WRITTEN EVIDENCE OF

DUSTIN MADSEN, CPA, CA, CPA (IL, USA), CDP, CRRA

PRESIDENT

EMRYDIA CONSULTING CORPORATION (U.S. AND CANADA)

ON BEHALF OF
THE GENERAL SERVICE SMALL AND GENERAL SERVICE MEDIUM CUSTOMERS

IN THE MATTER OF

MANITOBA HYDRO

2023/24 & 2024/25 GENERAL RATE APPLICATION

EMRYDIA

April 3, 2023

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1 Introduction

Q: State your name and occupation.

A: My name is Dustin M. J. Madsen. I am the President of Emrydia Consulting Corporation (Emrydia). Emrydia is a consulting firm providing services to parties participating in the electric, gas and water utility industry in North America. Emrydia and its sister companies serve a broad range of clients, including but not limited to public advocates, small and large customer groups, regulated and unregulated electric utilities, regulators, and large international corporations that consume and produce electricity and gas. Emrydia provides expert advice and testimony through its group of Canadian and U.S. based consultants in the areas of depreciation, cost of capital, revenue requirement, cost-of-service, incentive-based regulation, planning for and completing the energy transition, income taxes, engineering matters, as well as a variety of broad and narrow regulatory and financial issues. Emrydia also prepares depreciation studies for clients using the proprietary depreciation model created by Mr. Madsen. Emrydia is incorporated in both Canada and the United States. Emrydia's business addresses are as follows:

304 8 Ave SW Suite #620
Calgary, AB T2P 1C1

401 Ryland St. Suite 200-A
Reno, NV 89502

Q: Summarize your educational background and professional experience.

A: I have 20 years of experience in auditing, accounting, and regulated businesses. I received a Bachelor of Commerce, major in accounting, awarded with Great Distinction from the Edwards School of Business at the University of Saskatchewan. I am a Canadian Chartered Professional Accountant and Chartered Accountant registered with CPA Alberta, as well as a US Certified Public Accountant registered with the Illinois Department of Financial and Professional Regulation. I am also a Certified Depreciation Professional with the Society of Depreciation Professionals and a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial Analysts.

My curriculum vitae is attached to this evidence and provides a complete description of my qualifications, regulatory and professional experience. I have provided services in several jurisdictions in Canada and the United States. In Canada, I have provided services in Alberta, British Columbia, Manitoba, the Northwest Territories, New Brunswick, and Ontario. I have provided services to consumer advocates, utilities, regulators, and other interested parties in regulatory applications. For customer groups, I have represented small residential customers, small and medium sized commercial customers, large industrial electric customers, and large industrial gas customers, as well as landowners.

I have testified before the Alberta Utilities Commission on numerous occasions and before the New Brunswick Energy and Utilities Board. I am scheduled to testify in rate cases on a variety of subject matters before the Manitoba Public Utilities Board (PUB) in this case, and the Ontario Energy Board, as well as potentially the British Columbia Utilities Commission, and regulators in the U.S.

Formerly I was a manager and consultant with two large regulated electric utilities operating in Alberta, Canada. I have testified and presented expert evidence on virtually every aspect of utility revenue requirements, including but not limited to depreciation, cost of capital, capital structure, income taxes, operating costs, capital, prudence issues, deferral accounts, reserve accounts, rate design, accounting and finance issues, incentive-based regulation, and best practices for utilities to minimize costs.

I also have specific professional experience with IFRS, including as an instructor and as an IFRS project manager. I outline that experience below in the depreciation section of my evidence.

Q: On whose behalf are you testifying in this proceeding?

A: In this matter, I have been retained by the General Service Small and General Service Medium customers (GSS/GSM).

Q: Summarize the instructions you received from your client.

A: I was retained by counsel for the GSS/GSM customers. Counsel instructed me to review both the Part I and Part II applications filed by Manitoba Hydro, and to specifically identify areas of concern. Based on my review, I identified several areas of concern, including depreciation matters, operating costs, information technology, and Part II matters relating to the design of GSS/GSM rates. Following identification of these issues and discussions with counsel, I was instructed to prepare evidence on the above matters.

In preparing my evidence, I was instructed to coordinate with the other interested parties in the proceeding on areas of common interest. I can confirm that in preparing my evidence I have coordinated with the Consumers Coalition (CC) and Manitoba Industrial Power Users Group (MIPUG).

Q: Briefly describe the content of your evidence before the Manitoba PUB.

A: In accordance with the instruction I received, I reviewed the evidence and responses to interrogatories filed by Manitoba Hydro, and prepared evidence in relation to:

- Depreciation expense.
- Operating costs.
- Information technology costs.
- Part 2 rate design pertaining to GSS/GSM customers.

Given the length of the evidence, I have structured the evidence with subheadings to assist parties with identifying topic areas that I address throughout the evidence.

Q: Confirm that you acknowledge your duty to provide opinion evidence that is fair, objective and non-partisan and that your evidence would not change were you to have been retained by another party in this proceeding.

A: Confirmed.

2 Executive summary

Q: Summarize your recommendations.

A: My recommendations for the PUB are as follows:

- Approve the continued use of the ALG procedure using the level of componentization as set out in the 2019 Depreciation Study.
- Confirm that the ALG procedure based on current componentization is IFRS-compliant.

- Approve as needed additional modifications to the deferral accounts proposed to address depreciation differences, including recovery periods, necessity for certain deferrals, and other matters.
- For account 3200M, I recommend the use of a 65-R3 Iowa curve as compared to a 60-R3 as recommended by Concentric.
- A reduction to applied for labour costs of $7.7 million and $11.1 million in 2023/24 and 2024/25, respectively.
- A reduction to applied for consulting costs of $19.8 million and $26.5 million in 2023/24 and 2024/25, respectively.
- Adoption of a phased-in zero-based budgeting approach to in future applications to support the forecast costs.
- Denial of the applied for costs related to the transition to SAP S/4HANA.
- Approval of the deferral account for all cloud computing arrangement costs, including any actual SAP costs incurred and other small software program costs.
- Approval of the cost-of-service changes recommended by Manitoba Hydro for the GSS-GSM customers.

Q: Summarize the documents you reviewed in preparing your evidence.

A: In preparing my evidence I reviewed the following documents:

- General review of all filed application materials and responses to information requests.
- Detailed review of Tabs 4, 6 and 8 of the Application, including a detailed review of relevant appendices to these tabs.
- Detailed review of Appendix 9.11, 9.l2, MFR 6, and MFR 95.
- Detailed review of round 1 and 2 responses to interrogatories from the PUB, MIPUG, CC, and GSS-GSM.

3 Depreciation expense

3.1 Introductory comments on depreciation expense

Q: Please summarize Manitoba Hydro's request in this application.

A: As set out in Appendix 4.3, the following are Manitoba Hydro's requests in relation to depreciation expense:

- Approve IFRS for determining depreciation for rate setting purposes.
- Approve ELG as the method for determining depreciation.
- Approve the cessation of additions to the Change in Depreciation Method deferral, approve an amortization period for this account and begin amortizing the balance into income on a straight-line basis.
- Approve the cessation of additions to the Loss on Retirement or Disposal of Assets deferral, approve an amortization period for this account and begin amortizing the balance into income on a straight-line basis.
- Approve a new regulatory deferral account and amortization period to smooth the differences caused by the transition of depreciation expense and recognition of gains and losses on disposition of assets from CGAAP to IFRS.

Manitoba Hydro has accumulated balances in the two existing deferral accounts of $355 million as of March 31, 2022.[1] Manitoba Hydro provided the following Figure to demonstrate the forecast growth in these deferral accounts:

[1] Appendix 4.3 (Amended), PDF page 16, Figure 5.

Figure 1 – Manitoba Hydro Figure 6 depicting forecast growth in depreciation method regulatory deferral account balances

Depreciation Method Regulatory Deferral Accounts (in Millions)	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Change in Depreciation Method	$ 288	$ 343	$ 398	$ 454	$ 511	$ 570	$ 631	$ 693	$ 757	$ 823
Loss on Retirement or Disposal of Assets	67	70	73	76	79	82	85	88	91	94
Opening balance - depreciation method deferrals	355	413	471	530	590	652	716	781	848	917
Change in Depreciation Method	55	55	56	57	59	61	62	64	66	68
Loss on Retirement or Disposal of Assets	3	3	3	3	3	3	3	3	3	3
Additions - depreciation method deferrals	58	58	59	60	62	64	65	67	69	71
Change in Depreciation Method	343	398	454	511	570	631	693	757	823	891
Loss on Retirement or Disposal of Assets	70	73	76	79	82	85	88	91	94	97
Closing balance - depreciation method deferrals	$ 413	$ 471	$ 530	$ 590	$ 652	$ 716	$ 781	$ 848	$ 917	$ 988

	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42
Change in Depreciation Method	$ 891	$ 961	$ 1,034	$ 1,109	$ 1,186	$ 1,266	$ 1,348	$ 1,433	$ 1,520	$ 1,610
Loss on Retirement or Disposal of Assets	97	100	103	106	109	112	115	118	121	124
Opening balance - depreciation method deferrals	988	1,061	1,137	1,215	1,295	1,378	1,463	1,551	1,641	1,734
Change in Depreciation Method	70	73	75	77	80	82	85	87	90	93
Loss on Retirement or Disposal of Assets	3	3	3	3	3	3	3	3	3	3
Additions - depreciation method deferrals	73	76	78	80	83	85	88	90	93	96
Change in Depreciation Method	961	1,034	1,109	1,186	1,266	1,348	1,433	1,520	1,610	1,703
Loss on Retirement or Disposal of Assets	100	103	106	109	112	115	118	121	124	127
Closing balance - depreciation method deferrals	$ 1,061	$ 1,137	$ 1,215	$ 1,295	$ 1,378	$ 1,463	$ 1,551	$ 1,641	$ 1,734	$ 1,830

In addition to requesting an amortization of the above deferral balances, Manitoba Hydro has also requested a phase-in of the adoption of the Equal Life Group procedure for depreciation, stating the following:

> Manitoba Hydro recognizes there will be a significant impact to net income annually of approximately $70 million due to the change to the IFRS ELG method of depreciation for rate setting purposes in combination with the cessation and amortization to net income of the two existing deferral accounts. To mitigate these impacts on customer rates, Manitoba Hydro recommends phasing-in the impact of using the IFRS ELG method of depreciation for rate setting purposes by establishing a new regulatory deferral account to reduce the impact to revenue requirement.
>
> Manitoba Hydro is seeking PUB approval to establish a regulatory deferral account to defer the annual increase in total depreciation expense (including gains and losses) from transitioning to the IFRS ELG method for rate setting purposes. Manitoba Hydro is proposing to defer the increase in total depreciation expense (i.e. compared to the CGAAP ASL method) commencing September 1, 2023 with annual reductions in the

deferral amount over a 15-year period. The 15-year phase in period allows for a gradual transition to using IFRS ELG for rate setting purposes at a pace that minimizes the impact on customer rates. Manitoba Hydro is recommending the deferred costs be amortized into income on a straight-line basis over a period of 30-years effective October 1, 2023.[2]

Q: Do you agree with Manitoba Hydro's requested relief as set out above?

A: No. While I agree with Manitoba Hydro that IFRS should be accepted for depreciation purposes, I disagree that only the ELG procedure or a more componentized version of the ALG procedure is permitted. As I discuss below, the issue Manitoba Hydro seeks to address through its requested relief is influenced by both accounting and depreciation considerations. Specifically, Manitoba Hydro has identified an accounting issue it seeks to address through a change in depreciation procedures. In turn the change in depreciation procedures creates new and separate revenue requirement and depreciation issues, that ultimately are not needed to address the perceived accounting issue.

From an accounting perspective, Manitoba Hydro has created the problem it is now seeking to address. The underlying cause of the problem is Manitoba Hydro's unnecessarily restrictive interpretation of IFRS. This interpretation, while technically permitted, is not required, is out of the ordinary, and unnecessarily complicates the recovery of Manitoba Hydro's depreciation-related costs, particularly as it relates to the componentization of Manitoba Hydro's assets.

From a depreciation perspective, Manitoba Hydro is proposing to address an accounting issue through the adoption of either the ELG procedure, as proposed, or through the adoption of an "IFRS-compliant" average life group (ALG) procedure. The ALG depreciation study, which is also referred to by Alliance Consulting as an "ASL" or "Average Service Life" study,[3] relies on a significantly greater level of asset

[2] Appendix 4.3 (Amended), PDF page 30, lines 10 to 25.
[3] The most commonly accepted terminology used by depreciation experts is the Average Life Group procedure, and I refer to it as such throughout my evidence. Therefore, I refer in my evidence to the current ASL-compliant

componentization[4] than is necessary. Adopting a change in depreciation procedures to address a perceived accounting issue is not appropriate and, in my opinion, would be inconsistent with best practices of regulators to ensure that the depreciation expense approved for collection from customers is reflective of the *entire* useful or economic life of the underlying assets. To that end, I also do not consider a change to the current depreciation procedure warranted based on accepted depreciation practices.

The following evidence on depreciation has two sections. First, I discuss the accounting issue and explains why the current ALG procedure, including the recognition of gains and losses within accumulated depreciation, is permitted under IFRS using offsetting deferral accounts in the case of gains and losses. For this reason, as outlined in the second section, Manitoba Hydro's requested relief, in particular the request to adopt ELG as the method to determine depreciation, is unnecessary. The second section also discusses the relative merits of the ELG and ALG procedures, the reasons for Manitoba Hydro's perceived need to move to the ELG procedure, and my specific recommendations related to depreciation expense.

3.2 ELG/ALG deferral account and IFRS accounting requirements

3.2.1 Summary of experience with IFRS

Q: Briefly summarize your experience with IFRS related to regulated utilities.

A: I am a Canadian CPA and CA, as well as a U.S. CPA. I have extensive in-person and online teaching experience related to International Financial Reporting Standards (IFRS). I was previously an experienced facilitator for the Chartered Accountant School of Business (CASB) having taught multiple times each of the CASB modules. Each module contained an accounting component compliant with IFRS, and I taught the courses to hundreds of

depreciation rates approved in PUB Order No. 59/18 as the ALG compliant rates to avoid any confusion with the current application.

[4] Asset componentization generally refers to the process of separating a group of assets into smaller groups of assets with similar expected useful lives or life characteristics.

prospective Chartered Accountants. I also previously taught IFRS courses for utility accounting professionals through IASeminars.

While working within FortisAlberta, I was the IFRS project manager and the IFRS project sponsor for information technology changes driven by the transition to IFRS. I assisted in the review and interpretation of every IFRS for FortisAlberta, prepared comprehensive accounting and technical analysis, and was heavily involved in the broader Canadian utility industry. Specifically, I worked with many other Canadian electric utilities through my work as the Vice Chair of the Canadian Electricity Association (now Electricity Canada) accounting and finance subcommittee. In that capacity I presented at several conferences and assisted in gathering representatives from each of the Big 4 accounting firms to discuss the IFRS accounting implications for regulated utilities.

I have testified as an expert on IFRS and accounting related matters on numerous occasions, most recently before the Alberta Utilities Commission, New Brunswick Energy and Utilities Board and Northwest Territories Public Utilities Board.

3.2.2 Manitoba Hydro's requested change in depreciation procedure is driven by an accounting interpretation

Q: Is the originating source of Manitoba Hydro's request to move to the ELG procedure for depreciation an accounting issue caused by Manitoba Hydro's interpretation of IFRS?

A: Yes. Absent the accounting interpretation taken by Manitoba Hydro in its financial statements, the relief requested by Manitoba Hydro would be unnecessary. With that said, I accept that a change from the ALG to ELG procedure could be made for reasons other than to comply with IFRS and I address these reasons separately. As discussed in detail below, in my view, none of the reasons that could be advanced for the change to the ELG procedure are persuasive. Specifically, among other reasons supporting the continuation of the ALG procedure, there is no demonstrable increase to the accuracy or reliability of the estimate under the ELG procedure as compared to the ALG procedure.

Manitoba Hydro explained how the issue it seeks to address originated in Appendix 4.3 and in further detail responding to information requests from parties. In response to GSS-

GSM/MH I-1l, Manitoba Hydro explained the three main accounting changes it made upon transition to IFRS as follows:

- Componentization and depreciation:
    - o IFRS requirements are similar to GAAP requirements. However, IFRS is more rigorous in terms of identifying separate components and addresses non-physical components of assets. IFRS permits the grouping of assets in determining the depreciation charge and assets can be grouped as long as they are from a homogeneous group, are individually insignificant in value, and have similar useful lives. To the extent assets include components with different lives that would materially impact depreciation, these components must be separately depreciated.
    - o To address the depreciation accuracy requirements of IFRS, Manitoba Hydro increased its level componentization and changed from ASL (Average Life Group/ALG) to ELG, which accommodated a lower level of componentization than would have been required under ALG. For further discussion of the accuracy and componentization requirements for IFRS compliance with ALG versus ELG, please refer to the responses to PUB/MH I-109, PUB/MH I-122 and PUB/MH I-131 a-b).

…

- Gains and Losses on Disposal of Assets:
    - o As discussed in the response to PUB/MH I-30 a) under prior Canadian GAAP, Manitoba Hydro retained gains and losses within accumulated depreciation. In contrast, IFRS requires that any gains and losses on the disposal or retirement of assets be recognized immediately in income.

…

- Elimination of Asset Removal Costs from Depreciation Rates:

o Prior to the implementation of IFRS, Manitoba Hydro's followed the common utility practice of including a negative salvage factor within its depreciation rates which allowed for the pre-collection of future asset removal costs during the life of the assets. <u>This practice is not allowable under IFRS</u>.[5]

[Emphasis added]

IFRS permits the exercise of professional judgment and in many instances that judgment is required to properly apply the standards to specific accounting facts. For this reason, it is reasonable for two accountants to exercise professional judgment and interpret the IFRS to provide for two different accounting results. It is important to avoid interpretations of the standards that improperly restrict the exercise of professional judgment and purport to direct a specific result, where more than one result is acceptable.

As quoted above, Manitoba Hydro has made several accounting interpretations based on IFRS. Although these interpretations are not optimal or preferred, they are permitted based on management's application of IFRS. IFRS is generally non-prescriptive and where significant judgment is exercised, a variety of acceptable accounting results can occur. This is not to say that IFRS does not set out certain specific requirements that must be followed. However, in establishing what is required, IFRS permits an accountant to exercise professional judgment to, for example, assess the level of componentization that is required.

However, in the underlined text also quoted above, Manitoba Hydro appears to move away from the exercise of professional judgment to suggest that IFRS "requires" a certain result or that another result is "not allowable". These conclusions are incorrect and not based in or supported by IFRS.

IFRS neither prohibits nor requires Manitoba Hydro to account for the items listed above in the manner suggested. Manitoba Hydro's suggestion that certain accounting treatments

[5] Manitoba Hydro responses to GSS-GSM IRs, PDF pages 25 to 28, GSS-GSM/MH I-1l.

are required or prohibited is directly contrary to the interpretation of IFRS. In each case those utilities have adopted different accounting interpretations and I am aware of no instance where an auditor has issued a qualified opinion based on those interpretations. If Manitoba Hydro's statements were an accurate reflection of the requirements of IFRS, many, if not every other Canadian utility reporting under IFRS, would be non-compliant with IFRS for one of the three accounting issues noted above. This is clearly not the case due to the judgment that is permitted to be exercised under IFRS.

Throughout the application and information responses, Manitoba Hydro appears to rely on the audit of its financial statements by its auditors as support for the accounting policies and estimates Manitoba Hydro has selected. For example, Manitoba Hydro states:

> Based on the direction provided by the PUB on April 4, 2016, Manitoba Hydro sought guidance from accounting advisors and determined that the Corporation would record the difference between the depreciation methods in a regulatory deferral (Change in deprecation method). This accounting treatment was reviewed by Manitoba Hydro's auditor in conjunction with the audit of the 2015/16 financial statements for which an unqualified opinion was issued.[6]

I do not dispute that Manitoba Hydro's financial statements have been audited and received a clean audit opinion. In this case, Manitoba Hydro has recognized the difference between the regulatory and financial reporting differences as a deferral account. Therefore, any misstatement in this case would be representative of a change in classification of an asset as demonstrated in the journal entry below:

Dr. Long-term/short-term asset

Cr. Long-term/short-term asset

Classification differences of this nature are not uncommon in my experience as an auditor and are unlikely to result in a qualified audit opinion on their own, unless there is a clear

[6] Manitoba Hydro responses to PUB IRs, PDF page 587, PUB/MH I-131c.

violation of IFRS. This is not the case in this instance. Further, as a former auditor, it is important to provide context for the relationship between management and the auditor, as well as the role the auditor plays in the financial statements.

Manitoba Hydro's financial statements are prepared by management based on the assumptions, estimates and accounting policies that Manitoba Hydro determines to be appropriate. The financial statements, including all notes to the financial statements, are those of management, not the auditor. This is important as Manitoba Hydro's auditors are not permitted to participate in the selection of accounting policies or the determination of accounting estimates. An auditor cannot advise on the proper accounting treatment for a transaction and audit that transaction.

This relationship appears to be acknowledged in part by Manitoba Hydro. Specifically, Manitoba Hydro explains that its auditor applies "professional judgment and maintains professional skepticism".[7] Further, Manitoba Hydro confirms that the financial statements are management's, and the auditor assesses whether the "financial statements as a whole are presented fairly, in all material respects, in accordance with the applicable financial reporting framework."[8]

The key here is that a party cannot conclude based on an audit that the accounting policies and estimates selected by management would be the same accounting policies and estimates that the auditor would apply if it were the accountant making those decisions. Instead, the auditor simply assesses whether the accounting policies and estimates selected by management provide for financial statements that "as a whole are presented fairly, in all material respects". An auditor does not explicitly approve in its audit report the selection of one accounting policy or estimate over another. As long as the policy or estimate is fair and does not result in a material misstatement of the financial statements, then the auditor is likely to accept it.

[7] Manitoba Hydro responses to PUB IRs, PDF pages 528 and 529, PUB/MH I-115a.
[8] Manitoba Hydro responses to PUB IRs, PDF pages 528 and 529, PUB/MH I-115a.

The PUB also asked Manitoba Hydro to explain the discussions it had with its external auditors or other accounting advisors on the requirements under IFRS for componentization for an IFRS-compliant depreciation study.[9] In response, Manitoba Hydro states:

> b) Manitoba Hydro engaged an expert depreciation consultant to complete the IFRS-compliant ASL depreciation study as required by the PUB in Order 43/13, Directives 8 and 9. Manitoba Hydro has not recommended the implementation of IFRS-compliant ASL and therefore, has not engaged or discussed the adequacy of the recommended level of componentization from the IFRS-compliant depreciation study with its external auditor. Manitoba Hydro is not utilizing IFRS-compliant ASL for financial reporting purposes and as such the componentization has not been assessed as part of an audit engagement.

