Depreciation Issues Document

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1. Executive Summary

In Board Order 42-23 the PUB identified the following six policy issues related to the appropriate choice of a depreciation methodology. The PUB asked that the parties arrange for a discussion between their respective depreciation experts ahead of the hearing to find common ground and narrow any areas of disagreement.

Following this direction, technical conference meetings on depreciation have been held with an objective of clarifying each identified policy issue and outlining viable alternatives to the PUB to address the policy issues on a combined basis in an attempt to have the depreciation issues resolved as part of the current rate application proceeding.

The following outlines areas of consensus between Manitoba Hydro (MH), Manitoba Industrial Power User's Group (MIPUG), Consumers Coalition (Coalition) and General Service Small/General Service Medium customer classes (GSS/GSM) (collectively "the Parties") reached during the technical conference meetings:

- The principle that **it's preferable for Manitoba Hydro to apply the same depreciation methodology for financial reporting (i.e. an IFRS compliant methodology) and rate-setting purposes**, assuming it results in just and reasonable rates for customers. This removes the need to maintain separate accounts between financial reporting and rate-setting and improves the comparability and understandability of the financial statements. Currently, Manitoba Hydro is unique amongst its Canadian utility peers as it uses a different basis of depreciation for financial reporting and rate-setting purposes and uses previous CGAAP for rate setting purposes.
- The **whole life technique should continue to be used for the calculation of depreciation**. While both whole life and remaining life techniques are acceptable, Manitoba Hydro's practice is to apply the whole life technique.
- **Judgement is required in order to determine the appropriate level of componentization and it should be based on significance/materiality**. A review of the level of componentization required for IFRS-compliant depreciation is appropriate. An IFRS-ALG methodology can likely be achieved with a lower level of componentization than identified in the Alliance study.
- **Amortization periods for depreciation related regulatory deferral accounts are required**. These are required to ensure there is an ability for Manitoba Hydro to recover regulatory deferral costs, which is a requirement of IFRS 14 and promotes

intergenerational equity (i.e., customers who are benefitting from in-service assets are paying for those assets vs. future customers paying).

The topics where there is not full agreement are the depreciation methodology to be applied (ALG vs. ELG) and the treatment of gains & losses. These issues were discussed together as it is difficult to treat them independently. During this combined discussion, there were areas of concurrence as well as areas of divergence. These are summarized below:

- **ALG and ELG depreciation procedures both provide a rational and systematic method for determining depreciation expense**, are both acceptable under IFRS and both can be applied for rate setting purposes. The Parties did not agree on whether one of the depreciation methodologies was preferable over the other or whether both methodologies provide just and reasonable rates for customers.
- **For financial reporting purposes IFRS requires the recognition of gains and losses in net income but also permits deferral of those gains and losses for regulatory purposes** if directed by the PUB. The Parties did not reach consensus on the approach used to calculate losses for ELG and ALG.

The Parties acknowledge that either approach (ELG or ALG) is rational, systematic, and implementable but differ in their views on the merits and drawbacks of the two approaches, and whether both approaches lead to just and reasonable rates. While the two approaches are both internally coherent approaches to depreciation, there was no consensus as to which is preferred or whether both lead to just and reasonable rates. Note, it is not possible for Manitoba Hydro to convert to IFRS-ALG depreciation immediately on receipt of an Order, as further work would be required to refine componentization and implement changes to Manitoba Hydro's financial systems.

On this basis, MH, MIPUG and GSS/GSM have identified two primary, combined approaches (Alternatives 1 and 2) to address the identified depreciation issues. These two approaches are aligned with the areas of consensus and consider the financial implications. Coalition submits that full compliance with the PUB's directives on depreciation have not been met in the current proceeding and an interim decision (Alternative 3 or 4) should be considered.

The following four alternatives have been identified for the PUB to consider to address the depreciation issues:

Alternative	Description
Alternative 1	Accept IFRS-ELG as presented in the Amended Financial Forecast Scenario
Alternative 2	Accept IFRS-ALG, with implementation following a further regulatory review process to finalize componentization
Alternative 3	Continue with previous CGAAP-ASL on an interim basis without amortization of the existing deferral accounts[1] until the PUB opines on depreciation matters
Alternative 4	Continue with previous CGAAP-ASL on an interim basis and commence amortization of the existing deferral accounts until the PUB opines on depreciation matters

Manitoba Hydro considers Alternative 1 preferable, but Alternative 2 is also viable, MIPUG and GSS/GSM recommend Alternative 2 and Coalition recommends either Alternative 3 or 4. The position of each party is outlined in detail in Section 8.2.

2. Issue:

In Board Order 42-23 the PUB identified the following 6 policy issues related to the appropriate choice of a depreciation methodology:

1. The use of an IFRS-compliant depreciation methodology for rate-setting purposes;
2. The use of the Average Service Life (ASL) procedure as opposed to the Equal Life Group (ELG) procedure;
3. The use of the remaining life technique as opposed to the whole life technique;
4. The required level of componentization;
5. The treatment of interim gains and losses; and
6. The establishment and disposition of deferral accounts

In addressing these 6 policy issues related to depreciation, the PUB asked that:

a) Depreciation-related evidence is to be delivered by way of concurrent evidence; and

[1] Alternative 3 would require the PUB to include a finding in their Order that amortization periods will be determined once a final decision is made on depreciation policy issues, to address financial reporting and audit risks related to the future recovery of the depreciation deferral account balances.

b) The Parties are requested to arrange for a discussion between their respective depreciation experts ahead of the hearing in an attempt to find common ground and narrow the areas of disagreement.

3. Approach & Participants:

Three technical conferences to discuss the identified depreciation policy issues have been held between Manitoba Hydro, counsel & advisors for the PUB and Interveners, but without involvement of the respective clients. This document does not represent a negotiated outcome, or a document indicating agreement by the intervenor entities. References to "MIPUG", "Coalition" or "GSS/GSM" taking a position in this document should be read as being a reference to the experts for the party taking this view, rather than the party itself.

The purpose of the technical conferences was to find common ground on the depreciation issues where possible and narrow the scope of any areas where there remains disagreement as requested by the PUB. The first technical conference was held on April 13, 2023 and included legal counsel for each party. Following the first technical conference, Manitoba Hydro met with Patrick Bowman (independent expert on behalf of MIPUG), Dustin Madsen (independent expert on behalf of GSS/GSM) and Ian Innis (from Elenchus Research on behalf of the PUB) on April 18, 2023 to discuss the depreciation policy issues in further detail. A third meeting of the same participants with the addition of Darren Rainkie (independent expert on behalf of Coalition) was held on May 2, 2023. Additionally, on matters related to IFRS compliance, the MIPUG expert takes no position, and the comments represent the view of Manitoba Hydro, Coalition and GSS/GSM.

Each of the participating experts have submitted evidence to the PUB in this proceeding. In each case, that evidence remains valid and a part of the public record. None of the participants were asked to, nor have they, varied or withdrawn their evidence, conclusions, or recommendations as a result of this process.

4. Objective

The parties participating in the depreciation technical conferences were seeking to reach agreement on identified policy issues where possible and, where agreement was not possible, narrow the scope on the unresolved issue. The objective was to clarify each identified policy issue and outline viable alternatives to the PUB to try and address the policy issues on a combined basis such that the topic of depreciation could potentially be resolved as part of the current rate application proceeding.

5. Summary of Findings

The summary of the findings from the technical conference discussions are outlined below. The analysis to support each finding is detailed in Section 6 and Section 7:

1. It's preferable that Manitoba Hydro apply the same IFRS-compliant depreciation methodology for financial reporting and rate-setting purposes, assuming it results in just and reasonable rates for customers (*discussed in section 6.1*);
2. Manitoba Hydro should continue to use the whole life technique for the calculation of depreciation (*discussed in section 6.2*);
3. Based on both regulatory principles and accounting standard requirements, amortization periods should be applied on the existing depreciation related deferral accounts to ensure a cost recovery mechanism is in place. The amortization periods should be based on the remaining useful life of the assets contributing to the accounts (*discussed in section 6.3*);
4. Manitoba Hydro should continue to review its componentization as part of future depreciation studies, including if a change to an ALG procedure is made. Any changes to componentization should be based on significance/materiality and provide for just and reasonable rates for customers (*discussed in section 6.4*);
5. While there are differences in the ALG and ELG procedures and the resulting calculated depreciation expense amount, both provide a rational and systematic method for determining depreciation expense, are both acceptable under IFRS, and can be applied for rate setting purposes (*discussed in section 6.5*); Cumulative net income over the 20-year forecast period is $267 million higher if an ALG methodology is applied vs. an ELG methodology (Note: This assumes deferral of gains and losses);
6. The continued deferral of gains and losses (with amortization of the resulting regulatory deferral account balance) is acceptable under IFRS (as per IFRS 14). Deferral of gains and losses over the remaining life of each account leads to a comparable approach to the

traditional ASL procedure as it was applied under previous CGAAP. Deferral of gains and losses has a greater (positive) impact on net income under ALG compared to ELG (based on Manitoba Hydro's current approach and calculations) as compared to not deferring and amortizing these amounts (*discussed in section 6.6*); There would be an increase to net-income over the 20-year forecast period associated with the deferral of gains and losses, particularly for ALG ($318 million versus *$34 million for ELG*) (*discussed in section 7.2*);

7. Establishing a phase-in deferral would reduce the impact to net income of implementing an IFRS-compliant depreciation methodology, particularly for ELG, but may not be necessary if an ALG approach is adopted (*discussed in section 6.7*);
8. Based on the analysis, MH, MIPUG and GSS/GSM have identified 2 combined approaches to address the identified depreciation issues. Alternative 1 is the approach as submitted in Manitoba Hydro's Application. Alternative 2 is to transition to an ALG methodology with continued deferral of gains and losses. In both cases the balances in the existing regulatory deferral accounts would be amortized; and
9. Coalition submits that full compliance with the PUB's directives on depreciation have not been met in the current proceeding and an interim approach continuing the use of previous CGAAP ASL depreciation (Alternatives 3 and 4) with or without amortization of the existing regulatory deferral accounts, until the PUB opines on depreciation matters.

6. Discussion of Identified Key Depreciation Policy Issues

6.1. The use of an IFRS-compliant depreciation methodology for rate-setting purposes

Issue:	Manitoba Hydro currently applies a different depreciation methodology/calculation for financial reporting purposes vs. rate-setting purposes. To accommodate this approach first an IFRS-compliant depreciation methodology is applied for Manitoba Hydro's financial reporting and then a regulatory deferral account is used to apply a different methodology for rate-setting.
Key question(s):	Why is it important or beneficial to apply the same depreciation methodology for financial reporting and rate-setting purposes?
Position of MH, MIPUG, Coalition and GSS/GSM:	All Parties agree that it is preferable that Manitoba Hydro apply, to the extent possible, the same overall depreciation methodology for financial reporting purposes as for rate-setting purposes. This removes the need to maintain separate accounts between financial reporting

	and rate-setting and improves the comparability and understandability of the financial statements. Some degree of variation may remain, to be addressed through regulatory deferral accounts. The need for regulatory deferral accounts should generally be minimized to the extent practical, so long as this can be achieved while also achieving just and reasonable rates.
Evidence on record	MH: Appendix 4.3, Section 1.4.14 (pages 29-30). MIPUG: Pre-filed evidence P. Bowman: Recommendation #9 with support on page 38. GSS/GSM: Pre-filed evidence D. Madsen: Page 10, lines 7-8.
Financial analysis	The depreciation expense applied in Manitoba Hydro's Amended Financial Forecast Scenario is an IFRS-compliant ELG methodology.
Resulting finding:	**It's preferable that Manitoba Hydro be able to apply the same IFRS-compliant depreciation methodology for financial reporting and rate-setting purposes.**

6.2. The use of the remaining life technique as opposed to the whole life technique

Issue:	Manitoba Hydro has consistently applied the whole life technique in the calculation of depreciation expense. The IFRS-compliant ASL Depreciation Study was conducted using a remaining life technique and was subsequently updated to reflect a whole life technique for comparability purposes in order to satisfy PUB Order 43/13 Directive 8 & 9. The new study has raised PUB concerns over which technique should be used by Manitoba Hydro.
Key question(s):	What impact does the whole life vs remaining life technique have on depreciation expense?
Position of MH, MIPUG, Coalition and GSS/GSM:	All Parties agree that it is preferable that Manitoba Hydro continue to use a whole life technique for calculating depreciation expense. Continuing to use the whole life technique eliminates the need for Manitoba Hydro to change its current method, provides comparability to its prior depreciation expense and does not require a depreciation study to update its depreciation technique from whole life to a remaining life. It was not Manitoba Hydro's intent to cause confusion regarding depreciation techniques or to raise concern over the appropriateness of Manitoba Hydro's existing whole life technique. Manitoba Hydro did not specify depreciation technique in its request for IFRS-compliant ASL Depreciation Study proposals. Additionally, regardless of technique, the depreciation expense applied should result in just and reasonable rates for customers.

