net income, less BC Hydro's non-consolidated net income, less the net income of BC Hydro's subsidiaries except Powerex, less the amount that BC Hydro's consolidated net income changes due to foreign currency translation gains and losses on intercompany balances between BC Hydro and Powerex; and (b) zero": Exhibit B-1, p. 8-17, pdf p. 979, fn. 334.
[98] Exhibit B-16, BCUC IR 3.313.2.2, pdf pp. 310-312.
[99] Exhibit B-1, p. 8-17, pdf p. 979.
[100] Exhibit B-16, BCUC IR 3.313.2, pdf pp. 306-207.
[101] As noted by BC Hydro in its Final Argument, pp. 248-249, pdf pp. 258-259.

DISCUSSION AND SUPPORT:

107. The tables below from InterGroup's Evidence compare the test year revenue requirement impact depending on the years of Powerex Net Income that are averaged:

Table 1: Powerex Net Income Five-Year Average F2014 - F2018 Compared to F2015 - F2019 ($ Millions)[102]

$ Millions	Reference Appx A	F2014	F2015	F2016	F2017	F2018	Avg.
Actual Powerex Net Income	Sch 1.0, L17	$157.6	$120.1	$58.7	$130.2	$136.6	**$120.6**

$ Millions	Reference Appx A Ev. Update	F2015	F2016	F2017	F2018	F2019	Avg.
Actual Powerex Net Income	Sch 1.0, L17	$120.1	$58.7	$130.2	$136.6	$435.7	**$176.3**

108. InterGroup's Evidence supported the inclusion of the actual Powerex Net income for F2019 in the five year average to update the forecast Powerex Net Income in the test years (F2020 and F2021), on the basis that the forecasting methodology was to be based on the most recent five years.[103] In the Evidentiary Update, the most recent five years would include F2019.

109. BC Hydro rejected this approach, and suggested that the Powerex F2019 results were not expected to occur to the same extent going forward.[104] However, when a forecast method entirely depends on actual results (as in this case), it does not make sense to update the actual results and then ignore these results where they are appropriately applied to the test years. Specifically, the InterGroup Evidence noted that:

> It is also important to note that despite BC Hydro's claims to the contrary, including the F2019 data in the RRA five-year average does not assume those specific conditions or results noted above are expected to occur "to the same extent going forward", given that the function of averages will effectively only weight the results by 20% (a 1/5 weighting to each year of the averaging period). It is simply recognition that since BC Hydro has opted for simplicity in its forecasting method over accuracy it should at least use the best updated data

[102] Exhibit C11-11, p. 35, pdf p. 39, Tables 5-1 and 5-2.
[103] Exhibit C11-11, p. 36, pdf p. 40 ("[I]ncluding the F2019 data in the RRA five-year average… is simply recognition that since BC Hydro has opted for simplicity in its forecasting method over accuracy it should at least use the best updated data available for to represent the wide range of changing trading and marketing conditions that influence Powerex Net Income".)
[104] Exhibit B-17, AMPC IR 3.3.2, pdf p. 29.

> available for to represent the wide range of changing trading and marketing conditions that influence Powerex Net Income.[105]

110. BC Hydro responded to InterGroup's Evidence in its Rebuttal Evidence by suggesting that the current forecast of Powerex Net Income (excluding F2019 actuals) "continued to be a reasonable estimate at the time the evidentiary update was prepared":

> Forecast Trade Income is based on a five-year average and ratepayers receive the benefit of actual Trade Income through the use of the Trade Income Deferral Account. BC Hydro continues to believe that the five-year average approach is appropriate and expects to include fiscal 2019 actual Trade Income in the five-year average calculation for forecasting Trade Income in its next Revenue Requirements Application.
>
> BC Hydro limited the scope of the Evidentiary Update to targeted adjustments primarily related to fiscal 2019 actuals and the new Cost of Energy forecast. In BC Hydro's view, considering the historical range of actual Trade Income, the current Trade Income forecast of $120.6 million, based on fiscal 2014 to fiscal 2018 actuals, continued to be a reasonable estimate at the time the Evidentiary Update was prepared. In contrast, BC Hydro updated the Cost of Energy forecast in the Evidentiary Update because changing conditions meant that the original forecast was no longer reasonable.[106]

111. Yet, BC Hydro subsequently provided updated quarterly results for F2020 Trade Income in its response to an undertaking, which showed that the Trade Income for the nine months ending December 31, 2019 was $159 million (i.e., for the first nine months of F2020, with three months outstanding).[107] This is approximately $40 million higher than the F2020 Trade Income calculated based on BC Hydro's proposed forecast ($120.6 million) and only $17 million lower than the Trade Income calculated by updating the five-year average to include F2019 actuals ($176.3 million),[108] with three months of the fiscal year remaining.

112. Mr. Bowman addressed these problems squarely in his opening statement:

> First, using a five-year average is intended to avoid any need to figure what may or may not reoccur. Updating for Fiscal 2019 only affects 20 percent of the forecast as it's only one year of the five that will be averaged, so it's not depending on reoccurrence. The intent of the method is to avoid this type of discretion.

[105] Exhibit C11-11, InterGroup Evidence, p. 36, pdf p. 40.
[106] Exhibit B-28, p. 12, pdf p. 15, Q/A 7.
[107] Exhibit B-46, BC Hydro Undertaking No. 24.
[108] See para. 107, above.

> Second, Powerex net income has been typically under forecast by BC Hydro in four out of five years from fiscal 2015 to 2019.
>
> Third, although it did not update the Powerex forecast, BC Hydro updated the market electricity purchases forecast in its June 2019 filing for the test years to increase the unit costs compared to the original October 2018 forecast. Further, after updating, the market unit costs are now above the fiscal 2015 to 2018 level and closer to the five-year average. BC Hydro's response to Undertaking 24, which was recently filed, confirms that Powerex results up to the end of Quarter 3 Fiscal 2020 are consistent, if not ahead of our recommendation. I hesitate to make that last point, because the intent is not to try to update for ongoing results which are still subject to change, but if anything it confirms the direction that we would be providing.
>
> And fourth, BC Hydro sought to extend the 2018 Powerex letter agreement indefinitely to allow forward market purchases of electricity. This agreement was put in place because Mid-C markets had decreased supply, driving day-ahead market prices up, and BC Hydro indicates it has no basis to believe this Fiscal 2019 market condition will reverse itself. Taking those four things into account, we do not see the basis to say Fiscal 2019 should be ignored when the results are known.[109]

113. BC Hydro, on the other hand, confirmed its position on this issue in cross-examination:

> MR. KEEN: Q That's something that you didn't change even though you had F2019 actuals available to you, right?
>
> MR. WONG: A That's correct. What we did change is the -- put in the forecasts -- or sorry, the actuals for Fiscal 2019. So those were reflected all through, and to the benefit of the ratepayers. What we did not do is update the five year average for Powerex net income. And maybe just to go back and give the panel some understanding why we didn't do that, when we did -- as I mentioned in my opening statement, when we did the evidentiary update we wanted to reflect the Fiscal '19 actuals that came through, and so that was one of the major changes, and the other was the reservoir levels and the impacted cost of energy.
>
> We didn't change the Powerex net income because essentially the number we have in the application is an estimate and it's basically using a five-year average. So updating it, we felt like it's just changing one estimate for another estimate and we didn't feel that that was appropriate, especially given the fact that there was -- especially given the fact that there was a deferral account associated with

[109] Transcript Volume 11, p. 1970, pdf p. 146, l. 3 – p. 1971, pdf p. 147, l. 11.

trade income. And so like with Fiscal '19, any changes that happen get to the full benefit of the ratepayer.[110]

114. BC Hydro's Final Argument responds by arguing that updating the five-year average to include F2019 actuals in the Evidentiary Update should not be considered "in isolation", and specifically that the unfavourable impact of lower than forecast domestic sales revenue should be considered before updating the five-year average for Trade Income.[111]

115. This response misses the point. AMPC is arguing that the Evidentiary Update should reflect a consistent approach, and against gearing the outcome by preferring certain stale figures. In this sense, AMPC is arguing the opposite of updating inputs "in isolation", and the recent lower domestic sales forecast BC Hydro brandishes in response is misdirected.

116. The same discretion that led BC Hydro to conclude that the F2019 Powerex Net Income would not repeat itself and an update of the forecast for F2019 actuals should be excluded (which has proven to be incorrect) has now morphed into an argument that a very late-breaking load forecast variation should be included in the Commission's analysis to set off against a Net Income forecast based on full actuals.

117. The purpose of using a five-year average methodology is to avoid discretion and debates about set-offs and speculation.

118. BC Hydro's reliance on actual load data filed February 27, 2020 is belied by its November 18, 2019 submission that the June 2019 load forecast (only put on the public record in October) was not an input into the Application and had limited relevance.[112]

119. And BC Hydro did reduce domestic energy sales (and resulting domestic revenues) in its Evidentiary Update for F2020 by 271 GWh, to include April and May 2019 actuals.[113] The Evidentiary Update also accounted for changes to the Cost of Energy forecast based on a more recent Energy Study which predicted "decreased planned hydroelectric generation (water rentals) and purchases from IPPs and Long-Term Commitments" and "higher planned market electricity purchases" due to "[d]ry conditions and lower water inflows".[114]

120. Updating the Powerex Net Income forecast to rely on actuals available at the time of the Evidentiary Update is consistent with these other steps. A failure to update it is an exercise of discretion to upset a methodology that, ironically, was specifically designed to avoid discretion. The Commission should prefer AMPC's approach to the wild picking and choosing BC Hydro attempts in response.

[110] Transcript Volume 7, p. 906, pdf p. 86, l. 21- p. 907, pdf p. 87, l. 20.
[111] BC Hydro Final Argument, paras. 586-587, pdf p. 261.
[112] Exhibit B-24, p. 4, pdf p. 7.
[113] Exhibit B-19, pp. 3-4, pdf pp. 7-8, and Appendix A, p. 76, pdf p. 96.
[114] Exhibit B-19, pp. 7-9, pdf pp. 11-13.

121. More broadly, BC Hydro's position reflects an issue that has been pervasive in this proceeding: BC Hydro's tendency to conclude that so long as a topic is included in a deferral account, it is acceptable to ignore actuals or undertake incomplete updates, since the deferral account will solve all fairness issues later on.

122. This is not appropriate. A deferral account should capture changes that arise within the test years after a prospective rate hearing occurs. They should not be an excuse to tolerate an inconsistent application of principles. This issue is discussed in greater detail in **Appendix B**.

123. Finally, as both Powerex Net Income and Storm Restoration forecasts use a non-discretionary five-year average (unlike the load forecast), both should be updated according to that method.[115]

[115] As appropriately noted by BC Hydro, the storm restoration account also uses a five year average, for which F2019 actuals were also available at the time of the Evidentiary Update. It is appropriate to apply consistent treatment for this account as well. See BC Hydro Final Argument, paras. 580-581, pdf p. 259.

APPENDIX D: FINANCE CHARGES AND INTEREST RATE FORECASTS

ISSUE

124. BC Hydro has a history of over-forecasting the test year interest rates that underpin the finance charges within its revenue requirement. In the current proceeding, BC Hydro also failed to update its forecasts for known information that, absent such an update, will lead to large deferral account accruals, calculated at approximately $60 million.

125. Specifically, BC Hydro has failed to update its forecasts relating to long-term debt, short-term debt and sinking funds, as follows:

a. **Long-Term Debt:** BC Hydro's actual borrowings in the F2020 test year include three long-term issuances, as follows:

   i. $300 million on June 11, 2019 for 9.5 years at 2.95%;

   ii. $150 million on June 24, 2019 for 30 years at 2.80%; and

   iii. $100 million on June 7, 2019 for 31 years at 2.95%.[116]

   Yet, BC Hydro did not attempt to update its long-term debt rates even with these known lower interest rate conditions. In its Evidentiary Update, filed two months after the three long-term debt issuances described above, in August 2019, BC Hydro's average long-term forecast debt rate is significantly higher than these three issuances, at 3.46% for F2020 and 3.76% for F2021.[117]

b. **Short-Term Debt:** For the F2020 and F2021 test years, BC Hydro's Evidentiary Update forecasts short-term interest rates at 2.35% and 2.69% respectively.[118] This is based on the Treasury Board of BC's January 2019 forecast for three-month rates.[119]

c. **Sinking Funds**: BC Hydro's forecast sinking fund income is based on the forecast U.S. long-term interest rate provided by the Treasury Board of BC, originally at 3.55% for both test years in the Application, but increased in the Evidentiary Update to approximately 3.89% for F2020 and 3.76% for F2021.[120]

[116] Exhibit B-13, AMPC IR 2.26.1, Attachment 1, pdf pp. 33-34, ll. 31, 77, 81 and 82.
[117] Exhibit B-19, Appendix A, Schedule 8.0, p. 63, pdf p. 83, l. 83.
[118] Exhibit B-19, Appendix A, Schedule 8.0, p. 63, pdf p. 83, l. 92.
[119] Exhibit B-6, BCOAPO IR 1.72.1, pdf p. 583 with duration explained in BCOAPO IR 1.72.2, pdf p. 585.
[120] Exhibit B-13, AMPC IR 2.27.1, pdf p. 44; Exhibit C11-11, p. 43, pdf p. 47. The sinking fund rates were calculated by dividing the sinking fund income for each year by the end of year balance. See Exhibit B-19, Appendix A, p. 63, pdf p. 83, ll. 70-71.

AMPC SUMMARY AND RECOMMENDATION:

126. The Commission should direct BC Hydro to update its finance charge forecasts for known conditions, to ensure the best available data is used to set rates. Specifically:

a. For **long-term debt**, BC Hydro should update its forecast to reflect interest rates arising from the debt locked in during the test years and available at the time of the Evidentiary Update in August 2019.

b. For **short-term debt**, BC Hydro should likewise update its forecast to include short-term interest rate information that should have been available at the time of the August Evidentiary Update, and ended up being released in the BC Ministry of Finance's update in early September 2019; and

c. For **sinking fund income**, BC Hydro should update its forecast to reflect the best information regarding test year levels, in line with the timeframes used for long-term debt rates (known actuals from the first part of the F2020 test year) or short-term debt (updated forecasts from the BC Ministry of Finance in September 2019).

127. The variances in the finance charges described above represent known and locked-in cash expenses affecting the test years.

128. BC Hydro has a Total Finance Charges Regulatory Account to capture variations in finance charges due to variances from interest rate forecasts.[121] However, a regulatory deferral account should at most be used to capture variances from the best available forecasts – it is not a replacement for updating forecasts for known values. Otherwise, as here, the utility risks intergenerational inequities, timing issues, and a lack of transparency at the time of the next revenue requirement application.

129. Prioritizing industrial rate competitiveness means not unduly relying on deferral account mechanics, and taking principled available steps that will fairly lower rates now.

130. The Evidentiary Update was a reasonable final opportunity before the oral hearing to identify the best available data. AMPC submits that the evidence available at that time can fairly be used now to set rates.

[121] See for example Exhibit B-1, pp. 7-36 – 7-37, pdf pp. 926-927.

DISCUSSION

A. Background

131. As explained in AMPC's response to BCUC IR 4.1, the impact on BC Hydro's revenue requirement if it were to update its finance charge forecasts based on known conditions and values is as follows: [122]

- For long-term debt – due to BC Hydro's considerable amount of hedging for the test years, it is hard to estimate the impact on revenue requirement of maintaining a 2.95% interest rate based on recent borrowings. However, it is estimated that the impact on the unhedged portion of long-term debt may reduce the finance charge by about $2 million for 2020 and $7 million for 2021.[123] It is not as clear how these rates could impact the hedged portion of long-term debt, including the debt management regulatory account, which uses a point in time interest rate to calculate hedged positions (i.e. subject to large changes depending on interest rates).

- For short-term debt - lowering the F2020 rate from 2.35% to 1.73% and F2021 rate from 2.69% to 1.71% would appear to decrease finance charges by $18.3 million in F2020 (from $69.3 million to $51.0 million) and by $29.8 million in F2021 (from $81.9 million to $52.1 million).

- For sinking fund income – BC Hydro did not provide the background calculations supporting interest impacts of sinking funds in its [Evidentiary Update] filing.[124] However sinking fund income is included as an offset to finance charges, forecast at $7.8 million for F2020 and $7.7 million for F2021. Likely changes in sinking fund rates would be smaller in magnitude than the interest rate impacts noted above, potentially on the order of $3 million over the past few years.[125] It is possible revenue requirement impacts would be within this range.