From this response, Manitoba Hydro confirms that its "IFRS-compliant ASL" has not been reviewed by an IFRS expert or its external auditors.[10] This confirmation is to be expected. As I discussed above, an auditor cannot advise, and thus it is highly unlikely for an auditor to opine in advance, certainly not in writing, on whether management's selection of a certain accounting estimate or policy would be accepted prior to management confirming its intention to adopt that accounting estimate or policy. The auditor's role is to assess the accounting policies and estimates adopted by management and not to provide advice on every possible alternative policy or estimate available to management.

In conclusion, I consider that limited weight should be assigned to the auditor's sign off and clean audit opinion for Manitoba Hydro. Notably, were Manitoba Hydro to present to its auditors a balanced accounting analysis supporting the adoption of the Concentric 2019 ALG procedure as a reasonable <u>estimate</u> of the depreciation expense going forward, including evidence of this practice being accepted under IFRS for other Canadian entities,

[9] Manitoba Hydro responses to PUB IRs, PDF page 585, PUB/MH I-131b.
[10] Manitoba Hydro responses to PUB IRs, PDF page 586, PUB/MH I-131b.

then I would expect that the auditors would consider that evidence in the completion of its audit.

As a final point, I note that the decisions of the PUB in this case will also be weighed by the auditor. Specifically, a key element of the determination of depreciation for a regulated utility is the rate approved by the regulator. Throughout IAS 16 – Property, plant and equipment there is an extensive discussion around the recognition of costs with a future economic benefit (IAS 16.7) and further the actual depreciation charge is described as the consumption of the "future economic benefits embodied in an asset" (IAS 16.56 and .57).

IFRS recognizes that the economic life of an asset is uncertain. However, this is not the case for a regulatory utility. Specifically, the PUB in this case approved the economic life of the assets and the period over which the costs will be recovered. Any party would be hard pressed to demonstrate quantitatively that any economic life exists for Manitoba Hydro's assets other than the life approved by the PUB. Therefore, if the PUB continues to approve the use of the ALG procedure, as I recommend below, and the PUB concludes that the ALG procedure is IFRS compliant, these conclusions will be weighed by the auditor in any future audit of Manitoba Hydro.

Below I discuss in further detail why Manitoba Hydro's interpretation of IFRS in relation to componentization and the recognition of gains and losses is an outlier, despite arguably being compliant with IFRS. The key point to keep in mind is that while Manitoba Hydro has identified accounting issues that it feels it must address, those issues need not exist. Indeed, the issue is properly conveyed as an accounting construct created by Manitoba Hydro. It is not appropriate to address accounting issues, which are subject to judgment, and in this case largely impact the timing of recovery of costs, through changes in Manitoba Hydro's revenue requirement.

I do not address Manitoba Hydro's accounting interpretation regarding the elimination of asset removal costs from depreciation rates. However, Manitoba Hydro is incorrect that the practice of including negative net salvage in depreciation rates is "not allowable under IFRS". I accept that there may be other non-accounting related reasons to defer the collection of negative net salvage costs, but those reasons also have implications for both current and future ratepayers. The inclusion of negative net salvage in depreciation expense results in higher depreciation expense, all else being equal. Removing the negative net salvage transfers the burden of those costs to future ratepayers. Notwithstanding the above, I have not proposed a change to the applied for treatment of these costs. Therefore, I will not address this issue further.

3.2.3 Manitoba Hydro's proposed asset componentization is not an IFRS requirement

Q: Is Manitoba Hydro's proposed componentization of its assets either under ELG or the "IFRS-compliant" ALG depreciation study a requirement under IFRS?

A: No. IAS 16 – Property, plant and equipment provides guidance on the accounting for physical assets. A copy of the standard is available at the following link from ifrs.org.[11] As it pertains to componentization, the specific requirements have been unchanged since Manitoba Hydro's adoption of IFRS.

IAS 16 does not specifically define the concept of "componentization" as is commonly cited by parties including Manitoba Hydro. Instead, the interpretation regarding the need to "componentize" assets is generally drawn from guidance from various accounting firms. The guidance of accounting firms is not authoritative and further that guidance is subject to significant variation in application to a specific set of facts. Indeed, I have experienced the same accounting firm signing off on an audit opinion approving different accounting treatments for two utilities with fundamentally the same set of facts.

This is not surprising as each auditor would be auditing the accounting policies and estimates selected by management. Where management of each utility selects different accounting policies or estimates, and those policies are both compliant with IFRS, the same auditor could agree with two different results.

[11] https://www.ifrs.org/content/dam/ifrs/publications/pdf-standards/english/2022/issued/part-a/ias-16-property-plant-and-equipment.pdf?bypass=on

IAS 16.43 to .49 sets out the guidance with the bolded portion being considered the "requirement" and the unbolded portions providing context to assist an accountant in exercising their professional judgment. I have provided the guidance below:

> **Depreciation**
>
> **43 Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately.**
>
> 44 An entity allocates the amount initially recognised in respect of an item of property, plant and equipment to its significant parts and depreciates separately each such part. For example, it may be appropriate to depreciate separately the airframe and engines of an aircraft. Similarly, if an entity acquires property, plant and equipment subject to an operating lease in which it is the lessor, it may be appropriate to depreciate separately amounts reflected in the cost of that item that are attributable to favourable or unfavourable lease terms relative to market terms.
>
> 45 A significant part of an item of property, plant and equipment may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.
>
> 46 To the extent that an entity depreciates separately some parts of an item of property, plant and equipment, it also depreciates separately the remainder of the item. The remainder consists of the parts of the item that are individually not significant. If an entity has varying expectations for these parts, approximation techniques may be necessary to depreciate the remainder in a manner that faithfully represents the consumption pattern and/or useful life of its parts.
>
> 47 An entity may choose to depreciate separately the parts of an item that do not have a cost that is significant in relation to the total cost of the item.

> **48 The depreciation charge for each period shall be recognised in profit or loss unless it is included in the carrying amount of another asset.**
>
> 49 The depreciation charge for a period is usually recognised in profit or loss. However, sometimes, the future economic benefits embodied in an asset are absorbed in producing other assets. In this case, the depreciation charge constitutes part of the cost of the other asset and is included in its carrying amount. For example, the depreciation of manufacturing plant and equipment is included in the costs of conversion of inventories (see IAS 2). Similarly, depreciation of property, plant and equipment used for development activities may be included in the cost of an intangible asset recognised in accordance with IAS 38 *Intangible Assets*.

As noted earlier, the above guidance on accounting for depreciation expense does not mention the concept of componentization. Rather, this concept is interpreted from the application of IAS 16.43 which requires that each item of property, plant and equipment that is "significant" is depreciated separately. The standards do not define significant.

IAS 16.44 to .47 provides further guidance on depreciating separate assets with IAS 16.47 permitting an entity to "choose to depreciate separately the parts of an item that do not have a cost that is significant in relation to the total cost of the item."

In practice, "significant" has been interpreted to be an amount that is "material" as defined by an auditor,[12] which is both a qualitative and quantitative assessment of materiality. In other instances, the standard has been interpreted in a less restrictive manner to provide for a result that is generally reasonable given that depreciation is an estimate and subject to significant judgment. In this case, there is an inherent need for judgment given that no depreciation estimate or level of componentization will be 100% accurate.

[12] In practice the actual difference would need to be less than the established level of materiality and likely reflective of a lower level of transaction specific materiality.

It is accepted in the accounting profession that unreasonable efforts to componentize assets to an immaterial level are unnecessary and indeed not required under IFRS. Finally, as Manitoba Hydro appears to have done, the term “significant” has been interpreted to mean that where a subcomponent has a different life than other related subcomponents, that subcomponent is “significant”, and therefore must be componentized.

The important consideration here is that depreciation expense is an estimate and thus a perfect level of componentization is neither required under IFRS nor expected. All estimates will be inexact and are subject to change, which is why IFRS permits the change of an estimate prospectively as opposed to retroactively as is the case for a change in accounting policy or an error. This is particularly pertinent for long-lived mass property assets such as those depreciated by Manitoba Hydro, because it is entirely expected that the expected useful lives of those assets will change over time.

In response to a PUB information request, Manitoba Hydro altered its position on a change in depreciation expense being a change in accounting policy, stating:

> Based on the questions raised by intervenors in the current Application, Manitoba Hydro has reviewed recent amendments to existing accounting standards (IAS 8) and further guidance provided in IAS 16 Basis for Conclusions paragraph 33) and agrees that there appears to be justification for treating a change from ELG to IFRS-compliant ASL deprecation as a change in accounting estimate, which would apply prospectively.
>
> Manitoba Hydro has assessed the impact of prospective vs. retrospective changes and has concluded that the impact on the total forecast deprecation related expenses would not be material. Figure 1 provides a comparison of total depreciation related expense determined for the IFRS-compliant ASL scenario when applied retrospectively versus prospectively. The difference

is due to increased amortization of regulatory deferral accounts in the retrospective scenario resulting from opening balance adjustments.[13]

I can confirm that under IFRS a change in depreciation expense would be a change in accounting estimate unless the previous depreciation expense estimate contained an error. Absent an error, a change in the amount of depreciation expense would not be a change in accounting policy and thus would be accounted for on a prospective basis.

3.2.4 Recommended interpretation of "significant" components

Q: How do you recommend that the level of significance be determined?

A: Manitoba Hydro confirms that IFRS does not specifically set out the level of componentization required and that the guidance "requires interpretation."[14] I agree. Absent clear guidance, judgment is required having regard to the reasonableness of the result achieved and the process used.

I prefer an approach which defines "significant" in the context of whether the additional level of componentization would materially impact the financial statements. Therefore, in this case I consider the use of "significant" and "materiality" to be interchangeable in the context of whether further componentization would be required under IFRS. There is no generally accepted rule for establishing a quantitative level of materiality, and even where one is established, the level of materiality needs to be assessed separately on a transaction or account level to ensure it remains reasonable. The assessment of materiality is also inextricably linked to the concept of risk.

Guidance on determining a reasonable materiality level for an audit of financial statements is provided in Canadian Auditing Standard 320 – Materiality in Planning and Performing an Audit, which states:

> **Determining Materiality and Performance Materiality When Planning the Audit**

[13] Manitoba Hydro responses to PUB IRs, PDF pages 529 and 530, PUB/MH I-115b.
[14] Manitoba Hydro responses to GSS-GSM IRs, PDF page 5, GSS-GSM/MH I-1g.

Considerations Specific to Public Sector Entities (Ref: Para. 10)

A3. In the case of a public sector entity, legislators and regulators are often the primary users of its financial statements. Furthermore, the financial statements may be used to make decisions other than economic decisions. The determination of materiality for the financial statements as a whole (and, if applicable, materiality level or levels for particular classes of transactions, account balances or disclosures) in an audit of the financial statements of a public sector entity is therefore influenced by law, regulation or other authority, and by the financial information needs of legislators and the public in relation to public sector programs.

Use of Benchmarks in Determining Materiality for the Financial Statements as a Whole (Ref: Para. 10)

A4. Determining materiality involves the exercise of professional judgment. A percentage is often applied to a chosen benchmark as a starting point in determining materiality for the financial statements as a whole. Factors that may affect the identification of an appropriate benchmark include the following:

- The elements of the financial statements (for example, assets, liabilities, equity, revenue, expenses);
- Whether there are items on which the attention of the users of the particular entity's financial statements tends to be focused (for example, for the purpose of evaluating financial performance users may tend to focus on profit, revenue or net assets);
- The nature of the entity, where the entity is in its life cycle, and the industry and economic environment in which the entity operates;
- The entity's ownership structure and the way it is financed (for example, if an entity is financed solely by debt rather than equity, users may put more emphasis on assets, and claims on them, than on the entity's earnings); and

> - The relative volatility of the benchmark.
>
> A5. Examples of benchmarks that may be appropriate, depending on the circumstances of the entity, include categories of reported income such as profit before tax, total revenue, gross profit and total expenses, total equity or net asset value. Profit before tax from continuing operations is often used for profit-oriented entities. When profit before tax from continuing operations is volatile, other benchmarks may be more appropriate, such as gross profit or total revenues.

The audit of the financial statements of a public sector entity is "influenced by law, regulation or other authority". This is important as Manitoba Hydro is a public sector entity owned by the Government of Manitoba and regulated by the Manitoba PUB.

Having regard for this guidance, I note that per Appendix 3.1, Manitoba Hydro's March 31, 2022 net property, plant and equipment balance is $26.376 billion. The total impact of the proposed change in depreciation expense due to increased componentization is approximately $55 million in 2023/24 and $56 million in 2024/25 per Figure 6 of Appendix 4.3 (Amended). To put this difference into perspective, a change of $55 million represents 0.2% of a change in the net property, plant and equipment balance of $26.376 billion.

The question of significance and materiality at this level is whether the users of the financial statements, which is the Government of Manitoba, creditors, and the broader Manitoba public would consider a change in the property, plant and equipment balance of 0.2% to be material, given the difference is due to an estimate.

In my opinion, a difference of 0.2% relative to the net property, plant and equipment is not significant, and likely not material to the users of the financial statements, given the difference relates to an estimate which is subject to change and correction in the future.

Extending this assessment a level lower, Alliance Consulting provided GSS-GSM-MH II-1 in a working Excel file which provided the total plant investment as at March 31, 2019 and calculated the percentage of the total IFRS-ASL annual accrual amount being proposed for each new component.

I do not intend to go through each explanation provided by Alliance Consulting to support the increased level of componentization being proposed to be “IFRS-compliant”. However, the single largest new component by accrual size identified by Alliance Consulting is for account 3000F-01 – Road, Steel Structures and Civil Site Work with an investment of $1.358 billion, IFRS-ASL depreciation rate of 1.75% and an annual accrual amount of $23.8 million. The explanation for the componentization is as follows:

> Subcomponent account consists of significant portion of original investment in Source account 3000F that was being depreciated using a 55 year life. New subcomponent account proposes 55 year life.

The new account being proposed has a 55-year life similar to the original account, and yet is proposed for componentization. There are many similar examples. In other instances, the life of the previous assets is not disclosed, or the difference is not significant from the perspective of a single component (i.e., 60 years ELG versus 65 years ALG for Account 4000L-01).

Regarding the basis for the selected componentization, Alliance Consulting confirms that IAS 16.43 was relied upon when determining the level of componentization required under IFRS and as used in the ALG depreciation study.[15] As support for its additional level of componentization under ALG, Alliance Consulting also identified the following IAS 16 guidance as supporting its conclusions:

> IAS 16.50 states “the depreciable amount of an asset shall be allocated on a systematic basis over its useful life.” If a group of assets consists of assets with a wide range of lives, the timing of depreciation is not aligned accurately with the useful life of the shorter- or longer-lived assets within the group. ELG separates assets into “equal life groups” and would tend to better mirror the IFRS guidance. The ALG procedure does not separate assets into equal life groups but relies on the average life for all assets

[15] Manitoba Hydro responses to GSS-GSM IRs, PDF page 5, GSS-GSM/MH I-1h.

> within the group. In order to more closely align ALG with the IFRS standards, additional componentization is necessary to create more homogeneous life groups in order for the assets within the group to reflect the life assigned to the group instead of an average that does not recognize assets with shorter and longer projected lives.[16]

Alliance Consulting's response appears to interpret IFRS in a manner that is not intended. Specifically, the systematic allocation of depreciation is achieved by both the ELG and ALG methods assuming both have a reasonable level of componentization. IFRS does not specifically require ELG or ALG. Depreciation is an estimate, and as an estimate, IFRS explicitly recognizes that the systematic allocation of the costs may change. This is reasonable, and perfection is not the requirement, nor is it achievable in any event.

In summary, the impact of the proposed change from current ALG-based rates to ELG based rates is not significant. Similarly, none of the changes being proposed in Alliance Consulting's "IFRS-compliant" depreciation study are significant either individually or in aggregate.

The changes being proposed are not "required" by IFRS. The existing level of componentization under the previously approved ALG-based rates and lives is IFRS compliant as it results in a reasonable level of depreciation that complies with the requirements of IAS 16.43 and other relevant guidance. Further, in addition to being unnecessary, a change from the ALG to the ELG procedure would be complicated, would break from past practice in Manitoba and other Canadian jurisdictions, and ultimately, the pros do not outweigh the cons.

3.2.5 Componentization under the ALG rates in the 2019 depreciation study is IFRS compliant

Q: Is the level of componentization proposed in the 2019 depreciation study sufficient under IFRS when applied to ALG rates?

[16] Manitoba Hydro responses to GSS-GSM IRs, PDF page 3, GSS-GSM/MH I-1b.

A: Yes. As discussed above, the difference between the 2019 ELG and ALG rates[17] would not be characterized as significant under IFRS. MFR 95 includes the Concentric 2019 depreciation study with both ELG and ALG compliant rates. I have reviewed the depreciation parameters recommended in that report and comment on those parameters in a separate section below.

In response to a PUB information request, Manitoba Hydro provided a summary of the impact on depreciation and amortization expense for a series of scenarios.[18] Figures 1 and 2 summarize the impacts of the Concentric 2019 Depreciation Study using ELG and the Concentric 2019 Depreciation Study using ALG, respectively. The following table summarizes the amounts by year and the difference:

Table 1 – Comparison of calculated depreciation under ELG and ALG (2019 Concentric depreciation study)

($ in thousands)	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**
2019 Depreciation Study - ELG	$ 618,445	$ 631,785	$ 642,755	$ 657,249	$ 669,197
2019 Depreciation Study - ALG	$ 588,488	$ 601,570	$ 611,273	$ 625,329	$ 635,873
Difference	$ 29,957	$ 30,215	$ 31,482	$ 31,920	$ 33,324
Difference %	4.84%	4.78%	4.90%	4.86%	4.98%

The applied for revenue requirement and financial forecasts are based on the 2019 Depreciation Study – ELG. The difference between the ELG and ALG procedures produces an impact that requires an increase in rates charged to customers. The difference may be significant from the perspective of revenues, but the difference is not significant from the perspective of overall depreciation expense. This is particularly the case when the individual account differences are reviewed.

In response to PUB/MH I-82a-c Attachment 1, Manitoba Hydro provided a comparison of the 2014 and 2019 depreciation study rates under ELG and ASL (ALG) excluding salvage recovery.[19] I have reviewed the differences in those rates, including differences for some of

[17] The ALG rates in this context are the rates based on the 2019 Depreciation Study and not the ALG rates being proposed by Alliance Consulting.
[18] Manitoba Hydro responses to PUB IRs, PD pages 361 to 366, PUB/MH I-81a-e Figures 1 to 6.
[19] Manitoba Hydro responses to the PUB, PDF pages 370 to 379, PUB/MH I-82a-c Attachment 1.

the largest accounts by investment, and do not consider the differences to be significant. As an example, Account 2000G for Transmission Lines – Metal Structures had an account balance as of March 31, 2019, of $1,671,075,743, which represents 7.6% of the $22,112,338,301 of total investment.[20] The 2019 ELG rate for this account is 1.25% whereas the 2019 ALG rate is 1.17% for a difference of 0.08%.[21]

While a change of 0.08% may appear to have a significant impact on applied for revenue requirement (0.08% * $1.7 billion = $1.4 million), the difference is not significant from a depreciation perspective. The difference in this account of approximately $1.4 million[22] will be recovered over the remaining life of the assets with the ALG procedure. Further, whether a change in the depreciation expense estimate is material from a revenue requirement or cash flow perspective to either customers or Manitoba Hydro is subjective. It is also a separate assessment and thus not relevant to the determination of whether additional componentization of the assets would be "significant".

In summary, the depreciation expense calculated using the ALG procedure provides for an appropriate, systematic allocation of depreciation expense related to the significant components comprising Manitoba Hydro's system. The further components identified as being required by Alliance Consulting are not actually required by IFRS.

3.2.6 The deferral account to address componentization can be avoided

Q: If Manitoba Hydro accounted for the componentization of its assets under IFRS in the manner employed by other regulated electric utilities would there be a regulatory deferral account?

A: No. The account exists only because Manitoba Hydro has chosen to adopt an interpretation of IFRS that differs from the treatment required by the Manitoba PUB. While the approach taken by Manitoba Hydro is IFRS compliant, I also consider that recognizing depreciation as required by the PUB is also IFRS-compliant.

[20] Tab 10 – MFR 95, PDF pages 44 and 46.
[21] Manitoba Hydro responses to the PUB, PDF page 753, PUB/MH I-82a-c Attachment 1, line 18.
[22] The actual difference will vary with the forecast balances.

3.2.7 Proposed treatment of gains and losses can be addressed through the ordinary approach to group depreciation

Q: Is Manitoba Hydro's proposed accounting for gains and losses on retirement consistent with the IFRS requirements?

A: Not necessarily. However, in this case, there is some commonality of position among parties to expense gains and losses, with some utilities reporting under IFRS choosing to set up those amounts in a separate account akin to a deferral account.

IAS 16.67 to .72 sets out the requirements for the derecognition of the carrying amount of an asset that was previously recognized under IAS 16. Specifically, the standard provides the following guidance. Once again, the bolded text is intended to illustrate the "requirements" with the unbolded text providing additional guidance:

> **Derecognition**
>
> **67 The carrying amount of an item of property, plant and equipment shall be derecognised:**
>
> **(a) on disposal; or**
>
> **(b) when no future economic benefits are expected from its use or disposal.**
>
> **68 The gain or loss arising from the derecognition of an item of property, plant and equipment shall be included in profit or loss when the item is derecognised (unless IFRS 16 Leases requires otherwise on a sale and leaseback). Gains shall not be classified as revenue.**
>
> 68A However, an entity that, in the course of its ordinary activities, routinely sells items of property, plant and equipment that it has held for rental to others shall transfer such assets to inventories at their carrying amount when they cease to be rented and become held for sale. The proceeds from the sale of such assets shall be recognised as revenue in accordance with IFRS 15 Revenue from Contracts with Customers. IFRS 5 does not apply when assets that are held for sale in the ordinary course of business are transferred to inventories.

> 69 The disposal of an item of property, plant and equipment may occur in a variety of ways (eg by sale, by entering into a finance lease or by donation). The date of disposal of an item of property, plant and equipment is the date the recipient obtains control of that item in accordance with the requirements for determining when a performance obligation is satisfied in IFRS 15. IFRS 16 applies to disposal by a sale and leaseback.
>
> 70 If, under the recognition principle in paragraph 7, an entity recognises in the carrying amount of an item of property, plant and equipment the cost of a replacement for part of the item, then it derecognises the carrying amount of the replaced part regardless of whether the replaced part had been depreciated separately. If it is not practicable for an entity to determine the carrying amount of the replaced part, it may use the cost of the replacement as an indication of what the cost of the replaced part was at the time it was acquired or constructed.
>
> **71 The gain or loss arising from the derecognition of an item of property, plant and equipment shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the item.**
>
> 72 The amount of consideration to be included in the gain or loss arising from the derecognition of an item of property, plant and equipment is determined in accordance with the requirements for determining the transaction price in paragraphs 47–72 of IFRS 15. Subsequent changes to the estimated amount of the consideration included in the gain or loss shall be accounted for in accordance with the requirements for changes in the transaction price in IFRS 15.