Evidence on record	MH: Appendix 9.12, Section 1.2.2 (page 10 lines 12-23); Appendix 9.12 Attachment 2; PUB/MH I-81 e), MIPUG/MH II-28 a-e). MIPUG: Indicated preference for whole life technique in technical conference. GSS/GSM: Pre-filed evidence D. Madsen: Page 59 lines 9-11.
Financial analysis	The depreciation technique applied in Manitoba Hydro's Amended Financial Forecast Scenario and the scenarios presented in this document use depreciation rates determined with the whole life technique for the calculation of depreciation expense.
Resulting finding:	**Manitoba Hydro should continue to use a whole life technique for calculating depreciation expense.**

6.3. The establishment and disposition of deferral accounts

Issue:	Manitoba Hydro has been deferring the Change in depreciation methodology which is the difference between ELG vs previous CGAAP ASL depreciation expense and the Loss on retirement or disposal of assets since it transitioned to IFRS as the PUB required more information to opine on the depreciation method for rate setting purposes.
Key Question(s):	Why is it important or beneficial to dispose of deferral accounts?
Position of MH, MIPUG, Coalition and GSS/GSM:	MH, Coalition and GSS/GSM agree that IFRS 14 requires a recovery mechanism for the disposition of regulatory deferrals to demonstrate recoverability of costs from customers. MIPUG agrees that recoverability has regulatory merit as it is not appropriate to create orphaned accounts with no means for them to be addressed. All Parties agree that amortizing these costs over the remaining life of the assets contributing to the accounts is reasonable for customer rates as it yields the same result had the amounts been retained in accumulated depreciation. All Parties agree that Additions to the Change in depreciation method deferral are not required if the PUB accepts an IFRS-compliant depreciation method (either ALG or ELG) for rate setting purposes and the balance should be amortized.
Evidence on record	MH: Appendix 4.3 Section 1.4.4, 1.4.17 and 1.4.18 (pages 16-18 and 31-32); PUB/MH I-16 b); PUB/MH I-115 a). MIPUG: Pre-filed evidence P. Bowman: Recommendation #8 with support on page 35; Recommendation #10 with support on pages 37-38. GSS/GSM: Pre-filed evidence D. Madsen: Page 38 lines 13-15; Page 40 lines 21-22; Page 41 row 23.
Financial analysis	Alternatives 1, 2 and 4 include amortization of the Change in depreciation method deferral and the Loss on retirement or disposal of assets deferral over the remaining life of the assets contributing to the accounts.

Resulting finding:	**Based on regulatory principles and accounting standard requirements, amortization periods should be applied on the existing depreciation related deferral accounts to ensure costs are recovered from customers. The amortization periods should be based on the remaining useful life of the assets contributing to the accounts.**

6.4. The required level of componentization

Issue:	Manitoba Hydro filed an IFRS-compliant ASL Depreciation Study as required by PUB Order 59/13 Directive 8 & 9. The study recommended an increase of 410 depreciation components.
Key question(s):	How to determine the appropriate level of componentization for an IFRS-compliant ALG depreciation method?
Position of MH, MIPUG, Coalition and GSS/GSM:	All Parties agree that judgement is required in order to determine the appropriate level of componentization to achieve IFRS compliance and that IFRS compliance could be achieved with ALG with a lower level of componentization than identified in the Alliance study. Manitoba Hydro should continue to review its componentization in the future as part of its regular depreciation studies regardless of the procedure recommended. If IFRS-ALG is recommended for rate setting purposes, Manitoba Hydro will need to apply judgement in determining the appropriate level of componentization using the information from the IFRS-compliant ASL Depreciation Study, in conjunction with an assessment of which components are necessary because they cause a significant impact on total depreciation expense including gains and losses.
Evidence on record	MH: Appendix 4.3, Section 1.4.8 and 1.4.10 (pages 22-23 and page 25 line 28 – page 26 line 3); PUB/MH I-109 Section 1.2; PUB/MH I-122 a-b). MIPUG: Pre-filed evidence P. Bowman: Recommendation #6 & #7 with support on pages 32-33. GSS/GSM: Pre-filed evidence D. Madsen: Page 14 lines 18-20.
Financial analysis	The estimates provided for ALG reflect the scenario using the IFRS-compliant ASL Depreciation Study componentization. Although additional work would be required to determine the appropriate level of componentization by eliminating immaterial/insignificant components, at this time, the study is considered by Manitoba Hydro to be a reasonable estimate of depreciation expense once the new components are established.
Resulting finding:	**Manitoba Hydro should continue to review its componentization as part of future depreciation studies, regardless of whether a change to an ALG procedure is made. Any changes to componentization should be based on significance/materiality.**

6.5. The use of the Average Service Life (ASL) procedure as opposed to the Equal Life Group (ELG) procedure

Issue:	The ALG and ELG depreciation procedures result in differences in both depreciation expense and gains and losses.
Key Question(s):	Does the procedure used to calculate depreciation significantly impact customers?
Position of MH, MIPUG, Coalition and GSS/GSM:	All Parties agree that the ELG and ALG depreciation procedures are both acceptable under IFRS. There is a wide variation amongst peers with respect to depreciation procedure. There are merits to both procedures, and both provide a rational and systematic method for determining depreciation expense. The Parties did not reach consensus on the preferred methodology to apply for rate setting purposes (ELG or ALG). The position of each party is discussed in Section 8.2.
Evidence on record	MH: Appendix 4.3, Section 1.4.15 (page 30); Appendix 9.12, Section 1.1 (pages 2-3); PUB/MH I-118a-c; PUB/MH II-37. MIPUG: Pre-filed evidence P. Bowman: Recommendation #5 with support on pages 23-31. GSS/GSM: Pre-filed evidence D. Madsen: Page 10 lines 7-8 (not explicit but per D. Madsen is intended to refer to ELG and ALG both being IFRS compliant).
Financial analysis	Under ALG depreciation expense is lower than ELG, and gains and losses as calculated by Manitoba Hydro are higher under ALG compared to ELG. See Section 6.6 for a discussion of the treatment of gain and losses. Under ALG there will be a delayed transition, due to a needed componentization review and implementation process. This delay will lead to an increase the Change in depreciation method deferral of approximately $140 million, assuming continued deferral and amortization of the previous CGAAP ASL vs ELG difference until implementation of IFRS-compliant ALG (after completion of a further review process as defined by the PUB). However, once implemented, there will likely be less need for a transition deferral. See Section 7.3 for a comparison of financial results determined using the ELG vs ALG depreciation procedures.
Resulting finding:	**While there are differences in the methodologies and resulting depreciation expense amount, ALG and ELG both provide a rational and systematic method for determining depreciation expense and are both acceptable under IFRS. However, there are differing views on the suitability of each method for rate setting purposes.**

6.6. The treatment of interim gains and losses

Issue:	Manitoba Hydro currently calculates gains and losses on the retirement of assets and records them in income. This approach changed when Manitoba Hydro transitioned to IFRS as gains and losses were no longer recorded to accumulated depreciation.
Key question(s):	Does the treatment of gains and losses impact customer rates?
Position of MH, MIPUG, Coalition and GSS/GSM:	MH, Coalition and GSS/GSM agreed that for financial reporting purposes, IFRS requires the recognition of gains and losses in net income per IAS 16.68 and IFRS 14 would permit the deferral of gains and losses for regulatory purposes if Manitoba Hydro was directed to defer these costs (assuming an amortization period is established). The Parties do not agree on whether it is necessary to defer and amortize gains and losses. The position of each party is discussed in Section 8.2. Regardless of the procedure recommended (ALG or ELG), the calculation of gains and losses requires judgement. The Parties did not agree on the approach that Manitoba Hydro uses for calculating gains and losses but did agree that gains and losses could be deferred while still complying with IFRS.
Evidence on record	MH: Appendix 4.3, Section 1.4.5 (pages 18-20); PUB/MH I-130 c); PUB/MH II-13. MIPUG: Pre-filed evidence P. Bowman: Recommendation # 8 with support on pages 34-35. GSS/GSM: Pre-filed evidence D. Madsen: Page 31 lines 26-30.
Financial analysis	Deferring gains and losses would have a positive impact on net income under an ALG procedure, and an insignificant impact on net income under the ELG procedure. See Section 7.2 for a comparison of financial results determined with and without deferral of gains and losses for both the ELG vs ALG depreciation procedures.
Resulting finding:	**Deferring gains and losses has a positive impact on net income.**

6.7. Establishment of a phase-in deferral account

Issue:	As part of the Amended Financial Forecast, Manitoba Hydro recommended establishing a phase-in deferral account to smooth the impact to customers as a result of increased depreciation as an IFRS-compliant depreciation expense is higher than previous CGAAP ASL.
Key Question(s):	Does the establishment of a phase-in impact customer rates?
Position of MH, MIPUG, Coalition and GSS/GSM:	All Parties agree that phase-in deferral is warranted if the ELG procedure is selected. The Parties do not agree on the necessity for a

	phase-in if ALG is selected. The position of each party is discussed in Section 8.2.
Evidence on record	MH: Appendix 4.3, Section 1.4.16 (pages 30-31). MIPUG: Pre-filed evidence P. Bowman: Recommendation #9 page 2 with support on page 38. GSS/GSM: Pre-filed evidence D. Madsen: Per technical conference.
Financial analysis	Establishing a phase-in deferral would reduce the impact to net income of implementing an IFRS-compliant depreciation methodology, particularly for ELG. Removing the phase-in from the Amended Financial Forecast Scenario decreases cumulative net income by $223 million over the 20-year forecast.
Resulting finding:	**A phase-in deferral has a positive impact on net income, particularly for ELG, but may not be necessary if an ALG approach is adopted.**

7. Financial Analysis of Key Remaining Issues

As summarized in Section 5 and discussed in detail in Section 6, the Parties reached agreement on many of the depreciation policy items but did not reach full consensus on 1) the appropriate depreciation procedure (ALG vs. ELG), or 2) and the treatment of gains and losses. To further assess these remaining depreciation policy items, financial analysis was conducted to understand how decisions around both issues could impact forecasted net income (or revenue requirement) and the forecasted debt-to-capitalization ratio and rate path.

The financial analysis conducted was structured to isolate the impact of each policy decision (depreciation method & treatment of gains & losses). As such, the scenarios and associated amounts do not represent a combined and implementable approach to address all depreciation items. Rather, the analysis allows for a specific assessment around the depreciation methodology (ALG vs. ELG) and treatment of gains and losses. Please see **Section 8 Proposed Alternatives for PUB Consideration** for combined and implementable approaches to address all depreciation items.

7.1. Common Assumptions

The analysis presented in Sections 7.2 and 7.3 have the following common assumptions:

- There is no phase-in of IFRS-compliant depreciation.
- Amortization of the depreciation methodology and Loss on retirement or disposal of assets deferral accounts begins on September 1, 2023.
- IFRS-ELG and IFRS-ALG are both shown with immediate implementation to allow an effective comparison of the gains & losses and depreciation methodology issues.

Therefore, the September 2023 phase-in of ELG proposed in the Amended Financial Forecast Scenario, and the additional implementation time required to convert to ALG have been excluded from the analysis in Sections 7.2 and 7.3.

- The same 2% rate path has been assumed for all scenarios in order to assess the depreciation methodology impacts to financial results, all else being equal. The use of a 2% rate path for this analysis is not intended to endorse or suggest acceptance of that rate path.
- The IFRS-compliant ALG scenarios used for this analysis have been modeled based on the IFRS-Compliant ASL Depreciation Study provided by Alliance. Additional work would be required to determine the appropriate level of componentization.

7.2. Treatment of Gains & Losses

As noted in Section 6.6, based on Manitoba Hydro's current approach for calculating gains and losses, it is anticipated that a decision to defer gains and losses would have a near-term positive impact on net income under an ALG procedure but an insignificant impact on net income under a ELG procedure. The treatment of gains and losses has been isolated for demonstration purposes, to allow for a direct comparison. For ELG the difference in net income over the 20-year forecast with vs. without the deferral of gains and losses is $34 million. For ALG the difference in net income over the 20-year forecast with vs. without the deferral of gains and losses is $318 million. These results are shown in Figure 1 (net income under ELG with/without deferral of gains and losses) and Figure 2 (net income under ALG with/without deferral of gains and losses) below with net income quantified in the table shown in Figure 3.

Figure 1 Forecast Net Income under ELG

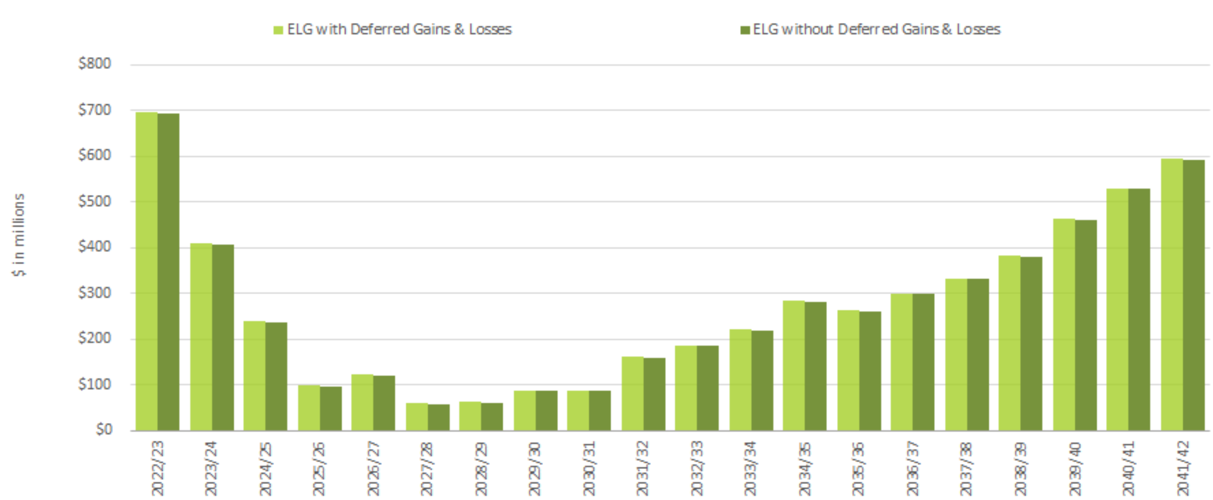


Figure 2 Forecast Net Income under ALG

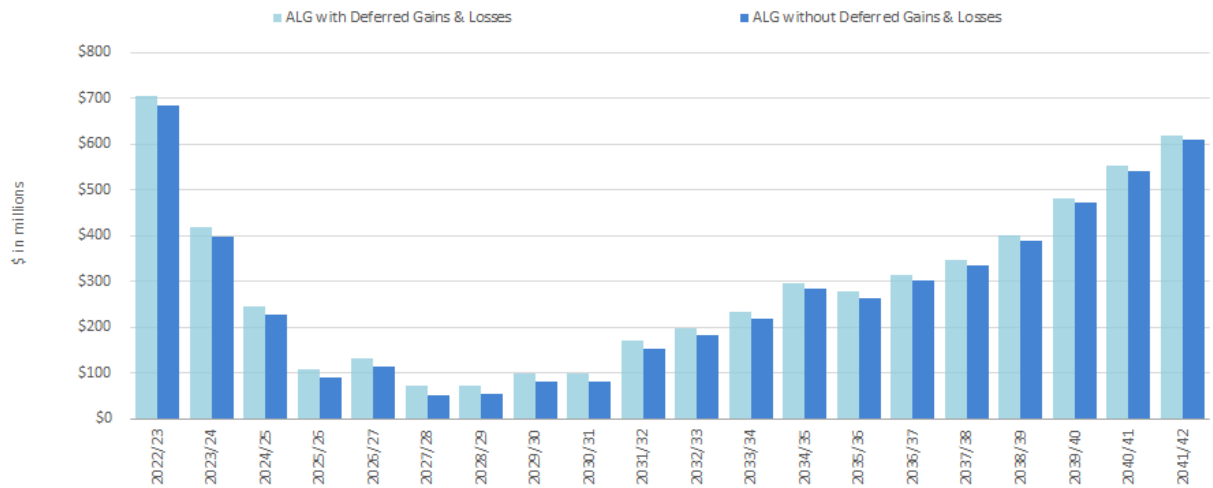


Figure 3 Forecast Net Income Comparisons of ELG and ALG with and without Deferred Gains & Losses