[122] Exhibit C11-14, pdf p.16 (footnotes as per original).
[123] For example, BC Hydro's response to AMPC IR No 2.26.1 Attachment 1 shows that for fiscal 2020 remaining new unhedged long-term debt is $425 million at 3.76% interest rate [$8.7 million interest expense shown by BC Hydro compared to $15.9 million full year interest expense assuming new debt borrowed about middle of fiscal year] and $500 million for fiscal 2021 at 4.06% interest rate [$13.5 million interest expense shown by BC Hydro compared to $20.3 million full year interest expense assuming new debt borrowed in fourth month of the fiscal year]. With interest rate at 2.95% for both fiscal years, interest expense for $425 million would reduce by about $2 million for 2020 [$425M*2.95%/12*6.5 months=$6.8M-$8.7M], and for 2021 reduction in interest expense would be about $7 million [($425M*2.95%=$12.5M-$15.9M) + ($500M*2.95%/12*8=$9.8M-$13.5M).
[124] Appendix A, Schedule 8.0 details Finance Charges, with change in sinking fund and sinking fund income hard entered (i.e. not easy to reconcile how sinking fund rate changes may impact annual finance charges).
[125] See Table 5-8 from InterGroup Evidence, page 43.

132. BC Hydro should be able to easily quantify these changes in an undertaking or compliance filing, and the likely impact on revenue requirement of all three types of debt could be in excess of $20 million in F2020 and upwards of $40 million in F2021. This is approximately equal to a 0.45% rate decrease in F2020 and a 0.75% rate decrease in F2021 (as a percentage of BC Hydro's total revenue requirement of approximately $5.2 billion).

B. Appropriate Timing for Updating Interest Rate Forecasts

133. AMPC does not take issue with the underlying forecasts that BC Hydro uses from the Government of British Columbia. Rather, AMPC is concerned about the staleness of the forecasts and BC Hydro's failure to update them at the time of the Evidentiary Update,[126] even though BC Hydro's finance staff should be able to obtain such information from the provincial government as required.[127] As noted by Mr. Bowman at the oral hearing:

> On finance charges and the debt management regulatory account, the cost of interest is a real cash outflow in the test years. It is a cost of providing service. Our Section 5.2 explains that in these situations the best available information should be used. We make recommendations about using information that was or should have been available for the evidentiary update for long-term and short-term interest rates.
>
> It is already known that long-term debt has been locked in at rates below the RRA forecast for the test years, which will reduce BC Hydro's costs. Such known variances in actual expenses and cash requirements are not ideal situations to adjust via a regulatory deferral account. Instead, they should be adjusted in the test year forecasts. On short-term debt, a reliable public source, the B.C. Treasury Board, has updated forecasts from the original January 2019 forecast that's been used by BC Hydro. Rates have lowered materially. The forecast used by BC Hydro is very stale.
>
> Similarly, it appears sinking fund earnings have been ahead of forecast during a period when over forecasting debt costs have been a sustained problem for utilities, including BC Hydro, each of these items merits using reasonably up to date actual borrowing costs and updates to interest rates from the B.C. Treasury Board where such changes are material.[128]

134. In contrast, BC Hydro stated in its Rebuttal Evidence that:

> The Evidentiary Update used the most recent interest rates forecast available to BC Hydro from the Government of B.C., at the time the forecast was prepared. This forecast was as of January 4, 2019. In BC Hydro's view, the interest rates

[126] See for example AMPC's response to BCUC IR 4.3.1: Exhibit C11-14, pdf p. 20.
[127] See for example Mr. Layton's testimony at Transcript Volume 7, p. 898, pdf p. 78, l. 18 – p. 899, pdf p. 79, l. 13, reproduced at paragraph 136, below.
[128] Transcript Volume 11, p. 1971, pdf p. 147, l. 12 – p. 1972, pdf p. 148, l. 13.

> forecast used for the Evidentiary Update is reasonable. Continuing to update finance charge forecasts is impractical given that markets change on a daily basis. Through the use of regulatory accounts, ratepayers will ultimately pay the actual costs over time.[129]

135. There are two large problems with this response. First, BC Hydro's reliance on regulatory accounts to address any forecasting issues regarding finance charges, as set out in its Rebuttal Evidence response, is misplaced, especially given BC Hydro's admitted history of over-forecasting both long-term and short-term interest rates.[130] Regulatory accounts are not a substitute for accurate and timely forecasting, as described in greater detail in **Appendix B**. BC Hydro repeated its reliance on regulatory accounts in Final Argument, noting that "BC Hydro's Total Finance Charges Regulatory Account is an efficient mechanism to ensure that customers will pay the actual finance costs in the event that interest rates emerge differently from forecasts".[131] AMPC maintains that regulatory accounts are best used as mechanisms to match the timing of costs to benefits, not as a catch-all to avoid updating forecasts for the test years, and the resulting rates, to account for better, more accurate information.

136. Second, BC Hydro should have been able to obtain an updated interest rate forecast from the Government of British Columbia in August 2019 with relative ease, given Mr. Layton's explanation at the oral hearing:

> MR. KEEN: Q And when you say a Treasury Board forecast, is that the publication that the Ministry of Finance issues, or is that a phone call that you make to somebody within government to say, "What's the number?"
>
> MR. LAYTON: A Government provides us with those numbers. I believe typically they do <u>end up</u> in government documents. They're <u>eventually issued</u>, as you'll know, through the InterGroup evidence when a <u>subsequent government publication</u> was issued and showed different rates. So, in other word, yes, we do get the information from government, but <u>it typically will align with a subsequent release</u> that they put out.
>
> MR. KEEN: Q Okay. So when we refer to Ministry of Finance documents and you talk about the Treasury Board information, there's no difference in the quality of the information, it's just the timing and the means of delivery, is that fair?

[129] Exhibit B-28, p. 13, pdf p. 16, Q/A 8.
[130] Transcript Volume 7, p. 894, pdf p. 74, l. 17 – p. 896, pdf p. 76, l. 1 (**long-term debt**) and p. 902, pdf p. 82, l. 21 – p. 903, pdf p. 83, l. 14 (**short-term debt**). See also Exhibit C11-11, p. 41, pdf p. 45, Table 5-6.
[131] BC Hydro Final Argument, para. 489, pdf p. 219.

> [MR. LAYTON]: A Yeah, and they're actually the same in this case, that the Treasury Board and the Ministry of Finance I think are used interchangeably in this case.[132] [emphasis added]

137. In its Rebuttal Evidence and Final Argument, BC Hydro unfairly caricatures InterGroup's Evidence by suggesting that BC Hydro does not need to update its finance charge forecasts given that "markets change on a daily basis".[133] However, at the oral hearing, Mr. Layton acknowledged that InterGroup's Evidence actually recommended using a quarterly government publication and forecast for an update, rather than a "daily" report:

> MR. KEEN: Q Okay. So now if we can go to the rebuttal evidence, Exhibit B-28, question 8, page 13. I just want to make sure we understand each other in terms of what InterGroup is recommending, and what BC Hydro has said in its response.
>
> So, in response to question 8, BC Hydro says,
>
> > "The evidentiary update used the most recent interest rates forecast available to BC Hydro from the Government of B.C. At the time the forecast was prepared, this forecast was as of January 4th, 2019. In BC Hydro's view, the interest rates forecast used for the evidentiary update is reasonable, continuing to update finance charge forecasts is impractical given that markets change on a daily basis."
>
> Just so we're clear, you recognize that InterGroup is recommending using a quarterly government publication for an update, yes?
>
> MR. LAYTON: A Yes.[134]

138. BC Hydro's current forecasts for long-term and short-term debt will lead to material known variances in actual cash costs for the test years. They should be updated to reflect known conditions and values at the time of the Evidentiary Update.

C. BC Hydro linking pension discount rates and forecast interest rates does not take into account that the interest rates will affect cash costs over the test periods, while the pension discount rate as a non-cash expense will not.

139. BC Hydro suggests that InterGroup's positions regarding interest rate forecasts and pension discounts rates are inconsistent:

[132] Transcript Volume 7, p. 898, pdf p. 78, l. 18 – p. 899, pdf p. 79, l. 13.
[133] Exhibit B-28, p. 13, pdf p. 16, Q/A 8; BC Hydro Final Argument, para. 489, PDF P. 219.
[134] Transcript Volume 7, p. 904, pdf p. 84, l. 18 – p. 905, pdf p. 85, l. 11.

> Despite advocating for updating the forecast finance charges to reflect interest rate forecasts post-dating the Evidentiary Update, InterGroup opposed BC Hydro's decision to use the appropriate, updated pension discount rate available when BC Hydro prepared the Evidentiary Update. InterGroup favoured the continued use of the pension discount rate from the Application. A common feature of both of InterGroup's recommendations is that, if accepted, they would tend to reduce BC Hydro's proposed rates. BC Hydro submits that InterGroup's position would produce an unreasonable result.[135]

140. Mr. Wong explained BC Hydro's concern further in cross-examination, while discussing the fact that BC Hydro had used higher long-term debt rates in its forecast than that rates it had actually experienced to date for the test years:

> MR. KEEN: Q And higher in BC Hydro's experience in terms of issuing long-term debt, yes?
>
> MR. WONG: A Higher than the issuance we had in 2019.
>
> MR. KEEN: Q Okay. And so in future years we'll get the benefit of that, but not in rates for this test period. Yes?
>
> MR. WONG: A That's correct, but as I said, interest rates will also impact other areas under the evidentiary update that if you were to get that benefit of the interest rates for the debt now, we should also be updating pension costs because what we don't want to do is have a mismatch in timing. Meaning that the pension costs would increase with the reduction of interest rates and so we don't want to put one through which reduces interest rate costs in the rates knowing that pension costs will increase because you should have ability to net those two for the benefit of the ratepayer and make sure that the impacts are managed or they are as smooth as possible.[136]

141. Mr. Wong's explanation, however, ignores that discount rate forecasts and interest rate forecasts have different uses:

a. the pension discount rate is used to evaluate a current liability amount that is then amortized over many years (including the test years), while

b. interest rate forecasts are used to estimate borrowings and costs undertaken within the test years.

[135] BC Hydro Final Argument, para. 588, pdf pp. 251-252.
[136] Transcript Volume 7, p. 890, pdf p. 70, ll. 2-20.

142. Nevertheless, BC Hydro did update its pension discount rate in its Evidentiary Update to April 1, 2019,[137] but did not update its interest rates to reflect information known at the time. As explained by Mr. Bowman at the oral hearing:

> For both finance charges and pension costs BC Hydro therefore proposes to include only the most speculative and least consequential changes, which is the discount rate that raises revenue requirements and not to include known and highly reliable changes that effect actual cash costs and that benefit ratepayers such as interest rates and also the known change to MSP premiums. This is inconsistent with prudent and fair rate making.[138]

143. Mr. Bowman further explained during cross-examination by Mr. Ghikas:

> MR. GHIKAS: Q … as I understand it part of your rationale -- and I know there's others and we'll come to those, but part of your rationale for taking a different approach was with respect to what is known and locked in and what might change, right?
>
> MR. BOWMAN: A Yes. What is known and locked in and is actually affecting the test year on a cash out the door basis and once it's paid, it's paid. Pension is very different than that, it's valuing a future item. Interest rate is actually about what you're paying in the year. So I think that's -- there is a future adjustment point there. Pensions can be revalued many, many times before you get to the average 13 year life or however far it goes in the future, whereas the interest rate is locked in and it's going to be paid. They are two really different items.[139]

144. Finance charges are a cash item impacting the test years. It is therefore reasonable and prudent to adjust the interest rates used in the F2020 and F2021 test year forecasts, and not to wait for regulatory accounts to apply benefits to ratepayers in a future period.

145. Further clarifying the differences between pension and finance charges and the underlying rates used to value them, Mr. Bowman explained in cross-examination:

> MR. GHIKAS: Q Okay. So, now in terms -- so you pointed me a number of times to the declining interest rates since the evidentiary update. And I just want to confirm a few things with you. First of all movements in interest rates are generally correlated with movements in the pension discount rate, aren't they?
>
> MR. BOWMAN: A The pension discount rate is tied to hypothetical portfolio of long term bonds and so it's tied to the yield on those bonds which is basically an interest rate.

[137] Exhibit B-19, p. 12, pdf p. 16.
[138] Transcript Volume 11, p. 1973, pdf p. 149, l. 23 – p. 1974, pdf p. 150, l. 5.
[139] Transcript Volume 11, p. 2069, pdf p. 245, ll. 9-24.

> MR. GHIKAS: Q Yes. So the answer is yes?
>
> MR. BOWMAN: A Yes.
>
> MR. GHIKAS: Q And if interest rates go down, other things equal, the discount rates will also go down, won't they?
>
> MR. BOWMAN: A The interest rates yes, but for the members -- for the purposes of valuing a future liability, when interest rates go down and you borrow money you lock in at that interest rate. You know what you're paying. For the purpose of valuing a future liability a discount rate goes down your present calculation of something you're going to pay many years in the future changes.[140]

146. The F2019 discount rate update for pension costs is calculated for the F2019 period, while the F2020 and F2021 test year interest rates are rates forecast for the two fiscal years, respectively. The discount rate and interest rates are used for different purposes, and different treatment for rate setting purposes is therefore appropriate.

147. The Commission should also reject BC Hydro's submission in Final Argument, that "[a] common feature of both of InterGroup's recommendations is that, if accepted, they would tend to reduce BC Hydro's proposed rates. BC Hydro submits that InterGroup's position would produce an unreasonable result."[141]

148. This submission ignores the underlying factors that lead to InterGroup's conclusion. BC Hydro does not address the very real cash flow and timing differences captured in the different rates (i.e., even though pension discount rates and interest rates are linked, the corresponding *costs* are not), and ignores that BC Hydro's proposed approach was to only adopt the changes that cause rate *increases*.

D. It is not contested that BC Hydro has overforecast its interest rates, for both short-term and long-term debt. It also has a history of overforecasting its sinking funds.

149. Using long-term debt interest rates as an example, BC Hydro's Evidentiary Update uses forecast interest rates of 3.46% in F2020 and 3.76% in F2021,[142] even though it had known borrowings in June 2019 (F2020) ranging from 2.80% to 2.95%.[143] As Mr. Wong noted in cross-examination:

[140] Transcript Volume 11, p. 2071, pdf p. 247, l. 25 – p. 2072, pdf p. 248, l. 22.
[141] BC Hydro Final Argument, para. 588, pdf pp. 251-252.
[142] Exhibit B-19, Appendix A, Schedule 8.0, p. 63, pdf p. 83, l. 83.
[143] Exhibit B-13, AMPC IR 2.26.1, Attachment 1, pdf pp. 33-34, ll. 31, 77, 81 and 82.

> MR. KEEN: Q But when it comes to the component of rates that reflect the long-term debt forecast, we can be pretty sure right now that we are overforecasting for F2020, yes?
>
> MR. WONG: A I would say that -- I can agree with you that the rates used in the evidential update for the long-term debt forecasts are higher than what the current government forecasted rates are for the same periods.[144]

150. BC Hydro does not address InterGroup's concerns regarding known overforecasting or the appropriateness of addressing it within the test years, except to note that the finance charges in the test years are reasonable for rate setting, that regulatory accounts are an efficient means to address interest rate changes, and that interest rate risk is mitigated by BC Hydro's hedging strategy.[145] Issues relating to overreliance on regulatory accounts are discussed in further detail in **Appendix B**, and BC Hydro's hedging strategy is discussed in further detail in **Appendix G**.

E. Other utilities and utility boards have sought to correct inaccurate interest rate forecasting within test periods, rather than relying on regulatory accounts.

151. As noted in AMPC's response to BCUC IR 4.2, interest rate forecasts are a consistent challenge for utilities and utility regulators because it is difficult to forecast the market conditions which could impact the accuracy of finance charge forecasts, including GDP growth, inflation, short-term and long-term debt uncertainty, yield curves, exchange rates, market uncertainty with respect to international trade, and others.[146]

152. In AMPC's response to BCUC IR 4.3, regarding methodologies used by other utilities to forecast finance charges, InterGroup provided examples of the approaches taken by different utilities and noted that:

> a key regulatory principle for improving the reasonableness of test-year forecasts of interest rates and finance charges is that they should incorporate the most recent available actual information and forecasts. It is common for regulators to require utilities to update their interest expense forecasts prior to final approval of rates, where updated information indicates a material variance from originally filed information.[147]

153. BC Hydro has acknowledged that it has an issue with overforecasting interest rates but still insists that its approach of using regulatory accounts to capture the variance at a later date is reasonably. This approach is inferior to the methods used by other utilities and utility

[144] Transcript Volume 7, p. 889, pdf p. 69, l. 19 – p. 890, pdf p. 70, l. 1.
[145] BC Hydro Final Argument, paras. 483-485 and 489, pdf pp. 217-218 and 219.
[146] Exhibit C11-14, pdf p. 17.
[147] Exhibit C11-14, pdf p. 18.

regulators to ensure that ratepayers are charged for the services provided (and finance charges incurred) within the applicable rate period.