It appears based on the evidence provided by Manitoba Hydro that the decision to expense gains and losses on retirement of assets stems from the requirements under IAS 16.68. I do not dispute that IAS 16.68 requires the gain or loss on derecognition of an asset to be included in profit or loss. However, in this case, it is important to note that IFRS also acknowledges depreciation as an estimate.

Assume a simple example where there is a single asset in an account such as a building. In this case, if the asset is derecognized before the end of its useful life, then a gain or loss will be recognized. This is appropriate.

For mass property assets depreciated using either the ALG or ELG procedure, the purpose of the calculation is to assign a reasonable amount of depreciation to the assets reflective of the average life of the assets. In each case, it is acknowledged that assets may have different lives within a single account.

As an example, assume in 2001, Manitoba Hydro added 1000 transmission poles. Now assume in 2010, 15 of those transmission poles were retired due to a requirement to relocate the facilities. The remaining 985 transmission poles would continue to be depreciated under both ALG or ELG. Specifically, under either ALG or ELG, it is expected that some assets will be retired before the average service life, while other assets will be retired after the average service life. Differences in depreciation are ordinarily accounted for using a reserve account where the remaining life technique is not employed. Therefore, under both ALG and ELG, the retirement of 15 transmission poles will be accounted for, and any impact on future depreciation expense will be considered as will the impact of any over or under recovery of depreciation expense previously charged.

Combining both the originally proposed amount of depreciation expense and the subsequent amortization of any differences charged back to accumulated depreciation provides for total depreciation expense. This total amount of depreciation expense provides a reasonable amount of depreciation for the assets under either the ALG or ELG procedure.

Therefore, a key question for an accountant is whether the estimated depreciation expense under either procedure results in an actual gain or loss under mass property assets. Specifically, while a gain or loss can be mathematically derived under either procedure, the underlying assumption in the depreciation expense calculation is that some assets have different lives. Some assets will retire before the average service life and other assets will retire after the average service life.

For this reason, for mass property assets that are subject to future adjustments by the regulator, it may be reasonable to conclude that interim retirements of a small portion of assets would not result in gains or losses to the extent those retirements are consistent with the experience contemplated in the depreciation expense. Specifically, if the Iowa curve[23] assumes 1% of the investment retires in a certain year and the actual experience is relatively consistent with this expectation, then under either the ALG or ELG procedure no gain or loss should be recognized on retirement.

I note this interpretation has been accepted in Canada for companies reporting under IFRS that also rely on both ALG and ELG to determine the amount of depreciation expense. In response to PUB/MH I-118a-c, Manitoba Hydro explained that based on an Electricity Canada survey, five utilities use the ALG procedure for regulatory reporting purposes and four of those five also use the ALG procedure for financial reporting purposes.[24] Similarly, one utility recovers deferred gains and losses through future depreciation rates.[25] While the utility is not listed, I note that AltaLink, regulated by the Alberta Utilities Commission, maintains a separate account related to deferred gains and losses for financial reporting purposes, and recovers those amounts through the regulatory process by amortizing the costs over the remaining life of the assets.

In its recent December 31, 2022, annual report available on www.sedar.com, AltaLink states:

> When an asset is retired or disposed of in the normal course of business, the gain or loss is recognized immediately in the statement of comprehensive income. Generally, losses or gains are recoverable from or repayable to the AESO through future transmission tariffs. The Partnership recognizes the related amounts in revenue and records the amount as financial assets or liabilities related to regulated activities. Capital inventory and land are capitalized but not depreciated. CWIP is capitalized but not depreciated until the assets are available for use and the costs have been transferred to lines, substations, and buildings and equipment.

[23] I discuss the concept of Iowa curves in further detail in Section 3.2 below.
[24] Manitoba Hydro responses to the PUB, PDF pages 536 to 538, PUB/MH I-118a-c.
[25] Manitoba Hydro responses to the PUB, PDF pages 536 to 538, PUB/MH I-118a-c.

In summary, when a mass property asset is retired, the gain or loss on disposal is either recorded within accumulated depreciation if supported by the estimation process, or it is set up as a separate account that remains amortized over the remaining life of the assets or some other period of time. This approach mirrors the impact of the regulatory accounts and is reasonable.

Given the smaller size of the balance in the deferral account related to gains and losses, I recommend that the PUB continue the deferral account for gains and losses with an approved amortization period consistent with recovery over the remaining life of the assets. This approach balances the need to comply with IFRS with the fact that the difference is not material and it may not be worth tracing back the gains and losses to the individual depreciation study accounts to support no gain or loss being recognized under IFRS.

3.2.8 Componentization level proposed by Alliance Consulting is not required to comply with IFRS

Q: Is the level of componentization proposed by Alliance Consulting Group necessary to comply with IFRS?

A: No. The level of componentization being proposed by Alliance Consulting is at a level of detail that does not result in a significant change to the amount of depreciation expense recorded. Accordingly, while the study provides for a result that is technically "IFRS-compliant" based on an exercise of judgment, the result achieved by the currently approved ALG (Average Service Life) procedure is also IFRS compliant. Further, the use of the ALG procedure provides continuity, is known and understood in Manitoba and other Canadian jurisdictions, avoids rate volatility, and also avoids the need to make a complex transition for regulatory purposes.

3.2.9 Approval of a recovery period for deferral accounts is required by IFRS 14

Q: Does Manitoba Hydro require an approved recovery of its deferral account balances to comply with IFRS 14?

A: Yes. Under both the existing IFRS 14 and the Exposure Draft for a revised IFRS 14, it is important that a recovery period be determined. The existing IFRS 14 states:

33 For each type of rate-regulated activity, an entity shall disclose the following information for each class of regulatory deferral account balance:

(a) a reconciliation of the carrying amount at the beginning and the end of the period, in a table unless another format is more appropriate. The entity shall apply judgement in deciding the level of detail necessary (see paragraphs 28–29), but the following components would usually be relevant:

(i) the amounts that have been recognised in the current period in the statement of financial position as regulatory deferral account balances;

(ii) the amounts that have been recognised in the statement(s) of profit or loss and other comprehensive income relating to balances that have been recovered (sometimes described as amortised) or reversed in the current period; and

(iii) other amounts, separately identified, that affected the regulatory deferral account balances, such as impairments, items acquired or assumed in a business combination, items disposed of, or the effects of changes in foreign exchange rates or discount rates;

(b) the rate of return or discount rate (including a zero rate or a range of rates, when applicable) used to reflect the time value of money that is applicable to each class of regulatory deferral account balance; and

(c) <u>the remaining periods over which the entity expects to recover (or amortise) the carrying amount of each class of regulatory deferral account debit balance or to reverse each class of regulatory deferral account credit balance</u>.

…

36 <u>When an entity concludes that a regulatory deferral account balance is no longer fully recoverable or reversible, it shall disclose that fact, the</u>

> reason why it is not recoverable or reversible and the amount by which the regulatory deferral account balance has been reduced.

As set out above, the recovery period is a key piece of information to be disclosed and arguably all balances should be recoverable over a reasonable period of time. The revised IFRS 14 Exposure Draft states as follows regarding subsequent measurement:[26]

> 55. In measuring a regulatory asset or regulatory liability after its initial recognition, an entity shall at the end of each reporting period:
>
> (a) update the estimated amounts and timings of future cash flows arising from the regulatory asset or regulatory liability to reflect conditions existing at that date (paragraphs 56–57); and
>
> (b) continue to use the discount rate determined at initial recognition, except as described in paragraph 58.

While only an Exposure Draft, this requirement is aligned with the requirements of subsequent measurement in other IFRS. Therefore, I expect it will continue to be a relevant consideration if and when the standard is issued and becomes effective.

The requirement to set a reasonable recovery period for costs is also consistent with guidance from the Supreme Court of Canada which states:[27]

> As discussed above, a key principle in Canadian regulatory law is that a regulated utility must have the opportunity to recover its operating and capital costs through rates: *OEB*, at para. 16. This requirement is reflected in the *EUA* and *GUA*, as these statutes refer to a reasonable opportunity to recover costs and expenses so long as they are prudent. A regulator must determine whether a utility's costs warrant recovery on the basis of their reasonableness — or, under the *EUA* and *GUA*, their "prudence". Where

[26] https://www.ifrs.org/content/dam/ifrs/project/rate-regulated-activities/published-documents/ed2021-rra.pdf
[27] ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission), 2015 SCC 45 (CanLII), [2015] 3 SCR 219, the SCC stated (at para. 61):

> costs are determined to be prudent, the regulator must allow the utility the opportunity to recover them through rates. The impact of increased rates on consumers cannot be used as a basis to disallow recovery of such costs.[10] This is not to say that the Commission is not required to consider consumer interests. These interests are accounted for in rate regulation by limiting a utility's recovery to what it reasonably or prudently costs to efficiently provide the utility service. In other words, the regulatory body ensures that consumers only pay for what is reasonably necessary: *OEB*, at para. 20.

At footnote 10, the Supreme Court also found:

> Regulators may, however, take into account the impact of rates on consumers in deciding *how* a utility is to recover its costs. Sudden and significant increases in rates may, for example, justify a regulator in phasing in rate increases to avoid "rate shock", provided the utility is compensated for the economic impact of deferring its recovery: *TransCanada Pipelines Ltd. v. National Energy Board*, 2004 FCA 149, 319 N.R. 171, at para. 43.

The requirement to permit a reasonable period of time for recovery of costs is necessary for a regulator, though the regulator can exercise some judgment in determining the period of recovery.

The two deferral account components that require a recovery period are the difference in depreciation expense related to ELG versus ALG and gains and losses. Under the whole life depreciation technique applied using either the ELG or ALG procedure, gains and losses and differences in depreciation are charged through accumulated depreciation and then amortized over the expected remaining life of the assets. This is an appropriate result and provides for a reasonable recovery period for the costs that has been long accepted by Canadian and U.S. regulators and is consistent with the approach I previously described for AltaLink.

In its response to a PUB information request to refile its financial forecast assuming the request to recover the difference between ELG & ASL as a regulatory asset is denied and the continuation of deferral and amortization of interim losses, Manitoba Hydro states:

> b) This scenario has been provided as requested. However, should the PUB direct Manitoba Hydro to implement this scenario, management's assessment of recoverability as required under IFRS 14 would indicate that there is no evidence that the balance would be recovered in future years. As such, Manitoba Hydro would be required to write off the balance in the account to be in compliance with IFRS. Please refer to Appendix 4.3 section 1.4.4, and the response to PUB/MH I-115 a) for further discussion regarding Manitoba Hydro's concerns about the continued growth in these regulatory deferral accounts without an established recovery mechanism.[28]

I agree with Manitoba Hydro that there should be a defined period of recoverability for any costs. It is important for the PUB to establish some definite and reasonable period of recovery of the costs subject to deferral account treatment to permit continued recognition. However, as I discuss below, this is already the case as the ELG and ALG procedures will ultimately charge the same amount of depreciation expense over the life of the assets and thus any difference will ultimately be recovered.

In response to PUB/MH I-30d), Manitoba Hydro provided a figure depicting the final results from amortizing the deferral account differences over the expected remaining service life of the accounts contributing to the balance in the deferral account.[29] Further, Manitoba Hydro states:

> The merit of amortizing the loss on retirement or disposal of assets is that a recovery mechanism is established for this deferral account. A recovery mechanism ensures compliance with IFRS 14 which requires evidence that deferred amounts will be recovered or refunded in future rates. As

[28] Manitoba Hydro responses to the PUB, PDF page 61, PUB/MH I-16b).
[29] Manitoba Hydro responses to the PUB, PDF pages 169 and 170, PUB/MH I-30d).

> indicated in PUB/MH I-118 c), based on the Electricity Canada survey conducted by Manitoba Hydro, all other Canadian utilities responding have recovery mechanisms established for their regulatory deferral accounts.
>
> …
>
> Figure 1 above demonstrates that amortizing this regulatory deferral over the expected remaining service life of the accounts contributing to the balance would have a minimal annual impact and as such supports Manitoba Hydro's objective of providing value to its customers through stable and predictable rates while ensuring recoverability of this regulatory deferral.
>
> Regardless of the amortization period selected, the impact to net income would be relatively low as the balance in the account is small compared to Manitoba Hydro's depreciation related regulatory deferral accounts. Any approach to amortization would provide a benefit as it provides a defined mechanism for recovering these costs.[30]

Finally, regarding the need to recover the unamortized gains and losses, Manitoba Hydro states:

> Manitoba Hydro's application reflects the proposal for the PUB to accept IFRS ELG depreciation for rate setting purposes including cessation of the change in depreciation method and the loss on retirement or disposal of assets accounts. Cessation of the deferrals will cause the cumulative balance in the accounts to be orphaned requiring establishment of recovery mechanisms. A recovery mechanism ensures compliance with IFRS 14 which requires evidence that deferred amounts will be recovered or refunded in future rates. As indicated in PUB/MH I-118 c), based on the

[30] Manitoba Hydro responses to the PUB, PDF pages 169 and 170, PUB/MH I-30d).

> Electricity Canada survey conducted by Manitoba Hydro, all other Canadian utilities who responded have recovery mechanisms established for their regulatory deferral accounts.[31]

While Manitoba Hydro has not proposed a recovery period consistent with the expected remaining life of the assets, the above statements do not exhibit clear opposition to such a result. Recovery of the costs over the expected remaining life of the assets has numerous benefits:

- It is consistent with the recovery period generally accepted by depreciation experts, and employed by Concentric in this application,[32] where the ALG or ELG procedure and whole life technique are employed.
- The result would be consistent with the regulatory rates and require no further tracking or costs to reconcile differences from period to period.
- Recovery would be automatically updated to reflect more current results as part of subsequent depreciation studies.
- The recovery period would not be established based on an arbitrary period such as 20 to 30 years, and thus align with the intergenerational equity considerations inherent in depreciation estimates.
- The recovery period would align with the inherent depreciation expense recovery principles that permit the recovery of investment over the remaining expected useful life of the assets.

In summary, I recommend that the PUB direct a recovery period for the deferral accounts consistent with the recovery of the costs over the remaining useful life of the assets. I note that if Manitoba Hydro aligns its financial reporting with IFRS, which I consider to be

[31] Manitoba Hydro responses to PUB IRs, PDF page 541, PUB/MH I-120.
[32] MFR 95 Attachment 1, PDF page 5.

appropriate, then the ELG vs. ALG deferral will naturally unwind and only the gains and losses deferral account will be impacted.

3.2.10 Implementation considerations

Q: Are there any implementation considerations for your recommendations?

A: Yes. Concentric has calculated depreciation rates in MFR 95 Attachment under both the ELG and ALG procedures, using the straight-line method and the whole life technique in both cases. The whole life technique requires the depreciation expert to calculate the difference between the book accumulated depreciation and the calculated accrued depreciation. Once calculated the difference is then amortized over the remaining expected or probable life of the assets.

The book reserve for Manitoba Hydro is $6.488 billion compared to the ALG calculated reserve of $5.239 billion for a difference of $1.249 billion.[33] Using the ELG procedure, the book reserve is $6.641 billion, and the calculated accrued reserve is $5.795 billion for a difference of $0.846 billion. These balances represent a credit position (i.e., amount to be refunded to customers) as the amount collected from customers and included in the book reserve is greater than the theoretical amount of depreciation that should have been collected over the same period using the proposed depreciation rates.

Manitoba Hydro requested the ability to settle deferral account balances that represent a debit position (i.e., amount to be collected from customers) of $355 million at the beginning of 2022/23 and $413 million at the end of 2022/23. I understand the difference in the deferral account has been calculated from the basis of the ELG procedure to the existing ALG procedure.

As I discuss above, the ALG versus ELG difference is driven by a difference in accounting policies. Therefore, it need not be calculated and is not reflected in the theoretical reserve. If Manitoba Hydro changes its depreciation estimate for financial reporting purposes the difference will no longer exists. Regardless though, even if the difference continues to exist

[33] Tab 10 – MFR 95 Attachment, PDF page 92.

that difference already has an approved recovery period. Specifically, over the life of the assets if Manitoba Hydro uses the ELG whole life depreciation procedure and for regulatory purposes the ALG whole life depreciation procedure is approved, then ultimately the difference will draw down to zero when the final asset is retired. No other recovery period is required.

For the gains and losses, I understand this to be the difference between the gains and losses recovered under ALG versus ELG. Therefore, in the same sense these differences would not be addressed in the difference between the calculated and book reserve discussed above. However, in the same sense, those amounts will unwind naturally over the life of the assets and thus already have an approved recovery method.

Notwithstanding the above, the PUB need not be concerned with the accumulated difference in the deferral account if Manitoba Hydro continues to use the ELG procedure for financial reporting purposes. This is because the difference in the account is significantly lower than the difference between the theoretical and book reserve under either the ALG or ELG procedure. While the deferral account is forecast to grow per Figure 6 of Appendix 4.3, it only exists due to an accounting difference and the PUB can receive some comfort from the large credit balance that exists to notionally if not actually offset the growing deferral balance that will ultimately reverse itself.

3.3 Concentric depreciation study

3.3.1 Introduction to Iowa curves

Q: What is an "Iowa curve" and how is it used in calculating depreciation expense?

A. Iowa curves were first developed by Robley Winfrey at the Iowa State University with input and assistance from several others including Edwin Kurtz and Harold Cowles. Much of this work is available as part of Bulletin 125 and 155. The Iowa curves were based on a comprehensive study of the lives of different types of assets. Based on the study of those lives a series of curves were developed that provided for a statistical fit to the various lives. There are four classes of curves, including S-curves, L-curves, R-curves, and O-curves. These curves are broadly accepted and tested in Canada and North America and have been consistently accepted by regulators for determining a reasonable depreciation expense.

The most used Iowa curves for regulated electric utility plant are a R-curves (right-modal), S-curves (symmetric) and L-curves (left-modal). R-curves tend to be the most used curves for electric utility plant as they reflect relatively few retirements in the earlier years of the assets useful life and greater retirements occurring after the average service life of the assets.

The following figures provide illustrations of both the survivor and frequency curves for each of the above S-curves, R-curves, and L-curves. The survivor curves should be viewed with the y-axis as the percentage surviving, and the x-axis as the remaining average life. The frequency curves depict the retirement ratio on the y-axis and the remaining average life on the x-axis.

A survivor curve illustrates over time the percentage of the assets that are expected to continue to be in service, whereas a frequency curve provides the expected rate of retirement over time. As an example, assume that a 10-year average service life is assumed for an S6 Iowa curve. Once the average service life is selected, that life replaces the x-axis with “100%” becoming the average service life of 10 years. Therefore, using Figure 2 below, the S6 curve would suggest that 100% of the investment would remain in the account through approximately “80%” or 8 years of the asset’s life. In other words, no assets would be expected to be retired until approximately year 8, after which point the assets would retire quickly through to “120%” of the remaining life or by 12 years.

The frequency curve reflects the frequency of retirements as shown by the survivor curve. Specifically, looking at Figure 3 for the S6 curve, there are once again few retirements expected until approximately “80%” or year 8 in the above example. At this point the frequency curve peaks very quickly to reflect an increased frequency of retirements from approximately age 8 through to age 12. In summary, the survivor and frequency curves are two different ways of depicting the same information.

The selection of a specific survivor curve (i.e., S6 or R5) is informed by the depreciation expert’s judgment regarding the visual and mathematical fit, peer data, and discussions with management and operations staff as I discuss below.