	ELG with Deferred Gains & Losses	ELG without Deferred Gains & Losses	Difference
	NET INCOME IN MILLIONS OF DOLLARS		
2022/23	696	693	3
2023/24	410	407	3
2024/25	238	236	3
2025/26	100	98	3
2026/27	124	121	2
2027/28	61	59	2
2028/29	63	61	2
2029/30	88	86	2
2030/31	89	87	2
2031/32	161	159	2
2032/33	187	186	2
2033/34	222	220	2
2034/35	284	283	1
2035/36	263	261	1
2036/37	300	299	1
2037/38	332	331	1
2038/39	382	381	1
2039/40	462	462	1
2040/41	530	529	1
2041/42	593	593	0
20-Year Total	**5 587**	**5 553**	**34**

	ALG with Deferred Gains & Losses	ALG without Deferred Gains & Losses	Difference
	NET INCOME IN MILLIONS OF DOLLARS		
2022/23	705	683	22
2023/24	419	397	22
2024/25	247	227	20
2025/26	109	90	20
2026/27	134	114	19
2027/28	72	53	18
2028/29	74	55	18
2029/30	99	81	17
2030/31	100	83	17
2031/32	171	154	17
2032/33	198	184	14
2033/34	234	219	15
2034/35	298	283	14
2035/36	277	263	14
2036/37	315	302	13
2037/38	348	336	12
2038/39	401	389	12
2039/40	482	471	11
2040/41	552	542	11
2041/42	619	609	10
20-Year Total	**5 854**	**5 536**	**318**

It should be noted that while the analysis indicates that under ALG there is a benefit to deferring gains and losses, while there is a minimal impact under ELG based on an assumed level of asset retirements. If significant unexpected asset retirements were to occur (e.g., early failure of a large piece of equipment), there could be a more noticeable positive impact to net income resulting from the deferral of gains and losses under both approaches. These calculations are dependent on how the gains and losses under the ALG and ELG procedures are determined, which is subject to judgment.

When the impact of deferring gains and losses is isolated, Manitoba Hydro's analysis indicates that while there would be an increase to net-income over the 20-year forecast period associated with the deferral of gains and losses, particularly under an ALG methodology, the increase to net income is not sufficient to accelerate the achievement of the assumed debt-to-capitalization target or change the proposed rate path. With or without the deferral of gains and losses, for both ALG and ELG, the same debt-to-capitalization target continues to be achieved in 2039/40 based on an identical rate path. This is outlined below in Figure 4 and Figure 5 with the debt ratios quantified in the table shown in Figure 6.

Figure 4 Forecast Debt Ratio under ELG

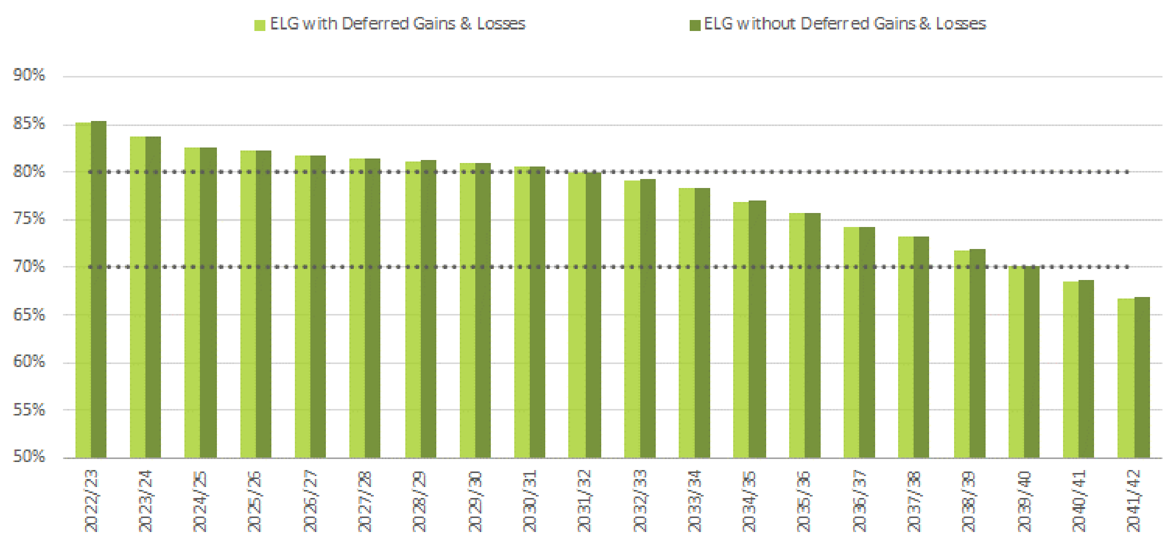


Figure 5 Forecast Debt Ratio under ALG

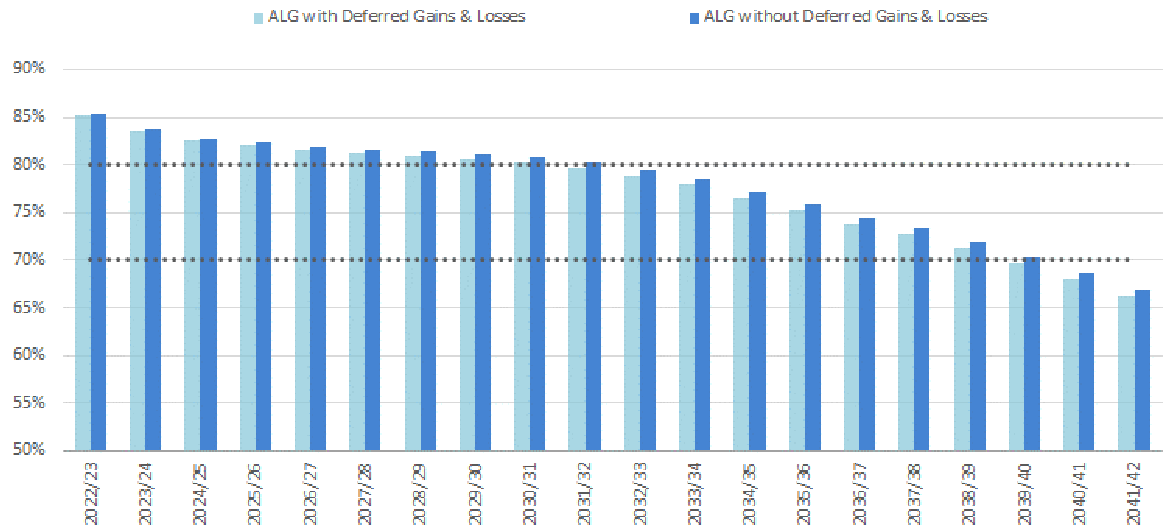


Figure 6 Forecast Debt Ratio Comparisons of ELG and ALG with and without Deferred Gains & Losses

	ELG with Deferred Gains & Losses	ELG without Deferred Gains & Losses	Difference
	DEBT RATIO IN % ASSUMING A 2% RATE PATH		
2022/23	85%	85%	0%
2023/24	84%	84%	0%
2024/25	83%	83%	0%
2025/26	82%	82%	0%
2026/27	82%	82%	0%
2027/28	81%	81%	0%
2028/29	81%	81%	0%
2029/30	81%	81%	0%
2030/31	81%	81%	0%
2031/32	80%	80%	0%
2032/33	79%	79%	0%
2033/34	78%	78%	0%
2034/35	77%	77%	0%
2035/36	76%	76%	0%
2036/37	74%	74%	0%
2037/38	73%	73%	0%
2038/39	72%	72%	0%
2039/40	70%	70%	0%
2040/41	69%	69%	0%
2041/42	67%	67%	0%

	ALG with Deferred Gains & Losses	ALG without Deferred Gains & Losses	Difference
	DEBT RATIO IN % ASSUMING A 2% RATE PATH		
2022/23	85%	85%	0%
2023/24	84%	84%	0%
2024/25	82%	83%	0%
2025/26	82%	82%	0%
2026/27	82%	82%	0%
2027/28	81%	82%	0%
2028/29	81%	81%	0%
2029/30	81%	81%	0%
2030/31	80%	81%	-1%
2031/32	80%	80%	-1%
2032/33	79%	79%	-1%
2033/34	78%	79%	-1%
2034/35	77%	77%	-1%
2035/36	75%	76%	-1%
2036/37	74%	74%	-1%
2037/38	73%	73%	-1%
2038/39	71%	72%	-1%
2039/40	70%	70%	-1%
2040/41	68%	69%	-1%
2041/42	66%	67%	-1%

The primary reason why the proposed rate path to achieve the assumed debt ratio target by 2039/40 is unchanged, is due to a minimal change in net debt since depreciation is a non-cash item. An increase in net income due to a difference in depreciation expense does not impact cash flow and therefore does not substantially impact net debt. An increase in net income over the forecast period due to depreciation only impacts retained earnings (i.e., the capitalization/equity portion of the debt-to-capitalization ratio).

Figure 7 below provides a comparison of Revenue-Cost-Coverage (RCC) ratios resulting from application of IFRS-ELG and IFRS-ALG depreciation scenarios to the Prospective Cost of Service Study presented in Tab 8, with and without deferral of gains and losses. Please refer to Appendix B for additional information regarding the PCOSS scenarios provided below. As discussed in Appendix B, assuming implementation of rate changes over a five-year timeframe, as proposed by Manitoba Hydro in Tab 8, an RCC change of +/- 0.1% is not considered to be material enough to impact proposed customer rates.

Figure 7 Impact of Gain-Loss Treatment on RCC Ratios by Customer Class

	IFRS-ELG				IFRS-compliant ALG		
Revenue Cost Coverage Ratios by Customer Class	**Without Deferred Gains & Losses**	**With Deferred Gains & Losses**	**Impact of Deferring Gains & Losses**		**Without Deferred Gains & Losses**	**With Deferred Gains & Losses**	**Impact of Deferring Gains & Losses**
Residential	94.2%	94.2%	0.0%		94.2%	94.3%	0.1%
General Service - Small Non Demand	109.5%	109.5%	0.0%		109.6%	109.6%	0.0%
General Service - Small Demand	101.8%	101.8%	0.0%		101.9%	101.9%	0.0%
General Service - Medium	100.2%	100.2%	0.0%		100.3%	100.3%	0.0%
General Service - Large 0 - 30kV	98.2%	98.2%	0.0%		98.2%	98.0%	-0.2%
General Service - Large 30-100kV	113.3%	113.3%	0.0%		113.1%	112.6%	-0.5%
General Service - Large >100kV	114.4%	114.3%	-0.1%		114.1%	113.5%	-0.6%
Area & Roadway Lighting	106.9%	106.8%	-0.1%		103.5%	108.7%	5.2%

Based on Manitoba Hydro’s analysis, when the impact of deferring gains and losses is isolated, the differences in RCC shown in Figure 7 above indicate that:

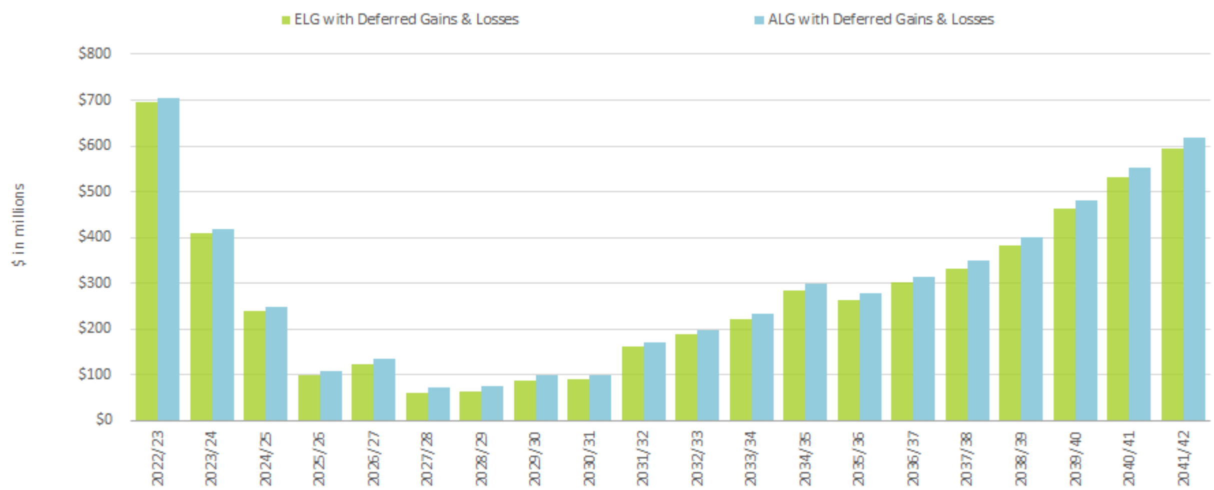
- The treatment of gains and losses does not significantly impact proposed rates for the Residential, General Service Small (GSS) and General Service Medium (GSM) classes regardless of which depreciation procedure is used.
- With use of ELG, the deferral of gains and losses does not significantly impact proposed differential rates for any customer class.