154. The Commission should accordingly direct BC Hydro to update its finance charge forecasts for known conditions, to ensure the best available data is used to set rates.

155. Again, BC Hydro's proposed solution to known interest rate variances (i.e., reliance on a regulatory account) reflects the broader issue of BC Hydro's overuse of regulatory accounts, here to justify using dated and poor forecasts since the deferral account will purportedly, someday, address all variances. This is an ill-advised approach to setting revenue requirement and should not be used for known and material cash cost impacts affecting the test years.

APPENDIX E: PENSION COSTS AND MSP PREMIUMS

ISSUE

156. BC Hydro updated its pension cost forecast as part of its Evidentiary Update. The update was based on an email from a third party actuary containing a new discount rate, increasing rates by over $67 million in each test year.

157. InterGroup's written evidence proposed to retain the Application's original discount rate because the new discount rate was unsupported by detailed analysis (at any point), produced a dramatic effect, and was an outlier relative to earlier years. This was further justified because pension costs are largely a non-cash item.

158. At the oral hearing Mr. Bowman noted that in the F2017 revenue requirement proceeding BC Hydro had flagged the same concern of discount rate volatility driving significant swings in rate recovery, and had unsuccessfully proposed using a simple 5-year average of discount rates instead. The InterGroup panel endorsed that method as an even better approach in principle – but not significantly different in impact relative to simply retaining the Application's original discount rate.

RECOMMENDATION

159. For rate setting purposes, the calculation of BC Hydro's pension costs should prioritize stability, such that ratepayers contribute consistently and equally over the long-term to fund future pension costs, as these are a non-cash expense in the test years and will not be paid out, on average, for many years.

160. AMPC supports the original InterGroup recommendation.[148] The Commission should not accept a significant change in rates absent support, particularly for a non-cash item. The Application's original discount rate is more reasonable.

161. However, a preferable and longer-term solution, which Mr. Bowman and Ms. Davies discussed with Commissioner Fung at the oral hearing,[149] is for the Commission to direct BC Hydro to adopt a five-year average of discount rates (an approach which BC Hydro proposed at the last RRA). A five-year average would address both BC Hydro's concern regarding the inclusion of the most current discount rate information and AMPC's concern regarding stability.

162. Separately, the Commission should direct BC Hydro to include the known effects of the MSP premium cost change into its revenue requirements for the test years.

[148] Exhibit C11-11, p. 46, pdf p. 50.
[149] Transcript Volume 11, p. 2075, pdf p. 251, l. 23 – p. 2078, pdf p. 254, l. 24.

DISCUSSION

A. Background

163. BC Hydro's post-employment benefit costs fall into two categories:

a. **Current service costs** are the annual costs of accruing employees' post-employment benefits. These costs recognize the cost of the future benefits earned by the employees in the current year. Current service costs are included in the Standard Labour Rates and charged to current work (both in capital and operating expenses).[150]

b. **Non-current service costs** are composed of plan income on pension plan assets and interest expense on post-employment benefit liabilities (which are included in finance charges).[151] Non-current service costs are tracked through the Non-Current Pension Cost Regulatory Account. BC Hydro adjusts the opening balance of this account based on the present value calculation of the future liability which is undertaken periodically by its external actuarial consultants. Annualized recovery amounts collected from ratepayers in the test years for this account are calculated based on the EARSL.[152] Finance charges are accrued on actual balances even though this is a non-cash account. In recent years, finance charges have been quite extensive due to the large amounts recorded to this account.[153]

164. BC Hydro uses a discount rate to estimate its long-term future pension liability. It is not a cost that BC Hydro will actually incur over the test year period. BC Hydro's forecast methodology is calculated based on short-term market conditions at a single point in time.

165. In order to determine BC Hydro's pension costs, BC Hydro's external actuary undertakes an actuarial valuation, which estimates the plans' funded status (assets less liabilities) at a specific point in time (for the non-current portion). The actuarial valuation also estimates the current pension service costs. Actuarial valuations update plan membership, as well as economic and demographic assumptions as required for account purposes.

166. The external actuary also calculates a discount rate, based on market conditions and Canadian AA Corporate bonds as well as the Expected Average Remaining Service Life ("EARSL").[154]

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[150] Exhibit B-1, p. 5G-15, pdf p. 702.
[151] Exhibit B-1, p. 5G-15, pdf p. 702.
[152] Exhibit B-1, p. 7-44 - 7-45, pdf pp. 934-935.
[153] For example, see Exhibit B-19, Appendix A (Excel attachment), Tab 2.2, l. 82, which shows that annual carrying costs charged to this account for each year from F2015-F2019 have been between $52.1 million and $72.6 million, which is ultimately recovered from ratepayers.
[154] Exhibit B-1, p. 5G-16, pdf p. 703.

167. At the oral hearing, Mr. Layton confirmed the following details regarding the derivation of the original 3.83% discount rate, as set out in an October 5, 2018 email from Morneau Shepell:

> MR. KEEN: Q And so there there's mention of the Morneau Shepell curve, the discount rate and then the Blooomb[e]rg AA corporate 30 year index and the discount rate associated with that. So I gather Morneau Shepell takes the bond index and doing what it does, its actuaries derives from that a discount rate and projects what your costs are going to be.
>
> MR. LAYTON: A Yes.[155]

168. The Evidentiary Update updated the discount rate used to value BC Hydro's pension liability for both the current portion and non-current portion to 3.33%.[156] BC Hydro's external actuary did not undertake a full analysis to update BC Hydro's pension liability, but did update the discount rate valuation used to determine the present value of BC Hydro's future pension liability (lowering it from 3.83% to 3.33%), and also updated the EARSL from 12 to 13 years.[157]

169. This change significantly increased the test year costs for the Non-Current Pension Cost Regulatory Account, as well as test year collections for the current service pension costs (within operating costs). The 0.5% change is the largest discount rate change since 2015.[158]

170. Table 5-9 in InterGroup's expert report calculated the effect of the updated discount rate, updated below as "Table 2" to show "gross" current period pension costs.[159]

Table 2: Gross Pension Costs Impact on Test Years – Original Compared to Evidentiary Update ($Millions) – Updated per BC Hydro Rebuttal Evidence

	F2020			F2021		
	Plan	**Update**	***Diff***	**Plan**	**Update**	***Diff***
Non-Current Pension Cost Regulatory Account Recovery - Operating	16.0	56.8	***40.8***	16.0	56.8	***40.8***
Non-Current Pension Cost Regulatory Account Recovery - Finance Charges						
Current Service Pension Costs	103.5	130.0	***26.5***	105.6	132.5	***26.9***
Total Test Year Impact	**119.5**	**186.8**	***67.3***	**121.6**	**189.3**	***67.7***

[155] Transcript Volume 7, p. 865, pdf p. 45, ll. 15-22; Exhibit B-17, AMPC IR 3.5.1, Attachment 1, pdf p. 35.
[156] Exhibit B-19, p. 12, pdf p. 16.
[157] Exhibit B-19, p. 12, pdf p. 16; Exhibit B-17, AMPC IR 3.5.4.2, pdf p. 47.
[158] Exhibit B-17, AMPC IR 3.5.3, pdf pp. 39-41.
[159] Exhibit C11-11, p. 45, pdf p. 49. Also see exhibit B-28, p. 17, pdf p. 20 and Transcript Volume 7, p. 863, pdf p. 43, l. 6 - p. 864, pdf p. 44, l. 15. As this table reflects gross current service pension costs, a portion of the current service pension costs will be capitalized and will therefore not impact the test years. This does not impact the Non-Current Pension Cost Regulatory Account recoveries.

171. Also impacting the Non-Current Pension Cost Regulatory Account is a $70 million gain to the account, again added in the Evidentiary Update, due to the elimination of MSP premium costs starting May 16, 2019 (i.e. six weeks into the F2020 test year).[160] BC Hydro proposes to amortize this gain in rates starting in F2022, in accordance with BCUC Order No. G-47-18, as the gain was not known with certainty by the end of F2019 and pursuant to accounting rules could not be recognized as of the date required by the BCUC rules for the deferral account.[161]

B. The revised discount rate and underlying pension liability was unsupported.

172. For the updated discount rate of 3.33%, neither the 30 year corporate index nor any other supporting information was available at the time of Morneau Shepell's discount rate update on April 4, 2019.[162] The only supporting information BC Hydro provided to justify the new 3.33% discount rate was a one-page email from its external actuary, Morneau Shepell.[163]

173. When comparing pension-related expenses to other expenses, it is important to consider that pension costs are largely non-cash expenses. At the oral hearing, Mr. Bowman explained the importance of this in relation to the difference between the pension cost and finance cost updates from the Evidentiary Update (the latter of which are also impacted by external market conditions):

> MR. GHIKAS: Q … The updated rates -- you go on to say:
>
> > "The updated rates are for debt that is not yet -- that has been placed. Unlike the update to pension discount rate discussed in Section 5-3 of this submission, there is no speculation or future adjustments that will occur to these effects. Setting just and reasonable rates for the test years includes updating the relevant known values irrespective of the presence of deferral and regulator accounts."
>
> So pausing there, as I understand it part of your rationale -- and I know there's others and we'll come to those, but part of your rationale for taking a different approach was with respect to what is known and locked in and what might change, right?
>
> MR. BOWMAN: A Yes. What is known and locked in and is actually affecting the test year on a cash out the door basis and once it's paid, it's paid. Pension is very different than that, it's valuing a future item. Interest rate is actually about what

[160] Exhibit B-28, p. 14, pdf p. 17, Q/A 9; Transcript Volume 7, p. 878, pdf p. 58, ll. 6-23.
[161] Exhibit B-16, BCUC IR 3.300.3, pdf p. 149; Transcript Volume 7, p. 879, pdf p. 59, ll. 3 – p. 880, pdf p. 60, l. 5.
[162] Exhibit B-17, AMPC IR 3.5.1, Attachment 2, pdf p. 36.
[163] Exhibit B-17, AMPC IR 3.5.1, pdf pp. 33-36.

> you're paying in the year. So I think that's -- there is a future adjustment point there. Pensions can be revalued many, many times before you get to the average 13 year life or however far it goes in the future, whereas the interest rate is locked in and it's going to be paid. They are two really different items.[164]

174. InterGroup was unable to evaluate the rationale for the cost change resulting from this single discount rate update, including whether or not that discount rate appropriately represents BC Hydro's future pension liability, and therefore recommended retaining the 3.83% pension discount rate from the original Application, for both the current and non-current pension costs in the test years.[165]

175. AMPC agrees. To be clear, AMPC does not challenge the general credibility of Morneau Shepell. AMPC challenges the absence of detail from Morneau Shepell via BC Hydro to justify a significant rate increase, and argues that holding BC Hydro to its onus is justifiable, especially as pension costs are largely a non-cash item.

C. BC Hydro's current approach may be appropriate for financial reporting purposes but does not reflect fair ratemaking principles.

176. Mr. Wong explained under cross-examination that "accounting rules require us to use the beginning of the year's discount rate to record current pension costs in our income statement. And so in fiscal '21 we are actually using this discount right now to record our current service pension costs. And we've had two quarters already that have been reviewed by external auditors and there haven't been issues raised associated with that recording of current pension costs."[166]

177. AMPC takes no issue with this requirement for the purposes of financial reporting, but there are many reasons to vary from financial reporting methods when setting rates. AMPC also notes that Mr. Wong's comment specifically related to the current portion of pension costs, and that he did not provide any comment regarding the approach to non-current pension costs for quarterly reporting. This is especially important given the impact non-current pension costs have on rates, and will likely have on finance charges applied to the F2020 and F2021 years prior to the next RRA (discussed in greater detail below).

178. As noted by Mr. Bowman at the oral hearing, when comparing BC Hydro's treatment of the updated discount rate to the MSP premium issue:

> For both finance charges and pension costs BC Hydro therefore proposes to include only the most speculative and least consequential changes, which is the discount rate that raises revenue requirements and not to include known and

[164] Transcript Volume 11, p. 2068, pdf p. 244, l. 25 – p. 2069, pdf p. 245, l. 24.
[165] Exhibit C11-11, p. 46, pdf p. 50.
[166] Transcript Volume 7, p. 870, pdf p. 50, l. 19 – p. 871, pdf p. 51, l. 2.

> highly reliable changes that effect actual cash costs and that benefit ratepayers such as interest rates and also the known change to MSP premiums. This is inconsistent with prudent and fair rate making.[167]

D. BC Hydro's current approach results in volatility in pension costs

179. Prior to the discount rate of 3.33% now proposed by BC Hydro, the previous three rates it used, going back to 2015, were in a tight range between 3.81% and 3.94%.[168] Notably, in its F2017-F2019 RRA, BC Hydro proposed to use a five year average of discount rates to bring more stability to its forecast.

180. The BCUC disagreed and rejected this approach.[169] However, when the Commission ruled on this issue in the F2017-F2019 RRA, it was not faced with the market volatility and resulting revenue requirement impact present in the current proceeding. Without a change in methodology for pension cost forecasts, ratepayers may continue to see large swings in annual allotments for pension costs in future years.

181. As explained by Mr. Bowman during the oral hearing:

> [MR. BOWMAN]: … In regards to pension costs and the discount rate, section 5.3 of our evidence, we're dealing with an issue that is about stability. Pension costs are primarily non-cash items that in many cases will not be paid out until well into the future. The value of such obligation varies over time according to the assumed discount rate at any given point in time. The value of such obligation varies and such changes can reverse multiple times before these amounts will ever be paid out. Even though this item is non-cash and relates to future payments, BC Hydro proposes to collect an additional 50 to 60 million dollars per year based solely on new discount rates in the evidentiary update due to the March 31st, 2019 value of the discount rate.
>
> We were surprised by this change in BC Hydro's evidentiary update given BC Hydro has previously expressed concern that "pension costs are highly sensitive to changes in the discount rate." And proposed a five year average mechanism to mitigate this instability in the previous RRA.[170]

182. Mr. Bowman discussed these issues further, in response to questions from Commissioner Fung, as follows:

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[167] Transcript Volume 11, p. 1973, pdf p. 149, l. 23 – p. 1974, pdf p. 150, l. 5.
[168] Exhibit B-17, AMPC IR 3.5.3, pdf pp. 39-41.
[169] BCUC Decision and Order G-47-18, pp. 67-72, pdf pp. 74-79, available online at: https://www.bcuc.com/Documents/Proceedings/2018/DOC_50971_03-01-2018_BCH_F17-19_RRA_Decision_WEB.pdf
[170] Transcript Volume 11, p. 1972, pdf p. 148, l. 15 – p. 1973, pdf p. 149, l. 9.

> COMMISSIONER FUNG: Mr. Bowman, I just want to go back to the question of the pension discount rate. Assuming we accept your criticism of what has been done, what is it exactly that you are proposing that BC Hydro ought to have done in this case, given that they have got the actuarial discount rate from their expert as of 2019, that it has dropped to 3.33 percent. We know that over the past five years there has been a tight range from 3.81 percent to 3.94 percent. What are they supposed to have done for this particular test period according to your expert evidence?
>
> MR. BOWMAN: A Well, for the purposes of the filing I will be specific. Our evidence says that we shouldn't use the 3.33. But I think in retrospect, and looking at the sum total, this issue has a fair bit of spilled ink on it, in terms of the last hearing and this one. I think BC Hydro raised valid concerns about stability. I know they proposed a five year average discount rate at the time, which probably in retrospect is something that I would have been supportive of, and I would be supportive of at this point.
>
> It is probably frankly better than what is even in the evidence maybe just ignore the 3.33. Probably you should build in the 3.33 but in combination with the fact that it has been 3.8 and it could easily go back up again. And ignoring that wouldn't be the first thing you do.
>
> So I think all things being equal, recognizing there is a priority on stability for something that is not being cash out the door, that is just valuing a future liability, and achieving that stability was something like BC Hydro proposed last time, would be beneficial. Something like a five year average which probably would bring you in around the 3.7 range or something of that nature, 3.6 would be advisable.
>
> Outside of that, what we suggested is ignore the 3.3 and use 3.8. So mathematically it wouldn't be that different, but it is probably the stablest approach in terms of the proposals before you.[171]

183. For this reason, the Commission may wish to direct BC Hydro to use a five-year average to calculate its discount rate for rate-making purposes, since such an approach would:

a. better stabilize both current and non-current pension costs and external influencing factors (such as discount rates); and

b. better reflect the usefully incurred costs to ratepayers on an annual basis.