Figure 2 – S-curves – survivor curves

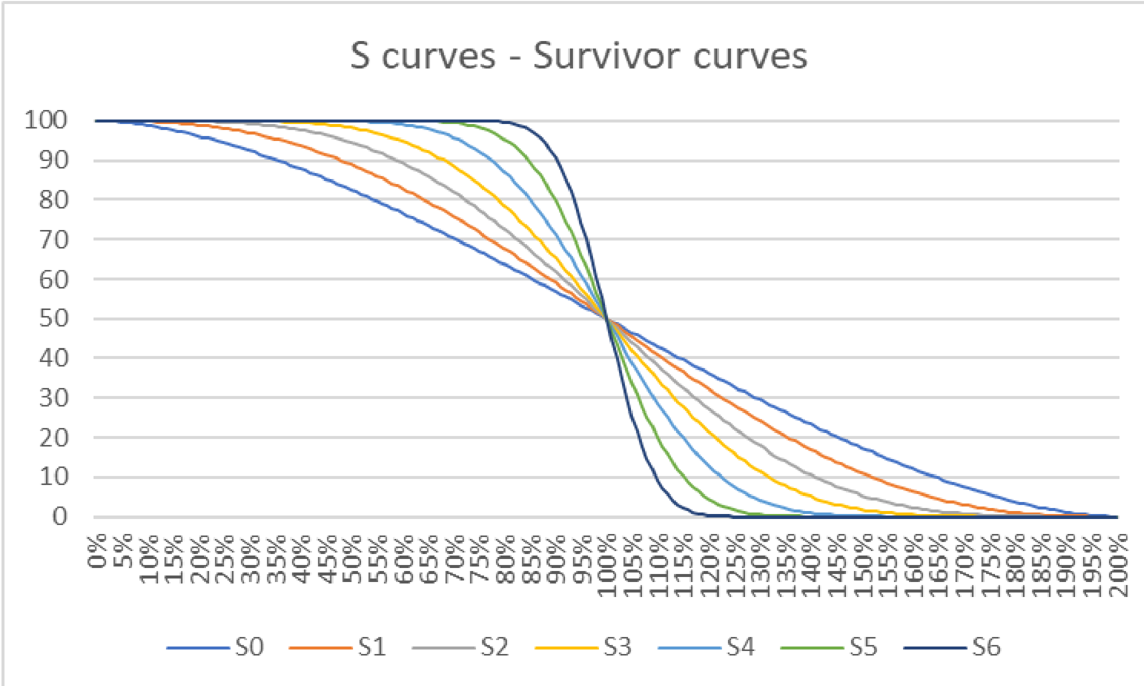


Figure 3 – S-curves – frequency curves

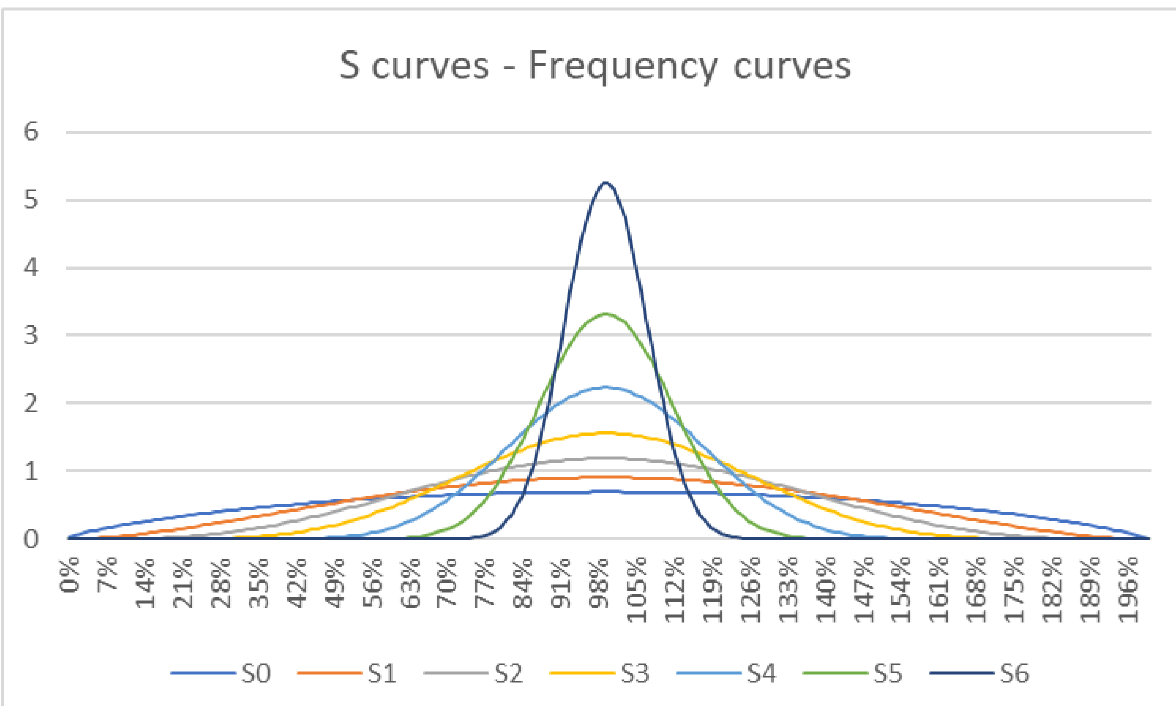


Figure 4 – R-curves – survivor curves

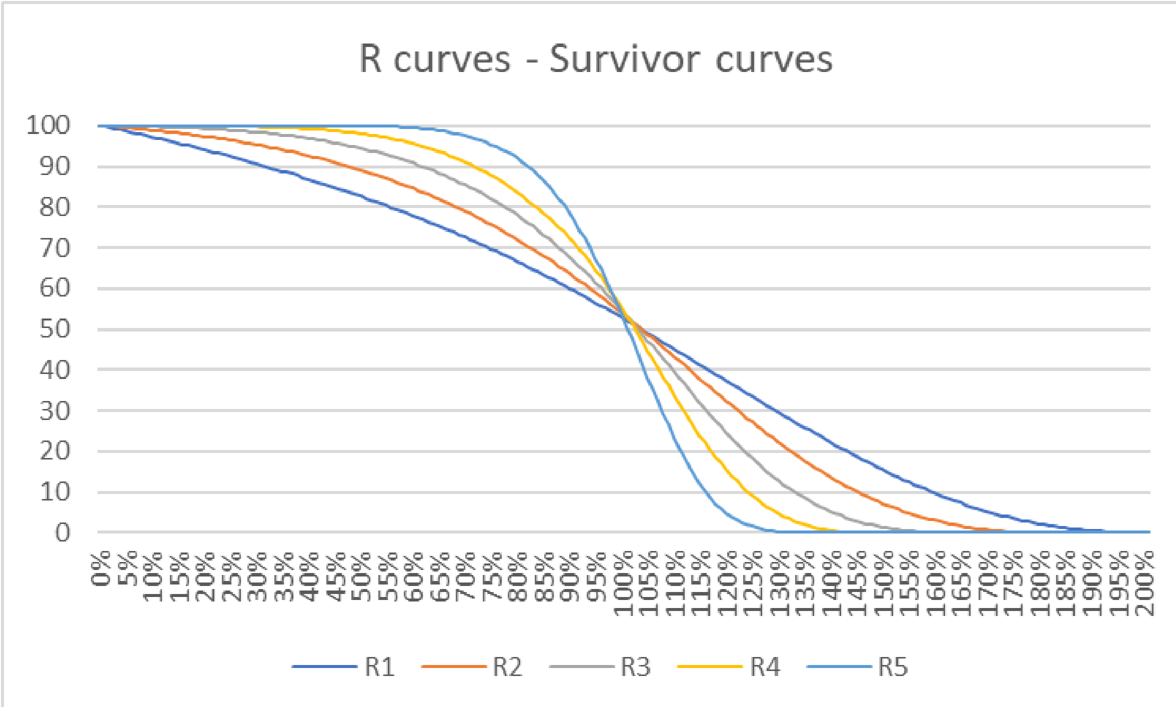


Figure 5 – R-curves – frequency curves

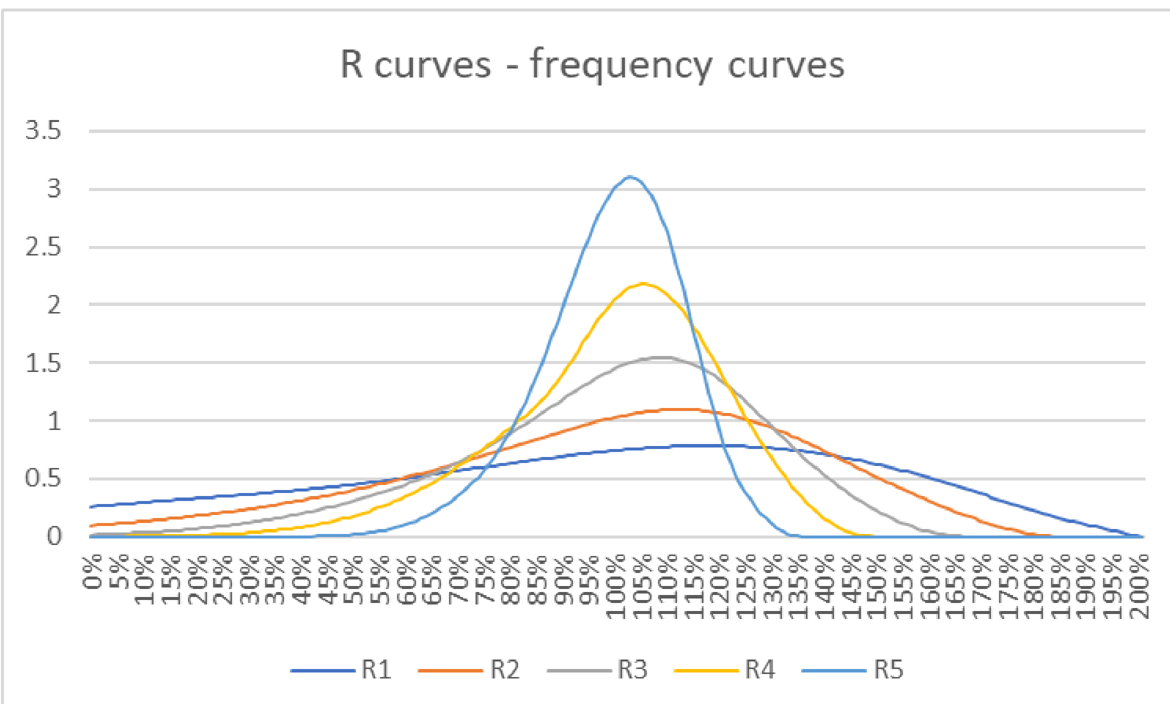


Figure 6 – L-curves – survivor curves

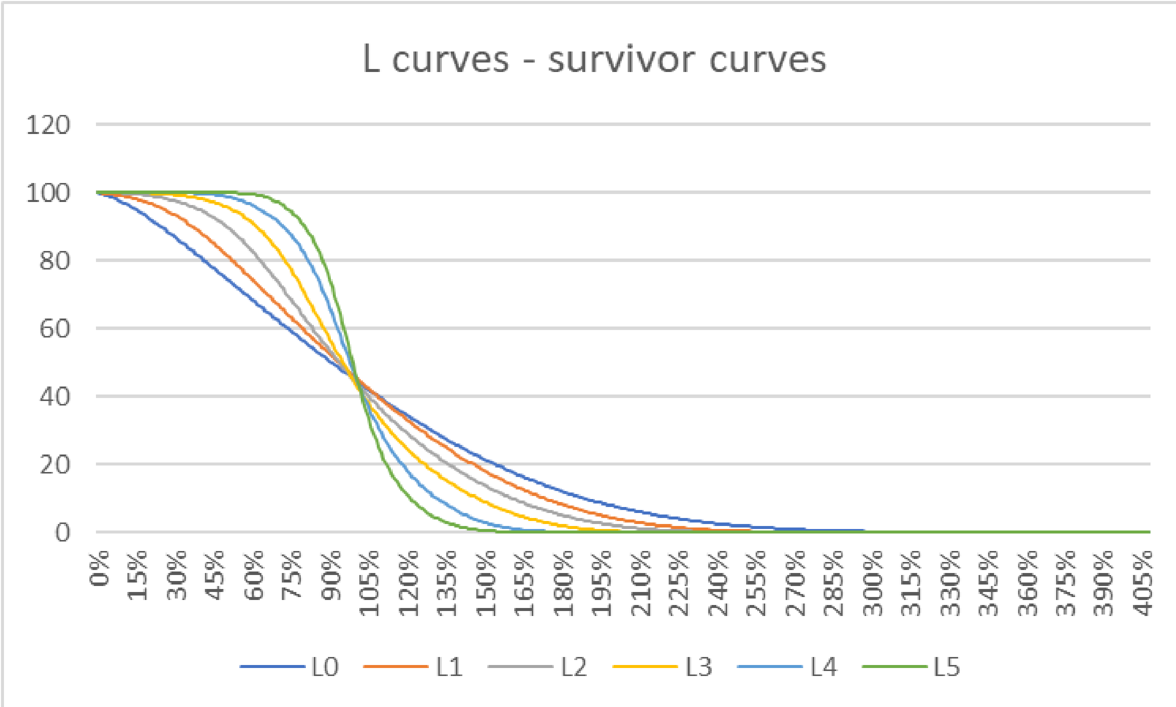
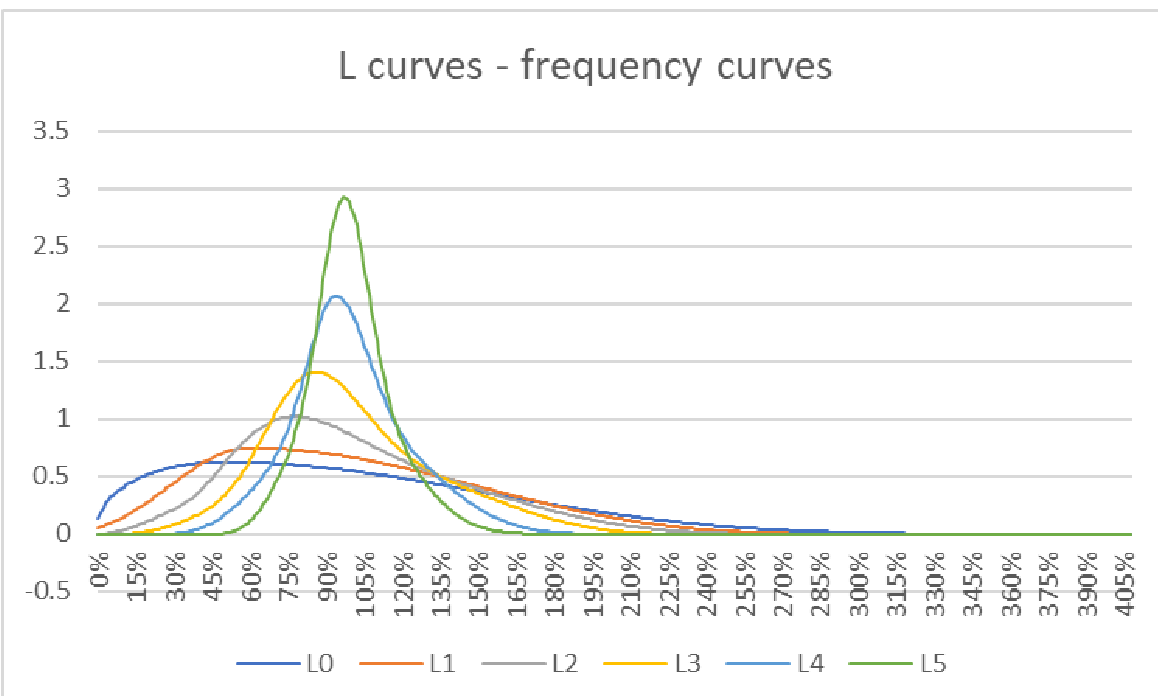


Figure 7 – L-curves – frequency curves



In addition to the above curves, depreciation experts have also calculated and relied upon half-curves such as an R2.5 curve, which is calculated by taking the average of the data points for both the R2.0 and R3.0 curves.

3.3.2 Use of Iowa curves under the ALG and ELG procedures

Q: Are Iowa curves utilized in both ALG and ELG procedure calculations?

A: Both the ALG and ELG procedures are based on actuarial analysis of mortality patterns to estimate how long an asset will be in use. In Canada, and in particular for regulated utilities, experts tend to rely largely on the Iowa survivor curves to assess the mortality characteristics of assets. Both the ALG and ELG procedures rely on the selection of an Iowa curve based on several factors, including but not limited to:

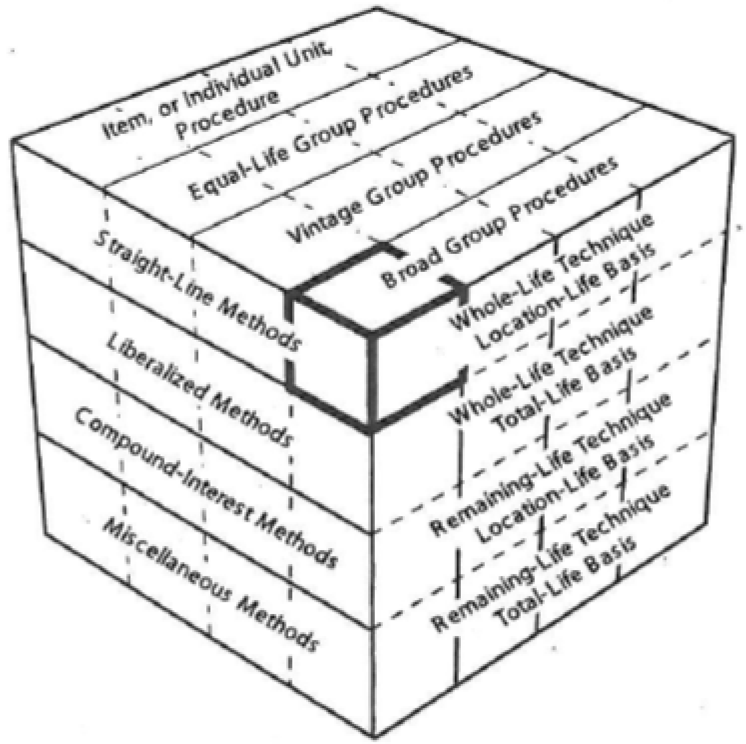
- Visual and mathematical fit of the observed retirement data to the selected survivor curves.
- Peer data on the average service lives and survivor curves used in other jurisdictions.
- Discussions with management and operational personnel to understand the life characteristics of the assets and other relevant operating, technical and maintenance details that may impact the lives of the assets.

3.3.3 Differences between the ALG and ELG procedures

Q: Please briefly explain the difference between the ALG and ELG procedures.

A. Depreciation experts employ a variety of depreciation procedures, methods, and techniques. The American Gas Association and Edison Electric Institute previously prepared the following figure to illustrate these:

Figure 8 – AGA and EEI "Depreciation Cube"



To properly calculate depreciation expense a depreciation expert must choose at least one procedure, method, and technique. The depreciation method determines how the depreciation expense will be allocated over the life of the asset. The simplest and most common example is straight-line depreciation, which provides for an even charge each year. Other methods that accelerate or decelerate the depreciation are more commonly used for tax purposes.

Procedures are employed to systematically allocate an asset or assets into subgroups. For example, a vehicle would be considered an individual unit group and depreciated accordingly. Other common methodologies employed are the equal life group and average life group methodologies. These two procedures employ actuarial analysis and are most used for mass property accounts such as Manitoba Hydro's assets.

Finally, a technique must also be selected to determine the specific asset life to be used in the depreciation formula. As an example, the whole life technique calculates depreciation expense over the entire life of the asset from inception to retirement. The remaining life technique calculates depreciation expense over just the expected remaining life.

ALG and ELG are depreciation procedures. The ALG procedure, also referred to as the Average Service Life (ASL) method or procedure, calculates depreciation expense based on the theoretical average life of the assets based on proposed survivor curves. For example, assume an average life of 10 years for an account and thus an accrual rate of 10%. The same accrual rate would be theoretically applied to each asset in the account regardless of its actual life.

The ELG procedure, also referred to as the Unit Summation procedure, calculates depreciation expense based on a similar approach to ALG but in theory calculates a different depreciation rate for each subgroup of assets. For example, if an asset lives five years in the group it would be depreciated at a rate of 20%, whereas an asset with a 10-year life would be depreciated at a rate of 10%. Concentric provides a helpful summary of the ALG and ELG procedures in its depreciation study.[34]

Regardless of the depreciation procedure selected the purpose of the exercise is to depreciate the same amount of value over a period of time. While the amount charged in any one period may vary by virtue of the procedure selected, the total amount depreciated will not vary. Manitoba Hydro confirms that ALG (ASL) and ELG depreciation procedures will recover the same amount of depreciation over the asset lives.[35]

In summary, both the ALG and ELG procedures rely on Iowa curves and an analysis of historical retirement and operational data. However, the ELG procedure differs in that each group of assets with a distinct service life is included in its own group and depreciation is calculated by summing the depreciation expense from each group, which often accelerates the amount of depreciation expense claimed for an account. This acceleration is unnecessary for Manitoba Hydro, is not gradual and moderate, exacerbates intergenerational inequities and does not result in a superior estimate of depreciation expense.

[34] Tab 10 – MFR 95 Attachment, PDF page 31.
[35] Manitoba Hydro responses to PUB IRs, PDF page 484, PUB/MH I-110.

3.3.4 Detailed discussion of the ELG procedure

Q: Does the ELG procedure provide a better estimate of depreciation expense?

A: Concentric's evidence suggests that the ELG procedure provides a better estimate of depreciation expense than the ALG procedure as included in the 2019 Depreciation Study. I disagree. As I highlight below, while the ELG procedure may in theory be more mathematically accurate, that accuracy remains subject to the realistic constraints of applying an estimation procedure to long-lived assets.

The ELG procedure is applied to an account based on a proposed Iowa curve. That curve will not provide a perfect representation of the actual individual lives of each subcomponent of the assets in the account. Instead, the ELG procedure assumes that the assets will retire in a manner similar to that depicted in the proposed Iowa curve. This assumption is an estimate and just like any estimate of depreciation determined using the ALG procedure, will change in the future.

In Appendix 4.3, Manitoba Hydro states:

> Under ELG, depreciation expense is higher for Manitoba Hydro given the age composition of its current asset base, and asset retirement gains and losses are lower due to the increased precision in depreciation calculations during the life of the asset, which more accurately reflect the service lives of the individual assets within each depreciable component. Effectively, the ELG method provides better matching of depreciation expense with the useful lives of the assets, which is reflected by the relatively low gains or losses recognized on retirement under ELG.
>
> Under ASL, depreciation expense is lower (compared to ELG) for Manitoba Hydro given the age composition of its current asset base and asset retirement gains and losses are higher as the average depreciation calculation is less accurate relative to the service lives of the individual assets within each depreciable component. The larger gains and losses recognized on retirement of assets under ASL reflect the reduced accuracy inherent in the ASL depreciation calculation. ASL assumes that there will be an equal proportion of assets retiring before and after the average

> service life and that gains and losses will offset over time. While this is true in theory, it is not what happens in practice as assets are not replaced at the same cost as the original asset due to inflation and changes in technology, etc. With a continuously growing asset base, in any given year the value of the asset retiring prior to the average life is likely to exceed the value of the assets retiring after the average life (because they are older and cost less). Consequently, losses on assets retiring prior to the average service life of the pool are likely to exceed the gains on assets retiring after the average service life.[36]

Theoretically, the above statements are accurate, but the theoretical correctness of the statements needs to be considered in light of the following:

- Depreciation expense is an estimate, and that estimate will change over the life of the assets. Regardless of the depreciation procedure selected, the final depreciation estimate will not be known with certainty until the final asset is retired.
- Actual depreciation of the physical assets does not follow the procedure selected. For example, if the ELG procedure is chosen, Manitoba Hydro does not establish in its accounting records a detailed breakdown of each asset by account and by service life.

In response to a PUB request, Manitoba Hydro provided the following example to illustrate the difference between ALG and ELG:[37]

[36] Manitoba Hydro 2023/24 & 2024/25 GRA, Appendix 4.3 (Amended), PDF pages 18 and 19.
[37] Manitoba Hydro responses to PUB IRs, PDF page 482, PUB/MH I-109.

Figure 9 – Manitoba Hydro figure depicting the difference between ALG and ELG depreciation

Assumptions:

Component Group A	Cost	Service Life (Years)	Salvage	ASL Depreciation Rate	ELG Depreciation Rate
Asset 1	$ 100	1	0		100%
Asset 2	$ 100	2	0		50%
Asset 3	$ 100	3	0		33%
Average Service Life		2		50%	

ASL Depreciation Calculation	Asset 1	Asset 2	Asset 3	Total Depreciation	Total Loss (Gain) on Retirement	Total Expense
	$ 100	$ 100	$ 100			
Depreciation Year 1	50	50	50	$ 150		
Retirement	(100)	-	-			
Loss (Gain) on Retirement	50				$ 50	$ 200
Depreciation Year 2	-	50	50	$ 100		
Retirement		(100)				
Loss (Gain) on Retirement		-			$ -	$ 100
Depreciation Year 3	-	-	50	$ 50		
Retirement			(100)			
Loss (Gain) on Retirement			(50)		$ (50)	$ -
Total				$ 300	$ -	$ 300

ELG Depreciation Calculation	Sub Component Asset 1	Sub Component Asset 2	Sub Component Asset 3	Total Depreciation	Total Gain (Loss) on Retirement	Total Expense
	$ 100	$ 100	$ 100			
Depreciation Year 1	100	50	33	$ 183		
Retirement	(100)	-	-			
Loss (Gain) on Retirement	-				$ -	$ 183
Depreciation Year 2	-	50	33	$ 83		
Retirement		(100)				
Loss (Gain) on Retirement		-			$ -	$ 83
Depreciation Year 3	-	-	33	$ 33		
Retirement			(100)			
Loss (Gain) on Retirement			-		$ -	$ 33
Total				$ 300	$ -	$ 300

The above simple example is an adequate representation of the calculations under the ALG and ELG procedures. However, it ignores one key consideration. Specifically, under the above ALG calculations, the ordinary practice using the whole life technique is to also calculate an adjustment to recover any unrecovered investment over the remaining life of the assets. Therefore, as an example, while there would be a loss in year 1 of $50, the entry to recognize that loss from a group depreciation perspective would be as follows in year 1:

Dr. Accumulated depreciation $50

Cr. Loss on disposal $50

In year 2, if the calculation of depreciation is accurate and updated frequently, the entry in the following year would be as follows to reflect the amortization of the differences included in the accumulated depreciation account:

Dr. Depreciation expense $25

Cr. Accumulated depreciation $25

The same entry as above is recorded in year 3. Therefore, in year 3, the utility would review this fact against the calculated "gain" in year 3 and observe that the amount of depreciation recognized over the life of the assets accurately reflects the total depreciation expense. The same amount would then be charged against the accumulated depreciation reserve account using the following entry which is the opposite of the loss entry recognized in year 1.