- With the use of ALG, the differences in the RCC ratios for General Service Large (GSL) and the Area and Roadway Lighting (A&RL) classes indicate a potential impact to proposed customer rates resulting from the treatment of gains and losses, as indicated in Figure 7 above.
  - For the GSL customer classes the RCC ratios are further above the 95% - 105% zone of reasonableness (ZOR), indicating the potential for lower rates without deferral of gains and losses, but for the reasons discussed in Tab 8, section 8.4.2, these differences in RCC are not likely to be material enough to impact the rates proposed by Manitoba Hydro for these classes.
  - With respect to the A&RL class, deferral of gains and losses results in an RCC above the ZOR, compared to a RCC within the ZOR without deferral of gains and losses. As such, the difference in RCC is significant enough that it would likely affect the proposed rates for the class, resulting in a lower proposed rate for the class with deferral of gains and losses. Given the relatively small share of total revenue allocated to the A&RL class, it would be unlikely for this change to materially impact proposed rates for the other customer classes.

7.3. Depreciation Methodology – ELG vs. ALG

As noted in Section 6.5, assuming deferral of gains and losses to isolate the impact of ALG vs. ELG depreciation expense for demonstration purposes, depreciation expense under an ALG approach is on average $15 million lower year-over-year compared to depreciation expense under an ELG approach. All else being equal, the resulting impact is that over the 20-year forecast period cumulative net income is $267 million higher if an ALG methodology is applied vs. an ELG methodology. This is shown in Figures 8 and 9 below with net income and debt ratios quantified in the table shown in Figure 10.

Figure 8 Forecast Net Income Comparison of ELG and ALG with Deferred Gains & Losses



When the depreciation procedure is isolated, despite the difference in cumulative net income between ALG and ELG, assuming a constant rate path, the same target debt-to-capitalization ratios would be achieved by 2039/40. This is shown in Figure 9 below. As outlined in section 7.2, the proposed rate path is unaffected as depreciation expense is a non-cash item.

Figure 9 Forecast Debt Ratio Comparison of ELG and ALG with Deferred Gains & Losses

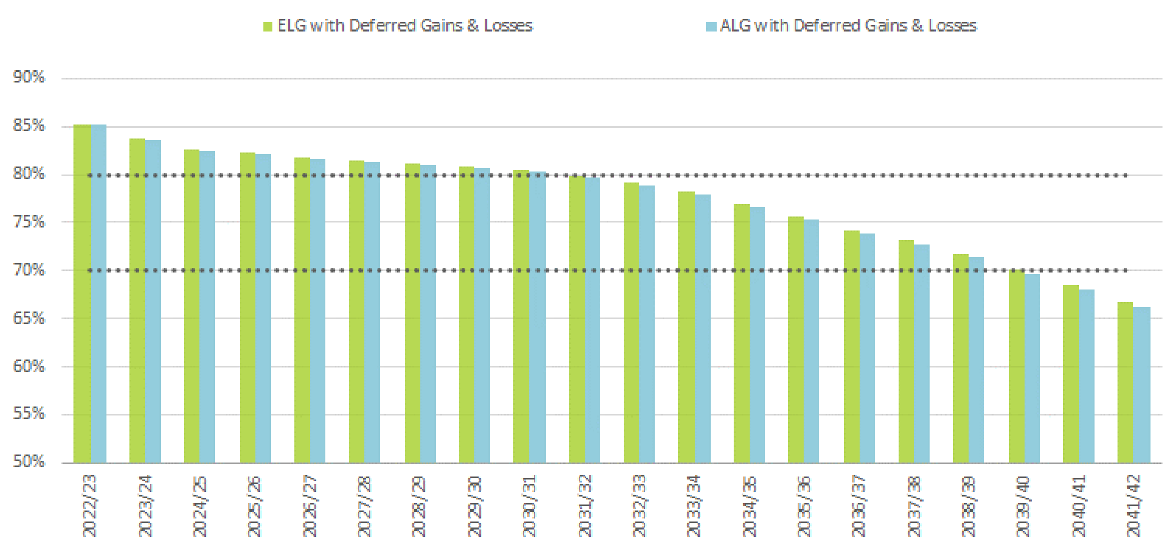


Figure 10 Forecast Net Income & Debt Ratio Comparison of ELG and ALG with Deferred Gains & Losses

	ALG with Deferred Gains & Losses	ELG with Deferred Gains & Losses	Difference
	NET INCOME IN MILLIONS OF DOLLARS		
2022/23	705	696	9
2023/24	419	410	9
2024/25	247	238	9
2025/26	109	100	9
2026/27	134	124	10
2027/28	72	61	10
2028/29	74	63	11
2029/30	99	88	10
2030/31	100	89	11
2031/32	171	161	10
2032/33	198	187	11
2033/34	234	222	12
2034/35	298	284	14
2035/36	277	263	14
2036/37	315	300	15
2037/38	348	332	16
2038/39	401	382	19
2039/40	482	462	19
2040/41	552	530	22
2041/42	619	593	25
20-Year Total	**5 854**	**5 587**	**267**

	ALG with Deferred Gains & Losses	ELG with Deferred Gains & Losses	Difference
	DEBT RATIO IN % ASSUMING A 2% RATE PATH		
2022/23	85%	85%	0%
2023/24	84%	84%	0%
2024/25	82%	83%	0%
2025/26	82%	82%	0%
2026/27	82%	82%	0%
2027/28	81%	81%	0%
2028/29	81%	81%	0%
2029/30	81%	81%	0%
2030/31	80%	81%	0%
2031/32	80%	80%	0%
2032/33	79%	79%	0%
2033/34	78%	78%	0%
2034/35	77%	77%	0%
2035/36	75%	76%	0%
2036/37	74%	74%	0%
2037/38	73%	73%	0%
2038/39	71%	72%	0%
2039/40	70%	70%	0%
2040/41	68%	69%	-1%
2041/42	66%	67%	-1%

Figure 11 below provides a comparison of Revenue-Cost-Coverage (RCC) ratios resulting from application of IFRS-ELG versus IFRS-ALG depreciation scenarios to the Prospective Cost of Service Study presented in Tab 8. In order to isolate the impact attributable to the depreciation procedure for demonstration purposes, both scenarios assume the deferral of gains and losses. Please refer to Appendix B for additional information regarding the PCOSS scenarios provided below.

Figure 11 Impact of Depreciation Procedure on RCC Ratios by Customer Class

Revenue-Cost-Coverage Ratios by Customer Class	IFRS-ELG With Deferred Gains & Losses	IFRS-ALG With Deferred Gains & Losses	Difference
Residential	94.2%	94.3%	0.1%
General Service - Small Non Demand	109.5%	109.6%	0.1%
General Service - Small Demand	101.8%	101.9%	0.1%
General Service - Medium	100.2%	100.3%	0.1%
General Service - Large 0 - 30kV	98.2%	98.0%	-0.2%
General Service - Large 30-100kV	113.3%	112.6%	-0.7%
General Service - Large >100kV	114.3%	113.5%	-0.8%
Area & Roadway Lighting	106.8%	108.7%	1.9%

Based on Manitoba Hydro's analysis, when the depreciation procedure impact is isolated, the differences in RCC shown in Figure 11 above indicate that:

- The selection of depreciation procedure does not significantly impact the proposed rates by customer class.
- As discussed in section 7.2 above, the differences in RCC for the Residential, GSS and GSM classes are immaterial, and as such the choice of depreciation procedures does not impact proposed rates for these classes.
  - For the GSL customer classes the RCC ratios are further above the ZOR with use of IFRS-ELG, indicating the potential for lower rates for these classes with use of ELG, but for the reasons discussed in Tab 8, section 8.4.2, these differences in RCC are not likely to be material enough to impact the rates proposed by Manitoba Hydro for these classes.
  - With respect to the A&RL class, the use of IFRS-ALG results is an RCC which is further above the ZOR than ELG, indicating the potential for a lower rate with use of IFRS-ALG vs IFRS-ELG, but for reasons discussed in Tab 8, the difference RCC is not likely significant enough that it would likely affect the proposed rates for the class. In addition, even if the proposed rate for the A&RL class was impacted, given the relatively small share of total revenue allocated to the A&RL class, it would be unlikely that such a change would materially impact proposed rates for the other customer classes.

8. Proposed Alternatives for PUB Consideration

Based on the analysis outlined in Sections 6 and 7, MH, MIPUG and GSS/GSM have identified two primary, combined approaches to address the identified depreciation issues as part of the current proceeding. These two approaches are aligned with the areas of consensus and consider the financial implications as outlined in Section 7.

Alternative 1 – IFRS-ELG as presented in the Amended Financial Forecast	Alternative 2 – IFRS-ALG
Cease gain & loss deferral and depreciation method deferral, amortize deferral balances and phase-in ELG depreciation	Convert to ALG following completion of a further review process as defined by the PUB*, continue gains and losses deferral, continue depreciation methodology deferral until ALG transition; commence amortization of deferral balances effective September 1, 2023

** It is not possible for Manitoba Hydro to convert to IFRS-ALG depreciation immediately on receipt of an Order, as further work would be required to refine componentization and implement changes to Manitoba Hydro's financial systems.*

A comparison of Alternative 1 and 2, based on the depreciation policy items, implementation considerations and financial impacts is presented in Appendix A.

Based on the need to refine componentization and the potential for different financial impacts resulting from that refinement of componentization, Coalition submits that full compliance with the PUB's directives on depreciation have not been met in the current proceeding, and that a final decision on depreciation matters cannot be made at this time. As such, other interim approaches (Alternatives 3 & 4) should be considered rather than those outlined above. These alternatives are discussed in detail in the Consumers Coalition's position in Section 8.2.

Alternative 3 – Previous CGAAP without Amortization	Alternative 4 – Previous CGAAP with Amortization
Continue depreciation methodology and gains and losses deferrals without amortization until the PUB opines on depreciation matters*	Continue to defer depreciation methodology differences and gains and losses until the PUB opines on depreciation matters, commence amortization of deferral balances effective Sept, 2023

** Alternative 3 would require the PUB to include a finding in their Order that amortization periods will be determined once a final decision is made on depreciation policy issues, to address financial reporting and audit risks related to the future recovery of the depreciation deferral account balances.*

A comparison of Alternative 3 and 4, based on the depreciation policy items and implementation considerations has not been provided as such decisions would be made in a subsequent proceeding.

8.1. Comparison of Proposed Alternatives

A comparison of financial impact for the proposed alternatives is presented below.

Figure 12 below provides a comparison of net income and debt ratios for Alternatives 1 and 2. Please refer to Appendix C (Figures 17 through 34) for financial statements and metrics reflecting Alternatives 1 and 2. Please note that the financial statements and metrics for Alternative 1 are also available in Appendix 4.1 (Amended) of Manitoba Hydro's application. Alternative 1 reflects depreciation determined using IFRS-ELG effecting September 1, 2023, with phase-in and no deferral of gains and losses, whereas Alternative 2 reflects depreciation determined using IFRS-ALG effective April 1, 2026, with deferral of gains and losses, without phase-in.

Figure 12 Forecast Net Income & Debt Ratio Comparison of Alternatives 1 and 2

	Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)	Alternative 2 - IFRS-ALG	Difference
	NET INCOME IN MILLIONS OF DOLLARS		
2022/23	751	751	-
2023/24	469	462	(7)
2024/25	295	289	(5)
2025/26	149	151	1
2026/27	166	129	(37)
2027/28	97	67	(30)
2028/29	92	69	(23)
2029/30	111	94	(17)
2030/31	105	95	(9)
2031/32	169	166	(3)
2032/33	190	195	6
2033/34	219	230	12
2034/35	277	293	16
2035/36	250	272	22
2036/37	282	310	28
2037/38	309	344	35
2038/39	358	396	38
2039/40	439	477	38
2040/41	507	548	40
2041/42	569	613	43
20-Year Total	**5 803**	**5 951**	**147**

	Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)	Alternative 2 - IFRS-ALG	Difference
	DEBT RATIO IN % ASSUMING A 2% RATE PATH		
2022/23	85%	85%	0%
2023/24	83%	83%	0%
2024/25	82%	82%	0%
2025/26	82%	82%	0%
2026/27	81%	81%	0%
2027/28	81%	81%	0%
2028/29	80%	81%	0%
2029/30	80%	80%	0%
2030/31	79%	80%	0%
2031/32	79%	79%	0%
2032/33	78%	78%	0%
2033/34	77%	78%	0%
2034/35	76%	76%	0%
2035/36	75%	75%	0%
2036/37	73%	73%	0%
2037/38	72%	72%	0%
2038/39	71%	71%	0%
2039/40	70%	69%	0%
2040/41	68%	68%	0%
2041/42	66%	66%	0%

Figure 13 below provides a comparison of net income for Alternative 3 and 4. Alternatives 3 and 4 reflect depreciation based on previous CGAAP ASL, with continuation of depreciation methodology and gains and losses deferrals. Alternative 3 does not include amortization of deferral balances whereas Alternative 4 assumes amortization commencing September 1, 2023. Alternative 3 has been previously filed as COALITION/MH I-41 c) and PUB/MH I-111 b)-i). Alternative 4 has been previously filed as COALITION/MH I-41 d).