[171] Transcript Volume 11, p. 2075, pdf p. 251, l. 23 – p. 2077, pdf p. 253, l. 13.

184. If the Commission determines that more information is required before doing so in this test period, maintaining the 3.83% discount rate for test year calculations (as opposed to adopting the 3.33% discount rate) adds the value of stabilizing the revenue requirement until supporting information can be brought forward at the next RRA.

185. BC Hydro has expressed concern with the prospect of changing interest rates but not the pension discount rate, as it views the two issues as correlated. Mr. Bowman discussed this matter under cross-examination and, again, explained that different ratemaking treatments can be readily justified as between cash and non-cash items. In short, BC Hydro's concern is unfounded:

> MR. GHIKAS: Q Okay. So, now in terms -- so you pointed me a number of times to the declining interest rates since the evidentiary update. And I just want to confirm a few things with you. First of all movements in interest rates are generally correlated with movements in the pension discount rate, aren't they?
>
> MR. BOWMAN: A The pension discount rate is tied to hypothetical portfolio of long term bonds and so it's tied to the yield on those bonds which is basically an interest rate.
>
> MR. GHIKAS: Q Yes. So the answer is yes?
>
> MR. BOWMAN: A Yes.
>
> MR. GHIKAS: Q And if interest rates go down, other things equal, the discount rates will also go down, won't they?
>
> MR. BOWMAN: A The interest rates yes, but for the members -- for the purposes of valuing a future liability, when interest rates go down and you borrow money you lock in at that interest rate. You know what you're paying. For the purpose of valuing a future liability a discount rate goes down your present calculation of something you're going to pay many years in the future changes. But then they go back up it changes again, and this is -- I don't think the utility and I are necessarily on different pages on this one when you look at the filing in the last RRA were they expressed a concern about the issue of stability. The pension liability is going to swing both ways over many times before you ever get to actually paying it out. And BC Hydro recommended approaches that would help deal with the stability of that rate. And it wasn't accepted by this board at that time because it wasn't -- it didn't yield the test that the board was looking for, but the issue of stability was never pooh poohed, it was never said that stability isn't important in that. And I think this just underlines it, that the discount rate had been very stable for the last couple of years, it's stayed around 3.8, all of a sudden it drops to 3.3 in the 11th hour before the hearing. So you have an

> opportunity to bring in -- to test and bring in other proposals is a little bit more limited.
>
> But I share BC Hydro comments about the pension issue should be about stability because it's still, you know, as much as 3.33 is an actual in the sense that BC Hydro actually used it to calculate a liability, it's not an actual for the purposes of paying out cash. It's a number that's going to change, up and down over many years. And so I think from that purpose it's different than interest rates and long term stability is where we should look.[172]

MSP Premiums

186. The elimination of MSP premiums came into effect May 16, 2019, approximately six weeks into the F2020 test year. As a result, BC Hydro has proposed to delay the inclusion of the $70 million one-time benefit in the Non-Current Pension Cost Regulatory Account until the next test period, consistent with accounting rules.[173]

187. Mr. Bowman explained the distinction between accounting rules and deferral account rules in this context while under cross-examination, as follows:

> MR. GHIKAS: Q Okay, so let's go just up to line 4 there, immediately above. So you referred in that passage that we were just reading to the MSP premiums and again you refer to it in line 4,
>
> > "The RRA does not credit rate payers with the offsetting known benefits of eliminating MSP premiums during the same timeframe."
>
> So let's first of all -- you understand BC Hydro filed rebuttal evidence on this point in question 9, specifically to the effect that it would have violated accounting rules to recognize MSP gains in financial results before the MSP legislation had even been passed, you understand that?
>
> MR. BOWMAN: A I read the section. I think in order to arrive where BC Hydro does you need two things to be meet, one is you have the accounting rule and the other is you have the deferral account rule which is under the control of this board. You need both of those to be in place to arrive where they do at the MSP proposal. And the deferral account proposal in regard to this board is something that I think this board has the ability to take into consideration and vary.

[172] Transcript Volume 11, p. 2071, pdf p. 247, l. 25 - p. 2073, pdf p. 249, l. 24.
[173] Exhibit B-28, pp. 13-15, pdf pp. 16-18, Q/A 9.

> MR. GHIKAS: Q Okay, and vary, so you're agreeing that what you're recommending is different from what the actual current state of affairs are with respect to the orders that BC Hydro has to follow?
>
> MR. BOWMAN: A Yeah, if think if there is a known change in costs that had been passed, it came six weeks to late to be included for accounting rules. But I think it would unfortunate if this board said, well then we'll ignore it for a couple of years and let the balances accrue in the deferral account and only then we're going or have the amount flow through to rate payers. If they are affecting the test years, if it's rules under control of this board I don't see any reason why you would put off including that in rates as a valid change in costs.[174]

188. Regarding the typical practice of deferring variances until the next test period, Mr. Bowman responded during cross-examination that a change in costs arriving six weeks too late to be counted in the previous period should not limit the Commission from making a decision on the current test years:

> MR. GHIKAS: Q Okay. So, you understand that the current state of the order that you are suggesting the Commission might vary is that variances are caught in the regulatory account and amortized in the next test period, right?
>
> MR. BOWMAN: A Right, that the rules that this Commission have approved for that account says we deal with balances one they've arisen and that balance wasn't in place at March 31st, 2019 so we're not going to deal with it. And I'm saying that's not a reason to turn a blinder to something that's going to affect test years and it is known.[175]

189. The MSP change is material, is known, affects the test years, and can be easily included in rates. Accordingly, AMPC adopts Mr. Bowman's recommendation: vary slightly the BCUC-controlled deferral account rule to mitigate the unintended effect of a six-week delay in legislation, to properly match costs with benefits.

[174] Transcript Volume 11, p. 2062, pdf p. 238, l. 4 - p. 2063, pdf p. 239, l. 15. Note: as clarified immediately after this reference, Mr. Bowman was referring to the British Columbia Utilities Commission when he said 'board'.
[175] Transcript Volume 11, p. 2064, pdf p. 240, ll. 5-16.

APPENDIX F: DEPRECIATION

ISSUE

190. Depreciation (or Amortization) costs make up a large portion of BC Hydro's overall revenue requirement. Amortization on capital assets represents $885.4 million or 16.9% of total revenue requirement for F2020, and $904.5 million or 17.4% of total revenue requirement for F2021.[176]

191. Depreciation is not a cash flow linked cost, but rather recovers (on an annualized basis) previously expended capital costs considered used and useful in rates today. These amounts are based on detailed and subjective underlying assumptions, including asset specific average service lives, data on BC Hydro's operating asset complement and retirement history, and considerations for future costs related to removal/resale.

192. BC Hydro has not updated its depreciation study since 2005, and at that time, only part of its asset base was included in this assessment. Specifically, it did not include transmission related expenses as these assets were owned by British Columbia Transmission Corporation at the time.[177]

193. BC Hydro's 2005 depreciation study specifically notes that "[t]he depreciation rates should be reviewed periodically to reflect the changes that result from plant account activity. Complete depreciation studies, which reevaluate the depreciation parameters, should be performed every three to five years."[178]

194. Yet, 15 years later, BC Hydro is still relying primarily on its 2005 depreciation study results to set appropriate depreciation costs for the test years,[179] claiming its depreciation expense remained adequate for the test years.[180] InterGroup's Evidence and AMPC's cross-examination expressed severe concern about this highly unusual stance.

195. During the gap between oral hearing segments, BC Hydro revised its position to confirm that it would undertake a depreciation study, but that insufficient time remained to do so before it filed its next Revenue Requirement Application. [181]

[176] Exhibit B-19, Appendix A (Excel). Total Amortization of Capital Assets from Tab 7.0, line 5 for Update test years, divided by Total Revenue Requirement, Tab 1.0, line 23.
[177] In 2010, all of BCTC's rights, property, assets, contracts and permits were transferred to and vested to BC Hydro pursuant to s. 22 of the *Clean Energy Act*, S.B.C. 2010, c. 22.
[178] BC Hydro F2007-F2008 Revenue Requirements Application, AMPC IR 1.23.4, Appendix F, pdf p. 9.
[179] Transcript Volume 5, p. 432, pdf p. 112, ll. 14-16; Transcript Volume 6, p. 581, pdf p. 8, ll. 10-12.
[180] Transcript Volume 5, p. 435, pdf p. 115, ll. 4-6.
[181] Exhibit B-43.

AMPC RECOMMENDATION:

196. Updated and tested depreciation information is a necessary component of ensuring fair electricity rates and BC Hydro's 2005 depreciation study does not meet this standard.

197. AMPC accepts that it would be challenging for BC Hydro to complete and file a depreciation study with its next Revenue Requirement Application, if BC Hydro began now – but not impossible. The implication is that BC Hydro has been planning for a more than two decade gap between studies. AMPC is not aware of any other utility, in BC or elsewhere, that avoids expert scrutiny in this manner. BC Hydro pointed to no peers.

198. At this stage, the Commission should reject BC Hydro's judgment concerning appropriate depreciation study frequency and timing. A standalone Commission process - if necessary - can focus on appropriate depreciation expense. Subsequent RRA processes can consider when and how to incorporate such outcomes into rates.

199. Fair rates demand that the Commission impose firm dates for BC Hydro to file a study and progress reports, require the study be treated as a priority, and require the study to extend to all assets, including a detailed management review of asset condition, technological advancements since the 2005 study, peer review comparisons, and experienced retirement data.

FURTHER COMMENTS:

200. Whether or not BC Hydro should be directed to undertake a depreciation study in the near term, as InterGroup recommended in its written Evidence, is now a moot point. BC Hydro has committed to do so. Much of the content of the record concerning this matter, and associated argument, can therefore be set aside.

201. The only remaining item is whether the Commission chooses to impose structure on how and when BC Hydro undertakes a study, or whether the Commission is comfortable with BC Hydro's judgment. AMPC addresses several aspects of BC Hydro's Final Argument below to show that the Commission must take control of the issue:

a. **BC Hydro claims the cost of a depreciation study outweighs the benefits.**[182]

BC Hydro reported its last depreciation study only cost $160,000.[183] Peer utilities broadly find value in regular depreciation studies (typically every 3-5 years) to set one of, if not the largest, component of any revenue requirement application.[184] The Commission should be troubled by BC Hydro's claim here.

[182] Transcript Volume 5, p. 435, pdf p. 115, ll. 8-23.
[183] Exhibit B-13, AMPC IR 2.41.1.
[184] Exhibit C11-14, BCUC IR 5.1.

b. **BC Hydro claims its internal accounting scrutiny is sufficient[185] and that external auditors would raise concerns about any material misstatement**,[186] **noting the change it sought for analog meter useful lives and depreciation expense via BCUC Order G-115-11.[187]**

Avoiding a material misstatement is different than setting fair rates. The standards and expectations of rate setting can exceed those of accounting for financial reporting.[188] The expert evidence of InterGroup on this point, that depreciation studies play an important role in confirming that rates are just and reasonable for ratepayers,[189] is uncontroversial, uncontroverted, and should guide the Commission.

BC Hydro's effort to avoid undercollection of meter costs illustrates the hazard that a full, and tested, depreciation study is intended to guard against. During the period when BC avoided updating its depreciation study, other utilities have trended towards extending major electrical asset service lives (remedying overcollection).[190]

c. **BC Hydro cites a limited account review with Gannett Fleming in 2010 to conclude that, in aggregate, potential changes would have a limited impact on depreciation expense,[191] and claims InterGroup's peer comparisons support BC Hydro's asset lives and depreciation expense as reasonable.**

Peer experience is a major input into depreciation study average service life considerations. But no conclusions that can fairly be relied upon today can be drawn from a partial effort a decade ago. InterGroup's written evidence noted:

> Specific methods, parameters and testing for this review are not described in the attachment provided regarding findings at the time and the conclusions were not tested in a regulatory forum.[192]

Further, BC Hydro consistently had asset class service lives under or at the bottom of the age ranges for the peer utilities that InterGroup reviewed, and two asset classes (Turbines – Hydro Composite & Distribution Transformers) have useful life parameters under the peer comparison (not one as indicated by BC Hydro). This strongly suggests that depreciation expense may be higher than warranted.[193] BC Hydro's sense of the need for and scope of depreciation review is flawed.

[185] Transcript Volume 5, p. 434, pdf p. 114, ll. 1-5.
[186] Transcript Volume 7, p. 945, pdf p. 125, l. 24 - p. 946, pdf p. 126, l. 4.
[187] BC Hydro Final Argument, p. 205, pdf p. 215, footnote 777.
[188] Exhibit C11-14, BCUC IR 5.2.
[189] Exhibit C11-11, p. 48, pdf p. 52.
[190] Exhibit C11-11, p. 51-53, pdf p. 55-57.
[191] Exhibit B-13, AMPC IR 2.41.2.
[192] Exhibit C11-11, p. 49, pdf p. 53.
[193] Exhibit C11-14, BCUC IRs 5.1 and 5.2.

202. Given the above, there is a material risk that BC Hydro's Application is over-collecting depreciation expense from current ratepayers. AMPC seeks two remedies in response:

a. The Commission must take firm measures to ensure the depreciation study is comprehensive and ensure a properly scoped study is swiftly executed; and

b. Make a clear finding that the rates that the Application seeks may be conservatively high due over-collection of this non-cash item, which may be relevant to and assist future Commission Panels in other near-term BC Hydro rate matters.

APPENDIX G: HEDGING

ISSUE

203. BC Hydro has and will be undertaking significant borrowings in the coming years to fund its capital projects. BC Hydro's Treasury team manages approximately $23 billion in total debt and $8 billion in financial derivatives, including hedges.[194] BC Hydro's debt management strategy prioritizes "cost certainty"[195] and now aims to hedge 75% of its long-term borrowings to 2025 (currently 71% in the test period, as compared to its former strategy of hedging 50%), to mitigate interest rate risk (i.e., against increases in long-term interest rates).[196]

204. BC Hydro's hedging activities have large financial impacts. For example, a 1 percent change in forward interest rates results in an $800 to $900 million variation in the fair value of the financial contracts BC Hydro uses for hedging purposes.[197]

205. At the time of the oral hearing AMPC was concerned that BC Hydro's hedging strategy focused unduly on cost certainty and ensuring that 75% of the debt is hedged, as opposed to minimizing the overall cost of debt – including by hedging less if warranted. That concern endures now, and its importance has been reemphasized given the effect of the COVID-19 circumstances on interest rates.

AMPC SUMMARY AND/OR RECOMMENDATION:

206. BC Hydro maintains the Debt Management Regulatory Account to capture mark-to-market unrealized gains and losses until hedges are settled. Once settled, realized gains and/or losses on hedges are amortized over the term of the associated long-term debt, beginning in the test period subsequent to that in which the associated long-term debt is issued.[198] BC Hydro charges the realized gains/losses to ratepayers via finance charges.

207. While it is very difficult to assess the relative success of the hedging strategy across BC Hydro's current reporting structure, BC Hydro's Evidentiary Update includes a $12.4 million

[194] Exhibit B-1, p. 5E-8, pdf p. 572.
[195] Exhibit B-1, p. 5E-8, pdf p. 572. See also the testimony of Mr. Wong at Transcript Volume 7, p 953, pdf p. 133, ll. 2-6 and ll. 16-20: "And essentially what we want to do is lock in, to create certainty for BC Hydro and ratepayers, the interest rate we're going to have on our debt that we're going to be issuing over the next five years… And we feel that certainty of costs for BC Hydro is really important, which is why we entered into these future debt hedges or it may be called interest rate hedges as we go through this conversation".
[196] BC Hydro Final Argument, para. 484, pdf p. 217; Transcript Volume 7, p. 953, pdf p. 133, ll. 21-26; Order G-42-16, p. 6 of 10, pdf p. 8, available online at: https://www.bcuc.com/Documents/Proceedings/2016/DOC_46024_G-42-16_Reasons.pdf
[197] Exhibit B-19, Appendix D, pp. 2-3, pdf pp. 119-120. Further detail on individual hedges was provided as Attachments to responses to AMPC IR 3.14.2 (Exhibit B-17, pdf pp. 87-91) and BCUC Panel IRs 2.17.3.2 and 2.17.3.3 (Exhibit B-31, pdf pp. 141-145).
[198] Exhibit B-1, pp. 7-46 – 7-47, pdf pp. 936-937; Exhibit B-31, BCUC Panel IR 2.17.2, pdf pp. 133-134.

refund through the Debt Management Regulatory Account to ratepayers in each test year, from net gains realized in the previous test period.[199] BC Hydro's realized gains and losses on future debt hedges include: a $187.1 million gain in F2017, a $29.3 million loss for F2018, a $321.0 million loss for F2019 and a $100.9 million loss for F2020.[200]

208. These figures suggest that BC Hydro has overvalued the risk of increasing interest rates relative to the risk of declining interest rates since at least F2018.