Dr. Gain on disposal $50

Cr. Depreciation expense $50

Therefore, no gain on disposal would be recognized in year 3 as 100% of the depreciation expense of all the assets will have been recovered.

In summary, referring to the earlier example, after the above entries are considered, the ALG procedure with a true-up for differences versus a perfect ELG procedure with no required true-up would provide for the following expenses in each year:

Table 2 – Summary of ALG versus ELG depreciation differences

	ALG without true up	ALG with true up	ELG no true up
Year 1	200	150	183
Year 2	100	125	83
Year 3	0	25	33
Total	**300**	**300**	**300**

While there are still differences between the ALG and ELG procedures after factoring in the true-up this is to be expected. This is because each procedure is based on different theoretical assumptions.

However, neither set of assumptions will perfectly mirror the actual lives of the assets. The example set out above is helpful to provide an illustration of the theoretical differences between the two procedures, but it operates on the assumption that in year 1 there is a perfect forecast of the lives of each of the assets over the three years. If for example by the end of year 1 it is determined that Asset 1 will last until year 2, Asset 2 will last until year 3, and Asset 3 will last until year 5, then the calculations and assumptions performed under either ALG or ELG will be incorrect and result in an incorrect amount of depreciation expense being claimed.

In practice these differences are magnified. For example, even where the ELG procedure is selected accountants for Manitoba Hydro will not actually track and depreciate the physical assets at the same level of detail. The ELG procedure groups assets by type of asset and by service life. Therefore, assets expected to survive 1 year are grouped together within the same vintage and account, and assets that survive 2 years are similarly grouped and so on.

Manitoba Hydro will not separately identify each asset that is included in each category and depreciate those assets based on their specific group and rate. For example, Manitoba Hydro does not go out and tag each physical asset and assign a depreciation rate to that specific asset based on its expected life. This is because such an effort would be exceptionally costly and subject to significant judgment, and thus would not likely be materially accurate relative to a more general approach to depreciating assets.

When using the ELG procedure, while it is calculated using a blend of multiple depreciation rates unlike the ALG procedures, the ELG procedure still ultimately uses one single rate for each account applied to all assets in that account. Therefore, while the rate is determined in theory at a detailed level by subgroup, the overall rate is not applied at the same level of detail to each subgroup of assets.

Finally, it is important to note that even if Manitoba Hydro tracked and depreciated each asset separately and Manitoba Hydro similarly tracked the depreciation of each sub component of the assets using the rate required by the ELG procedure, there would still be differences between the two depreciation estimates unless the actual depreciation expectation based on physical asset tagging and tracing perfectly matched the selected Iowa curve for the entire life of the assets.

For this reason, no depreciation estimate will ever be perfect, including ELG and ALG. The test must be whether the result provides for a reasonable estimate of the recovery of the forecast depreciation expense over the expected useful life of the assets. This test can be met under both the ELG and ALG procedures. Regardless of whether the ELG procedure is more theoretically accurate, in practice the ELG procedure does not provide a superior estimate of the actual expected life of the assets. This is because the depreciation expectation from the ELG procedure will not reflect actual experience and will need to be adjusted over time. No depreciation expert can conclude definitively that depreciation rates determined under ELG will, over the entire life of the assets, provide for a better reflection of the actual service life of the assets over time than an alternative procedure such as ALG. To do so would require perfect knowledge of the future that does not exist.

In summary, the results of the above example calculations are purely theoretical. Those results do not reflect the actual consumption patterns of the physical assets. The only way they could is if the actual assets retired were perfectly consistent with the selected Iowa curves over their entire useful life, which is not possible. Regardless of whether ALG or ELG is used in combination with the whole life or remaining life technique, each depreciation estimate will be subject to change in the future. Frequent updates to depreciation studies are best practice and to be expected.

3.3.5 Both the ALG and ELG procedure are acceptable for estimating depreciation expense

Q: Are ALG and ELG both acceptable procedures to use to recognize depreciation expense?

A: Yes. Both ELG and ALG are used in North America and are also commonly employed and accepted by regulators in Canada.[38] The ALG procedure is more common in the United States as are other methods of depreciating assets.

[38] The inconsistency for Manitoba Hydro arises in its accounting interpretation that IFRS does not permit the currently approved ALG (ASL) procedure and level of componentization.

The purpose of a depreciation procedure is to develop a reasonable and systematic estimate of the consumption of the value of an asset over time. This estimate is developed in conjunction with a depreciation method (i.e., straight-line, declining balance, or unit of production) and technique (i.e., remaining life and whole life) to determine the amount of depreciation expense to record for an asset. I discussed this process above.

3.3.6 Pros and cons of the ALG and ELG procedures

Q: What are the pros and cons of the ALG and ELG procedures?

A: As discussed earlier it is impossible for any depreciation expert to conclude that one depreciation procedure will with certainty provide for a better and more accurate recovery of depreciation expense over the actual life of the assets. The ELG or ALG procedure may provide a better estimate for certain individual accounts and overall after a review of all available data upon the conclusion of the lives of all assets. However, any result will simply be by happenstance. For this reason, it is best to focus on the mechanical considerations of each of the procedures, and in any event, I already acknowledge above the theoretical advantage ELG has in the determination of depreciation expense estimates.

First, I will review the pros and cons of the ELG procedure followed by the pros and cons of the ALG procedure.

- **ELG procedure pros:**
    - **Accuracy** – The ELG procedure is dependent on the selected survivor curve, which can significantly influence the amount of depreciation expense. For example, shifting a curve from a 15-R2.5 curve to a 15-R2.0 curve may provide for a refined amount of depreciation expense and increase accuracy. This permits more variation in the depreciation expense charge then is permitted under the ALG procedure.
    - **Improved cash flows** – The ELG procedure for Manitoba Hydro accelerates the collection of depreciation expense thus improving cash flow metrics in the short-term. While depreciation is a non-cash item, its inclusion in rates improves cash revenues, and thus improves overall cash flows.

- **ELG procedure cons:**
  - **Variability –** Differences in the selected survivor curve can have significant impact on the depreciation expense in a negative manner as well. Assuming a 15 year average life but selecting either an L1.0, S1.0 or R1.0 Iowa curve can have a material impact on the amount of depreciation expense charged and the timing of that expense despite the consistent use of a 15-year average life. While this can improve accuracy, it can also increase inaccuracy if the curve is not reasonably reflective of the future retirement patterns for the assets. It can also create significantly greater period to period variability due to simultaneous changes in life estimates and curves.
  - **Complexity** – The ELG procedure is a complex procedure to employ requiring a significant number of detailed calculations which are made easier by complex computer models. Given the current processing power of many PCs and laptops, this is not a significant limiting factor in adopting the ELG procedure. However, the ELG procedure can continue to be difficult for some parties to understand if they are unfamiliar with depreciation procedures, the derivation of Iowa curves, and the importance of retirement data.
- **ALG procedure pros:**
  - **Simplicity** – The ALG procedure is simple to apply and understand. Complex models are not required to understand or perform the individual calculations.
  - **Less potential volatility** – Changes from year-to-year in the retirement data are less likely to influence a change in the ALG procedure unless those changes suggest a change in the average service life.
- **ALG procedure cons:**
  - **Lower cash flows –** Manitoba Hydro's cash flows under the ALG procedure will be lower as the non-cash depreciation charge is reduced as compared to the ELG procedure.

- **Accuracy** – The ALG procedure does not result in significant variation due to the selection of the survivor curve, and thus tweaks or refinements to the amount of depreciation expense charged may not be as easy to implement.

Regardless of the procedure selected, there are pros and cons. No single procedure will be perfect, and no single procedure can ensure the forecast depreciation expense will be perfectly representative of the actual depreciation expense.

As a final point, the amount of depreciation expense forecast to be recovered under the ELG procedure increases as compared to the ALG procedure. Some parties may prefer a lower current depreciation expense to permit additional time to refine the estimate over the long lives of the assets. Other parties may prefer an acceleration of the depreciation expense to permit additional recovery in the near term, reduce debt financing levels in the short to long-term and permit less potential for under recovery of investment.

Ultimately the selection of a reasonable depreciation expense is heavily dependent on the assessment of intergenerational equities between generations of customers. The total amount of depreciation expense is unchanged over the life of the assets as only the amount collected in each year under the procedures is changed. Therefore, whether the increase in depreciation expense is a positive or negative consequence of adopting the ELG or ALG procedures is subjective.

Notwithstanding the above, I note that the ALG procedure in this case may provide a benefit to customers as Manitoba Hydro is forecasting other changes to its rates, including significantly rising OM&A costs and potential future volatility in its forecast financial scenarios due to uncertainty. The ALG procedures lower depreciation expense in the test period and provides some ability for parties to “wait and see” what happens in the future before accelerating the recovery of current period depreciation expense.

3.3.7 Recommended depreciation procedure for Manitoba Hydro

Q: Which depreciation procedure do you recommend for Manitoba Hydro and why?

A: I recommend that the PUB direct the continued use of the ALG procedure using the componentization levels determined under Concentric’s 2019 Depreciation Study. As outlined above, the primary driver for Concentric’s recommended change to the ELG procedure for Manitoba Hydro at this time is to address a perceived accounting issue. It is inappropriate to change depreciation procedures to address a perceived accounting difference, particularly when that difference is not prescribed under IFRS.

Ignoring the accounting driven reason for the change in depreciation procedure, I am not convinced of a need to shift to the ELG procedure for Manitoba Hydro. There is no clear and objectively verifiable benefit to making a change at this time. Further, there is no evidence that the existing ALG (ASL) procedure currently in place results in an unreasonable level of depreciation expense.

Accordingly, for all the reasons set out above, I recommend the PUB approve the use of the ALG procedure combined with the straight-line method and whole-life technique to calculate Manitoba Hydro's forecast depreciation expense.

3.3.8 Specific concerns regarding Account 3200M

Q: Excluding the use of the ELG procedure by Concentric, do you have any other specific concerns regarding the applied for depreciation rates?

A: I have reviewed Concentric's study, reviewed the lives and survivor curves of the various accounts and generally agree with the lives recommended by Concentric. While I may have selected a different life-curve combination for certain accounts, most changes would not have been significant.

However, there is one exception. Specifically, for Account 3200M – Substations – HVDC Synchronous condensers and unit transformers. For Account 3200M, Concentric is requesting a life shortening to 60-R3 from 65-R4.

Concentric's explanation for the proposed life shortening appears to be based on mathematical curve fitting where the 60-R3 curve provides a slightly better residual measure of 0.3100 compared to the 65-R4 residual measure of 0.5883.[39] Other limited information is cited by Concentric as support for its request. Through the interrogatory

[39] Tab 10, MFR 95, PDF page 24.

process, Concentric provided its meeting notes from discussions with management on the account, which provided limited additional information.[40] Similarly, there were no comparators included in Concentric's peer analysis.[41]

The residual measure calculated by Concentric is described as follows:

> The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion which is called the Residual Measure. This Residual Measure is based on a least square's solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve. The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the Residual Measure the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely-used practice of fitting Iowa curves up to one percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.[42]

A residual measure of zero means that the observed retirement data perfectly fits to the selected survivor curve. Therefore, all else being equal, a lower residual measure as selected by Concentric would provide a better "fit" to the observed retirement data.

[40] Manitoba Hydro Responses to MIPUG, PDF page 225, MIPUG/MH I-55-Attachment 1.
[41] Manitoba Hydro Responses to MIPUG, PDF page 247, MIPUG/MH I-55-Attachment 1.
[42] Tab 10, MFR 95, PDF page 12.

However, context for the selection of a curve based solely on the mathematical fit is required.

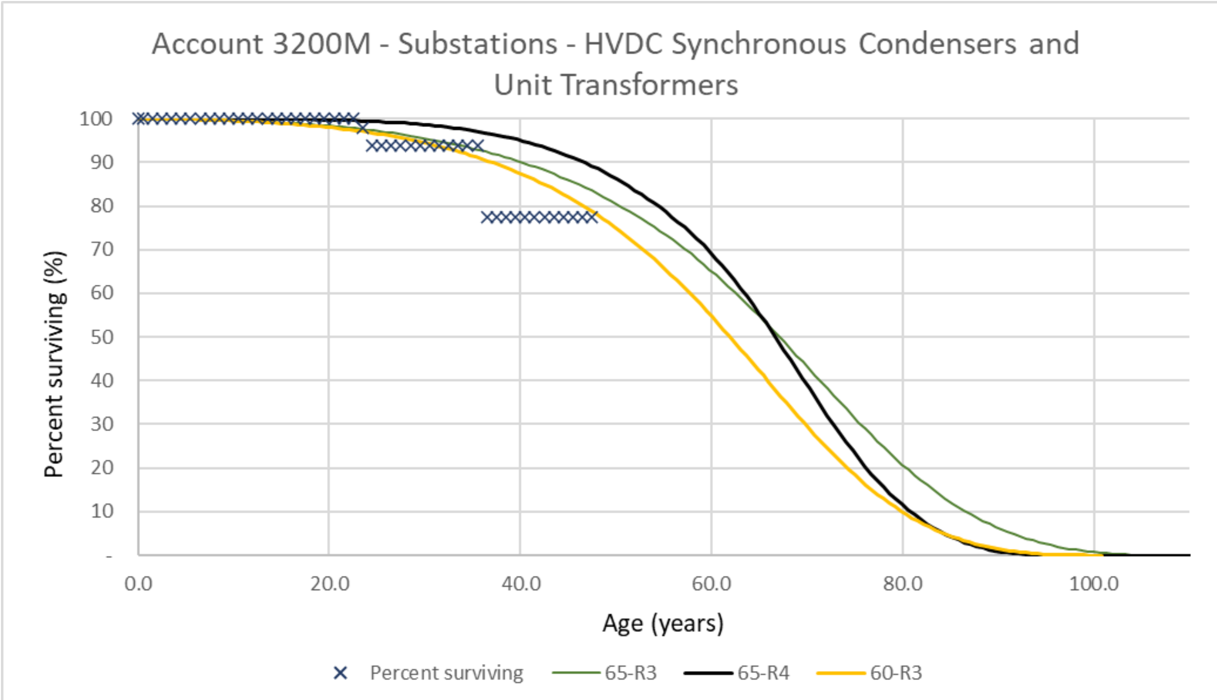
First, while a 60-R3 curve provides a better mathematical fit, both the 60-R3 and 65-R4 curves provide a good mathematical fit. Many other accounts have a curve selected based on a higher residual measure, and a higher residual measure may not necessarily mean a curve should not be selected. For example, Account 3200S had a 35-R5 curve selected where the residual measure was 2.3005,[43] which albeit was an improvement over the previous account. An issue with plotting a survivor curve against observed retirement data is that the retirement data can follow a retirement pattern that does not fit well to a specific curve. The key point is that altering the life-curve for account 3200M simply based on a marginal improvement in the mathematical fit is inappropriate.

Second, there are few retirements recorded, with observed retirements only occurring in age 22.5, 23.5 and 35.5.[44] This relatively limited history of retirements makes drawing conclusions on the observed retirement data of limited value.

Finally, it is important to consider other characteristics of the observed retirement data when selecting a curve. Notably, from a review of the retirement data included in Section 1, the exposures for Account 3200M are stable after age 0 at $128.9 million through to approximately age 22.5.[45] As shown on the survivor curve selected by Concentric, the 60-R3 curve declines through approximately age 17.5 and thus does not fit the exposures through age 22.5 as well as the 65-R4 curve does as shown below:

[43] Tab 10, MFR 95, PDF page 25.
[44] Tab 10, MFR 95, PDF pages 254 and 255.
[45] Tab 10, MFR 95, PDF page 254.

Figure 10 – Account 3200M – Emrydia modeled survivor curves



In this case judgment needs to be exercised as the 60-R3 curve provides a superior fit to the observed retirement data through the remaining ages, albeit based on limited retirement data for this account. However, both a 65-R4 as previously approved, and a 65-R3 curve continue to provide a strong visual fit to the observed retirement data while also better fitting the data through age 22.5 which is the period of highest exposures.

Overall, it appears that a 65-R3 curve provides the best balance between the two bookends. Specifically, a 65-R3 curve better fits the retirement data through age 22.5 than a 60-R3, but also provides a better fit to the observed retirement data through age 35.5, which the 60-R4 curve does not provide. A 65-R3 curve also provides a better alignment with the currently approved Iowa curve of 65-R4, which is preferrable given the limited retirement data.

In conclusion, I consider there to be inadequate justification at this time for a life shortening to account 3200M and recommend that the PUB either direct the existing life-curve to be maintained at 65-R4 or make a more moderate and gradual adjustment to a 65-R3 curve. Either approach would be appropriate and provides more time for the account to mature, more retirements to occur, and better information to become available to support a change in life if necessary.

4 Operating and administrative costs

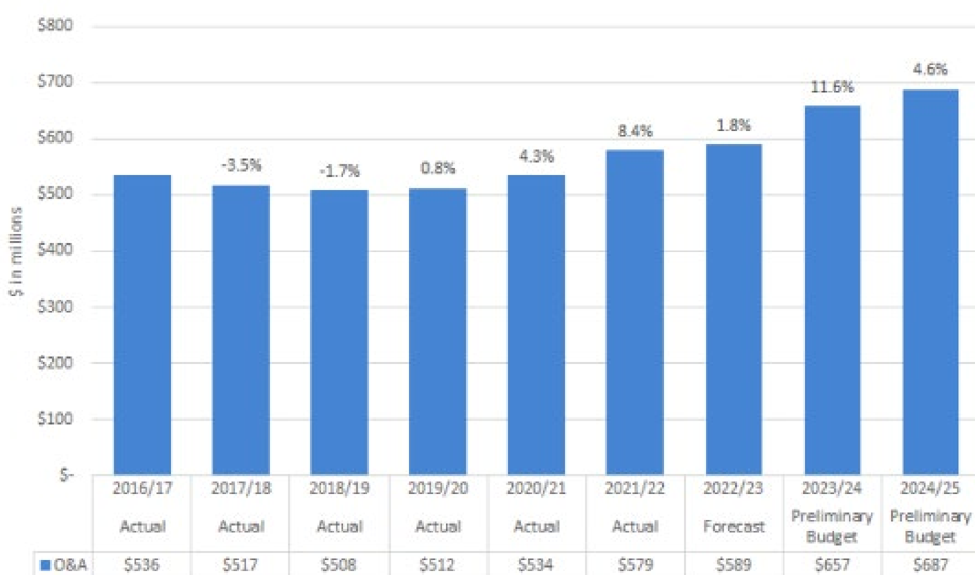
4.1 Introduction to operating and administrative cost issues

Q: Please summarize the cost increases Manitoba Hydro is proposing for operating and administrative costs relative to prior years.

A: As shown from the below figure from Manitoba Hydro's application, the O&A expenses are forecast to increase significantly in the test period:

Figure 11 – Manitoba Hydro's summary of O&A expenses from 2016/17 to 2024/25

Figure 6.1 O&A Expenses, 2016/17 – 2024/25



O&A expenses declined from 2016/17 and remained somewhat flat through to 2021/22 when an increase of 8.4% occurred. That increase continued through 2022/23 with a further smaller increase of 1.8% which suggests some stability to costs returned to Manitoba Hydro following its exit from cost control efforts during the pandemic, before the current forecast increases in 2023/24 and 2024/25 of 11.6% and 4.6%, respectively.

4.1.1 Drivers behind the increase operating and administrative costs

Q: What are the primary drivers for Manitoba Hydro's operating and administrative cost increase in the test periods?

A: As shown in the table below, the increase is broad-based across most cost elements, but a primary source of the increase is employee related expenditures ($33.7 million or 7%) and consulting and professional fees ($22.8 million or 91%).[46] These are the two areas I focus on in my evidence:

Table 3 – Manitoba Hydro breakdown of O&A costs by cost element for 2023/24 compared to 2022/23

Figure 2. O&A by Cost Element

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
2022/23 vs 2023/24

(In thousands of $)	2022/23 Forecast	2023/24 Preliminary Budget	Variance	%	Ref
Employee Related Expenditures					
Wages & Salaries	$ 458 803	$ 482 838	$ 24 035	5%	1
Overtime	62 639	64 480	1 841	3%	
Employee Benefits	152 528	158 807	6 279	4%	
Other	72 699	82 588	9 889	14%	2
Total Employee Related Expenditures	746 668	788 713	42 045	6%	
Less: Capitalized Labor & Overhead	(247 909)	(256 238)	(8 329)	3%	
Operational Employee Related Expenditures	498 759	532 475	33 716	7%	
Materials & Tools	31 665	33 696	2 031	6%	3
Consulting & Professional Fees	25 050	47 809	22 759	91%	4
Construction & Maintenance Services	29 926	33 642	3 715	12%	5
Building & Property Costs	34 233	37 615	3 382	10%	6
Equipment Maintenance & Rentals	20 771	23 446	2 675	13%	7
Consumer Services	7 945	7 973	28	0%	
Customer & Public Relations	1 651	2 018	368	22%	
Sponsored Memberships	1 770	1 920	150	8%	
Computer Services	8 298	12 362	4 065	49%	8
Communication Systems	1 771	1 830	59	3%	
Research & Development Costs	2 333	2 333	-	0%	
Administrative Services	6 557	6 519	(38)	-1%	
Donations, Sponsorships & Grants	1 756	1 712	(44)	-2%	
Collections Costs	9 170	9 170	-	0%	
Other	(713)	(1 192)	(479)	67%	
Cost recoveries	(21 939)	(19 026)	2 913	-13%	9
O&A charged to gas operations	(70 000)	(77 100)	(7 100)		
Operating & Administrative Expenses	**$ 589 000**	**$ 657 200**	**$ 68 200**	**12%**	

[46] Manitoba Hydro responses to PUB IRs, PDF page 298, PUB/MH I-62c) Figure 2.