Figure 13 Forecast Net Income Comparison of Alternatives 3 and 4

	Alternative 3 - Previous CGAAP-ASL No Amortization	Alternative 4 - Previous CGAAP-ASL with Amortization	Difference
2022/23	751	751	-
2023/24	471	462	9
2024/25	306	289	16
2025/26	169	151	18
4-Year Total	**1 696**	**1 653**	**43**

Figure 14 below provides a comparison of net income for Alternatives 1 through 4.

Figure 14 Forecast Net Income Comparison of Alternatives 1 through 4

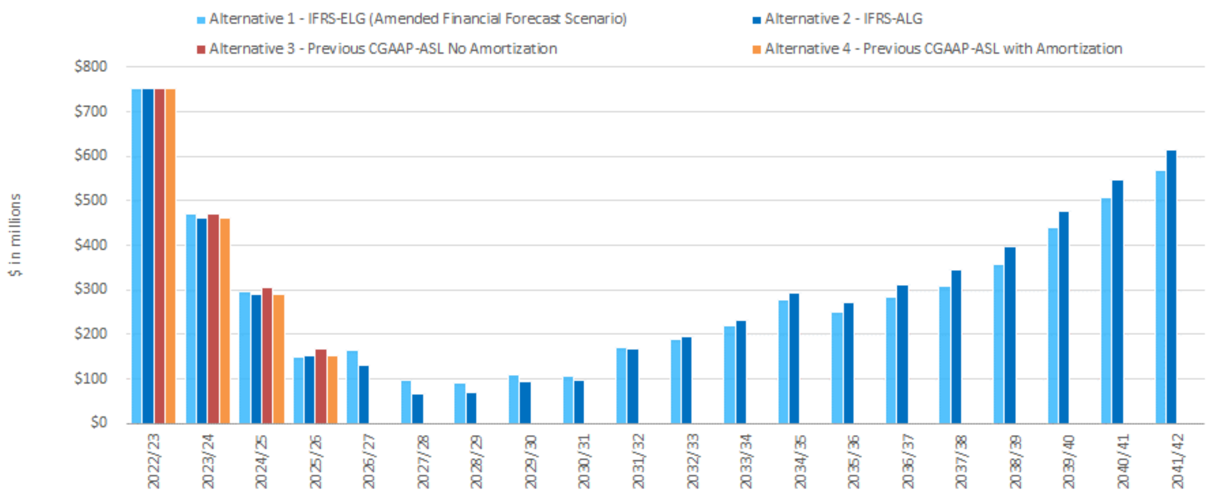


Figure 15 below provides a comparison of the RCC ratios for 2023/24 by customer class determined in PCOSS24 (based on the Amended Financial Forecast Scenario) versus those calculated with the application of IFRS-ALG depreciation. The following comparison does not reflect PCOSS analysis of the 2026/27 forecast, differences in depreciation resulting from componentization changes or differences in regulatory deferral amortization resulting from the deferred implementation of Alternative 2. As such, the RCC's ratios provided below would differ, but given the minimal impact to RCC's resulting from the treatment of gains and losses (as discussed in Section 7.2) and from choice of depreciation procedure (as discussed in Section 7.3), Manitoba Hydro considers the differences in RCC ratios reflected in Figure 15 to be indicative of a reasonable comparison of the alternatives.

The RCC ratios by customer class have not been calculated for Alternatives 3 and 4 but given the minimal difference in net income for the test years, these alternatives are not expected to materially impact the proposed rate path or the proposed differential rates by customer class.

Figure 15 Comparison of RCC Ratios by Customer Class – PCOSS24 vs IFRS-compliant ALG

Revenue-Cost-Coverage Ratios by Customer Class	PCOSS24	IFRS-ALG With Deferred Gains & Losses	Difference
Residential	94.4%	94.3%	-0.1%
General Service - Small Non Demand	109.7%	109.6%	-0.1%
General Service - Small Demand	101.8%	101.9%	0.1%
General Service - Medium	100.3%	100.3%	0.0%
General Service - Large 0 - 30kV	97.9%	98.0%	0.1%
General Service - Large 30-100kV	112.4%	112.6%	0.2%
General Service - Large >100kV	113.2%	113.5%	0.3%
Area & Roadway Lighting	108.2%	108.7%	0.5%

As discussed in Section 7.2 and Section 7.3 above, based on Manitoba Hydro's analysis, the differences in RCC ratios reflected in Figure 15 above are not material enough to significantly impact the proposed rates by customer class.

8.2. Party Positions Regarding Proposed Alternatives

Party Positions Regarding Proposed Alternatives	
Manitoba Hydro	While Manitoba Hydro considers both Alternative 1 and 2 to be viable, it considers Alternative 1 to be preferred as it could be implemented immediately on receipt of direction from the PUB and fully resolves the depreciation issues. Furthermore, based on the analysis outlined in Section 8.1, since depreciation is a non-cash item the difference in net income between Alternatives 1 and 2 is not material enough to impact Manitoba Hydro's proposed rate path, the proposed differential rates by customer class, or the achievement of the 70% debt ratio target by 2039/40. It should also be noted that there has been a shift in Canadian electric utility depreciation practices since 2015, with Manitoba Hydro no longer being an outlier in the use of an ELG procedure (PUB/MH II-37). While Alternative 1 assumes a phase-in of ELG depreciation over 15 years with amortization over 30 years and does not include the deferral of gains and losses, Manitoba Hydro is open to consideration of deferring gains and losses and alternate approaches to the proposed 15-year phase-in (based on the analysis outlined in Section 7) together with an ELG approach.

	Although Alternative 2 (ALG) would be viable, it would take several years and require administrative effort and costs to implement. The Parties all agree that further work should occur to refine the level of componentization that is currently proposed by Alliance for ALG, to remove components of immaterial amount or insignificant effect to either depreciation expense or gains and losses. After this work, Manitoba Hydro would proceed with the effort to convert to ALG. Additional resources (permanent FTE) would be required to execute this conversion and provide on-going support. This would result in increased O&A expenses which are not anticipated to be material to Manitoba Hydro's overall electric segment. Since Alternative 2 could not be implemented immediately, a transition period would be required where the current CGAAP-ASL methodology (with amortization of the existing deferral balances) is continued until the new ALG methodology can be applied. If Alternative 2 is selected, a phase-in may not be necessary as the impacts to net income are expected to be smaller than ELG due to the proposed deferral of gains and losses under this alternative. Manitoba Hydro does not recommend either Alternative 3 or 4. MH believes that sufficient information has been provided to satisfy Directives 8 and 9 of Order 43/13. This is discussed in Tab 9, Section 9.11 Directive 17. The finalization of IFRS-ALG components is unlikely to change the financial outcome significantly enough to prevent the PUB from opining on depreciation matters as part of the current proceeding.
MIPUG	The MIPUG position is more fully set out in Exhibit MIPUG-6 and the responses to IRs on MIPUG-6. ELG is a highly inferior procedure for depreciation for a Crown utility with long-lived assets (the only other Crown utility shown in PUB/MH II-37 that uses ELG is NB Power). It results in significantly higher depreciation expense, that is not tied to the consumption of utility services, which is the outcome depreciation should be trying to achieve. The estimates in this paper reflect a comparison of Concentric's ELG study with Alliance's ALG study. Apples-to-apples, Concentric's studies show ELG costs $54 million more per year for 2022/23[2] (excluding gains and losses, which should be

[2] Data at PUB/MH-II-39 Figure 1 at $561 million ($588 million less $27 million gains and losses) versus PUB/MH-I-81 Figure 1 at $615 million ($618 million less $3 million gains and losses). The difference between ELG and ASL is $54 million

	amortized in any case); and Alliance shows ELG costs $30 million more per year[3]. It is only by comparing Alliance ALG (who is more aggressive in life estimates) to Concentric (who is less aggressive) that one comes up with the estimated difference being as small as $15 million per year as quoted in this paper ($267 million over 20 years) and even then ELG is still more costly. It is the MIPUG expert's view that this estimated gap is likely to increase as: 1. The Alliance components are tested by Hydro and only material relevant new components are implemented, and 2. Hydro then has its depreciation consultants complete a full and proper study of asset lives, akin to what was done by Concentric in this proceeding. In addition, implementing ELG today, as proposed by Hydro is sufficiently onerous that it requires a lengthy phase-in (30 years) which underlines the adverse impacts that ELG causes, and lengthy phase-in periods are not a desirable requirement for setting rates. A final decision on ALG can be made in this hearing, and although it takes some time to implement, once implemented in about 2 years time, there may well be no further need for phase-in as the impacts will be much smaller than ELG. Assertions that have been made about the need for additional componentization only if implementing ALG are not well founded. There is no text or procedure manual that says that assets of materially different lives can be combined as long as the utility uses ELG. No accounting standard references ELG, much less as a means to avoid componentizing properly. No depreciation textbook describes ELG as a solution for bad componentization. Now that Alliance has identified accounts where assets of materially different lives are mixed, it is incumbent on Hydro to consider implementing these components (if the net impacts are material) whether using ELG or ASL. The MIPUG position is more fully set out in Exhibit MIPUG-6 and the responses to IRs on MIPUG-6. The ALG approach set out in Alternative 2 is recommended. It maintains adherence to the approach used for rate setting in recent years, and the approach used prior to Hydro electing to adopt ELG. When combined with the proposed regulatory

[3] Data at PUB/MH-II-39 Figure 1 at $606 million ($628 million less $22 million gains and losses) versus PUB/MH-I-81 Figure 5 at $636 million ($639 million less $3 million).

	deferral accounts, it reflects a net impact that is equivalent to the most common industry standard approach to setting depreciation expense by utilities in North America. The only significant change represented by the ALG Alternative #2 as compared to past practice is to increase componentization. Where this reflects improved tracking of assets that were previously mixed into accounts with materially different lives, this is a beneficial factor that should be pursued regardless as to the depreciation procedure selected. Componentization is a matter that Hydro should be continually re-evaluating as part of tracking depreciation estimates. There is not likely to be a significant need for a phase-in of this approach, if any. The approach is also transparent, intuitive, and appropriately matches the service value delivered by a group of assets in a year to the net depreciation expense recorded. Finally, the ALG approach best reflects that material increases in depreciation expense are not required when the accumulated depreciation that is presently recorded on Hydro's balance sheet exceeds the estimated accumulated depreciation required at this time by between $700 million and $1.3 billion. In respect of Alternatives 3 and 4 being applied on an interim basis, these are viable alternatives available to the Board in the event it determined that the information available still does not meet the standard of a "full" information base to test the alternatives. If the Board makes this interim type determination, Alternative 3 is preferred to Alternative 4, as it most closely retains the existing ALG approach on an interim basis. However, MIPUG does not consider that an interim approach is required or prudent given the large number of issues that the Board may need to address in the next GRA. Further, selecting Alternatives 3 or 4 on an interim basis today has all of the downsides of selecting Alternative 2 in terms of the work that is demanded of Hydro by the next GRA, but without the clarity that the work will ultimately be worthwhile. Outside of an interim solution, it is also noted that Alternative 4 could effectively be pursued permanently, as practical differences between Alternative 4 and Alternative 2 are fundamentally very limited – solely related to the degree of componentization. MIPUG views that Hydro's ongoing practice should always include a continuing review of rational componentization where merited, regardless as to the alternative selected. For this reason, the MIPUG position would be that

	Alternatives 2 and 4 are basically a distinction without any material difference and would ultimately gravitate towards the precise same ultimate outcome. Alternatives 2 and 4 are both effectively indicating Hydro should keep doing what it has always done to set rates (ALG depreciation) and add new asset components where merited (including potentially where internal staff suggest it is helpful to achieve a clean IFRS audit under ALG, eliminating the need for one of the regulatory deferrals) with all amounts that are deferred for regulatory purposes being amortized over the remaining life of the assets. MIPUG also takes note of the evidence of GSS/GSM that the current regulatory approach of ASL would be IFRS compliant if used for financial reporting with limited to no additional componentization.
GSS/GSM	GSS/GSM supports the adoption of Alternative 2. The rate impacts of adopting a change to IFRS-ELG (Alternative 1) are significant and not warranted in this case. Further, Mr. Madsen's evidence outlines in detail why the ELG procedure should not be adopted, and GSS/GSM agrees with this evidence. GSS/GSM supports the use of IFRS-ALG as the preferred alternative (Alternative 2). GSS/GSM considers the definition of "IFRS-ALG" at this time to represent the current level of componentization under Concentric's 2019 Depreciation Study applying the ALG procedure. GSS/GSM also considers that the level of componentization under existing "CGAAP-ASL" would be IFRS compliant. GSS/GSM supports the use of the whole life technique and the amortization of any gains/losses, reserve imbalances, and deferrals over the expected remaining life of the assets. GSS/GSM considers that additional work may be required to refine the calculation of gains and losses under the ALG procedure. Such efforts would assist in refining the amount of costs included within accumulated depreciation as opposed to being included in a deferral account but will have no impact on overall rates. Regarding componentization, GSS/GSM supports some additional componentization to adopt ALG beyond that already contemplated in the Concentric 2019 Depreciation Study. However, GSS/GSM does not in principle consider material additional componentization to be required and would need to review any proposed incremental componentization to confirm that it is "significant" to depreciation expense. Further, GSS/GSM notes that additional componentization should not be assumed to increase depreciation expense, as further componentization may result in an overall extension of the asset lives, thus reducing depreciation expense.