209. The Commission should also direct BC Hydro to identify and report on its hedging strategies and outcomes in its next Revenue Requirements Application. As BC Hydro plans to continue hedging approximately 75% of all long-term borrowings over the coming years,[201] the Commission's direction should require BC Hydro to demonstrate how its debt management strategy has successfully minimized its cost of debt.

DISCUSSION AND SUPPORT:

210. The Commission approved the Debt Management Regulatory Account in Order G-42-16,[202] but specifically declined to provide guidance or direction to BC Hydro on its proposed debt management strategy.[203]

211. For its debt management strategy, BC Hydro proposed to use Future Debt Hedges (including bond locks and forward swaps) to hedge approximately 50% of all long-term borrowings issued from F2017 to F2024. Specifically, BC Hydro's proposed debt management strategy had the following essential elements:

a. To enter into approximately 20 to 30 FDHs of notional size between $100 and $400 million each with discrete maturities of up to 8 years based on changes in long-term interest rates. The size and determination of each FDH will depend on market conditions at the time of execution;

b. To hedge approximately 50 percent or up to $5 billion of future debt issuances between F2017 and F2024;

c. The hedge is entered into over a six-month period following Commission approval; and

d. That hedge is a combination of ten and 30-year forward Interest Rate Swaps and Government of Canada Bond Locks.[204]

[199] Exhibit B-17, AMPC IR 3.14.5, pdf pp. 97-98.
[200] Exhibit B-17, AMPC IR 3.24.4, pdf p. 298.
[201] Exhibit B-13, AMPC IR 2.25.1 Attachment 3, pp. 1-2, pdf pp. 29-30.
[202] Order G-42-16, pp. 8-9 of 10, pdf pp. 10-11, available online at: https://www.bcuc.com/Documents/Proceedings/2016/DOC_46024_G-42-16_Reasons.pdf
[203] Order G-42-16, pp. 6-8 of 10, pdf pp. 8-10, available online at: https://www.bcuc.com/Documents/Proceedings/2016/DOC_46024_G-42-16_Reasons.pdf

212. It is not clear when BC Hydro increased its hedging strategy from 50% of long-term debt to 75%. However, using the information from BC Hydro's Evidentiary Update, since its implementation, the balance of the Debt Management Regulatory Account had grown by over $476 million, from -$187.1 million in F2017 to the forecast F2021 year-end balance of $288.9 million. $434.3 million of this growth was from F2019 and F2020 alone.[205] BC Hydro further updated the balances of the Debt Management Regulatory Account as of December 31, 2019 in response to a BCUC Panel IR, though balances remained similar at $261.1 million for F2020 and $273.5 million for F2021. Perhaps more importantly, based on current positions, BC Hydro forecasts this balance to be sustained, forecasting an ending position of $284.9 million for F2024.[206]

213. It is also not clear that BC Hydro's current hedging strategy is in the best interest of ratepayers. During the oral hearing, BC Hydro described its debt management strategy as follows:

> MR. KEEN: Q Before you go on, can you just give us a quick sense as to what BC Hydro's hedging strategy is?
>
> MR. WONG: A Sure. Maybe it's for the panel. BC Hydro issues long-term debt in various tranches over the years and we have to do it in the future as well. And we have large capital expenditures and we take a look at our capital plan. Inclusive of Site C we're going to have about 3 billion a year for the period of time until after Site C, about a billion and a half a year of capital expenditures.
>
> So in order to fund those capital expenditures, we need to usually issue long-term debt. Our portfolio is usually made up of long-term debt. We don't know what the interest are, what locked-in interest rates will be until you actually get to issuing that debt. So, because we know we have this large portfolio of capital expenditures we budget against that based on the finance charges that we expect today. What we want to do is create some certainty around what those finance charges are going to be.
>
> So I think your question was, so what do we do about that? So we created a risk management strategy that's been reviewed by the executive team and the audit committee of our board. And essentially what we want to do is lock in, to create certainty for BC Hydro and ratepayers, the interest rate we're going to have on our debt that we're going to be issuing over the next five years. So what we do is

[204] Order G-42-16, p. 6 of 10, pdf p. 8, available online at: https://www.bcuc.com/Documents/Proceedings/2016/DOC_46024_G-42-16_Reasons.pdf
[205] Exhibit B-19, Appendix A (Excel attachment), Tab 2.2, ll. 150-154 comparing the F2017 year-end balance (the first year of the account) to the forecast year-end balance for F2021.
[206] Exhibit B-31, BCUC Panel IR 2.17.2, pdf pp. 133-134.

> we transact interest rate hedges, or we call them here future debt hedges, to lock in the interest rate today.
>
> And so it's very much like if you were to do a mortgage on your house and you take a fixed rate mortgage, you're locking in that rate on your mortgage for five years at a fixed rate so you're not subject to the variability of interest rates going up or going down and you have certainty over what your cost is going to be. And we feel that certainty of costs for BC Hydro is really important, which is why we entered into these future debt hedges or it may be called interest rate hedges as we go through this conversation.
>
> MR. KEEN: Q And you hedge up to 75 percent of your long-term debt?
>
> MR. WONG: A Yes, that's correct, for the next five years.[207]

214. Under cross-examination, BC Hydro explained its rationale for hedging 75 percent of long-term debt as being, essentially, that 100 percent was not possible:

> MR. KEEN: Q How did you come up with 75 percent?
>
> MR. WONG: A Well, we wanted to ensure that – 75 percent was built on the fact that wanting to create that, we didn't want to go to 100 percent because when you look at your cash-flow forecasts in the future they can change. As you've seen, the capital plan can go up or down and we're taking a look at what that variability related to that capital plan is.
>
> Given under the next five years a significant portion of that capital plan is Site C costs, so they are quite certain. And taking a look at history around how much is spent on capital we're looking at variability around that, and so 25 percent was not hedged because we figured there is some variability on the actual cash flows that will occur in the future, so that's where we came to the 75 percent.[208]

215. BC Hydro does not balance the risk of increasing interest rates, on the one hand, against the risk of hedging leading to cost increases if interest rates <u>either</u> remain low <u>or</u> reduce further. The only criterion BC Hydro seems concerned with is forecast certainty for its cash flow requirements. While this is important, it should not be the only consideration.

216. At the oral hearing, Mr. Keen cross-examined Mr. Wong regarding Attachment 1 to BCUC Panel IR 2.17.3, which shows the results of a series of hedges between September 29, 2017 and January 29, 2018.[209]

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[207] Transcript Volume 7, p. 952, pdf p. 132, l. 3 – p. 953, pdf p. 133, l. 24.
[208] Transcript Volume 7, p. 954, pdf p. 134, l. 15 – p. 955, pdf p. 135, l. 5.
[209] Exhibit B-31, BCUC Panel IR 2.17.3, Attachment 1 (Excel document), tab "FDH September 2019", Excel rows 29-37; Transcript Volume 7, p. 955, pdf p. 135, ll. 11-14.

217. This document shows that the majority of the hedges from F2018 were undertaken for periods of under a year.[210] This means that BC Hydro undertook a hedged position for debt that it was planning to borrow in the near term. Further, BC Hydro experienced a loss when settling each of these hedges - in fact, these hedges collectively cost ratepayers $58.4 million above the cost which BC Hydro would have incurred had it simply borrowed when it required the funds.[211]

218. Mr. Wong confirmed that this amount would be recovered from ratepayers:

> MR. KEEN: Q And so what was happening there is you were locking in an interest rate, and interest rates continue to decline?
>
> MR. WONG: A The actual interest rate relative to the date of settlement is lower than what we contracted at, yes.
>
> MR. KEEN: Q Yes, and so that gets recorded in terms of the mechanics of the associated regulatory account, and that's an amount that has to be collected from ratepayers, over the -- right?
>
> MR. WONG: A That's correct, it goes into the regulatory account and it gets amortized over the life of the debt. And essentially what happens is is that we've locked in the debt at the rate that we contracted it.[212]

219. Particularly for shorter-term hedges (i.e., less than a year), in an environment of lingering low interest rates, ratepayers would benefit more from avoiding short-term hedging than they would from interest rate certainty. AMPC is concerned that the costs of the above hedges reflect unmindful adherence to its 75% hedging policy rather than careful strategy.

220. BC Hydro also provided the following illustrative example that also suggests an overfocus on cost certainty, through blithe acceptance of additional costs to ratepayers:

> As an illustrative example, on September 28, 2017 BC Hydro entered into a 30-year FDH to fix the interest rate at approximately 3.36 per cent on a $250.0 million forecast debt issuance in September 2018. As a result, BC Hydro locked in total future interest costs of $254.7 million.
>
> When the $250.0 million debt was issued on August 24, 2018, market interest rates had decreased to 3.02 per cent. This decrease in interest rates resulted in a loss on the FDH of $16.7 million that was recognized in the Debt Management Regulatory Account (please refer to the “FDH September 2019” worksheet in Attachment 1 to BC Hydro’s response to BCUC Panel IR 2.17.3 (the second page of the attachment) which shows the $16.7 million loss in the “Settlement

[210] Exhibit B-31, BCUC Panel IR 2.17.3, Attachment 1 (Excel document), tab "FDH September 2019", Excel rows 29-37; Transcript Volume 7, p. 955, pdf p. 135, l. 18 – p. 956, pdf p. 136, l. 13.
[211] Exhibit B-31, BCUC Panel IR 2.17.3, Attachment 1 (Excel document), tab "FDH September 2019", summing Excel rows 29-37 for column "Settlement Value".
[212] Transcript Volume 7, p. 956, pdf p. 136, l. 21 – p. 957, pdf p. 137, l. 9.

> Value" column). However, BC Hydro was able to issue the debt at an effective interest rate of 3.02 per cent for total interest costs of $238.0 million which was $16.7 million ($254.7 million less $238.0 million) lower than originally forecast. It is this savings of $16.7 million in interest costs on the debt issue that will offset the $16.7 million loss on the FDH.
>
> As a result, the $16.7 million FDH loss is offset by $16.7 million in lower interest costs on the debt and ratepayers pay the net cost of $254.7 million over the life of the associated debt issue which is equivalent to the hedged interest rate of 3.36 per cent, which was the objective of the interest rate hedge - to lock in the interest rate for cost certainty purposes.[213]

221. AMPC's concern in the above example is that, while BC Hydro's financial instruments locked in debt at a rate equal to forecast to ensure "cost certainty", when compared against actuals, BC Hydro's hedging in this case cost ratepayers $16.7 million more than if BC Hydro had secured the debt without hedging.

222. As BC Hydro further explained in Final Argument:

> Future Debt Hedges fluctuate in value before they are settled as forward interest rates change. If forward interest rates increase/decrease relative to the hedged rate, then the Future Debt Hedges will incur an unrealized gain/loss. However, any actual gain/loss on the Future Debt Hedges will be offset by higher/lower interest costs when the associated future debt is issued. Accordingly, as Mr. Wong explained, the objective of BC Hydro's hedging strategy is based on the ability to lock in interest rates based on expected future debt issuances, rather than targeting a gain/loss that may occur over time. It has accomplished its purpose.[214]

223. Again, BC Hydro does not justify the cost of mitigating the risk of higher rates against the option of *not hedging* and purchasing debt at the time needed.

224. Mr. Wong's response, when asked whether BC Hydro ever considers whether to reduce its hedging activities below 75 percent, is instructive:

> [MR. KEEN:] … [D]oes BC Hydro ever stop to think -- does it go below that 75 percent level if it expects interest rates to continue to decline?
>
> MR. WONG: A What I can say is that we, in everything we do, take things -- do analysis and thoughtfulness around what we're doing here, and so we haven't had a situation yet, because we've been at the 75 percent, to make a decision on whether we would change that policy. We are actually in the point of now starting to review the annual review piece of it.

[213] Exhibit B-31, BCUC Panel IR 2.17.4, pdf pp. 146-147.
[214] BC Hydro Final Argument, para. 486, pdf p. 218.

> I would suggest that perhaps, you know, we could constantly take a look. And so yeah, I think that's sort of a representation of everything we do, and, you know, as it applies to these Treasury aspects as well.
>
> I mean we take a look at -- just as another example, the percentage of variable rate debt, we take a look at that and there's policies around how much we should have there. And we look at how much -- and that's around 15 percent. And of course, short-term interest rates are lower than long-term interest rates, but you don't want to leave a whole portfolio open to short-term interest rates only because as a variability, short-term interest rates go up and down. You could be left in a position where interest rates go very high and you haven't locked it in. So it wouldn't be prudent necessarily to have a very short-term -- a very big portfolio in short-term debt, as an example.
>
> MR. KEEN: Q Have you experienced a lot of up and down short-term interest rate variability recently?
>
> MR. WONG: A Not of recent, but I could say that it has happened in the past. I'm not talking for BC Hydro, I'm just talking in the market general.
>
> MR. KEEN: Q And so that annual review that you referred to that's coming up, that may calibrate your strategy relative to the current interest rate environment, yes?
>
> MR. WONG: A We certainly take all information to account to look at how we want to continue our risk management program.[215]

225. Mr. Wong further confirmed BC Hydro's focus was "[c]reating cost certainty".[216]

226. Mr. Wong's description of BC Hydro's hedging strategy as a "risk management program" focussed on "creating cost certainty" illustrates the issue with BC Hydro's approach to hedging. When BC Hydro brought its proposed hedging strategy to the Commission, it emphasized that "its debt management strategy was developed under the view that interest rates are at historical lows and there is greater risk associated with higher interest rates versus reward from lower interest rates", and that "execution of Future Debt Hedges as described in its Application, are part of a prudent debt management strategy to protect ratepayers from the risk of higher interest rates".[217]

227. BC Hydro's current approach to hedging is focused on attaining cost certainty for BC Hydro, rather than protecting ratepayers from the risk of higher interest rates. The Commission should accordingly direct BC Hydro to identify and report on its hedging strategies and outcomes in its next Revenue Requirements Application, and require BC Hydro to demonstrate how its debt management strategy has minimized its cost of debt.

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[215] Transcript Volume 7, p. 963, pdf p. 143, l. 4 – p. 964, pdf p. 144, l. 20.
[216] Transcript Volume 7, p. 965, pdf p. 145, ll.21-23.
[217] Order G-42-16, p. 7 of 10, pdf p. 9, available online at: https://www.bcuc.com/Documents/Proceedings/2016/DOC_46024_G-42-16_Reasons.pdf

APPENDIX H: INTERCONNECTIONS

ISSUE

228. Customers have been raising concerns about BC Hydro's interconnections process for years. For example, the Industrial Electricity Policy Review Task Force Final Report ("IEPR Report") from 2013 noted that "[d]elays in transmission availability are cited as an obstacle to industrial development in British Columbia" and that "BC Hydro's transmission interconnection process is perceived as slow, cumbersome, unresponsive and expensive by customers."[218]

229. BC Hydro has acknowledged that if the load interconnection process is perceived to be too lengthy, it could discourage load from coming to British Columbia.[219]

AMPC SUMMARY AND/OR RECOMMENDATION:

230. Interconnections have been a longstanding industrial competitiveness concern, and BC Hydro has not made meaningful improvement with respect to staff numbers, timelines and results. This is important because load growth mitigates the need for rate increases. It is therefore a false economy to underinvest in the resources needed to complete timely industrial interconnections.

231. The Commission should direct BC Hydro to prioritize service improvements with respect to the interconnections process, particularly given BC Hydro's stated desire to grow load, and report on concrete steps taken and improvements achieved as part of its next Revenue Requirement Application.