4.1.2 Reasonableness of applied for labour and consulting costs

Q: Are the applied for increases in labour and consulting costs reasonable and supported by evidence?

A: No. I have extensive experience reviewing forecast operating costs for Canadian utilities and the forecasts put forward by Manitoba Hydro are concerning for three reasons:

1. The increases appear to have limited quantitative evidence to support an activity-based escalation in costs consistent with the levels being forecast.
2. The forecast increase in costs would be disruptive to Manitoba Hydro if pursued and should, if indeed necessary, be phased in more gradually.
3. Some of the increases in consulting costs appear to be driven by software as a service cost, but the increase is unclear given that a portion of these costs are proposed to be addressed through deferral account treatment.

4.1.3 Evidentiary standard to support significant cost increases

Q: What evidence would be required to substantiate the applied for increase in costs?

A: The level of evidence required to support an increase in costs generally varies with the magnitude and nature of the increase being proposed. Some of the evidence to support increases in costs can include but is not limited to the following:

- Detailed cost benefit analysis for the pursuit of certain opportunities or projects.
- Reconciliations of the changes in both underlying activity levels and pricing, often referred to as a price-volume variance analysis.
- Benchmarking studies.
- Tracking of positions and full-time equivalents (FTEs) across periods.
- Business cases to support the addition of staff.
- Comprehensive needs assessments for certain consulting contracts and costs forecasted to be incurred.
- Detailed zero-based budgets developed from the bottom up to support requested increases in departmental costs.

In my experience, I have reviewed many of the above pieces of evidence to support applied for operating costs for a utility. Often all or most of the above are expected to be provided by a regulator where material cost increases are sought by the utility. This is the case as once costs are approved to be incurred it is quite difficult for those costs to be removed in a later period. As a surrogate for competition, regulation must ensure the utility only incurs those costs that are required to permit it to provide safe and reliable service to its customers.

Many changes related to operating and administrative costs can be attributed to a change in inflationary pressures from year-to-year. This is commonly the case for utilities which generally are mature entities without significant changes to their operational needs and thus underlying operating costs ordinarily trend with inflation. This is particularly the case for labour costs, which are ordinarily subject to some degree of inflation over time and commonly comprise the majority of a utility's operating costs, excluding fuel and purchased power. When this is the case, there is little that can be done to avoid cost increases absent cost cutting, as all entities are broadly impacted by changes in the broader economy.

Ideally, having a greater level of detail allows parties, such as myself, to analyze the nature of the requested costs to understand the specific business needs. Where detailed information is not available, which is generally the case in this matter, alternate means are necessary to assess the reasonableness of the request.

Manitoba Hydro's forecast costs present differently with significant forecast cost increases over recent levels. Additionally, as I discuss below, beyond explaining at a general level what the forecast increase relates to, there is minimal detailed evidence provided to support the applied for increase in costs. Finally, there appears to be no detail outlining why the proposed ramp up in spending over such a short period of time is appropriate and unavoidable. An alternative exists that warrants some consideration where the increases, some of which appear focused on ensuring reliability, which is important, are phased in over a more gradual period. This permits additional opportunities to identify cost savings and optimization, while also reducing secondary impacts on the organization.

4.1.4 Evidence provided by Manitoba Hydro to support forecast costs

Q: What evidence has Manitoba Hydro provided or not provided to support its forecast operating and administration costs?

A: The information provided by Manitoba Hydro generally is comprised of high-level explanations for why the increases are required by business unit for labour.[47] In the case of consulting costs, the information is also generally a high-level explanation.

Manitoba Hydro was asked to provide detailed activity-based rate and volume analysis to support its forecast costs, and in turn Manitoba Hydro advised the requested information was not available:

> Manitoba Hydro has provided the information it has available to support the O&A changes. Certain cost elements, such as Materials & Tools, Consulting & Professional Fees and Office Expenses, are comprised of numerous individual items with varying rate/volume impacts thus making a rate/volume analysis at a cost element level challenging due to the volume within each category.[48]

Manitoba Hydro also confirmed that it "does not track headcount information."[49] When asked to further explain this statement, Manitoba Hydro explained that it budgeted FTEs by position but does not report or track the requested information by position.[50]

Finally, Manitoba Hydro provided the step-by-step process it employed to budget its labour resources.[51] The process used to develop the labour budgets is one that can be characterized as a roll forward approach as opposed to a zero-based budgeting approach as I discuss below.

Specifically, rather than take a critical view of existing resources to understand the activity levels currently performed and obtain a better understanding of what is forecast to be

[47] Manitoba Hydro responses to PUB IRs, PDF page 303, PUB/MH I-62c) Figure 5.
[48] Manitoba Hydro responses to GSS/GSM information requests round 2, PDF page 11, GSS-GSM/MH II-3b).
[49] Manitoba Hydro responses to PUB IRs, PDF page 328, PUB/MH I-71b.
[50] Manitoba Hydro responses to GSS/GSM information requests round 2, PDF page 11, GSS-GSM/MH II-3c).
[51] Manitoba Hydro responses to GSS/GSM information requests round 2, PDF page 11, GSS-GSM/MH II-3c).

required and supported, Manitoba Hydro starts with the existing level of resources and largely adds to that level if required.

In conclusion, having reviewed the information provided by Manitoba Hydro, I conclude that the level of information provided by Manitoba Hydro is inadequate to support the forecast increases in labour and consulting costs. Specifically, as I discuss below, while some of the increase in costs may be necessary, I cannot objectively confirm based on a combination of qualitative and quantitative evidence that the costs are reasonable and necessary. Such evidence can only be provided by the party preparing the forecast, which in this case is Manitoba Hydro.

4.2 Zero-based budgeting

Q: Do you consider that Manitoba Hydro would benefit from a zero-based budgeting approach to forecasting its costs? If yes, please discuss the purpose of a zero-based budget and how it is developed.

A: Yes. The purpose of a proper zero-based budget is to obtain two key deliverables:

- The preparation of a budget that removes costs that are identified as not being necessary to the core operations of the entity.
- To provide for a budget that has a higher degree of accuracy when compared to actual costs.

Regarding the first item above, it is important to remember that a proper zero-based budgeting exercise is likely too onerous to perform on an annual basis.[52] This is because the exercise requires a significant amount of work to identify the core activities that the business must perform and confirm that those activities are being performed in the most efficient manner possible. Zero-based budgeting efforts require more effort than is generally required in a normal budgeting exercise. The level of increased effort would depend upon how rudimentary or complex an entity's budgeting processes are. In any

[52] For Manitoba Hydro, I do not recommend that the zero-based budgeting approach, if adopted, be approved for the entirety of Manitoba Hydro all at once or that it be performed on an annual basis.

event, simply starting from an “assumed zero-base” is not a zero-based budgeting exercise as it is truly intended.

Rather, a zero-based budgeting exercise requires a concerted effort to not only line up FTEs with activities, but to also understand whether there are more efficient means of executing those activities. For example, efficiencies could be obtained by having two individuals do the work that three previously did or by removing levels of management within the entity and redelegating authority levels to reduce the need for potentially duplicative management and review of resources and the work the resources perform. Finding efficiencies through a zero-based budgeting exercise requires significant detailed efforts from all employees.

For example, employees would be encouraged to communicate with those preparing the budgets to explain and understand whether there are any efficiencies (perceived or actual) that could be obtained from the work that is being performed, and whether there are any recommendations that the budgeting group should consider. Importantly, the exercise is not simply management attempting to develop a forecast, but rather the development of that forecast requires direct input from the employees to substantiate the level of effort that is required for each activity. This is the bottom-up component of the process.

The top-down component of the zero-based budgeting exercise requires senior management to further challenge employees and management to find additional efficiencies by setting defined budgets. For example, a department proposes costs of $11.0 million and management advises that the department is only approved costs of $10.0 million. This top-down approach drives employees to find all possible efficiencies before seeking approval from senior management to increase the cap.

Regarding the second item, a key expectation from a true zero-based budgeting exercise would be that there is a higher degree of accuracy of the forecasts. In fact, a proper zero-based budgeting exercise, if implemented aggressively, will likely result in a budget that the entity has difficulties achieving in the first year following the zero-based budgeting efforts. This is because the exercise is intended to identify known, anticipated or possible efficiencies within the activities being performed. It is also intended to provide clear incentives to management and employees to seek out further efficiencies given that the efficiencies are already embedded into the forecasts.

In my opinion, entities are more likely to work harder to find all possible efficiencies if the budget is already reduced, as opposed to if the budget is inflated. Put differently, no manager wants to have its shareholder bear additional operating costs if they are not truly necessary. This is why it is important for budgets prepared by Manitoba Hydro to demonstrate that it includes all known and possible efficiencies, particularly where cost increases are being proposed.

With the above context on the purpose of the zero-based budgeting exercise I will now outline the steps in the process. The first step in a zero-based budgeting exercise is to define the core questions that must be answered of each FTE (internal or external) and activity being performed within the entity. The following are the questions that would need to be addressed:

i. If the work being performed by this FTE (internal or external) is not completed, or the activity being forecast is not incurred, how will this directly impact the entity's ability to provide safe, reliable and cost-effective services to ratepayers?

ii. If the work performed by the FTE (internal or external) or the activity being forecast is not directly required to provide safe, reliable and cost-effective service to ratepayers and instead relates to a support role, if that support role is removed, will it directly impact the efforts of those FTEs directly working to provide safe, reliable and cost-effective services to ratepayers?

In support of answering each of the questions, there is a need for significant detailed information. Specifically, in addition to the above core questions, there are a series of steps that would be required. I note that many of the steps outlined below were performed by investor-owned utilities where I was previously employed.

i. A series of detailed Excel spreadsheets are prepared for each cost centre within the entity. Each spreadsheet includes the following information:

   a. The positions of each employee within the cost centre;

b. For each position, a detailed breakdown of the historical actual salaries, bonuses and other non-health and dental related benefits that the employee is entitled to. Note: For health and dental benefits, given the privacy of the information, this information is also calculated on a per employee basis but is often done separately within the Human Resources department and provided as an aggregate cost at the end of the budgeting cycle;

c. For each position, a detailed breakdown of the historical actual direct costs related to the employee is prepared, including costs related to travel, meals, training and other similar costs that can be directly attributed to an FTE;

d. For each position, an allocation of historical actual indirect costs related to each FTE is prepared, including other office expenses such as printing costs, information technology costs, rent, and other similar costs;

e. A detailed listing of each external contractor that provided services in the prior period, the services that were provided and why those services were required to provide safe, reliable and cost-effective service to ratepayers; and

f. Any other information relating to a direct or indirect cost incurred in relation to an FTE is summarized as relevant to each individual cost centre.

ii. Using these spreadsheets, each cost centre manager would then be expected to prepare the following further information in relation to the specific activities that would need to be performed in the cost centre:

a. A clear definition of the activities that the cost centre is required to complete in the forecast period, including an explanation of why those activities align with the key questions outlined above;

b. A detailed quantification of the expected amount of effort, in hours, that is expected to be required to perform the activities in the forecast period, including the basis for any calculations being performed;

c. A detailed explanation of why each of the activities cannot be performed through alternate lower cost means, such as by automating the activity through an IT solution or having the work outsourced to an external third party;

d. A detailed explanation of what the direct impact would be on the business if the forecast volume of work were reduced below the current forecast levels and how those levels compare to prior year efforts; and

e. For any activities forecast to be performed by external resources, an explanation of why obtaining that work from an external source results in the lowest cost option available to the entity, complete with all qualitative and quantitative information supporting the decision to use an external resource to perform the required work.

iii. Using the above activity information, the cost centre manager would then provide the following further information for each FTE and external resource:

a. Starting with each activity, the expected work level would be assigned down to each FTE (or external resource), and would include, if necessary, an assumption around expected overtime, whether paid or not, to complete the expected volume of work, or in the case of external resources, the hourly rate and forecast hours. If the work is general in nature and of a high volume, such as 10,000 hours for line patrols, then the activities would not need to be assigned to a specific FTE (or external resource) unless it is known that the FTE (or external resource) will be performing that work. Instead, in this case, the work can be evenly allocated amongst the group of FTEs (or external resources) that are forecast to do a portion of the work;

b. Once all the activities, broken down by hour, are assigned to each FTE and external resource, then the cost centre manager would review the assignment to determine if there are any FTEs that have excess capacity or if there are any underutilized FTEs. For employees with excess capacity, the cost centre manager would need to explain why it would not be appropriate to retain the employee on either an hourly or part-time basis to address the excess capacity. For all employees from prior years that are not assigned activities, the cost centre manager would need to remove the FTEs from the budget and provide for a precise forecast of the severance costs required for each position. No additional efforts would be required for external resources as it is assumed that they would only be paid for work that was actually performed;

c. Once the activities are assigned and the resources are known, then the cost centre manager would assign to each of the forecast FTEs all direct costs, such as travel, meals and entertainment and training. In conjunction with assigning these direct costs, the cost centre manager would be expected to provide specific details by FTE, such as the specific training or travel that is forecast, and why the costs are required per the above two key questions listed above; and

d. The cost centre manager would finally provide for an allocation of both the variable and fixed indirect costs related to its cost centre to each of the FTEs, and if necessary, any external resources, such as in-house contractors.

iv. After the above work is completed, there would be a series of reviews conducted, including:

a. The cost centre manager's work and detailed analysis would first be reviewed by the cost centre manager's immediate supervisor;

b. Once complete, the Excel workbook would be sent to the Forecasting and Budgeting department where the group would ask a series of detailed questions to test the assumptions that were made in respect of the activities identified and whether all efficiencies, including known, anticipated or possible efficiencies, were identified and incorporated into the forecasts. For example, assumptions around individual forecast salary increases for each FTE or forecast rate increases for each external contractor would be reviewed for appropriateness having specific regard for the business needs and thus the necessity for those increases; and

c. Finally, all decisions and activities would be reviewed by the Chief Financial Officer who would again ask a series of questions, similar to those outlined above, in respect of each budget, including any budget prepared by the Chief Executive Officer.

Once approved as final, the individual budgets would be aggregated into a single detailed budget. Often the core spreadsheets are based on a template, and thus each spreadsheet can be inserted into a summary model that aggregates the information by department.

I need to reemphasize that a zero-based budget is intended to get down to the base level of activities and work that an entity is required to perform in any given year. Every single cost is scrutinized at a detailed level, with input from employees to determine that every possible efficiency is obtained. Further, zero-based budgeting often builds in an expectation that further efficiencies are expected to be achieved, and those efficiency gains may be linked to incentives such as variable compensation.

In conclusion, for the above reasons, it is likely that a zero-based budget may not be easily achievable in the first year it is implemented. By this I mean the actual results may be higher than the budget. This is because management subsequently identifies other core activities that need to be performed that were not considered in the original budget and does not have sufficient excess capacity to perform those activities with the budgeted FTEs and external resources. However, these increases can be offset by unidentified efficiencies as well. This is why a zero-based budgeting exercise is time consuming and different from a more basic budgeting exercise as performed by Manitoba Hydro.[53] It is important to define all activities and ensure that the proper efficiencies are built in, and incentives provided to ensure the organization works toward achieving that budget.

Given the level of effort required to conduct a proper zero-based budget, and subsequent monitoring of that budget, I note that it would likely be beneficial to afford a utility, at minimum, one year to prepare the budget. Additionally, I note that a zero-based budget does not necessarily need to be employed for the entire business in the same year. While

[53] For clarity, my understanding of Manitoba Hydro's budgeting process is based on the explanation provided by Manitoba Hydro in its information responses. Based on that understanding it does not appear that Manitoba Hydro currently applies a zero-based budgeting approach as I outline in my evidence. However, I am not suggesting that detailed budgeting information may not be available to Manitoba Hydro in certain circumstances.

ideal as it ensures the business is working as a whole to achieve broad efficiencies and remove any redundancies, another alternative is to employ a rotating cycle of different cost centres. For example, one third of the business transitions to a proper zero-based budgeting process each year, with all operations transitioning fully in three years.

4.3 Labour costs

4.3.1 Introductory comments on labour costs

Q: Are the applied for labour costs for Manitoba Hydro reasonable?

A: Overall, for labour costs, I accept that some increase in costs may be reasonable to support continued reliability for Manitoba Hydro. Specifically, Manitoba Hydro provided the following table of FTEs which indicates that a majority of the increase in FTEs relates to operations staff:[54]

Table 4 – Manitoba Hydro straight time FTE by business unit (2013/14 to 2024/25)

Figure 1. Straight Time FTE by Business Unit

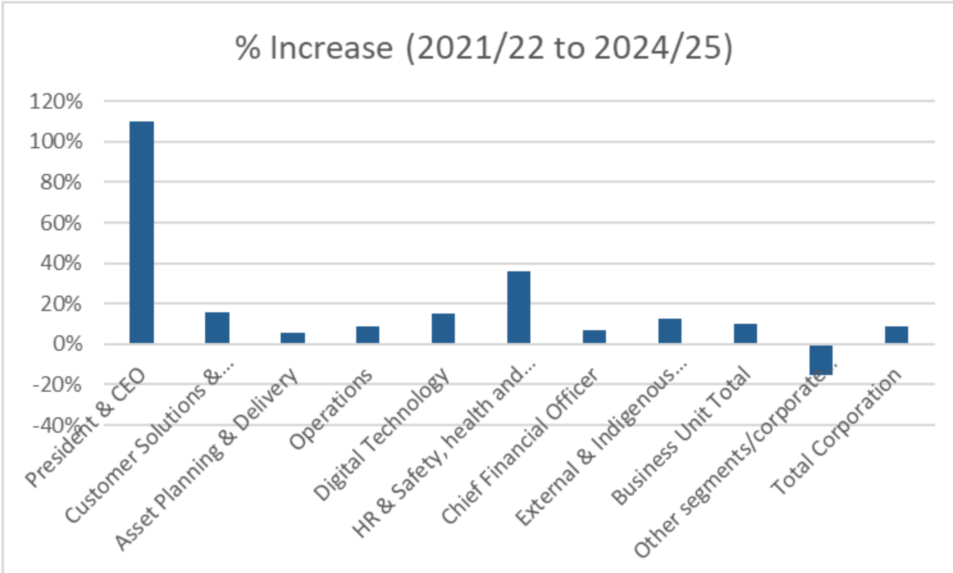
MANITOBA HYDRO
STRAIGHT TIME FULL TIME EQUIVALENT (FTE) EMPLOYEES BY BUSINESS UNIT

	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Actual	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget
President & CEO	14	15	14	14	10	9	8	8	10	19	21	21
Customer Solutions & Experience	520	498	484	475	428	377	373	317	316	355	363	365
Asset Planning & Delivery	1,711	1,731	1,771	1,848	1,776	1,586	1,509	1,352	1,236	1,272	1,282	1,307
Operations	3,008	2,946	2,875	2,804	2,600	2,427	2,407	2,253	2,386	2,533	2,550	2,598
Digital & Technology	314	308	295	288	272	252	249	237	237	246	263	273
HR & Safety, Health and Environment	181	171	176	178	164	150	159	149	154	168	188	209
Chief Financial Officer	500	493	479	465	410	346	352	335	349	364	368	372
External & Indigenous Relations and Comm	126	125	132	129	118	115	116	103	111	122	123	125
Business Unit Total	**6,374**	**6,287**	**6,226**	**6,201**	**5,778**	**5,262**	**5,173**	**4,753**	**4,799**	**5,079**	**5,158**	**5,270**
Other Segments/Corporate Adjustments	182	196	184	210	220	213	220	201	163	96	140	138
Total Corporation	**6,556**	**6,483**	**6,410**	**6,411**	**5,998**	**5,475**	**5,393**	**4,954**	**4,962**	**5,175**	**5,298**	**5,409**

From 2021/22 actual to 2024/25 preliminary budget, FTE levels increase by 447 FTEs (5,409 - 4,962) or 9% of the entire staff compliment. Of the 447 FTE increase, 212 (2,598 – 2,386) is related to the Operations department, but all departments are increasing as shown in the figure below:

[54] Manitoba Hydro responses to PUB IRs, PDF page 303, PUB/MH I-64a) Figure 1.

Figure 12 – Percentage increase in FTE levels from 2021/22 to 2024/25



The above figure is based on the data below:

Table 5 – Summary of changes in FTEs from 2021/22 to 2024/25

	Increase (2021/22 to 2024/25)	% Increase (2021/22 to 2024/25)
President & CEO	11	110%
Customer Solutions & Experience	49	16%
Asset Planning & Delivery	71	6%
Operations	212	9%
Digital Technology	36	15%
HR & Safety, health and Environment	55	36%
Chief Financial Officer	23	7%
External & Indigenous Relations and Communications	14	13%
Business Unit Total	**471**	**10%**
Other segments/corporate adjustments	- 25	-15%
Total Corporation	**446**	**9%**

As shown in the figure and table above, the FTE levels are increasing significantly across all business units. While Operations is the largest driver, several other business units are experiencing material increases such as the President & CEO which increase 110% to levels not seen historically. For the Operations group, Manitoba Hydro explains:

> Manitoba Hydro has extensive training programs to train and develop its trades staff as these specialized skills are generally not available on the

> contractor market. As identified in Figure 6.4, Tab 6 of the Application, Manitoba Hydro slowed down the hiring of trades trainees following the announcement of the Voluntary Departure Program and had to halt hiring in 2020/21 due to the government cost savings measures at that time. At the same time, Manitoba Hydro saw high levels of attrition, adding to a decrease in fully trained and experienced employees required to do maintenance work. While the trades trainee program has restarted, it takes two to four years to fully train new hires. Manitoba Hydro is increasing the hiring of trades trainees in the Test Years to help rebound to sustainable levels. Losing valuable trade experience results in additional challenges associated with using more junior staff to trouble shoot equipment deficiencies and increased response time to address breakdown of older equipment.[55]

Manitoba Hydro also states:

> Manitoba Hydro's recruitment plans are focused on addressing this potential level of turnover and the associated internal churn that arises from these changes. The increase in FTEs allows Manitoba Hydro to hire staff to be trained and ready to address anticipated levels of attrition.[56]

I accept the above explanation in part. This acceptance is informed in part by the SAIDI and SAIFI information adjusted for weather and transmission system interruptions which shows some negative trends.[57] Despite these negative trends, the SAIDI and SAIFI levels for Manitoba Hydro are not unusual when compared to the Electricity Canada peers.[58] This may suggest the ramp up in staffing can be phased in over a longer period of time to match retirements with new positions better and provide a staged approach to training the new staff.

[55] Manitoba Hydro responses to PUB IRs, PDF page 395, PUB/MH I-83a.
[56] Manitoba Hydro responses to PUB IRs, PDF page 396, PUB/MH I-83c.
[57] Manitoba Hydro responses to PUB IRs, PDF pages 402 to 404, PUB/MH I-85a-c.
[58] Manitoba Hydro responses to PUB IRs, PDF pages 402 to 404, PUB/MH I-85a-c.