	Finally, GSS/GSM does not consider that adopting Alternative 2 will have material implementation or ongoing FTE costs. The core issue regarding the adoption of Alternative 2 is whether additional componentization is required that would result in a "significant" impact on depreciation expense. This assessment is not considered to be complex, nor would the ongoing effort to implement Alternative 2 be complex as the level of componentization should not be expected to change materially. Further, GSS/GSM notes that implementation of Alternative 2 could in fact result in cost efficiencies as regulatory and financial reporting will be aligned, there would be no need to maintain two sets of books going forward, and the level of effort to track and reconcile the deferral accounts will also be eliminated. Regarding Alternatives 3 and 4, the GSS/GSM notes that Mr. Madsen's evidence considers the "CGAAP-ASL" approach to already be IFRS-compliant. Further, Mr. Madsen observed that the deferral accounts already have a natural amortization period as the total amount of depreciation collected will be equal under either the ALG, ELG or "CGAAP-ASL" procedure. For these reasons, the GSS/GSM consider Alternatives 3 and 4 to be viable. However, GSS/GSM continues to prefer Alternative 2 over 3 and 4, as Alternative 2, if implemented will result in an alignment of both regulatory and financial reporting, which has significant benefits through reduction in cost and effort for Manitoba Hydro.
Coalition	While the Coalition considers both Alternatives 1 and 2 to be viable in the longer-term, it is of the view that PUB Directives 8 & 9 from Order 43/13 have not been fully satisfied and as such the PUB cannot make final determinations on the depreciation policy issues in this proceeding and parties should provide interim alternatives for PUB consideration. The PUB was clear in Orders 43/13, 73/15 and 59/18 that the information that was outstanding for the PUB to make final determinations on depreciation policy issues was (1) an IFRS compliant ALG study and (2) a complete understanding of the financial and rate impacts of the differences between IFRS ELG and IFRS ALG depreciation methodologies. The PUB clearly reiterated in Order 59/18 (page 146), that in the absence of "full" compliance with these past depreciation directives - it would not make a final disposition with respect to the appropriate long-term depreciation methodology for rate-setting purposes and by extension was not in a position to endorse any amortization of depreciation regulatory deferral accounts (RDA).

	An assessment of the record of the current proceeding indicates that (1) MH's position is that it still has a significant work effort outstanding to develop a final position on the appropriate level of componentization under IFRS ALG and (2) MPUG's assessment is that there is no agreement amongst the parties to this engagement process on the financial and rate impacts of IFRS ELG as compared to IFRS ALG. These circumstances lead to the conclusion that despite the additional information that has been presented in the current proceeding that has assisted in narrowing the differences between interest parties - "full" compliance with the PUB's past depreciation directives have not been achieved in the current proceeding. The implications of this conclusion is that the PUB is not able to make final determinations with respect to the non-consensus issues flowing from the depreciation engagement process and cannot make a final determination on Alternative 1 (phase-in of IFRS ELG as per the amended financial forecast) or Alternative 2 (delayed conversion to IFRS ALG after a further PUB process). Accordingly, interim options should be assessed and presented to the PUB for the purpose of decision making in the current proceeding. There are two most likely interim options for the PUB. Alternative 3 would be to continue to defer amounts to the change in the depreciation method and gains/losses on disposition RDAs with no amortization for the interim period. However, the PUB would also make a finding that it agrees with the interested parties that amortization periods will be determined once a final decision on depreciation policy issues is made at the next GRA. This finding would be intended to deal with the financial reporting/audit risks associated with future recovery of RDA's in rates. Alternative 4 would be to continue to defer amounts to the change in the depreciation method and gains/losses on disposition RDA's and begin to amortize the RDA balances in the interim over the remaining useful lives of the assets contributing to the RDAs. The selection of either interim Alternative 3 or 4 would be based on the PUB's assessment it if prefers to (1) to provide "comfort" on financial reporting/audit risks and wait to commence the amortization of depreciation RDAs until a final determination on depreciation issues is made at the next GRA - or alternatively - to start amortizing the depreciation RDAs in advance of the final determination of depreciation issues at the next GRA, with the potential for further changes once final determinations are made.

	Additionally, care must be exercised in the proper assessment of the analysis of the potential impacts of the various scenarios and alternatives to the overall rate proposals and differentiated rate proposals in the current GRA. There is no consensus with respect to the 2% rate path based on achievement of the debt ratio target for 2039/40 (in the new legislative framework that is not operative until April 1, 2025), the straight-up comparisons of gains and losses and immediate implementation ELG vs. ALG are for demonstration purposes only and are not able to be implemented for the Test Years in the current GRA and there is no consensus amongst parties with respect to the financial and rate implications of Alternative 2. PCOSS24 and the proposed differential rates are based on the 2023/24 Test Year. As the 2023/24 net income forecasts for all four alternatives ($469M, $462M, $471M and $462M, respectively) are very close, the differences are immaterial and should not impact the PUB's decisions with respect to differential rate impacts or across the board rate impacts.

APPENDIX A – Comparison of Proposed Alternatives 1 and 2

The following table provides a comparison of depreciation policy items, implementation considerations and financial impacts for Alternatives 1 and 2:

	Alternative 1 – IFRS-ELG (Amended Financial Forecast Scenario)	Alternative 2 – IFRS-ALG
Implementation date	September 2023	April 2026
IFRS-compliant depreciation methodology for rate-setting purposes	IFRS compliant	IFRS compliant
Depreciation technique	Whole life	Whole life
Amortization of deferral accounts	Remaining useful life of the assets contributing to the accounts	Remaining useful life of the assets contributing to the accounts
Componentization	No immediate identified need for additional componentization	Further analysis required to determine extent of additional componentization required
Depreciation methodology	Adopt IFRS-ELG for regulatory purposes	Convert to IFRS-ALG for financial and regulatory purposes
Treatment of gains and losses	Cease deferral and amortize	Continue to defer gains & losses and amortize
Change in depreciation methodology	Cease deferral and commence amortization Sept 2023	Continue to defer until April 2026 (ALG transition date) Commence amortization Sept 2023 Balance in the Change in depreciation method deferral will grow by approximately $140 million until ALG implementation
Phase-In recommended	Yes (MH proposed 15 year phase-in amortized for 30 years)	No

	Alternative 1 – IFRS-ELG (Amended Financial Forecast Scenario)	Alternative 2 – IFRS-ALG
Implementation considerations	Negligible effort – could be implemented immediately on receipt of Order	Will require 2-4 years to fully implement (duration depends on number of additional components). Required steps are as follows: • Determine componentization • Depreciation Study ○ Update 2019 study data ○ Compile 2020-2024 study data • Regulatory Review • System changes • Historical asset conversion • Capital project conversion • Business process changes • Staff training (accounting and project staff)
Estimated cumulative impact to net income over 20-year forecast (*see Figures 12 & 14 below*)	Same net income as filed in Application	$147 million increase in cumulative net income
Impact on proposed rates by customer class	As submitted in MH's Application	Not determined as PCOSS analysis for 2026/27 has not been completed

APPENDIX B – Differential Rate Impact of Changes to Depreciation

The following section should be read in the context of Tab 8, Sections 8.3 and 8.4 (pages 6-14) which explains the use of class Revenue-cost-coverage (RCC) ratios in the development of proposed changes to rates by customer class.

Figure 16 below provides an estimate of the RCC ratios by customer class for 2023/24 that would result from use of IFRS-ELG or IFRS-ALG depreciation scenarios versus the depreciation assumptions embedded in the Amended Financial Forecast Scenario and reflected in PCOSS24. The RCC impact differs for each class due to the specific assets used by the class, as well as the degree that the change in depreciation is not consistent between each function.

The four IFRS PCOSS scenarios presented in Figure 16 below have been modelled based on the functionalized depreciation expense provided in PUB/MH I-81, including and excluding gains and losses. The IFRS-ELG scenarios reflect depreciation amounts shown in PUB/MH I-81 Figure 1, and the IFRS-ALG scenarios reflect depreciation amounts reflected in PUB/MH I-81 Figure 4. In order to determine and isolate the impact directly attributable to the depreciation methodology, the PCOSS scenarios assume full inclusion of IFRS-ELG and IFRS-ALG depreciation expense for 2023/24 without phase-in and excluding amortization of the existing deferral accounts.

Figure 16 RCC Ratios by Customer Class – PCOSS24 vs Alternate IFRS Depreciation Scenarios

Revenue Cost Coverage Ratios by Customer Class	PCOSS24	IFRS-ELG With Deferred Gains & Losses	IFRS-ELG Without Deferred Gains & Losses	IFRS-ALG With Deferred Gains & Losses	IFRS-ALG Without Deferred Gains & Losses
Residential	94.4%	94.2%	94.2%	94.3%	94.2%
General Service - Small Non Demand	109.7%	109.5%	109.5%	109.6%	109.6%
General Service - Small Demand	101.8%	101.8%	101.8%	101.9%	101.9%
General Service - Medium	100.3%	100.2%	100.2%	100.3%	100.3%
General Service - Large 0 - 30kV	97.9%	98.2%	98.2%	98.0%	98.2%
General Service - Large 30-100kV	112.4%	113.3%	113.3%	112.6%	113.1%
General Service - Large >100kV	113.2%	114.3%	114.4%	113.5%	114.1%
Area & Roadway Lighting	108.2%	106.8%	106.9%	108.7%	103.5%

RCCs are a comparison of total revenue to total costs, so an increase in RCC indicates that a rate decrease may be required, while an RCC decrease is indicative of the need for a potential rate increase. Rate changes consider the total costs and revenues for a class among other factors, so a change in class RCC in these scenarios would not translate directly into a rate adjustment but does provide an indication of the incremental rate change associated with a change in depreciation. The current Application proposes differentiating rates over five years to achieve the target RCC ratios, so the annual rate impact is approximately $1/5^{th}$ of the indicated RCC difference between each scenario.

APPENDIX C – Financial Statements and Key Financial Measures for Alternatives 1 and 2

Figure 17: Electric Operations Projected Operating Statement: Alternative 1 – IFRS-ELG – 2022/23 to 2031/32

ELECTRIC OPERATIONS PROJECTED OPERATING STATEMENT
Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)
(In Millions of Dollars)

For the year ended March 31	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**
REVENUES										
Domestic Revenue										
at approved rates	1 875	1 847	1 853	1 863	1 874	1 888	1 904	1 922	1 943	1 973
additional	-	24	74	113	153	195	238	284	331	382
Extraprovincial	1 283	1 153	964	780	778	754	740	748	768	766
Other	29	29	29	30	31	32	37	38	39	40
	3 186	3 052	2 920	2 786	2 836	2 869	2 919	2 991	3 081	3 161
EXPENSES										
Operating and Administrative	589	657	687	683	697	711	724	736	739	754
Net Finance Expense	909	900	886	906	915	927	936	946	949	923
Depreciation and Amortization	618	632	643	657	669	688	707	727	750	773
Water Rentals and Assessments	81	83	79	76	77	78	78	78	78	78
Fuel and Power Purchased	139	163	156	182	173	173	176	177	198	186
Capital and Other Taxes	160	162	163	165	166	168	170	171	173	175
Other Expenses	118	80	74	72	72	77	80	83	83	79
Corporate Allocation	7	7	7	7	7	7	7	3	1	1
	2 621	2 684	2 695	2 748	2 777	2 828	2 877	2 922	2 972	2 970
Net Income before Net Movement in Reg. Deferral	565	368	224	38	59	41	42	69	110	191
Net Movement in Regulatory Deferral	190	106	77	118	114	62	57	50	4	(12)
Net Income	755	474	301	156	173	104	99	119	113	178
Net Income Attributable to:										
Manitoba Hydro	**751**	**469**	**295**	**149**	**166**	**97**	**92**	**111**	**105**	**169**
Wuskwatim Investment Entity	4	5	6	7	7	7	7	8	9	9
Keeyask Investment Entity	-	-	-	-	-	-	-	-	-	-
Total Non-Controlling Interests	4	5	6	7	7	7	7	8	9	9
	755	474	301	156	173	104	99	119	113	178
Percent Increase	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	0.00%	2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	17.17%	19.51%

Figure 18: Electric Operations Projected Operating Statement: Alternative 1 – IFRS-ELG – 2032/33 to 2041/42

ELECTRIC OPERATIONS PROJECTED OPERATING STATEMENT
Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)
(In Millions of Dollars)