DISCUSSION AND SUPPORT:

232. At the oral hearing, Ms. Daschuk acknowledged that if the load interconnection process is perceived to take too long, it could discourage load from coming to British Columbia:

> MR. KEEN: Q …to be clear, you would agree with me that if the load interconnection process is perceived to take a long time, that can discourage load from coming to British Columbia, yes?
>
> MS. DASCHUK: A It could.[220]

233. However, despite this issue, and despite the reported customer concerns about BC Hydro's "slow, cumbersome, unresponsive and expensive" interconnections process since at least 2013,[221] BC Hydro continues to experience issues with:

[218] Exhibit C10-26, p. 31, pdf p. 4.
[219] Transcript Volume 12, p. 2133, pdf p. 49, l. 9 – p. 2134, pdf p. 50, l. 6.
[220] Transcript Volume 12, p. 2133, pdf p. 49, l. 9 – p. 2134, pdf p. 50, l. 6.

a. staff numbers;

b. timelines; and

c. results

in its interconnections process, as described in turn below.

Staff Numbers

234. BC Hydro has explained that:

> Two KBUs are responsible for managing a new industrial load through the interconnection processes:
>
> 1. The Interconnections and Shared Assets KBU (part of the Integrated Planning Business Group), which is responsible for all transmission interconnection requests and major distribution load interconnection requests. The guideline for major distribution load interconnection requests is a new distribution load request that has anticipated demand over 5 MVA or estimated connection costs in excess of $1 million; and
>
> 2. The Distribution Design and Customer Connections KBU (part of the Operations Business Group) which is responsible for other new distribution load requests (i.e., usually less than 5 MVA and/or less than $1 million in estimated connection costs).[222]

235. In its Application, BC Hydro notes that, within the Interconnections and Shared Assets KBU, the "Customer Interconnections and Policy department manages customer requests to interconnect, supply, or receive electrical services from the transmission and distribution system".[223] At the hearing, Ms. Daschuk said that this group "keeps the ball in the air between the said planners, the engineers and the project managers".[224]

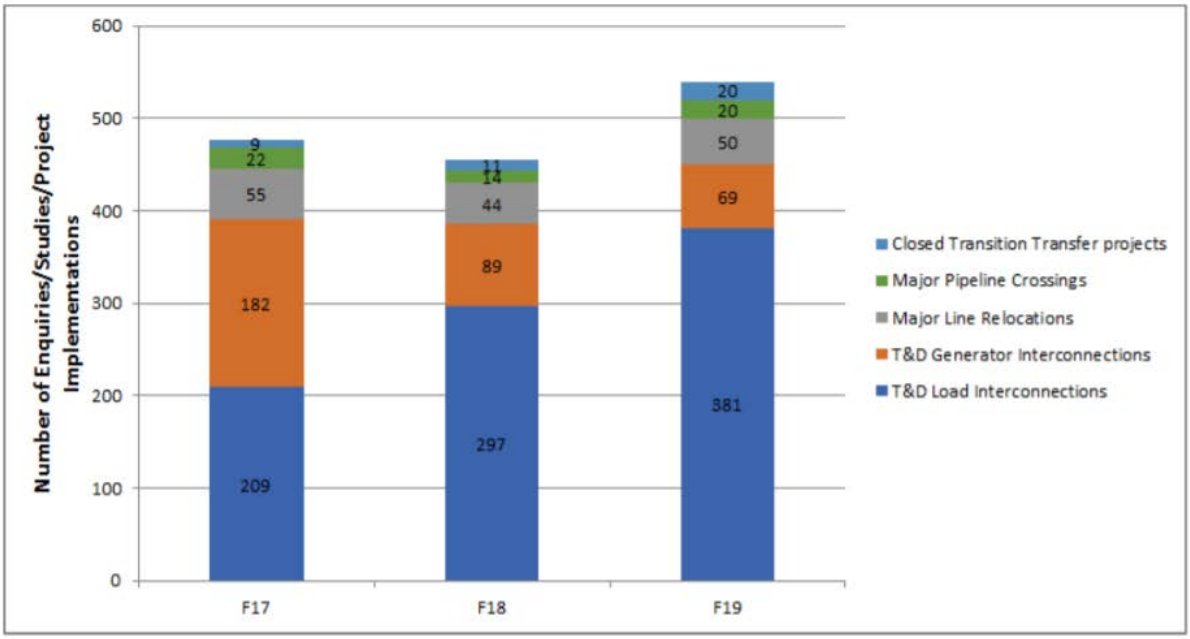
236. However, despite "increases in new load interconnection requests and tariff work, such as responding to FERC Order 845", which "have increased the total volume of work

[221] Exhibit C10-26, p. 31, pdf p. 4.
[222] Exhibit B-13, AMPC IR 2.35.1, pdf p. 83. BC Hydro further explains in its IR response that capital projects resulting from a new load interconnection request may be implemented by the Project Delivery KBU (Capital Infrastructure Project Delivery Business Group), Program and Contract Management KBU (Operations Business Group), or Distribution Design and Customer Connections KBU (Operations Business Group).
[223] Exhibit B-1, p. 5A-32, pdf p. 384.
[224] Transcript Volume 12, p. 2139, pdf p. 55, ll. 15-20.

managed by this department", the "number of FTEs in this department has remained the same".[225] [emphasis added]

237. Figure 5A-3 from BC Hydro's Application, reproduced below, shows that load interconnection enquiries, studies and project implementations (indicated in blue) nearly doubled between fiscal 2017 and fiscal 2019, from 209 to 381, and BC Hydro "expects that new load interconnection requests and activities will remain consistent or increase during the test period",[226] yet the same number of FTEs within the department are expected to handle this increased workload.

Figure 5A-3 Interconnections Project Activity



238. Ms. Holland further noted that there are only eight dedicated project managers for Facility Studies, subject to augmentation by contract staff.[227] These eight managers are responsible for supporting approximately 400 projects.[228]

239. Given BC Hydro's continued trouble meeting timelines and achieving satisfactory results for customers seeking an interconnection (as described further below), BC Hydro should prioritize further staffing to support interconnections, if necessary, as part of its revenue requirement.

[225] Exhibit B-1, p. 5A-34, pdf p. 386.
[226] Exhibit B-1, pp. 5A-34 – 5A-35, pdf pp. 386-387.
[227] Transcript Volume 12, p. 2140, pdf p. 56, l. 23 – p. 2141, pdf p. 57, l. 4.
[228] Exhibit B-1, p. 5B-13, pdf p. 413; Transcript Volume 12, p. 2181, pdf p. 97, ll. 4-18.

Timelines

240. In its Final Argument, BC Hydro notes that it "sets internal targets each year for the time to deliver on the studies to facilitate a load interconnection".[229] For transmission interconnections, the targets are 150 days for a System Impact Study and 180 days for a Facilities Study, and for distribution load interconnection requests the targets are 60 days for Planning Studies and 365 days for Facilities Studies.[230]

241. BC Hydro then reproduces the following table from its response to AMPC IR 2.35.5, asserting that the "table below shows that BC Hydro has completed its studies on average within its targets":[231]

	F2017		F2018		F2019		F2020*	
	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration	Total Number	Average Duration
System Impact Studies	10	131	18	84	21	109	9	131
Facilities Studies	3	176	7	215	4	276	0	0
Projects reaching in-service	9	N/A	11	N/A	19	N/A	1	N/A

Notes:
* Fiscal 2020 data cover the period from April 1, 2019 to July 31, 2019.

242. The table, however, actually demonstrate that, though BC Hydro has generally been within its target of 150 days for System Impact Studies, it on average significantly exceeded its target of 180 days for Facilities Studies in each of 2018 (average duration: 215 days) and 2019 (average duration: 276 days).

243. In its response to Undertaking No. 39, BC Hydro provided a copy of the Interconnections and Shared Assets Performance fiscal 2020 Dashboard for the period ending January 2020.[232] This document shows that, although Systems Impact Studies and Facilities Studies for transmission interconnections were within the targeted range (at 126 days and 114 days, respectively), Planning Studies and Facilities Studies well exceeded their targeted ranges (at 72 days and 514 days, respectively).

[229] BC Hydro Final Argument, para. 387, pdf p. 179; Exhibit B-13, AMPC IR 2.35.7, pdf p. 96.
[230] BC Hydro Final Argument, para. 387, pdf p. 179; Exhibit B-13, AMPC IR 2.35.7, pdf p. 96.
[231] BC Hydro Final Argument, para. 388; pdf p. 180, Exhibit B-13, AMPC IR 2.35.5, pdf p. 91.
[232] Exhibit B-51, pdf p. 7.

244. Ms. Daschuk further confirmed that the six to nine months' timeline used by BC Hydro as a yardstick for system impact studies has in fact itself been the subject of customer complaints during past connection and consultation processes.[233]

245. The figures cited above demonstrate that BC Hydro continues to face issues meeting timelines for interconnection studies, with the result that customers are faced with lengthy waiting periods for connection to BC Hydro's system. For example, for the partial fiscal year ended January 2020, the average wait time for a customer for a distribution Facilities Study was 514 days,[234] or almost a year and a half. That is simply too long.

246. BC Hydro also refers to the following table to support its assertion that "BC Hydro's targets compare well to other utilities using information published as of April 2019":[235]

Interconnection Activity	BC Hydro	AESO	Sask Power	Hydro One
System Impact Studies or equivalent	6 to 9 months	37 weeks (9 months)	4 to 12 months	4 to 7 months
Facilities Studies or equivalent	6 to 9 months	52 weeks (12 months)	6 to 18 months	5 to 8+ months
Implementation	No target set	No target set	6 to 18 months	1 to 2+ years

247. BC Hydro's reliance on this table is misplaced for three reasons:

a. BC Hydro has acknowledged that this table contains a combination of published target durations (for BC Hydro, Sask Power and Hydro One) and actual durations (for the AESO),[236] meaning that BC Hydro is, perhaps selectively, comparing "apples and oranges";

b. As described above, BC Hydro is not meeting its targeted timelines for several categories of studies, making comparisons to its timeline of limited use.

c. BC Hydro assembled the table but withheld <u>and made no mention</u> of the 2016 Black & Veatch benchmarking report it had commissioned on that very topic. The report was only produced at the hearing as the result of cross-examination and even then only in heavily redacted form.[237] BC Hydro's comparison efforts appear selective and should be received very skeptically by the Commission.

[233] Transcript Volume 12, p. 2165, pdf p. 81, l. 21 – p. 2166, pdf p. 82, l. 2.
[234] Exhibit B-51, pdf p. 7.
[235] BC Hydro Final Argument, para. 391, pdf p. 180; Exhibit B-13, AMPC IR 2.35.6, pdf p. 94.
[236] Exhibit B-49, BC Hydro Undertaking No 38, pdf p. 12.
[237] Exhibit B-47, Undertaking No. 32 Attachment 1.

Results

248. With respect to results, customers attempting to connect to BC Hydro's system continue to experience delays, expense, and frustration.

249. As noted above, the 2013 IEPR Report noted that "[d]elays in transmission availability are cited as an obstacle to industrial development in British Columbia" and that "BC Hydro's transmission interconnection process is perceived as slow, cumbersome, unresponsive and expensive by customers."[238]

250. The 2016 Black & Veatch report, which reviewed BC Hydro's interconnection process, identified a number of issues, including, among others, "[i]nadequate staffing levels to complete studies in a timely manner"[239] and complaints that the "[l]evel and effectiveness of early discussions with customers is inadequate".[240]

251. Issues with interconnections persist today. When presented with a newspaper article that describes the "unnecessary costs and… lost revenue due to the delays" that the City of Fort St. John has experienced while waiting to connect to BC Hydro's system,[241] Ms. Daschuk also acknowledged that it took more than two years for the City to get a power connection,[242] and that Fort St. John had expressed concerns to BC Hydro about the "serious wait times":

> MR. KEEN: Q You've mentioned, Ms. Daschuk, that this is an issue for Ms. Mitha's group, but just preliminarily, Fort St. John has expressed concerns about connecting to BC Hydro system for some of its projects, yes?
>
> MS. DASCHUK: A Absolutely.
>
> MR. KEEN: Q And the concerns relate to what they describe in the article as serious wait times, yes?
>
> MS. DASCHUK: A That is absolutely what the article says, yes.
>
> MR. KEEN: Q That's what the article says, but that's in fact accurate, that Fort St. John has expressed concerns to BC Hydro about serious wait times.
>
> MS. DASCHUK: A They have.[243]

[238] Exhibit C10-26, p. 31, pdf p. 4.
[239] Exhibit B-47, Undertaking No. 32 Attachment 1, p. 27 of 76, pdf p. 89.
[240] Exhibit B-47, Undertaking No. 32 Attachment 1, p. 30 of 76, pdf p. 92.
[241] Exhibit C11-25.
[242] Transcript Volume 12, p. 2187, pdf p. 103, ll. 2-5.
[243] Transcript Volume 12, p. 2185, pdf p. 101, l. 14 – p. 2185, pdf p. 101, l. 1.

252. Taken as a whole, Ms. Daschuk agreed that the press reports regarding Fort St. John's concerns echoed the concerns from the 2013 IEPR Report:

> [MR. KEEN:] But it's fair to say that the concerns that have been reported in the press sound a lot like the concerns we heard in 2013, that the BC Hydro connection process was slow, cumbersome, unresponsive, and expensive. Is that fair?
>
> MS. DASCHUK: A There are certainly concerns here that sound consistent with -- I would say these are entirely different types of customer connections, but yes.[244]

253. BC Hydro has had issues with the performance of its interconnection process for years.

Conclusion

254. The Evidence described above demonstrates that BC Hydro continues to experience issues with respect to adequate staffing levels to support interconnections, meeting targeted timelines, and achieving satisfactory results for customers seeking to connect to BC Hydro's system.

255. The Commission should accordingly direct BC Hydro to prioritize service improvements with respect to the interconnections process, and directly report on its efforts and results as part of its next Revenue Requirement Application.

[244] Transcript Volume 12, p. 2190, pdf p. 106, l. 26 – p. 2191, pdf p. 107, l. 8.

APPENDIX I: CAPITAL PROJECTS

ISSUE

256. BC Hydro's Application pro-actively notes that "[o]ver the past several years, BC Hydro has implemented a number of improvements to the delivery of its capital projects".[245] One such improvement was to start to do geotechnical work earlier in the process to avoid surprises, described as follows:

> The project delivery practices outlined above reflect a number of improvements that have been introduced over the past several years. Specifically, BC Hydro has:
>
> …
>
> - Integrated specific geotechnical risk management into the Engineering Design Practice which requires site investigations to be conducted early in the project delivery process and planned, as appropriate, throughout the phases of the project lifecycle.[246]

257. AMPC sought further information through the IR process and at the oral hearing about what led to this change in practice. BC Hydro ultimately provided only limited information about the costs those practices are designed to avoid, even after information requests and cross-examination and undertakings on that point.

AMPC SUMMARY AND/OR RECOMMENDATION:

258. BC Hydro has changed its processes regarding geotechnical investigations, but it has failed to provide adequate information on the record of this proceeding regarding the costs associated with its prior practice. The Commission should direct BC Hydro to identify the costs associated with foreseeable geotechnical-related delay and redundancies on certain capital projects (namely, the Campbell River Substation and Big Bend Substation projects), and disallow those amounts from the capitalized project costs.

DISCUSSION AND SUPPORT:

259. Through its IRs, AMPC sought additional information from BC Hydro regarding BC Hydro's geotechnical practices and projects which experienced cost exceedances.[247] BC

[245] Exhibit B-1, p. 6-14, pdf p. 731.
[246] Exhibit B-1, pp. 6-82 – 6-83, pdf pp. 799-800.
[247] Exhibit B-13, AMPC IR 2.36.2, pdf p. 100 ("For each of the projects listed above, explain why the actual cost exceeded the expected cost, including what modifications were required to the project and the date when BC Hydro first knew or reasonably could have known of the need for modifications"); Exhibit B-17, AMPC IR 3.21.2, pdf p. 228 ("Please provide a detailed explanation on when the seismic risks for the Campbell River Substation Capacity Upgrade project were identified, why they were not identified earlier, and identify what steps (if any) BC Hydro is taking to recoup the additional costs from third parties").

Hydro's responses to AMPC and BCUC staff IRs confirmed that several projects experienced increases in project costs as a result of unanticipated geotechnical issues or ground conditions. At the oral hearing, AMPC focused on the Kamloops Substation, Campbell River Substation and the Big Bend Substation projects.