I remain concerned that the forecast increase in Operations FTEs could be disruptive to Manitoba Hydro's business. Hiring and training new staff is time intensive and increasing FTE levels by 212 FTEs or 9% in such a short period of time will be difficult to achieve practically. Finding qualified individuals to fill the vacancies, including training new staff, will not be an easy task. Even assuming Manitoba Hydro can identify 212 qualified staff, not accounting for other turnover that is likely to occur, the efforts to onboard those staff will be significant. It appears Manitoba Hydro has contemplated this effort in part with an increase in human resource staff of 55 or 36% as shown above.

Notwithstanding the above, the cumulative increases across every business unit appear to be unlikely to be achieved and overly optimistic at best, and at worst, unnecessary. However, absent more detailed budgeting information, as discussed earlier, I am unable to conclude definitively that all of the forecast level of staff is necessary at this time.

4.3.2 Review of salary escalation rates

Q: Please comment on Manitoba Hydro's proposed salary escalation rates in the test years.

A: To support the components of its forecast labour cost increase, Manitoba Hydro provided the following table:[59]

[59] Manitoba Hydro responses to PUB IRs, PDF page 351, PUB/MH I-78a.

Table 6 – Manitoba Hydro breakdown of wages and salaries

Wages & Salaries Analysis (2020/21 to 2024/25)

	2020/21 Actual	2021/22 Actual	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget
Gross Wages & Salaries	440,808	448,464	508,482	554,490	569,166
Vacancy Allowance	-	-	(49,679)	(71,652)	(64,157)
Wages & Salaries	**440,808**	**448,464**	**458,803**	**482,838**	**505,009**
Wages & Salaries Analysis:					
Prior Year Balance		440,808	448,464	458,803	482,838
GWI for Previous Years - IBEW		(3,471)			
Merit/Progression		4,942	6,121	5,958	6,764
GWI and Provisions for GWI		4,835	-	5,724	7,593
Change in Vacancy Allowance		-	(49,679)	(21,972)	7,495
FTE Normal Operating Changes & Other		1,349	53,897	34,326	319
Wages & Salaries	**440,808**	**448,464**	**458,803**	**482,838**	**505,009**

As shown above, the major driver of increase in salaries and wages is an addition of staff as discussed earlier, partially offset by increases in vacancy rates. I discuss the vacancy rates in further detail below.

As it pertains to salary escalation, Manitoba Hydro appears to be proposing reasonable merit and progression salary increases. Based on the above information, the merit and progression increase forecast appears to be approximately 1.3% (5,958/458,803) in 2023/24 and 1.4% (6,764/482,838) in 2024/2025. Similarly, the gross wage increase (GWI) is forecast to be approximately 1.2% (5,724/458,803) in 2023/24 and 1.6% (7,593/482,838) in 2024/2025.

An increase in salaries and wages for these drivers appears reasonable and supported. In general, I would expect salaries to keep pace with inflation in the long term, and this level of salaries should permit Manitoba Hydro to remain competitive in its ability to retain resources going forward, keeping in mind the historical level of increases.[60] Importantly, the salary increases being forecast are not an unreasonable contributor to the forecast increases in the test period.

[60] Manitoba Hydro responses to GSS/GSM IRs, PDF page 37, GSS-GSM/MH I-3a) Figure 2.

4.3.3 Review of proposed vacancy rates and FTE increases

Q: Please comment on Manitoba Hydro's proposed vacancy in the year.

A: The vacancy rate is designed to measure the number of positions in a year that are vacant as reflected in the full-time equivalents. For example, if there are 100 positions and 95 FTEs throughout the entire year, then the vacancy rate would be 5%. A common practice is to forecast a vacancy rate that reflects standard expectations of vacancies in the business based both on historical experience and forecast needs.

Manitoba Hydro's vacancy (attrition) rate per year has averaged above 5% as shown in the Table below:[61]

Table 7 – Manitoba Hydro employee attrition data

Figure 2. Manitoba Hydro Employee Attrition Data

	Calendar Year						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Voluntary	0.78%	1.59%	1.64%	1.65%	1.98%	1.53%	1.84%
Involuntary	0.25%	0.31%	0.17%	0.39%	0.21%	0.04%	0.15%
Job Completion	0.19%	0.47%	0.33%	0.28%	0.68%	0.24%	0.19%
Retirement	3.30%	4.14%	8.75%	3.09%	3.95%	2.78%	3.19%
Other	0.22%	0.10%	0.28%	0.13%	0.37%	0.22%	0.50%
Total Attrition %	4.75%	6.60%	11.17%	5.53%	7.19%	4.81%	5.88%

Regarding forecast vacancies, as shown below, Manitoba Hydro has explained that it expects to have vacancies of 14% and 13% in 2023/24 and 2024/25, respectively.[62] Importantly, Manitoba Hydro explains that it also budgeted an enterprise-wide vacancy factor of 66 FTEs for 2022/23 in addition to the vacancies by business unit as provided below:[63]

[61] Manitoba Hydro responses to PUB IRs, PDF page 307, PUB/MH I-65b) Figure 2.
[62] Manitoba Hydro responses to GSS-GSM IRs, PDF page 48, GSS-GSM/MH I-5b.
[63] Manitoba Hydro responses to GSS-GSM IRs, PDF page 48, GSS-GSM/MH I-5b.

Table 8 – Manitoba Hydro summary of vacancies by business unit

MANITOBA HYDRO
STRAIGHT TIME FULL TIME EQUIVALENT (FTE) EMPLOYEES VACANCY

	2022/23 Forecast				2023/24 Preliminary Budget				2024/25Preliminary Budget			
	Gross FTE	Vacancy Factor	Net FTE	Vacancy %	Gross FTE	Vacancy Factor	Net FTE	Vacancy %	Gross FTE	Vacancy Factor	Net FTE	Vacancy %
President & CEO	19	0	19	0%	22	1	21	3%	22	1	21	3%
Customer Solutions & Experience	374	19	355	5%	440	77	363	17%	442	77	365	17%
Asset Planning & Delivery	1,429	157	1,272	11%	1,558	275	1,282	18%	1,569	262	1,307	17%
Operations	2,782	249	2,533	9%	2,927	377	2,550	13%	2,928	330	2,598	11%
Digital & Technology	273	27	246	10%	296	32	263	11%	303	30	273	10%
HR & Safety, Health and Environment	175	7	168	4%	237	49	188	21%	238	29	209	12%
Chief Financial Officer	386	22	364	6%	400	32	368	8%	401	29	372	7%
External & Indigenous Relations and Comm	127	5	122	4%	135	12	123	9%	135	10	125	7%
Business Unit Total	**5,565**	**486**	**5,079**	**9%**	**6,014**	**856**	**5,158**	**14%**	**6,037**	**767**	**5,270**	**13%**

In addition to the above table, Manitoba Hydro provided a listing of all positions that have been vacant for more than one year as of March 10, 2023.[64] Based on that listing there are more than 100 positions that have been vacant for more than a year with one having been vacant for more than 10 years (i.e., 3,760 days).

Based on the above information I have two concerns. First, the level of vacancies being forecast is significant and not an ordinary level of vacancy, either for Manitoba Hydro historically or for other Canadian utilities in general. Second, this high level of vacancy appears to be largely driven by a forecast increase in positions, not all of which appear to be necessary.

The above information confirms my recommendation that Manitoba Hydro would benefit from implementing a zero-based budgeting effort to forecast its resources going forward. A zero-based budgeting process could significantly reduce the level of existing positions to a more manageable level while also providing Manitoba Hydro with greater control over its current and forecast resources.

4.3.4 Recommended labour cost forecast for the test period

Q: What level of labour-related operating and administrative costs do you consider to be reasonable and supported for Manitoba Hydro in the test period?

[64] Manitoba Hydro responses to GSS-GSM IRs Round 2, PDF pages 16 to 19, GSS-GSM/MH I-5c.

A: Some increases such as a 110% increase in the President & CEO business unit, as shown in Figure 12, appear to have minimal support for the change. As shown in Table 6, Manitoba Hydro is forecasting a $53.9 million increase in FTEs in 2022/23 at the same time as it forecasts a $49.7 million increase in vacancies. The net increase in FTEs is $4.2 million in 2022/23 which is an increase of 0.9% ($4.2 million/$448.6 million).

While I disagree with Manitoba Hydro's proposal to increase both FTEs and vacancy by such significant levels, for the reasons discussed above, I accept that some moderate level of increase in overall FTEs is appropriate given the historically low levels and need to replace and train new staff. Therefore, I am supportive of the net change in FTE levels in 2022/23 as being reasonable and a starting point for the test period.

The 2023/24 net increase in FTE costs is $12.4 million ($34.3 million - $21.9 million). This change is more significant and represents a net increase in opening labour costs of 2.7% ($12.4 million/$458.8 million) before taking into consideration other salary escalation pressures discussed earlier. Similarly, in 2024/25 there is a net increase in FTE costs of $7.8 million ($0.3 million + $7.5 million) or 1.6% ($7.8 million/$482.8 million).

In response to a Coalition request, Manitoba Hydro outlines the costs it has no control over but increasing staffing levels is not one of them.[65] By far the most significant increase in costs is staffing levels as discussed above.

For the above reasons, I recommend that the PUB approve an increase in net FTE costs of only 1% per year related to increases in FTEs and offsetting vacancies. A rate of growth of 1% aligns with the forecast rate of growth in 2022/23. Further, a 1% increase in net FTEs should permit a more manageable increase in FTE levels over time for Manitoba Hydro. Limiting 2023/24 to a 1% increase provides the following revised salary and wages:

[65] Manitoba Hydro responses to Coalition IRs, PDF pages 36 and 37, COALITION/MH I-6h.

Table 9 – Summary of recommended labour changes (2023/24 and 2024/25)

($ 000s)	**2023/24**	**2024/25**
Prior year balance	458,803	475,073
Merit/Progression (@ applied for rate)	5,958	6,655
GWI and provisions for GWI (@ applied for rate)	5,724	7,471
Net increase in FTEs (FTE additions - vacancy)	4,588	4,751
Recommended wages & salaries	**475,073**	**493,950**
Applied for wages & salaries	**482,838**	**505,009**
Difference	**(7,765)**	**(11,059)**

As a final point, I emphasize that the above recommendation is based largely on the high-level evidence provided by Manitoba Hydro, some of which supports an increase, but much of which does not convince me of the magnitude of the increase proposed. My recommendation might be different were I able to review more detailed activity-based information to support the forecast costs.

4.4 Consulting costs

Q: What level of consulting-related operating and administrative costs do you consider to be reasonable and supported for Manitoba Hydro in the test period?

A: The primary issue with consulting-related operating and administrative costs is the limited detail providing a breakdown of current, historical and forecast costs by driver and activity. The greatest level of detail available is provided in the table below:[66]

Table 10 – Manitoba Hydro breakdown of consulting services costs

Figure 1. External Services and Materials by Cost Element (2012/13 to 2024/25)

(C$000s unless otherwise stated)	2012/13 Actual	2013/14 Actual	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Actual	2019/20 Actual	2020/21 Actual	2021/22 Actual	Compound Annual Growth 2012/13-2021/22	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget	Compound Annual Growth 2021/22-2024/25
Materials & Tools	24 827	27 939	24 723	26 264	25 389	24 451	27 040	29 133	30 067	34 740	3.8%	31 665	33 696	34 801	0.10%
Consulting & Professional Fees	10 817	14 657	16 154	15 311	15 840	10 746	12 986	12 639	9 694	15 409	4.0%	25 050	47 809	50 564	48.60%
Construction & Maintenance Services	16 392	16 944	17 969	16 991	16 821	18 904	21 712	22 500	20 493	23 524	4.1%	29 926	33 642	35 056	14.20%
Building & Property Costs	26 781	30 022	30 427	29 193	29 039	30 211	30 668	29 069	31 543	35 622	3.2%	34 233	37 615	38 673	2.80%
Equipment Maintenance & Rentals	14 680	15 007	17 118	18 750	18 734	19 142	19 581	20 213	19 425	21 302	4.2%	20 771	23 446	24 079	4.20%
Consumer Services	5 050	5 277	5 189	5 255	5 236	5 452	5 402	6 822	6 647	7 673	4.8%	7 945	7 973	8 078	1.70%
Customer & Public Relations	2 382	1 964	2 223	2 304	2 227	1 716	1 399	1 452	847	1 097	-8.3%	1 651	2 018	2 078	23.70%
Sponsored Memberships	1 767	1 249	1 550	1 703	1 677	1 651	1 729	1 760	1 681	1 631	-0.9%	1 770	1 920	1 921	5.60%
Computer Services	849	678	967	1 152	967	817	1 014	1 939	3 096	6 675	25.8%	8 298	12 362	15 230	31.70%
Communication Systems	1 817	1 963	1 705	1 736	1 668	1 699	1 270	1 465	1 528	1 634	-1.2%	1 771	1 830	1 673	0.80%
Research & Development Costs	3 372	2 195	2 534	2 903	2 355	1 985	1 763	2 040	1 688	2 209	-4.6%	2 333	2 333	2 333	1.80%
Administrative Services	5 539	5 517	6 293	6 149	6 071	6 068	5 774	6 099	5 712	7 083	2.8%	6 557	6 519	6 527	-2.70%
External services and materials	**$ 114 274**	**$ 123 412**	**$ 126 850**	**$ 127 711**	**$ 126 024**	**$ 122 843**	**$ 130 338**	**$ 135 132**	**$ 132 421**	**$ 158 598**	3.7%	**$ 171 968**	**$ 211 162**	**$ 221 014**	11.70%

[66] Manitoba Hydro responses to PUB IRs, PDF page 299, PUB/MH I-62b) Figure 1.

The forecast increases in consulting costs are alarming with a compound annual growth rate of 48.60% from 2021/22 to 2024/25 as compared to the historical rate of 4% from 2012/13 to 2021/22. Variance explanations to understand the applied for increases are limited, with the following explanation referring to cloud computing arrangement costs being the primary driver for the observed increase in costs:

> The increase is due primarily to costs associated with both the accounting rule treatment changes for cloud computing arrangements and an increase in cloud-based services. Also contributing to the increase are costs related to the Enterprise Technology Security Assessment Program, which occurs every three years, and an increase in consulting and professional fees related in part to northern attraction and retention initiatives.[67]

The same explanation that consulting fees are increasing due to cloud computing arrangement costs is repeated several other times.[68] Notwithstanding the various explanations provided, it is unclear how the items identified in the explanations are directly related to the breakdown provided or how each of the explanations directly contribute to the observed increases.

Absent clear evidence for a demonstrable need to increase consulting fees of this magnitude, I recommend that the consulting fees be limited to increases of 4% per year, which is consistent with the historical rate of growth and should provide ample incremental funds to support Manitoba Hydro's needs. In making this recommendation, I accept that some of the applied for increase is due to the forecast increase in cloud computing arrangement costs other than SAP costs, which are proposed to be expensed by Manitoba Hydro per the table below:[69]

[67] Manitoba Hydro responses to PUB IRs, PDF page 301, PUB/MH I-62b) Figure 3.
[68] For example, Manitoba Hydro responses to PUB IRs, PDF page 312, PUB/MH I-67 Figure 2.
[69] Manitoba Hydro responses to PUB IRs, PDF page 165, PUB/MH I-29b, Figure 2.

Table 11 – Manitoba Hydro breakdown of cloud-computing arrangement costs (2023/24 to 2030/31+)

MANITOBA HYDRO
CLOUD COMPUTING ARRANGEMENTS (OPERATIONAL EXPENSES)

($000)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31+
Integration Expenses:								
SAP S/4HANA	$10,986	$20,067	$21,181	$21,181	$22,071	$22,071	$20,089	$0
Small Software Systems[1]	11,300	6,750	6,750	6,750	6,750	6,750	6,750	6,750
Total Integration Expenses	**22,286**	**26,817**	**27,931**	**27,931**	**28,821**	**28,821**	**26,839**	**6,750**
Operating Expenses:								
SAP S/4HANA	0	0	0	0	0	0	0	8,918
Small Software Systems[2]	5,552	5,663	TBD	TBD	TBD	TBD	TBD	TBD
Total Operating Expenses	**5,552**	**5,663**	**0**	**0**	**0**	**0**	**0**	**8,918**
Total CCA Operational Expenses	**$27,838**	**$32,480**	**$27,931**	**$27,931**	**$28,821**	**$28,821**	**$26,839**	**$15,668**

As noted in Section 5 below, I recommend that the cloud computing arrangement costs related to other non-SAP costs also be included in the deferral account. I have accounted for this endorsement in my recommendation below:

Table 12 – Summary of recommended consulting cost reduction

($ 000s)	2021/22	2022/23	2023/24	2024/25
Consulting fees as applied for	**15,409**	**25,050**	**47,809**	**50,564**
Other CAA costs deferred (Section 4.3)			(11,300)	(6,750)
Revised level of costs	**15,409**	**25,050**	**36,509**	**43,814**
Recommended level based on escalation of 2021/22 costs @ 4%		**16,025**	**16,666**	**17,333**
Difference for 2023/24 and 2024/25			**(19,843)**	**(26,481)**

The reduction I have outlined above is based on 2021/22 actual costs to date which are higher than the actual costs incurred in recent years. I note that while Manitoba Hydro provided an update to the PUB for quarterly 2022/23 results, that update did not provide a specific amount for consulting services adjusted for cloud-computing arrangement costs.[70] Subject to review, I may accept updated 2022/23 consulting fees as the basis to escalate for future years if that level were adjusted for the cloud-computing arrangement costs. Similarly, I may accept adjustments to my recommendation if further evidence on the need

[70] Manitoba Hydro responses to the PUB IRs, PDF page 338, PUB/MH I-74a (Updated), Figure 1.

for incremental cloud-computing arrangement software costs are identified as I discuss in Section 5. However, based on current information I do not believe such a determination can be made.

Further, as part of my calculations, I assume two things:

i. "Other CAA costs deferred" as reported by Manitoba Hydro is entirely comprised of consulting fees. I note that this may not be the case and a portion of the costs may be labour and licensing costs, which may be classified to other areas. Therefore, my assumptions may change if additional information regarding the above adjustments were known.

ii. I assume that all SAP S/4 HANA costs related to consulting have already been removed and deferred from the consulting fees. If this adjustment has not been made or is made elsewhere in the financial statements for Manitoba Hydro, then my recommendation may differ.

5 Digital and technology costs

5.1 Introductory comments on digital and technology costs

Q: What are your concerns with Manitoba Hydro's applied for information and technology costs?

A: Manitoba Hydro is going through a transformative period, with information technology, also referred to as digital and technology (D&T) costs by Manitoba Hydro, representing a significant driver and facilitator of change. Notwithstanding the broader plan in place at Manitoba Hydro I have several concerns with Manitoba Hydro's forecast D&T costs, including:

- Manitoba Hydro is requesting significant cost increases many of which are unsupported by evidence that would be expected given the commensurate cost increase.
- Manitoba Hydro's proposed transition to SAP S4/HANA and the related costs ($150 million+) is highly preliminary and not supported by evidence.

- Manitoba Hydro has proposed a deferral account for certain SAP cloud computing arrangement (CCA) costs but not similar costs for small software systems.

5.2 Increases in costs to digital and technology are not well understood

Q: Should the PUB approve Manitoba Hydro's accelerated costs related to information and digital technology?

A: No. Many Canadian utilities are experiencing information technology cost pressures due to a combination of cyber security needs, work-from-home technology expectations driven by the pandemic, and a desire to accelerate transformation in certain technologies (i.e., cloud computing). Despite these pressures most Canadian utilities are attempting to take a more pragmatic and incremental approach to information technology costs, where the following table summarizes the trajectory of Manitoba Hydro's actual and forecast costs:[71]

Table 13 – Manitoba Hydro's actual and forecast digital technology costs (2020/21 to 2024/25)

Figure 3 – Digital & Technology Costs and Straight Time FTE for D&T and Manitoba Hydro

MANITOBA HYDRO *(in Millions)*	2020/21 Actuls	2021/22 Actuals	2022/23 Forecast	2023/24 Preliminary Budget	2024/25 Preliminary Budget
D&T O&A	$42	$55	$52	$81	$88
D&T Capital	$16	$19	$26	$18	$18
D&T Depreciation	$27	$28	$29	$30	$30
FTE - Corporation	4,954	4,962	5,175	5,298	5,408
FTE - D&T	237	237	246	263	273
(Cost ratio in Millions)					
O&A per Corp. FTE	$0.009	$0.011	$0.010	$0.015	$0.016
Capital per Corp. FTE	$0.003	$0.004	$0.005	$0.003	$0.003
Depreciation per Corp. FTE	$0.005	$0.006	$0.006	$0.006	$0.006
O&A per D&T FTE	$0.178	$0.232	$0.212	$0.310	$0.322
Capital per D&T FTE	$0.066	$0.080	$0.106	$0.069	$0.066
Depreciation per D&T FTE	$0.113	$0.119	$0.117	$0.115	$0.111

[71] Manitoba Hydro responses to GSS-GSM IRs, PDF page 55, GSS-GSM/MH I-6i, Figure 3.

D&T costs are forecast to increase significantly. Based on the information provided by Manitoba Hydro, total D&T O&A and capital spending in 2020/21 and 2021/22 was $58 million and $74 million, respectively. These spending levels increased moderately in 2022/23 to $78 million, before being forecast to increase to $99 million and $106 million 2023/24 and 2024/25, respectively.

I understand based on the information provided by Manitoba Hydro that the above costs include the full amount of spending on CCA costs in the test period, which as noted in Table 11 is $22.3 million in 2023/24 and $26.8 million in 2024/25. If my assumption is correct, then it appears that this spending accounts for the majority of the increase being forecast in both years.

However, what is not well explained in the Manitoba Hydro application is why the costs, outside of the SAP S4/HANA costs, are incremental. Specifically, it is unclear why the costs related to "other CCA costs" of $11.3 million in 2023/24 and $6.8 million in 2024/25 are incremental as it appears these costs have previously been capital-related costs. Assuming that the costs were previously incurred as a capital cost, the increase in costs should be limited to either inflationary increases in the costs or a change in volume. If the costs are truly new costs not previously incurred as either operating or capital costs, then that fact is not clearly explained by Manitoba Hydro in its Application. Rather, the primary driver for the increase is an accounting driven change to expense CCA costs as shown below:

> Manitoba Hydro engaged Deloitte to assist in preparing a guidance document on the accounting treatment of Cloud Computing Arrangements ("CCAs"), which is provided in this application as Appendix 6.1. The application of these guidelines result in many costs that would have previously been deemed a capital expenditure now being classified as an O&A expense. When determining the accounting treatment of CCAs, the evaluation process involves assessing whether the rights granted in the CCA are within the scope of IFRS 16 Leases or IAS 38 Intangible Assets and therefore eligible for capitalization. Otherwise, the arrangement is likely to be a service contract and recognized as an operating expense.