For the year ended March 31	**2032/33**	**2033/34**	**2034/35**	**2035/36**	**2036/37**	**2037/38**	**2038/39**	**2039/40**	**2040/41**	**2041/42**
REVENUES										
Domestic Revenue										
at approved rates	2 010	2 051	2 095	2 151	2 212	2 274	2 337	2 400	2 466	2 528
additional	437	495	558	627	702	781	866	955	1 050	1 148
Extraprovincial	754	762	783	707	693	705	682	643	615	588
Other	41	43	45	49	53	56	58	61	64	65
	3 242	3 352	3 482	3 534	3 660	3 816	3 942	4 059	4 195	4 329
EXPENSES										
Operating and Administrative	769	785	800	816	833	849	872	896	914	939
Net Finance Expense	928	929	929	915	904	900	893	876	863	853
Depreciation and Amortization	797	824	851	878	908	945	984	1 016	1 055	1 095
Water Rentals and Assessments	78	79	80	80	80	80	80	80	81	81
Fuel and Power Purchased	191	214	232	270	317	387	403	393	426	436
Capital and Other Taxes	177	181	182	184	187	189	191	194	196	198
Other Expenses	86	89	91	94	97	100	104	107	111	113
Corporate Allocation	1	1	1	1	1	1	1	1	1	1
	3 027	3 101	3 166	3 239	3 327	3 452	3 528	3 563	3 647	3 717
Net Income before Net Movement in Reg. Deferral	215	251	316	295	332	363	414	496	548	612
Net Movement in Regulatory Deferral	(15)	(21)	(26)	(33)	(37)	(42)	(40)	(39)	(23)	(24)
Net Income	200	230	289	262	295	322	374	457	526	589
Net Income Attributable to:										
Manitoba Hydro	**190**	**219**	**277**	**250**	**282**	**309**	**358**	**439**	**507**	**569**
Wuskwatim Investment Entity	10	11	12	12	13	13	16	17	18	19
Keeyask Investment Entity	-	-	-	-	-	-	-	-	-	-
Total Non-Controlling Interests	10	11	12	12	13	13	16	17	18	19
	200	230	289	262	295	322	374	457	526	589
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	21.90%	24.34%	26.82%	29.36%	31.95%	34.59%	37.28%	40.02%	42.82%	45.68%

Figure 19: Electric Operations Projected Balance Sheet: Alternative 1 – IFRS-ELG – 2022/23 to 2031/32

ELECTRIC OPERATIONS PROJECTED BALANCE SHEET
Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)
(In Millions of Dollars)

For the year ended March 31	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**
ASSETS										
Plant in Service	28 814	29 416	30 089	30 739	31 593	32 345	33 112	33 929	34 789	35 693
Accumulated Depreciation	(3 525)	(4 083)	(4 638)	(5 186)	(5 773)	(6 409)	(7 044)	(7 706)	(8 390)	(9 096)
Net Plant in Service	25 288	25 333	25 451	25 553	25 820	25 935	26 068	26 223	26 399	26 597
Construction in Progress	470	512	472	484	319	328	336	343	350	357
Current and Other Assets	2 222	1 513	1 630	1 688	1 550	1 636	1 744	1 599	1 701	1 892
Goodwill and Intangible Assets	1 034	1 006	981	954	925	896	866	836	805	774
Total Assets before Regulatory Deferral	29 014	28 364	28 535	28 678	28 614	28 796	29 013	29 000	29 255	29 621
Regulatory Deferral Balance	1 389	1 426	1 503	1 572	1 637	1 700	1 757	1 807	1 811	1 798
	30 403	29 790	30 038	30 251	30 251	30 495	30 770	30 807	31 066	31 419
LIABILITIES AND EQUITY										
Long-Term Debt	22 408	21 912	21 747	21 494	21 186	21 078	21 987	21 440	21 968	22 750
Current and Other Liabilities	3 931	3 389	3 440	3 742	3 861	4 089	3 336	3 783	3 379	2 748
Provisions	67	65	63	61	59	56	54	52	51	50
Deferred Revenue	626	683	755	830	891	917	945	973	1 004	1 038
Retained Earnings	3 575	4 044	4 339	4 488	4 654	4 751	4 843	4 953	5 058	5 227
Accumulated Other Comprehensive Income	(371)	(402)	(404)	(413)	(401)	(396)	(394)	(394)	(394)	(394)
Total Liabilities and Equity before Regulatory Deferral	30 236	29 692	29 940	30 202	30 251	30 495	30 770	30 807	31 066	31 419
Regulatory Deferral Balance	166	98	98	49	0	0	0	0	0	0
	30 403	29 790	30 038	30 251	30 251	30 495	30 770	30 807	31 066	31 419

Figure 20: Electric Operations Projected Balance Sheet: Alternative 1 – IFRS-ELG – 2032/33 to 2041/42

ELECTRIC OPERATIONS PROJECTED BALANCE SHEET
Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)
(In Millions of Dollars)

For the year ended March 31	**2032/33**	**2033/34**	**2034/35**	**2035/36**	**2036/37**	**2037/38**	**2038/39**	**2039/40**	**2040/41**	**2041/42**
ASSETS										
Plant in Service	36 672	37 680	38 768	39 910	41 171	42 495	43 923	45 182	46 564	48 003
Accumulated Depreciation	(9 818)	(10 579)	(11 346)	(12 134)	(12 963)	(13 841)	(14 753)	(15 690)	(16 642)	(17 650)
Net Plant in Service	26 853	27 101	27 422	27 776	28 208	28 655	29 170	29 491	29 922	30 354
Construction in Progress	365	373	381	492	753	662	536	826	726	569
Current and Other Assets	2 134	2 654	2 772	2 575	2 571	2 502	2 467	2 466	2 367	2 528
Goodwill and Intangible Assets	743	713	683	652	622	592	562	532	502	472
Total Assets before Regulatory Deferral	30 095	30 841	31 258	31 497	32 154	32 411	32 735	33 315	33 517	33 923
Regulatory Deferral Balance	1 783	1 763	1 736	1 704	1 666	1 625	1 585	1 546	1 523	1 499
	31 879	32 604	32 994	33 200	33 820	34 036	34 320	34 860	35 040	35 422
LIABILITIES AND EQUITY										
Long-Term Debt	22 932	23 256	22 943	22 786	22 602	22 316	22 180	21 928	21 442	21 024
Current and Other Liabilities	2 762	2 870	3 144	3 063	3 304	3 465	3 408	3 551	3 675	3 872
Provisions	49	48	47	45	44	43	42	40	39	38
Deferred Revenue	1 113	1 189	1 342	1 538	1 821	1 853	1 973	2 184	2 218	2 254
Retained Earnings	5 417	5 635	5 912	6 162	6 444	6 753	7 112	7 551	8 058	8 628
Accumulated Other Comprehensive Income	(394)	(394)	(394)	(394)	(394)	(394)	(394)	(394)	(394)	(394)
Total Liabilities and Equity before Regulatory Deferral	31 879	32 604	32 994	33 200	33 820	34 036	34 320	34 860	35 040	35 422
Regulatory Deferral Balance	0	0	0	0	0	0	0	0	0	0
	31 879	32 604	32 994	33 200	33 820	34 036	34 320	34 860	35 040	35 422

Figure 21: Electric Operations Projected Indirect Cash Flow Statement: Alternative 1 – IFRS-ELG – 2022/23 to 2031/32

ELECTRIC OPERATIONS PROJECTED INDIRECT CASH FLOW STATEMENT
Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)
(In Millions of Dollars)

For the year ended March 31	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
OPERATING ACTIVITIES										
Net Income (Loss)	755	474	301	156	173	104	99	119	113	178
Net Movement in Regulatory Deferral	(190)	(106)	(77)	(118)	(114)	(62)	(57)	(50)	(4)	12
Add Back:										
Depreciation and Amortization	618	632	643	657	669	688	707	727	750	773
Net Finance Expense	909	900	886	906	915	927	936	946	949	923
Adjustments for Non-Cash Items	39	13	13	12	11	10	6	2	(1)	(2)
Adjustments for Non-Cash Working Capital Accounts	(6)	82	41	43	45	46	47	48	49	50
Interest Paid	(1 064)	(834)	(935)	(941)	(936)	(946)	(962)	(978)	(979)	(950)
Interest Received	24	15	10	9	5	4	5	2	1	2
Cash Provided by Operating Activities	1 084	1 176	882	724	770	770	780	816	879	987
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	657	350	750	920	970	1 360	1 590	550	1 190	780
Retirement of Long-Term Debt	(1 103)	(1 439)	(875)	(901)	(1 183)	(1 274)	(1 468)	(680)	(1 096)	(663)
Repayments from/(Advances to) Investment Entities	22	(0)	(0)	(0)	(0)	(0)	(0)	(0)	7	11
Contributions from Non-Controlling Interests	0	0	0	0	0	0	0	0	0	0
Proceeds from Short-Term Borrowings, Net	0	0	0	0	0	0	0	0	0	0
Sinking Fund Investment Withdrawals	248	244	234	233	234	232	233	234	234	235
Sinking Fund Investment Purchases	(248)	(244)	(234)	(233)	(234)	(232)	(233)	(234)	(234)	(235)
Other	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(8)	(11)
Cash Provided by Financing Activities	(425)	(1 090)	(126)	18	(214)	86	122	(131)	94	116
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(672)	(692)	(699)	(735)	(713)	(756)	(784)	(825)	(867)	(911)
Additions to Intangible Assets	(20)	(12)	(18)	(14)	(13)	(13)	(13)	(13)	(14)	(14)
Net Contributions Received	44	72	81	83	74	38	41	45	48	53
Cash Paid for Mitigation and Major Development Obligations	(103)	(57)	(52)	(55)	(54)	(54)	(55)	(55)	(50)	(51)
Cash Paid for Transmission Rights Obligations	(21)	(20)	(19)	(19)	(18)	(17)	(16)	(15)	(15)	(14)
Other	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)
Cash Used for Investing Activities	(774)	(711)	(708)	(741)	(725)	(803)	(827)	(865)	(898)	(937)
Net Increase (Decrease) in Cash	(114)	(625)	48	0	(169)	53	74	(180)	75	166
Cash at Beginning of Year	1 047	933	308	357	357	188	241	315	135	210
Cash at End of Year	933	308	357	357	188	241	315	135	210	376

Figure 22: Electric Operations Projected Indirect Cash Flow Statement: Alternative 1 – IFRS-ELG – 2032/33 to 2041/42

ELECTRIC OPERATIONS PROJECTED INDIRECT CASH FLOW STATEMENT
Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)
(In Millions of Dollars)

For the year ended March 31	**2032/33**	**2033/34**	**2034/35**	**2035/36**	**2036/37**	**2037/38**	**2038/39**	**2039/40**	**2040/41**	**2041/42**
OPERATING ACTIVITIES										
Net Income (Loss)	200	230	289	262	295	322	374	457	526	589
Net Movement in Regulatory Deferral	15	21	26	33	37	42	40	39	23	24
Add Back:										
Depreciation and Amortization	797	824	851	878	908	945	984	1 016	1 055	1 095
Net Finance Expense	928	929	929	915	904	900	893	876	863	853
Adjustments for Non-Cash Items	(3)	(4)	(6)	(9)	(13)	(16)	(17)	(20)	(23)	(24)
Adjustments for Non-Cash Working Capital Accounts	51	52	53	54	55	57	58	59	60	61
Interest Paid	(961)	(961)	(966)	(959)	(949)	(946)	(936)	(926)	(914)	(899)
Interest Received	6	6	8	7	5	5	4	8	7	7
Cash Provided by Operating Activities	1 033	1 096	1 185	1 182	1 243	1 308	1 399	1 508	1 596	1 706
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	160	370	(40)	(10)	150	160	200	170	0	200
Retirement of Long-Term Debt	0	20	(49)	(275)	(150)	(338)	(449)	(339)	(425)	(488)
Repayments from/(Advances to) Investment Entities	9	10	11	12	12	12	12	15	16	16
Contributions from Non-Controlling Interests	0	0	0	0	0	0	0	0	0	0
Proceeds from Short-Term Borrowings, Net	0	0	0	0	0	0	0	0	0	0
Sinking Fund Investment Withdrawals	236	237	241	240	238	238	236	234	232	228
Sinking Fund Investment Purchases	(236)	(237)	(241)	(240)	(238)	(238)	(236)	(234)	(232)	(228)
Other	(11)	(12)	(13)	(14)	(14)	(15)	(14)	(18)	(19)	(20)
Cash Provided by Financing Activities	158	388	(91)	(287)	(2)	(180)	(251)	(171)	(428)	(291)
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(993)	(1 010)	(1 109)	(1 270)	(1 517)	(1 218)	(1 294)	(1 539)	(1 297)	(1 286)
Additions to Intangible Assets	(14)	(15)	(15)	(16)	(16)	(16)	(17)	(17)	(18)	(18)
Net Contributions Received	95	98	186	232	322	73	163	257	81	84
Cash Paid for Mitigation and Major Development Obligations	(51)	(50)	(50)	(51)	(50)	(51)	(52)	(53)	(54)	(55)
Cash Paid for Transmission Rights Obligations	(13)	(12)	(12)	(11)	(10)	(10)	(9)	(9)	(1)	0
Other	(0)	0	0	0	0	0	0	0	0	0
Cash Used for Investing Activities	(977)	(989)	(1 001)	(1 117)	(1 271)	(1 223)	(1 209)	(1 361)	(1 290)	(1 276)
Net Increase (Decrease) in Cash	214	495	93	(222)	(30)	(94)	(61)	(24)	(122)	140
Cash at Beginning of Year	376	590	1 085	1 178	956	926	832	771	747	625
Cash at End of Year	590	1 085	1 178	956	926	832	771	747	625	765

Figure 23: Electric Operations Projected Direct Cash Flow Statement: Alternative 1 – IFRS-ELG – 2022/23 to 2031/32

ELECTRIC OPERATIONS PROJECTED DIRECT CASH FLOW STATEMENT
Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)
(In Millions of Dollars)