260. Parts of BC Hydro's IR responses for the Campbell River Substation and the Big Bend Substation are reproduced below (following cross-examination,[248] AMPC has no further recommendations concerning the Kamloops Substation):

> **Campbell River Substation Capacity Upgrade**
>
> The forecasted actual cost of $32.7 million exceeds the expected cost of $25.4 million for this project for the following reasons:
>
> - Unforeseen geotechnical issues: a liquefiable layer was not identified until the geotechnical investigations were undertaken in the Implementation phase. This led to design changes that resulted in additional costs and schedule delay. BC Hydro's practice is now to undertake geotechnical investigations during the Definition Phase…[249]
>
> …
>
> The seismic risks for the Campbell River Substation Capacity Upgrade project were identified during geotechnical testing. This testing was completed during the Implementation phase, which occurs after the Definition phase, when the project budget was determined. For further information on the unforeseen geotechnical issues on the Campbell River Substation Upgrade Project, please refer to BC Hydro's response to AMPC IR 2.36.2.
>
> As discussed in section 6.4.11 of Chapter 6 of the Application, BC Hydro has improved its processes to address geotechnical issues in earlier project phases.[250]
>
> …
>
> **Big Bend Substation**
>
> The Big Bend Substation project was placed into service in 2017 and is forecast to be completed for $68.7 million. The forecast is 22 per cent over the Authorized Amount ($56.4 million) and 34 per cent over the Expected Cost ($51.3 million).

[248] Transcript Volume 12, p. 2220, pdf p. 136, l. 24 – p. 2221, pdf p. 137, l. 23.
[249] Exhibit B-13, AMPC IR 2.36.2, pdf p. 101.
[250] Exhibit B-17, AMPC IR 3.21.2, pdf pp. 228-229.

> The increase in project costs of approximately $17 million was primarily due to the following:
>
> - worse than anticipated geotechnical (subsurface) conditions which increased the cost of the site preparation and foundations ($5 million)…[251]

261. With respect to the Campbell River Substation project, Ms. Holland confirmed that designs changed, although said she was unable to answer specifically how much of the delay was attributable to those design changes (as opposed to other issues):

> MR. KEEN: Q I'm looking at the second sentence, the design changes that resulted in additional costs and schedule delay. How much delay was attributable to the design changes?
>
> MS. HOLLAND: A Of the overall schedule, the impact of the design changes, I don't know the answer to that.
>
> MR. KEEN: Q Okay, could you find that out please?
>
> MS. HOLLAND: A I'm just trying to assess whether we would have a breakdown in our schedule of a specific design change and its impact to the overall critical path. I'm not sure we will be able to provide that.
>
> MR. KEEN: Q Okay, but that's what is implied by that second sentence. "This led to design changes that resulted in additional costs and schedule delay."
>
> MS. HOLLAND: A Yes, we do say that. I think your question was "how much delay" and I'm saying I'm not sure that I can answer specifically how much delay is attributable to that one item.[252]

262. Ms. Holland could confirm, however, that the geotechnical issues resulted in 70 percent of the cost overruns for the Campbell River Substation project (i.e., 70 percent of $7.3 million dollars, or around $5 million).[253] She also confirmed that there are carrying costs associated with delays arising from idle time or demobilization, and increases in owners' costs (project management, etc.).[254]

263. With respect to the Big Bend Substation project, Ms. Holland noted that BC Hydro experienced challenges with performing geotechnical work at the property due to issues

[251] Exhibit B-5, BCUC IR 1.107.2, pdf p. 1061.
[252] Transcript Volume 12, p. 2204, pdf p. 120, ll. 9-26.
[253] Transcript Volume 12, p. 2205, pdf p. 121, ll. 1-21.
[254] Transcript Volume 12, p. 2207, pdf p. 123, l. 23 – p. 2208, pdf pp. 124 and 134.

related to the acquisition of the property – but chose to move directly into the implementation phase nevertheless:

> MR. KEEN: Q So this is one of the other projects that I infer would have driven BC Hydro's change in geotechnical investigation practices, fair?
>
> MS. HOLLAND: A This one is a little bit different. We did preliminary geotech as much as we were able to before we acquired this property. And we didn't find in that preliminary geotech what we subsequently found. Again, our preference is absolutely now to do it all. In this case, I'm not sure we still would have been able to do the detailed investigations in advance of the property acquisition. I'm not sure the property purchaser was in agreement, so we did what we were able to do.[255]
>
> …
>
> MR. KEEN: Q Thank you, that is helpful. And going back to what you mentioned about the lack of site access to do in-depth geotechnical work, what was the problem with accessing the site?
>
> MS. HOLLAND: A We needed to purchase the land from an owner and there was limited geotech that the owner was interested in allowing us to do prior to the acquisition.
>
> MR. KEEN: Q So you purchased the land, had limited geotechnical and then you moved into the implementation phase.
>
> MS. HOLLAND: A Yes.[256]

264. At the hearing, AMPC also sought to specify the costs arising from the geotechnical issues that the Campbell River Substation and Big Bend Substation projects encountered, specifically targeting whether there was any of redundant design work, demobilization, or idle time and, if so, the associated cost in each case.[257]

265. In each case, BC Hydro asserts that there were "no additional costs related to demobilization or idle time caused by design changes" for either of these projects, identifying approximately $50,000 as the cost of the Big Bend piling design that proved unsuitable:

[255] Transcript Volume 12, p. 2213, pdf p. 129, ll. 9-21.
[256] Transcript Volume 12, p. 2218, pdf p. 134, l. 15 – p. 2219, pdf p. 135, l. 1. 14.
[257] Transcript Volume 12, p. 2212, pdf p. 128, ll. 9-23; p. 2214, pdf p. 130, ll. 5-14.

Big Bend Substation Project

For the Big Bend Substation Project, the Implementation phase began in May 2013 and construction started in April 2015. The cost to address the geotechnical issues identified in the Implementation phase was $5 million. This included $2.9 million for the cost increase related to changing the design from piling methodology to deep soil mixing methodology. This change occurred [sic] during the detailed design stage, prior to the tender and award of the construction contract. The practice at that time did not require substantial design work on the piles during the Definition phase. Piling costs were estimated using the typical piling capacity. Costs related to design redundancy for piling estimates are estimated to be less than $50,000.

Due to further soil issues discovered during construction, the cost estimate increased by an additional $2.1 million. These soil issues resulted in greater depth of the deep soil mixing panels than originally designed, and required removal of large boulders below five meters to avoid damage to the deep soil mixing equipment. There were no additional costs related to demobilization or idle time caused by design changes from piling methodology to deep soil mixing methodology. However, the deep soil mixing required additional time to evaluate the tenders and an additional three months to address the removal of large boulders. Due to these geotechnical issues the overall schedule impact was in the order of six months.

Campbell River Substation Capacity Upgrade Project

For the Campbell River Substation Capacity Upgrade Project, the Implementation phase began in July 2015 and construction began in 2016 as planned. The cost to address the geotechnical issues identified in the Implementation phase was $3.4 million. The geotechnical issues were discovered early during Implementation Phase, while starting the detailed engineering. These geotechnical issues required design additions such as the design of piles, a new retaining wall, new seismic keys, new drainage, and additional soil replacements. There was no design redundancy, and there was no additional costs related to demobilization or idle time caused by design changes.[258]

[Underlining added]

266. Missing from the undertaking responses is clarity about redundant designs, demobilization, or idle time. BC Hydro's assertion that there were no additional costs for any

[258] Exhibit B-56, BC Hydro Undertaking No. 41, pdf p. 4.

of the categories for either project avoids an important element of the request, which is relevant to assessing potential carrying costs[259] or owners' costs.[260]

267. BC Hydro has acknowledged that there were delays to both the Campbell River and Big Bend Substation projects due to geotechnical issues. It has also acknowledged that there are inherent costs associated with delay, and that there were $50,000 in costs associated with redundant designs for the Big Bend project, in particular.

268. Although BC Hydro's Application begins by explaining that experience with geotechnical issues caused it to change its practices, it now claims through undertaking responses that its prior practice did not have any adverse consequences. It is difficult to reconcile these positions. In consequence, any compliance filing process to this proceeding should require further identification from BC Hydro of the extent of, and costs attributable to, geotechnical-related delay for the Campbell River Substation and Big Bend Substation projects. As with the $50,000 design redundancy identified for the Big Bend Substation, those amounts should be disallowed from BC Hydro's capital additions.

[259] Transcript Volume 12, p. 2207, pdf p. 123, l. 23 – p. 2208, pdf p. 124, l.
[260] Transcript Volume 12, p. 2218, pdf p. 134, ll. 2-14.

APPENDIX J: PROJECT WRITE-OFFS

ISSUE

269. In its Application, BC Hydro seeks to recover forecast project write-off expenses in rates, in the amount of $9.9 million in fiscal 2020 and $9.7 million in fiscal 2021, on the basis that its write-off decisions are "effective project and investment management practices and are the result of mature portfolio management practices to ensure [BC Hydro's] capital investments are prudent". The write-off amount is calculated as a historical percentage of write-offs relative to forecast total project costs.[261]

AMPC SUMMARY AND/OR RECOMMENDATION:

270. The Commission should reject the request. It is inconsistent with standard utility practices and the foundational regulatory principle that, as applicant, BC Hydro bears the onus of showing that its costs are prudent.

DISCUSSION AND SUPPORT:

271. The new approach to project write-offs proposed by BC Hydro is a significant departure from the current practice. Mr. Layton confirmed that, in the past, BC Hydro did not forecast project write-offs related to capital expenditures, but rather wrote them off against net income, with the result that such write-offs were a shareholder cost:

> MS. MIS: Is it correct that in previous revenue requirement applications BC Hydro did not forecast project write-offs related to capital expenditures, but rather wrote them off to net income?
>
> MR. LAYTON: A That's correct, yes.
>
> MS. MIS: Q So in the past these write-offs have essentially been a shareholder cost, is it correct?
>
> MR. LAYTON: A That's correct, yes.[262]

272. The write-off associated with the Terrace to Kitimat Transmission Project is an example of how such variances between forecast and actual project write-offs would work in practice, under BC Hydro's proposed new approach. BC Hydro has written off $13.6 million for this project, since it has decided to refurbish the existing transmission line instead of

[261] Exhibit B-1, pp. 8-21 – 8-22, pdf pp. 983-984.
[262] Transcript Volume 7, p. 1002, pdf p. 182, ll. 19-26. See also: Exhibit B-5, BCUC IR 1.161.1, pdf p. 1809 ("BC Hydro did not forecast project write-offs in prior test periods") and Exhibit B-13, BCOAPO IRs 2.122.1, pdf p. 360 and 2.147.1, pdf p. 430 ("As BC Hydro did not forecast project write-offs in the Previous Application, the actual write-offs were written-off against net income").

constructing a new line (as originally planned).[263] Mr. Kumar confirmed that the entire $13.6 million write-off was to the account of the shareholder.[264]

273. In contrast, under the new proposed method, Ms. Pinksen and Mr. Kumar confirmed that, using the forecast project write-off expense for fiscal 2020 ($9.9 million), and assuming there were no other write-offs, only $3.7 million would be to the account of the shareholder:

> MR. KEEN: Q So just to be clear about that, Ms. Pinksen, taking again the Kitimat to Terrace project as an example and thinking about F2020, there you've got a forecast of $9.9 million. And so the amount that would to the account of the shareholder would be subtracting 9.9 million from the 13.6, is that right?
>
> MR. KUMAR: A That is correct, provided there's no other write-offs in BC Hydro.
>
> MR. KEEN: Q Right, if that was the only write-off.
>
> MR. KUMAR: A That is correct.
>
> MS. PINKSEN: A Right.
>
> MR. KEEN: Q And so the shareholder would take a hit of $3.7 million and ratepayers would take the hit of the 9.9.
>
> MR. KUMAR: A That is correct.[265]

274. Ms. Pinksen confirmed that she was not aware of any other utility in Canada that takes a similar approach to forecasting project write-off expenses.[266]

275. BC Hydro claims that its proposed forecast project write-off costs are reasonable because the write-offs reflect prudent capital management practices.[267] In Final Argument, BC Hydro quotes from Mr. Layton's statements that "when we make those kind of prudent decisions, write-offs can happen", and that "those are prudently incurred costs and, therefore, the ratepayers should be willing to pay for a reasonable amount there".[268]

276. This justification must be rejected. First, as a textbook example of "begging the question" it should receive no weight (prudently incurred costs and reasonable costs are synonymous, in the eyes of the Supreme Court of Canada). Second, it is backwards, in that

[263] Exhibit B-5, BCUC IR 1.161.6, pdf p. 1818.
[264] Transcript Volume 12, p. 2239, pdf p. 155, ll. 21-24.
[265] Transcript Volume 12, p. 2241, pdf p. 157, ll. 7-21.
[266] Transcript Volume 12, p. 2241, pdf p. 157, ll. 22-24 and p. 2242, pdf p. 158, ll. 23-25.
[267] BC Hydro Final Argument, para. 369, pdf p. 170; Exhibit B-1, p. 8-21, pdf pp. 983 ("These decisions are effective project and investment management practices and are the result of mature portfolio management practices to ensure our capital investments are prudent").
[268] BC Hydro Final Argument, para. 370, pdf p. 170; Transcript Volume 7, p. 1003, pdf p. 183, l. 24 – p. 1004, pdf p. 184, l. 3.

it would require the Commission to reverse a core premise of how BC Hydro is regulated. BC Hydro is the applicant and has the onus to show its costs are prudent. The Supreme Court of Canada has rejected the notion that utilities benefit from a "presumption of prudence" absent specific statutory language, and further cautioned that regulators crafting such a presumption could run afoul of common statutory provisions that require just and reasonable rates.[269] AMPC accepts that some write-offs in some cases may reflect prudent practices, but rejects relief that would require the Commission to assume that fact broadly.

277. Examples of the hazard this practice would pose exist on this record. For example, BC Hydro's capital expenditures related to Site C in fiscal 2019 were 35 percent, or $287.5 million, above the planned expenditures for that year.[270] These increased expenditures related in part to unplanned investment in equipment, the settlement of claims and incentive payments, including a claim made by the main civil works contractor based in part on delays that it experienced as a result of dealing with BC Hydro.[271] The total potential cost of the associated settlement agreement is estimated to be up to $325 million.[272]

278. Similarly, BC Hydro is capitalizing $97.2 million related to the ILM project, resulting from an arbitration decision following a contractor's claim.[273] Mr. O'Riley confirmed that BC Hydro was required to pay $97.2 million for those "claims that were properly found to be the responsibility of BC Hydro".[274] He later clarified that:

> […] [T]here was a number of disputes that arose with respect to access and the routing of the line, which are under the contract for BC Hydro's responsibility, and the contractor found that those collectively disrupted -- sorry, the arbitrator found that those impacts disrupted the work, and that led to the arbitration award.[275]

279. Although the Commission is required to allow BC Hydro to recover the costs associated with Site C and the ILM project, recent large adverse arbitration awards and settlements (or the prospect of them) exhibit ample room for scrutiny and show that the Commission should firmly avoid any presumption that BC Hydro's costs are prudent. As always, BC Hydro must bear that onus.

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[269] *Ontario (Energy Board) v Ontario Power Generation Inc*., 2015 SCC 44 at paras. 80 and 104 and *ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission)*, 2015 SCC 45 at paras. 47-49. Also see Venessa Korzan and Moin A. Yahya, *A Requiem for the Presumption of Prudence after OPG and ATCO* (2016) Energy Regulation Quarterly, vol. 4, issue 4. Online: <https://www.energyregulationquarterly.ca/articles/a-requiem-for-the-presumption-of-prudence-after-opg-and-atco#sthash.0E8M3ls0.dpbs>
[270] Transcript Volume 5, p. 454, pdf p. 134, ll. 16-22; Exhibit B-17, AMPC IR 3.23.4, pdf p. 250.
[271] Transcript Volume 5, p. 454, pdf p. 134, l. 24 – p. 455, pdf p. 135, l. 25.
[272] Transcript Volume 5, p. 456, pdf p. 136, ll. 3-6.
[273] Transcript Volume 5, p. 458, pdf p. 138, ll. 9-18; Exhibit B-17, AMPC IR 3.20.1, pdf pp. 218-220.
[274] Transcript Volume 5, p. 459, pdf p. 139, ll. 3-7.
[275] Transcript Volume 5, p. 466, pdf p. 146, ll. 3-9.

280. The fact that cost recovery of many large BC Hydro projects is exempt from Commission judgment is important in the context of future rate of return considerations (i.e., BC Hydro faces little risk and a fair return should therefore be conservative). In this vein, another key consideration for the forecast write-off request is that it is not apparent that BC Hydro failing to recover project write-off expenses in any way undermines its ability to earn a fair return.

281. Absent guidance on what constitutes a fair return, and which risks the shareholder is bearing in exchange for charging rates that provide the opportunity for a return, there is nothing to suggest that BC Hydro's past practice regarding typical write-offs (i.e., that they are to the account of the shareholder) should be changed.