> CCAs generally do not meet the definition of a lease because the right to receive access to a supplier's software does not give an entity any decision-making rights about how and for what purposes the software is used. CCAs usually do not give rise to an intangible asset because the right to receive access to the supplier's software does not give an entity the power to obtain the future economic benefits flowing from the software and to restrict others' access to those benefits.
>
> As a result of the guidance provided, Manitoba Hydro is seeing a significant impact on O&A expenses related to CCA. The chart in Figure 6.18 below, identifies the incremental O&A costs associated with CCA, which in the Test Years is approximately 4-5% of the O&A Preliminary Budgets.[72]

While I appreciate that expensing a capital cost would increase O&A costs, it is unclear to me why total operating and capital outlays are increasing at the rate forecast. This appears to suggest that Manitoba Hydro is either forecasting material increases in existing costs, forecasting new software programs and users to be implemented, or a combination of both. The GSS-GSM customers requested "a variance explanation outlining all changes that have occurred from year-to-year, including the drivers for each change" related to D&T costs, and in response, Manitoba Hydro referred to Section 6.6 of its application, as well as its responses to COALITION/MH-I-83c and PUB/MH-I-71a.[73]

As noted above, Section 6.6 largely highlights the transition to the cloud, which explains why O&A costs are increasing, but not why overall costs are increasing, except for the proposed transition to SAP S4/HANA. The responses to other information requests as referred to by Manitoba Hydro similarly provide minimal context for the increase. The

[72] Manitoba Hydro 2023/24 & 2024/25 General Rate Application, Tab 06, Operating & Administrative Expenses, PDF page 30, lines 6 to 23.
[73] Manitoba Hydro responses to GSS-GSM IRs, PDF page 55, GSS-GSM/MH I-6a-k.

response to COALITION/MH-I-83c simply states the following for the change in Information Technology Services costs of $20.9 million from 2022/23 to 2023/24:

> Increase is primarily due to higher consulting services for cloud based services as well as higher overtime. These increases are partially offset by a decrease in leasing costs for the data centre which is moving to Manitoba Hydro facilities.[74]

While Manitoba Hydro also cites overtime as a driver for increased costs, the specific need for those costs remains unclear. An overall transition to support Strategy 2040 as also frequently raised by Manitoba Hydro is with respect quite vague given the forecast increase in costs. Certainly, Manitoba Hydro appears to fail to explain the costs and benefits of pursuing the increased D&T spending and why that spending is reasonable relative to other alternatives that may exist, including but not limited to maintaining the status quo in some cases.

For all the above reasons, I do not consider that Manitoba Hydro has supported its requested D&T spending levels and I provide specific recommendations for the spending levels in the sections that follow.

5.3 SAP S4/HANA transition should be denied and costs excluded

Q: Please comment on Manitoba Hydro's proposed adoption and costs related to SAP S4/HANA.

A: Manitoba Hydro characterized its request in relation to the SAP S4/HANA project in its application as follows:

> Manitoba Hydro has forecasted O&A expenditures for SAP S/4HANA CORE, the replacement for SAP ECC, of $156 million over a period of seven years from 2023/24 to 2029/30 as there is a high probability that the majority of this software technology will use a cloud-based solution.

[74] Manitoba Hydro responses to COALITION IRs, PDF page 507, COALITION/MH I-83c.

> Manitoba Hydro is in the early stages of determining the approach to the newer version of SAP and these cost projections may change.[75]

In response to a GSS-GSM information request, Manitoba Hydro confirmed that the $156 million of forecast costs, including $12.5 million of costs in 2023/24 and $22.9 million of costs in 2024/25,[76] is not supported by a business case and no final decision to pursue a replacement for SAP ECC has been formally approved:

> Manitoba Hydro is currently in phase 0 (pre-planning) of the SAP S/4HANA Project. The final deliverables of this phase include a readiness assessment and business case for SAP S4/HANA. As noted in Tab 6 of Manitoba Hydro's Application, Manitoba Hydro's current version of SAP ECC will not be supported beyond 2027 and as such Manitoba Hydro included forecasted costs for its replacement with SAP S/4HANA in its long-term financial forecast scenario. The final decision around adoption of SAP S/4HANA Cloud will not be made until after completion of the business case and readiness assessment.[77]

Manitoba Hydro also confirms that alternatives exist to transitioning to a new SAP system.[78] Finally, Manitoba Hydro confirms it will review all ongoing support options and risk as part of its pre-planning work.[79]

This is an important consideration as a transition to a new SAP system will be complex. Based on my experience, such transitions often require significant unexpected costs to be incurred to address original customizations within the legacy SAP system, transition those customizations to the new system or build new workarounds, and train all staff on the new system. In many cases, I have observed the actual costs to transition are often significantly

[75] Manitoba Hydro 2023/24 & 2024/25 General Rate Application, Tab 06, Operating & Administrative Expenses, PDF page 33, lines 13 to 17.
[76] Manitoba Hydro 2023/24 & 2024/25 General Rate Application, Tab 06, Operating & Administrative Expenses, PDF page 33, Figure 6.19.
[77] Manitoba Hydro responses to GSS-GSM Round 2 IRs, PDF pages 20 and 21, GSS-GSM/MH II-6a.
[78] Manitoba Hydro responses to GSS-GSM IRs, PDF page 54, GSS-GSM/MH I-6f.
[79] Manitoba Hydro responses to GSS-GSM IRs, PDF page 54, GSS-GSM/MH I-6g.

greater than originally estimated due to parties underestimating the level of effort and complexity inherent in the transition.

As set out above, the request to spend $12.5 million of costs in 2023/24 and $22.9 million of costs in 2024/25[80] is not supported by detailed evidence or a business case. This is a significant amount of spending to forecast without a defined plan or business case. Phase 0 spending may require some incremental increase in costs, but I do not consider it reasonable to commit to an increase in costs in the test period for SAP S4/HANA when there is already an increase in spending forecast for 2022/23, presumably to support phase 0.

Accordingly, I recommend that the PUB disallow the applied for SAP S4/HANA costs of $12.5 million and $22.9 million in 2023/24 and 2024/25, respectively. Until such time as Manitoba Hydro presents a detailed business case to support the incurrence of the forecast costs as being the best option available to Manitoba Hydro, I do not recommend approval of incremental costs. The existing level of costs, and the overall costs I recommend below should be sufficient to continue a reasonable level of ongoing maintenance costs for the existing SAP ECC system.

However, as separately discussed below, I do support the approval of a deferral account for SAP S4/HANA costs to provide for the deferral of the amounts akin to the result that would occur if the costs were capitalized. The use of the deferral account can be such that no costs are permitted to be included until a comprehensive business case supporting a decision to proceed with SAP S4/HANA or some other alternative is presented by Manitoba Hydro.

5.4 Deferral account for cloud computing arrangement costs should be approved

Q: Do you support Manitoba Hydro's request for a deferral account for operating costs related to SAP S4/HANA?

[80] Manitoba Hydro 2023/24 & 2024/25 General Rate Application, Tab 06, Operating & Administrative Expenses, PDF page 33, Figure 6.19.

A: Yes. However, I also recommend that the proposed deferral account be extended to all CCA costs. I have reviewed Appendix 6.1 which is the Cloud Computing Arrangements Accounting Guidance prepared by Deloitte for Manitoba Hydro and I generally agree with the conclusions and findings set out therein. I have reviewed the accounting guidance provided by IFRIC as included in Appendix 3, 4 and 5 of the Deloitte report, as well as the IFRS guidance in Appendix 2.

While I agree with the accounting guidance provided by Deloitte it is difficult for me to confirm based on the information provided by Manitoba Hydro that the treatment as proposed in the forecast costs is consistent with the guidance from Deloitte. Specifically, I am unable to confirm that costs are being properly expensed in certain cases consistent with the Deloitte guidance. While this is somewhat of a concern, approval of the deferral account reduces this concern as all costs continue to be deferred whether as part of the deferral or as part of capital.

My more significant concern is the rationale being applied by Manitoba Hydro to not treat all costs as being included within the proposed deferral account. In this regard, Manitoba Hydro states:

> Manitoba Hydro is also forecasting $13 million in 2023/24 and $8.5 million per year starting in 2024/25 for cloud computing arrangements related to the implementation of small software systems which will be expensed as costs are incurred. The average service life of small systems is approximately six years. Since these costs are regular and recurring, Manitoba Hydro is proposing not to defer these costs. If costs were deferred and amortized there would be no benefit to customers after 2027/28. From 2030/31 and on the annual amount deferred would equally offset the annual amount amortized, as shown in Figure 4.[81]

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[81] Manitoba Hydro 2023/24 & 2024/25 General Rate Application, Appendix 4.3 (Amended), Regulatory Deferrals, PDF page 12, line 24 to PDF page 13, line 5..

I disagree with this approach. While I appreciate that the benefits of deferral are outweighed by the increased amortization in the future, the primary reason to support the deferral of the costs is that the costs have longer term benefits for customers. While the costs are not permitted to be capitalized under IFRS, the costs do have sustaining benefits that are better aligned with deferring those costs over time.

Accordingly, I recommend that all CCA costs be treated in the same manner, and the deferral account include all CCA costs.

5.5 Summary of recommendations related to the level of digital and technology costs

Q: Please summarize your recommendations in relation to D&T costs in 2023/24 and 2024/25.

A: The following table summarizes my recommendations in relation to CCA costs for 2023/24 and 2024/25:

Table 14 – Recommended D&T costs (2023/24 and 2024/25)

($ millions)	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Digital and Technology O&A costs	**55**	**52**	**81**	**88**
Disallowance of SAP S4/HANA costs			(11)	(20)
Deferral of small software systems costs			(11)	(7)
Revised base level of costs	**55**	**52**	**59**	**61**

The recommendation provided above explicitly assumes that the $11 million and $7 million of costs related to small software systems in 2023/24 and 2024/25 is related to incremental software costs not previously incurred as either an operating or capital cost by Manitoba Hydro. Based on this assumption, the base level of costs escalates at a level that is greater than the average costs incurred in the last two years, including 2022/23 forecast. I note this escalation will permit the incremental “Operating Expenses” related to “Small Software Systems” of $5.6 million and $5.7 million in 2023/24 and 2024/25, respectively, to be included in the forecast total costs.

If this assumption is not correct, and the costs relate to programs that were previously incurred by Manitoba Hydro, then I would recommend reducing the level of costs in each year by a further $11 million and $7 million, respectively, to account for this fact.

Specifically, there appears to be no evidence to support the incremental nature of these costs relative to historical amounts. This observation applies equally to both the "Integration Expenses" and "Operating Expenses" related to Small Software Systems included on Table 11.

6 Part 2 Rate design matters

Q: Please summarize your observations regarding Manitoba Hydro's proposed rate design for the GSS and GSM customer classes.

A: In its cost-of-service filing, Manitoba Hydro proposed the following regarding the GSS-GSM customers:

- Propose differentiated rate adjustments with lower rates for the GSS-GSM customers to continue moving the GSS-ND into the zone of reasonableness.[82]
- Continued use of a declining block energy structure.[83]
- Cease rate harmonization of the GSS and GSM classes.[84]

I have reviewed Manitoba Hydro's proposed rate design, including changes to certain aspects related to the GSS/GSM customer classes and the variable rates for different classes to rebalance the revenue to cost ratios.

Based on that review, I consider that Manitoba Hydro's proposed rate design appears to be compliant with recent PUB directions and aligned with best practices for cost-of-service rate design including, for example, the Bonbright Principles some of which are cited by Manitoba Hydro.[85] Accordingly, I propose no changes to the rate design proposed by Manitoba Hydro at this time.

[82] Manitoba Hydro 2023/24 & 2024/25 General Rate Application, Tab 08, Cost of Service, Proposed Rates and Customer Impacts, PDF page 5, Figure 8.1.
[83] Manitoba Hydro 2023/24 & 2024/25 General Rate Application, Tab 08, Cost of Service, Proposed Rates and Customer Impacts, PDF pages 19 to 22, Section 8.7.1.
[84] Manitoba Hydro 2023/24 & 2024/25 General Rate Application, Tab 08, Cost of Service, Proposed Rates and Customer Impacts, PDF pages 23 to 24, Section 8.7.2.
[85] Manitoba Hydro 2023/24 & 2024/25 General Rate Application, Tab 08, Cost of Service, Proposed Rates and Customer Impacts, PDF pages 24 and 25, Section 8.7.3.

Q: Does this conclude your evidence?

A: Yes. This concludes the evidence of Dustin Madsen, CPA, CA, CPA (IL, USA), CDP, CRRA in Manitoba Hydro's 2023/24 & 2024/25 General Rate Application.

Listing of documents relied upon and texts referenced

- Depreciation Systems by Frank K. Wolf and W. Chester Fitch.
- Iowa Engineering Experiment Station Bulletin 125, "Statistical Analyses of Industrial Property Retirements" by Robley Winfrey.
- Iowa Engineering Experiment Station Bulletin 155, "Depreciation of Group Properties" by Robley Winfrey.
- Engineering Valuation and Depreciation by Anson Marston, Robley Winfrey, and Jean C. Hempstead.
- Public Utility Depreciation Practices, Compiled and Edited by Staff Subcommittee on Depreciation of The Finance and Technology Committee of the National Association of Regulatory Utility Commissioners.
- Principles of Public Utility Rates, by James C. Bonbright.

DUSTIN MADSEN CA, CPA, CPA (IL, USA), CDP, CRRA

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Consultant, Regulatory and Financial Reporting December 2011 - Present
Summary of Work for Various Clients
Calgary, Alberta

- Preparation of expert testimony in a wide variety of areas including cost-of-service, revenue requirement, income tax, valuation, depreciation, cost of capital, capital expenditures and prudence.
- Hands on experience in the strategic planning, development and coordination of all elements of regulatory proceedings, including preparation of interrogatories, evidence, responding to information requests, oral testimony, and preparation of written argument and reply argument.
- Recognized expertise and detailed knowledge of financial reporting and treasury processes, utility income tax principles, and International Financial Reporting Standards ("IFRS"), including a significant amount of online and face-to-face teaching experience.

Accounting, Finance, Tax and Regulatory Consultant January 2016 – Present
Emrydia Consulting Corporation (owner) Calgary, Alberta

- Preparation of evidence and expert testimony both written and oral on a variety of areas, including cost-of-service, revenue requirement, income tax, valuation, depreciation, and cost of capital. Some examples of oral testimony include:
    - Witness in the New Brunswick Power 2020-21 GRA on all revenue requirement matters and retained in the New Brunswick 2023-24 GRA.
    - Prepared a depreciation study, cost-of-service study and asset valuation for a utility client in Alberta.
    - Filed expert evidence in the Northwest Territories Power Corporation 2022-23 GRA on operating costs, capitalization and depreciation matters.
    - Filed expert evidence in the ATCO Electric 2020-2022 and 2023-2025 GTAs on a variety of matters.
    - Filed expert evidence in the AltaLink 2022-2023 GTA on a variety of matters.
    - Witness in AltaLink's 2019-2021 GTA on matters related to AltaLink's proposed change in salvage collection methodology, the reasonableness of AltaLink's applied for salvage costs, and line clearance mitigation expenditures.
    - Witness in the AESO's Capacity Market Application on various matters pertaining to the AESO's application.
    - Witness in Alberta PowerLine Fort McMurray West 500 kV Project, on matters pertaining to AESO compliance with legislative requirements, and cost concerns related to routing and the competitive procurement process.

- Witness in ATCO Electric Transmission's 2018-2019 GTA on matters related to deferral and reserve accounts, fixed and variable compensation, operating costs, head office costs, allocated costs, depreciation matters, and other various areas.
- Witness in the 2018 Generic Cost of Capital ("GCOC") Proceeding on matters relating to generic income tax methods and the recommended capital structure.
- Witness in ATCO Electric Transmission's 2015-2017 General Tariff Application ("GTA"), on matters relating to regulatory accounts, forecasting accuracy, approach to budgeting, operating costs, income taxes and other financial matters.

- Prepared a comprehensive cost-of-service study for an Alberta based distribution facility owner.
- Prepared a comprehensive business and succession plan for an Alberta based distribution facility owner.
- Completed a business valuation, including a calculation of the fair market value and replacement cost new less depreciation value of the assets of an Alberta based distribution facility owner.
- Provided advice to various parties in Alberta's regulated and unregulated utility industry on numerous matters including cost-of-service rate design, business issues, hedging, regulated rate option calculation, and other specific matters.

Business Valuation and Accounting/Regulatory Risk Consultant Nov 2015 – January 2016
Berkshire Hathaway Energy Canada Calgary, Alberta

- Advise senior management at Berkshire Hathaway Energy Canada on potential acquisition risks and rewards.
- Evaluate all financial, treasury, regulatory, operational and legal elements of potential acquisitions and coordinate with other senior team members to develop a go/no-go proposal for each potential acquisition.
- Construct and maintain a business valuation model to support calculations of the enterprise value, including development of assumptions around levered/unlevered discount rates, cash flows, terminal values and certain tax assumptions depending upon the ultimate structure of the transaction.

Regulatory Specialist (Consultant) November 2012 – July 2015
AltaLink L.P. Calgary, Alberta

- Drafted or coordinated the drafting of AltaLink's 2012/2013 Deferral Account Application and 2015/2016 GTA, including responses to information requests, updates to the applications and other matters as required.
- Assisted AltaLink, working in conjunction with other Alberta utilities, in the drafting of the 2013 GCOC R&V application and the Utility Asset Disposition

(UAD) Appeal. This work included detailed research and analysis into GCOC and UAD matters.
- Actively engaged in the AUC proceeding to assess the AltaLink sale, including responses to information requests and responding to due diligence questions from the sale itself.
- Prepared AltaLink's 2011, 2012, 2013 and 2014 Reports on Operations and Finances in compliance with AUC Rule 005.
- Assisted in the coordination of the 2013/2014 GTA oral hearing, including undertakings, preparation of cross-examination questions and monitoring of oral testimony.
- Prepared the public and confidential rebuttal evidence, responses to additional information requests, and argument/reply argument for the 2013/2014 GTA.
- Acted as AltaLink's lead representative on a variety of key applications filed by other Alberta Utilities, including PBR applications, GCOC, capital tracker applications, GTAs, Deferral Account Applications, and also the AESO's Tariff Application.
- Automated the majority of the Report on Operations model and improved the documentation related to the process, thereby reducing the time required to update the Report on Operations to a matter of a couple weeks rather than a couple months.
- Automated and refined the Hearing Cost and Legal Cost process, including filing of costs with the AUC, reconciliation of costs for accounting purposes, and installation of an improved internal information system for gathering and reporting.
- Continued monitoring of other proceedings and performed all other duties as required by the Vice President, Regulatory Rates and Tariffs.

Manager, Financial Reporting (Contract) April 2012 – October 2012
AltaLink L.P. Calgary, Alberta

- Managed the Financial Reporting group, and performed all duties as required of the Manager, Financial Reporting and any other duties as required.
- Coordinated the implementation of BPC to assist with the consolidation of financial results in SAP.
- Provided technical IFRS input for a variety of projects and Canadian Electricity Association matters.

Consultant, Corporate Finance and Tax February 2012 – April 2012
Enerflex Ltd. Calgary, Alberta

- Assisted with pre-implementation planning for IFRS 9 through 13.
- Reviewed the hedging policy in place at Enerflex to assess ongoing effectiveness and provided feedback on a new treasury management system.
- Reviewed annual financial statements, Management's Discussion and Analysis

and the AIF, and provided feedback for changes and improvements to the first quarter financial statements.

- Performed a review of existing accounting policies including embedded derivative review of major contracts, lessee and lessor accounting, segmented reporting, borrowing costs, stock options and more.

Manager, Forecasts and Budgets January 2010 – November 2011
IFRS Project Manager/Sponsor February 2007 – December 2010
Senior Financial Accountant, Financial Reporting February 2007 – March 2010
FortisAlberta Inc. Calgary, Alberta

- Prepared/reviewed monthly, quarterly and annual forecasts and all associated financial analysis for the CFO in comparison to actuals.
- Review of regulatory filings and annual regulatory financial statements submitted to the Alberta Utilities Commission.
- Preparation/review of annual Business Plan for approval by Board of Directors.
- Improvement of monthly and daily treasury forecasts and involvement in debt issuances and responses to due diligence requests.
- Management and review of the monthly tax calculation and development of various tax planning strategies from both a regulatory and financial reporting perspective.
- Assisted in the review of all corporate tax processes and calculation of tax provisions, as well as, design of complex tax planning strategies.
- Responsible for the planning and oversight of the conversion to International Financial Reporting Standards including the review of all policy papers, issues lists, system conversion issues etc.
- Responsible for financial reporting, including the preparation and review of financial statements in accordance with Canadian generally accepted accounting principles, the preparation and review of the MD&A, preparation of the monthly management report, and preparation and review of accounting research and policies.
- Involved in the design, implementation and ongoing improvements of various accounting processes and internal controls within financial reporting, accounts payable, capital assets, inventory, general accounting, treasury, taxation and payroll.
- Provided IFRS transition course for all Finance staff at FortisAlberta.
- Demonstrated effective time management, organization, supervisory and problem solving/analytical skills.

Vice Chair, CEA`s Finance and Accounting Subcommittee May 2011 – December 2011

Member May 2007 – December 2011
Canadian Electrical Association
Ottawa, Ontario

- Attended all bi-annual meetings as an active participant involved in presentations at the meetings, organized special purpose conference calls, prepared response letters to both the IASB and AcSB on a variety of topics, and assisted in the special subcommittee on Rate Regulated Accounting.
- Assisted the Chair in the preparation of meeting content, arranging speakers and guest attendees, and other duties as requested.

IFRS Classroom Facilitator June 2009 – November 2011
IASeminars London, England

- Classroom facilitator for IASeminars focusing on IFRS accounting within the Utilities and Energy industries.

Experienced Module Facilitator January 2006 – September 2009
CA School of Business
Calgary, Alberta

- Facilitated Modules 1 to 5 multiple times with class sizes between 8 and 20 students.

Senior Auditor September 2003 – February 2007
Deloitte and Touche LLP Saskatoon, Saskatchewan/ Calgary, Alberta

- Performed review, audit, SOX 404 and CSOX work for a variety of large multi-national clients including Petro Canada, Potash Corporation, and Superior Propane, as well as review and audit work for smaller to mid-sized for profit and not-for-profit organizations.
- Completed personal tax returns and assisted in the audit of corporate tax provisions.
- Provided audit and oil and gas accounting training to new and existing staff at Deloitte.

EDUCATION

Certified Rate of Return Analyst
Society of Utility and Regulatory Financial Analysts

Certified Depreciation Professional

Society of Depreciation Professionals

Certified Public Accountant
Illinois Board of Accountancy

Chartered Professional Accountant
Chartered Professional Accountants of Alberta

Chartered Accountant
Institute of Chartered Accountants of Alberta

Bachelor of Commerce, Major in Accounting, with Great Distinction
University of Saskatchewan