282. Indeed, the concept of a fair return ties to the investment that the shareholder has made in assets that are used, useful and prudently acquired to provide utility service. By definition, written off expenses are not for investments that are used.

283. The upcoming rate of return proceeding would be an appropriate venue for the Commission to consider whether the shareholder should in fact be compensated for the risk of write-offs. In the current proceeding, however, the effect of BC Hydro's proposal is to distinctly alter the framework for shareholder returns in the absence of the information that is necessary to properly evaluate the proposal.

284. The request poses multiple problems to how BC Hydro is regulated, and BC Hydro has not discharged its onus to show that recovering those costs from ratepayers is reasonable. The Commission should accordingly reject the request.

APPENDIX K: EARLY ACQUISITION OF PROPERTIES FOR SUBSTATION PROJECTS

ISSUE

285. BC Hydro has acquired properties in the West End and East Vancouver for use in two planned substation construction projects, spending $46.6 million and $66.8 million, respectively.[276] Although BC Hydro has already acquired the properties for these two projects, it is not planning to file a CPCN for the West End Substation Construction Project until fiscal 2023,[277] and it has not yet determined when it will file a CPCN for the East Vancouver Substation Construction Project.[278]

286. The West End and East Vancouver substations are intended to replace the existing Dal Grauer and Murrin substations.[279] BC Hydro may sell one or both of the Dal Grauer and Murrin substation properties once they are replaced by the new substations.[280] Currently, the gain or loss on such a sale would be recorded in the Real Property Sales Regulatory Account, but, if BC Hydro closes the account (as it says it might apply to do),[281] it asserts that the gain or loss would be to the account of the shareholder.[282]

AMPC SUMMARY AND/OR RECOMMENDATION:

287. AMPC is concerned with how early these properties were acquired. The choice to acquire the properties many years early risks biasing the alternatives presented in CPCNs and increase carrying costs. AMPC is also concerned that presently BC Hydro's account treatment appears to include the property in rate base in advance of any use for utility service – inconsistent with current utility regulation principles.

288. Accordingly, AMPC signals that careful attention must be paid to the timing and related quantum of these purchases in future CPCN and rate of return processes, and the Commission should be prepared to scrutinize and potentially disallow part the carrying cost of the properties when BC Hydro capitalizes the new substations.

289. Likewise, BC Hydro plans to apply to change how shareholders and ratepayers benefit from windfall property sales by closing the Real Property Sales Regulatory Account. According to the record this may happen in 2024 or 2025. The Commission should consider any such request carefully and ensure it receives the benefit of customer submissions.

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[276] Transcript Volume 12, p. 2244, pdf p. 160, ll. 9-21; Exhibit B-16, BCUC IR 3.291.2, pdf p. 16; Exhibit B-5, BCUC IR 1.118.1.1, pdf p. 1312.
[277] Exhibit B-5, BCUC IR 1.117.2, pdf p. 1305; Transcript Volume 12, p. 2244, pdf p. 160, ll. 22-24.
[278] Exhibit B-5, BCUC IR 1.118.2, pdf p. 1316; Transcript Volume 12, p. 2252, pdf p. 168, l. 24 – p. 2253, pdf p. 169, l. 2.
[279] Exhibit B-1, Appendix K – Attachment 1, p. 55 of 88, pdf p. 1717; Exhibit B-1, Appendix J – Attachment 1, p. 69 of 133, pdf p. 1572; Transcript Volume 12, p. 2243, pdf p. 159, l. 23 – p. 2244, pdf p. 160, l. 5.
[280] Transcript Volume 12, p. 2255, pdf p. 171, l. 25 – p. 2256, pdf p. 172, l. 11.
[281] Transcript Volume 12, p. 2257, pdf p. 173, ll. 9-15.
[282] Exhibit B-12, BCUC IR 2.249.4.1, pdf p. 501.

DISCUSSION AND SUPPORT:

290. BC Hydro has acquired properties for the West End Substation Construction Project and the East Vancouver Substation Construction Project, respectively, far in advance of filing a CPCN for either of those projects:

a. BC Hydro acquired the underground property rights at the Lord Roberts Annex School in fiscal 2019, for the West End Substation Construction Project, at a cost of $66.8 million.[283] It is not planning to file a CPCN for the West End Substation Construction Project until fiscal 2023.[284]

b. BC Hydro acquired property in East Vancouver for the East Vancouver Substation Construction Project in fiscal 2017, at a cost of $46.6 million.[285] It has not yet determined when it will file a CPCN for the East Vancouver Substation Construction Project.[286]

291. In its justification for the purchase of each of these properties, BC Hydro has emphasized that the purchase will provide certainty with respect to the site, cost and schedule for the respective substation construction projects.[287] However, Ms. Holland has confirmed that BC Hydro is not planning for the West End substation to be in service until calendar 2028,[288] and Mr. Kumar confirmed that BC Hydro is not planning for the East Vancouver substation to be in service within the next 10 years.[289]

292. AMPC looks forward to BC Hydro fulfilling its commitment to address all of the following elements in its CPCN application:

- the alternatives considered to supply the Downtown Vancouver area,
- the preferred alternative selection process, and
- the choices of West End / East Vancouver neighborhoods and site options within each neighborhood.[290]

293. AMPC is concerned, however, that justification processes that trail the acquisitions by 5-10 years will suffer from stale and one-sided data, undermining the intent of the process.

294. Also, in its response to Undertaking No. 42, BC Hydro confirmed that the properties acquired for the planned East Vancouver and West End substations are currently included

[283] Exhibit B-16, BCUC IR 3.291.2, pdf p. 16.
[284] Exhibit B-5, BCUC IR 1.117.2, pdf p. 1305; Transcript Volume 12, p. 2244, pdf p. 160, ll. 22-24.
[285] Exhibit B-16, BCUC IR 3.291.5, pdf p. 19.
[286] Exhibit B-5, BCUC IR 1.118.2, pdf p. 1316; Transcript Vol. 12, p. 2252,, l. 24-p. 2253 l. 2, pdf p. 168-9.
[287] **West End:** BC Hydro Final Argument, para. 361, pdf p. 167; Transcript Volume 12, p. 2245, pdf p. 161, l. 15 – p. 2246, pdf p. 162, l. 7; **East Vancouver:** BC Hydro Final Argument, para. 367, pdf p. 169.
[288] Transcript Volume 12, p. 2244, pdf p. 160, l. 25 – p. 2245, pdf p. 161, l. 2.
[289] Transcript Volume 12, p. 2253, pdf p. 169, ll. 3-10.
[290] BC Hydro Final Argument, pp. 157, pdf p. 167, and 159, pdf p. 169, paras. 362 and 368.

in BC Hydro's rate base. However, BC Hydro noted that its net income is currently prescribed by Direction No. 8, with the result that amounts "included or excluded from BC Hydro's rate base therefore have no effect on net income during the test period":

> BC Hydro's net income is currently prescribed by section 3 of Direction No. 8 to be a specific dollar amount of $712 million per fiscal year in each of fiscal 2020 and fiscal 2021, and is therefore not dependent on a specific rate base amount. Amounts included or excluded from BC Hydro's rate base therefore have no effect on net income during the test period.
>
> Rate base may potentially be relevant for future test periods, but BC Hydro is not able to speculate on what it may propose, or what the BCUC may approve, in terms of the use of rate base and the components thereof for the purpose of calculating return on equity.
>
> For reference, under IFRS the land is categorized as "land and buildings", and is currently included in BC Hydro's rate base.
>
> However, given Direction No. 8, rate base is not currently used to calculate return on equity in the test period.[291] [Underlining added]

295. BC Hydro added that it "is not able to speculate on what it may propose, or what the BCUC may approve, in terms of the use of rate base and the components thereof for the purpose of calculating return on equity."[292]

296. As the properties are intended for future use by specific projects that have not been applied for yet, AMPC would expect the Commission to carefully consider the appropriateness of including them in rate base if and when it has the opportunity. Given the large costs and atypical timing associated with the assets, and BC Hydro's explanation of the proximity of a rate of return proceeding, AMPC is flagging its concern now.

297. Mr. Leonard indicated that BC Hydro may also potentially sell one or both of the Dal Grauer and Murrin substation properties.[293] Such a sale would be at least 10 or 15 years in the future,[294] after BC Hydro expects to apply to close the Real Property Sales Regulatory Account (approximately 2024 or 2025).[295] Again, AMPC signals its concern that the Commission will need to consider such an application carefully in the future.

[291] Exhibit B-57, BC Hydro Undertaking No. 42, pdf p. 7.
[292] Exhibit B-57, BC Hydro Undertaking No. 42, pdf p. 7.
[293] Transcript Volume 12, p. 2255, pdf p. 171, l. 25 – p. 2256, pdf p. 172, l. 11.
[294] Transcript Volume 12, p. 2256, pdf p. 172, ll. 9-11.
[295] Transcript Volume 12, p. 2257, pdf p. 173, ll. 9-18.

APPENDIX L: DSM/LOAD CURTAILMENT

ISSUE

298. In its Application, BC Hydro has confirmed that its traditional DSM expenditures (which include capacity-focused initiatives)[296] "provide significant energy savings and capacity benefits and provide customers with the opportunity to save electricity and lower their bills, while reducing BC Hydro's revenue requirements".[297] However, BC Hydro does not currently have dispatchable capacity/curtailable capacity arrangements in place with customers for the purpose of obtaining energy and capacity savings.[298]

299. Participation in load curtailment programs can reduce the overall cost to serve a particular customer and permit that customer to realize energy bill savings. This would help to improve BC Hydro's competitiveness for industrial customers. Conversely, the loss of curtailable initiatives could erode BC Hydro's competitiveness.

300. BC Hydro's DSM plan continues to include capacity-focused pilots (such as load curtailment),[299] which will inform the resource options in the upcoming IRP,[300] but BC Hydro has reduced the overall budget for these initiatives by 12% over the fiscal 2017 to fiscal 2021 period.[301] More generally, BC Hydro has reduced the funding for the commercial and industrial sectors in its DSM portfolio in order to accommodate an increase in spending on DSM for the residential sector.[302]

AMPC SUMMARY AND/OR RECOMMENDATION:

301. BC Hydro needs to better integrate load curtailment options (and perhaps other DSM) into its resource planning. It should be using industrial load curtailment to a greater degree.

DISCUSSION AND SUPPORT:

302. BC Hydro has acknowledged that capacity-focused DSM programs such as load curtailment can provide real benefits and cost savings to BC Hydro and its ratepayers, such as by "[reducing] peak loads thereby allowing [BC Hydro] to defer capital investments in substation upgrades".[303]

[296] Exhibit B-1, p. 10-4, pdf p. 1034.
[297] Exhibit B-1, p. 10-14, pdf p. 1044; BC Hydro Final Argument, para. 541.
[298] Exhibit B-6, INCE IR 1.6.13, pdf p. 1694.
[299] Exhibit B-5, BCUC IR 1.183.1, pdf pp. 2018-2020 & BCUC IR 1.183.1, Att. 1, pdf pp. 2027-2029.
[300] Exhibit B-13, BCSEA IR 2.72.1, pdf p. 500; BC Hydro Final Argument, para. 535, pdf p. 237.
[301] Exhibit B-1, p. 10-21, pdf p. 1051; BC Hydro Final Argument, para. 534, pdf p. 237.
[302] BC Hydro Final Argument, para. 519, pdf pp. 231-232.
[303] Exhibit B-5, BCUC IR 1.183.1, pdf p. 2019.

303. For example, Mr. Hobson agreed that the load curtailment program being piloted at the Pineview substation could result in the deferral of capital investments.[304] BC Hydro confirmed in an undertaking response that potential capital investments of approximately $3.5 million could be deferred until after 2030 at this location.[305]

304. Mr. Kumar also agreed that, in principle, capacity-focused DSM projects could be considered as a potential surrogate for a large undertaking such as the Metro North Transmission Project and the associated large industrial loads on the north shore of Burrard Inlet.[306] Total forecast project costs for the Metro North project were within the range of $300 million to $530 million.[307]

305. BC Hydro has also experienced success with its testing of load curtailment programs. For example, BC Hydro described the results of the first two years of its industrial load curtailment pilot as "generally positive".[308] It also concluded that the concept tested in the third year of the pilot (distinct availability and performance payments) was a "success, from both a customer and BC Hydro perspective and would form the basis for any load curtailment program going forward".[309]

306. However, despite the benefits associated with load curtailment, and the successes that BC Hydro has experienced in its associated pilot programs, BC Hydro has nonetheless reduced the overall budget for these initiatives by 12% over the fiscal 2017 to fiscal 2021 period.[310] More generally, BC Hydro has reduced the funding for the commercial and industrial sectors in its DSM portfolio in order to accommodate an increase in spending on DSM for the residential sector.[311]

307. Further, the evidence on the record suggests that BC Hydro has not effectively integrated DSM planning (and load curtailment, in particular) into its resource planning.

308. For example, in the Application BC Hydro notes that its Conservation and Energy Management KBU is responsible for the management of BC Hydro's DSM programs, including capacity-focused initiatives.[312] Among other roles, this KBU:

a. "develops long-term DSM resource options to support BC Hydro's Integrated Resource Planning process [and] produces estimates of the potential for DSM in

[304] Transcript Vol. 14, p. 2680, pdf p. 2680, ll. 10-12. See also: Exhibit B-13, BCSEA IR 2.64.1, pdf p. 479.
[305] Exhibit B-57, BC Hydro Undertaking No. 60, pdf p. 70.
[306] Transcript Volume 12, p. 2266, pdf p. 182, ll. 2-22.
[307] Exhibit B-1, Appendix J – Attachment 1, p. 73 of 133, pdf p. 1576; Exhibit B-29, p. 6.
[308] Exhibit B-5, BCUC IR 1.183.1, Attachment 1, pdf p. 2028. BC Hydro noted that "in any formal program we would have to ensure we contracted more potential curtailment than needed to overcome the potential for non-compliance".
[309] Exhibit B-5, BCUC IR 1.183.1, Attachment 1, pdf p. 2029.
[310] Exhibit B-1, p. 10-21, pdf p. 1051; BC Hydro Final Argument, para. 534, pdf p. 237.
[311] BC Hydro Final Argument, para. 519, pdf pp. 231-232.
[312] Exhibit B-1, p. 5F-40, pdf p. 655.

BC Hydro's service territory…";[313]

b. undertakes the "design and management of DSM offers targeting BC Hydro's Industrial customers";[314]

c. produces "final estimates of the energy impacts of DSM programs, rate structures and codes and standards, and [identifies] opportunities for improvement";[315] and

d. "estimates energy savings at a project level".[316]

309. However, despite the broad mandate of the Conservation and Energy Management KBU, which includes generally assessing the potential for DSM in BC Hydro's service territory, Mr. Hobson, the Director of this KBU, asserted that generation assets were "outside of [his] area of knowledge":

> [MR. BAER:] … I'd like to ask a few questions about the Island Generation facility. So to confirm, the Island Generation facility is dispatchable, correct?
>
> MR. HOBSON: A <u>You're going to get outside of my area of knowledge in a hurry with respect to generation assets</u>.
>
> MR. BAER: Q Okay. Perhaps it would help if we went to some sources in the record and we can sort of use those to springboard for some of these questions. So if I could direct you to Exhibit B-6, that's INCE IR 1.7.3 and PDF page 1,718 for those following electronically.
>
> MR. HOBSON: A We have the IR but, again, <u>I think you're going to find that I'm going to have a limited understanding of this facility</u>.[317]

310. Mr. Hobson further noted that the "decisions around the use of Island Generation are going to go beyond what I can speak to".[318]

311. AMPC submits that BC Hydro should better integrate the consideration of load curtailment into its resource planning, both as a potential alternative to the use of generation assets such as the Island Generation facility and as a potential alternative to transmission or distribution expenditures, such as with respect to the Metro North Transmission Project or potential Pineview substation upgrades. More generally, BC Hydro should be considering industrial load curtailment as a real and creative option in its resource planning processes.

[313] Exhibit B-1, p. 5F-41, pdf p. 656.
[314] Exhibit B-1, p. 5F-42, pdf p. 657.
[315] Exhibit B-1, p. 5F-44, pdf p. 659.
[316] Exhibit B-1, p. 5F-44, pdf p. 659.
[317] Transcript Volume 14, p. 2683, pdf p. 111, ll. 2-17.
[318] Transcript Volume 14, p. 2685, pdf p. 113, ll. 21-23.