For the year ended March 31	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 174	3 039	2 907	2 772	2 822	2 853	2 899	2 971	3 060	3 139
Cash Paid to Suppliers and Employees	(1 049)	(1 044)	(1 099)	(1 116)	(1 121)	(1 141)	(1 162)	(1 178)	(1 203)	(1 203)
Interest Paid	(1 064)	(834)	(935)	(941)	(936)	(946)	(962)	(978)	(979)	(950)
Interest Received	24	15	10	9	5	4	5	2	1	2
Cash Provided by Operating Activities	1 084	1 176	882	724	770	770	780	816	879	987
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	657	350	750	920	970	1 360	1 590	550	1 190	780
Retirement of Long-Term Debt	(1 103)	(1 439)	(875)	(901)	(1 183)	(1 274)	(1 468)	(680)	(1 096)	(663)
Repayments from/(Advances to) External Entities	22	(0)	(0)	(0)	(0)	(0)	(0)	(0)	7	11
Contributions from Non-Controlling Interests	0	0	0	0	0	0	0	0	0	0
Proceeds from Short-Term Borrowings, Net	0	0	0	0	0	0	0	0	0	0
Sinking Fund Investment Withdrawals	248	244	234	233	234	232	233	234	234	235
Sinking Fund Investment Purchases	(248)	(244)	(234)	(233)	(234)	(232)	(233)	(234)	(234)	(235)
Other	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(8)	(11)
Cash Provided by Financing Activities	(425)	(1 090)	(126)	18	(214)	86	122	(131)	94	116
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(672)	(692)	(699)	(735)	(713)	(756)	(784)	(825)	(867)	(911)
Additions to Intangible Assets	(20)	(12)	(18)	(14)	(13)	(13)	(13)	(13)	(14)	(14)
Net Contributions Received	44	72	81	83	74	38	41	45	48	53
Cash Paid for Mitigation and Major Development Obligations	(103)	(57)	(52)	(55)	(54)	(54)	(55)	(55)	(50)	(51)
Cash Paid for Transmission Rights Obligations	(21)	(20)	(19)	(19)	(18)	(17)	(16)	(15)	(15)	(14)
Other	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)
Cash Used for Investing Activities	(774)	(711)	(708)	(741)	(725)	(803)	(827)	(865)	(898)	(937)
Net Increase (Decrease) in Cash	(114)	(625)	48	0	(169)	53	74	(180)	75	166
Cash at Beginning of Year	1 047	933	308	357	357	188	241	315	135	210
Cash at End of Year	933	308	357	357	188	241	315	135	210	376

Figure 24: Electric Operations Projected Direct Cash Flow Statement: Alternative 1 – IFRS-ELG – 2032/33 to 2041/42

ELECTRIC OPERATIONS PROJECTED DIRECT CASH FLOW STATEMENT
Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)
(In Millions of Dollars)

For the year ended March 31	**2032/33**	**2033/34**	**2034/35**	**2035/36**	**2036/37**	**2037/38**	**2038/39**	**2039/40**	**2040/41**	**2041/42**
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 219	3 327	3 456	3 505	3 627	3 780	3 905	4 019	4 152	4 285
Cash Paid to Suppliers and Employees	(1 231)	(1 276)	(1 313)	(1 372)	(1 440)	(1 531)	(1 574)	(1 593)	(1 649)	(1 687)
Interest Paid	(961)	(961)	(966)	(959)	(949)	(946)	(936)	(926)	(914)	(899)
Interest Received	6	6	8	7	5	5	4	8	7	7
Cash Provided by Operating Activities	1 033	1 096	1 185	1 182	1 243	1 308	1 399	1 508	1 596	1 706
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	160	370	(40)	(10)	150	160	200	170	0	200
Retirement of Long-Term Debt	0	20	(49)	(275)	(150)	(338)	(449)	(339)	(425)	(488)
Repayments from/(Advances to) External Entities	9	10	11	12	12	12	12	15	16	16
Contributions from Non-Controlling Interests	0	0	0	0	0	0	0	0	0	0
Proceeds from Short-Term Borrowings, Net	0	0	0	0	0	0	0	0	0	0
Sinking Fund Investment Withdrawals	236	237	241	240	238	238	236	234	232	228
Sinking Fund Investment Purchases	(236)	(237)	(241)	(240)	(238)	(238)	(236)	(234)	(232)	(228)
Other	(11)	(12)	(13)	(14)	(14)	(15)	(14)	(18)	(19)	(20)
Cash Provided by Financing Activities	158	388	(91)	(287)	(2)	(180)	(251)	(171)	(428)	(291)
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(993)	(1 010)	(1 109)	(1 270)	(1 517)	(1 218)	(1 294)	(1 539)	(1 297)	(1 286)
Additions to Intangible Assets	(14)	(15)	(15)	(16)	(16)	(16)	(17)	(17)	(18)	(18)
Net Contributions Received	95	98	186	232	322	73	163	257	81	84
Cash Paid for Mitigation and Major Development Obligations	(51)	(50)	(50)	(51)	(50)	(51)	(52)	(53)	(54)	(55)
Cash Paid for Transmission Rights Obligations	(13)	(12)	(12)	(11)	(10)	(10)	(9)	(9)	(1)	0
Other	(0)	0	0	0	0	0	0	0	0	0
Cash Used for Investing Activities	(977)	(989)	(1 001)	(1 117)	(1 271)	(1 223)	(1 209)	(1 361)	(1 290)	(1 276)
Net Increase (Decrease) in Cash	214	495	93	(222)	(30)	(94)	(61)	(24)	(122)	140
Cash at Beginning of Year	376	590	1 085	1 178	956	926	832	771	747	625
Cash at End of Year	590	1 085	1 178	956	926	832	771	747	625	765

Figure 25: Electric Operations Key Financial Measures: Alternative 1 – IFRS-ELG

ELECTRIC OPERATIONS KEY FINANCIAL MEASURES
Alternative 1 - IFRS-ELG (Amended Financial Forecast Scenario)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Annual Rate Increases	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Rate Increases	0.00%	2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	17.17%	19.51%	21.90%	24.34%	26.82%	29.36%	31.95%	34.59%	37.28%	40.02%	42.82%	45.68%
Net Income/(Loss)	$751	$469	$295	$149	$166	$97	$92	$111	$105	$169	$190	$219	$277	$250	$282	$309	$358	$439	$507	$569
Net Income/(Loss) before Net Movement in Reg. Deferral	$565	$368	$224	$38	$59	$41	$42	$69	$110	$191	$215	$251	$316	$295	$332	$363	$414	$496	$548	$612
Retained Earnings	$3 575	$4 044	$4 339	$4 488	$4 654	$4 751	$4 843	$4 953	$5 058	$5 227	$5 417	$5 635	$5 912	$6 162	$6 444	$6 753	$7 112	$7 551	$8 058	$8 628
Total Equity	$4 030	$4 511	$4 883	$5 055	$5 255	$5 393	$5 523	$5 663	$5 797	$6 000	$6 264	$6 559	$6 990	$7 438	$8 004	$8 346	$8 825	$9 476	$10 018	$10 623
Net Debt	$22 963	$22 529	$22 341	$22 371	$22 322	$22 356	$22 401	$22 451	$22 471	$22 424	$22 372	$22 270	$22 090	$22 030	$22 063	$21 983	$21 798	$21 656	$21 355	$20 930
Change in Net Debt - Inc/(Dec)	($330)	($435)	($187)	$29	($48)	$33	$46	$49	$21	($47)	($52)	($102)	($180)	($60)	$33	($80)	($185)	($141)	($302)	($425)
Cash Provided by Operating Activities	$1 084	$1 176	$882	$724	$770	$770	$780	$816	$879	$987	$1 033	$1 096	$1 185	$1 182	$1 243	$1 308	$1 399	$1 508	$1 596	$1 706
Cash Used for Investing Activities	($774)	($711)	($708)	($741)	($725)	($803)	($827)	($865)	($898)	($937)	($977)	($989)	($1 001)	($1 117)	($1 271)	($1 223)	($1 209)	($1 361)	($1 290)	($1 276)
Cash Surplus/(Deficit)	$310	$465	$174	($17)	$45	($33)	($47)	($49)	($19)	$50	$56	$106	$184	$65	($28)	$86	$190	$147	$306	$430
Self Financing Ratio	140%	165%	125%	98%	106%	96%	94%	94%	98%	105%	106%	111%	118%	106%	98%	107%	116%	111%	124%	134%
Cash Flow to Net Debt	4.7%	5.2%	3.9%	3.2%	3.5%	3.4%	3.5%	3.6%	3.9%	4.4%	4.6%	4.9%	5.4%	5.4%	5.6%	6.0%	6.4%	7.0%	7.5%	8.2%
Net Finance Expense	$909	$900	$886	$906	$915	$927	$936	$946	$949	$923	$928	$929	$929	$915	$904	$900	$893	$876	$863	$853
Debt Ratio	85%	83%	82%	82%	81%	81%	80%	80%	79%	79%	78%	77%	76%	75%	73%	72%	71%	70%	68%	66%
Interest Paid	$1 064	$834	$935	$941	$936	$946	$962	$978	$979	$950	$961	$961	$966	$959	$949	$946	$936	$926	$914	$899
EBIT Interest Coverage Ratio	1.80	1.51	1.32	1.16	1.18	1.10	1.10	1.11	1.11	1.18	1.20	1.23	1.29	1.27	1.30	1.33	1.39	1.48	1.57	1.65
EBITDA Interest Coverage Ratio	2.48	2.21	2.06	1.92	1.95	1.89	1.90	1.95	1.99	2.12	2.17	2.24	2.33	2.36	2.44	2.53	2.64	2.79	2.92	3.07
Capital Coverage Ratio	2.26	2.23	1.61	1.20	1.21	1.08	1.06	1.06	1.08	1.16	1.16	1.21	1.29	1.27	1.32	1.37	1.43	1.52	1.59	1.66

Figure 26: Electric Operations Projected Operating Statement: Alternative 2 – IFRS-ALG – 2022/23 to 2031/32

ELECTRIC OPERATIONS PROJECTED OPERATING STATEMENT
Alternative 2 - IFRS-ALG
(In Millions of Dollars)

For the year ended March 31	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
REVENUES										
Domestic Revenue										
at approved rates	1 875	1 847	1 853	1 863	1 874	1 888	1 904	1 922	1 943	1 973
additional	-	24	74	113	153	195	238	284	331	382
Extraprovincial	1 283	1 153	964	780	778	754	740	748	768	766
Other	29	29	29	30	31	32	37	38	39	40
	3 186	3 052	2 920	2 786	2 836	2 869	2 919	2 991	3 081	3 161
EXPENSES										
Operating and Administrative	589	657	687	683	697	711	724	736	739	754
Net Finance Expense	909	900	886	906	915	927	936	946	949	923
Depreciation and Amortization	618	632	643	657	676	694	713	733	755	777
Water Rentals and Assessments	81	83	79	76	77	78	78	78	78	78
Fuel and Power Purchased	139	163	156	182	173	173	176	177	198	186
Capital and Other Taxes	160	162	163	165	166	168	170	171	172	174
Other Expenses	118	80	74	72	72	77	80	83	83	79
Corporate Allocation	7	7	7	7	7	7	7	3	1	1
	2 621	2 684	2 695	2 748	2 784	2 833	2 883	2 927	2 975	2 973
Net Income before Net Movement in Reg. Deferral	565	368	224	38	53	35	36	64	106	187
Net Movement in Regulatory Deferral	190	99	71	119	84	39	40	38	(2)	(12)
Net Income	755	467	296	157	137	74	76	102	104	175
Net Income Attributable to:										
Manitoba Hydro	**751**	**462**	**289**	**151**	**129**	**67**	**69**	**94**	**95**	**166**
Wuskwatim Investment Entity	4	5	6	7	7	7	7	8	9	9
Keeyask Investment Entity	-	-	-	-	-	-	-	-	-	-
Total Non-Controlling Interests	4	5	6	7	7	7	7	8	9	9
	755	467	296	157	137	74	76	102	104	175
Percent Increase	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	0.00%	2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	17.17%	19.51%

Figure 27: Electric Operations Projected Operating Statement: Alternative 2 – IFRS-ALG – 2032/33 to 2041/42

ELECTRIC OPERATIONS PROJECTED OPERATING STATEMENT
Alternative 2 - IFRS-ALG
(In Millions of Dollars)

For the year ended March 31	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42
REVENUES										
Domestic Revenue										
at approved rates	2 010	2 051	2 095	2 151	2 212	2 274	2 337	2 400	2 466	2 528
additional	437	495	558	627	702	781	866	955	1 050	1 148
Extraprovincial	754	762	783	707	693	705	682	643	615	588
Other	41	43	45	49	53	54	56	58	61	62
	3 242	3 352	3 482	3 534	3 659	3 814	3 940	4 056	4 192	4 326
EXPENSES										
Operating and Administrative	769	785	800	816	833	849	872	896	914	939
Net Finance Expense	926	927	929	914	904	899	892	875	862	852
Depreciation and Amortization	799	825	851	878	906	940	975	1 005	1 041	1 077
Water Rentals and Assessments	78	79	80	80	80	80	80	80	81	81
Fuel and Power Purchased	191	214	232	270	317	387	403	393	426	436
Capital and Other Taxes	176	181	181	184	186	189	191	194	196	199
Other Expenses	86	89	91	94	97	100	104	107	111	113
Corporate Allocation	1	1	1	1	1	1	1	1	1	1
	3 027	3 101	3 166	3 238	3 324	3 446	3 518	3 552	3 632	3 698
Net Income before Net Movement in Reg. Deferral	215	251	316	296	335	368	422	505	560	628
Net Movement in Regulatory Deferral	(10)	(10)	(11)	(12)	(12)	(12)	(10)	(10)	6	4
Net Income	205	242	306	285	323	356	411	494	566	632
Net Income Attributable to:										
Manitoba Hydro	**195**	**230**	**293**	**272**	**310**	**344**	**396**	**477**	**548**	**613**
Wuskwatim Investment Entity	10	11	12	12	13	13	16	17	18	19
Keeyask Investment Entity	-	-	-	-	-	-	-	-	-	-
Total Non-Controlling Interests	10	11	12	12	13	13	16	17	18	19
	205	242	306	285	323	356	411	494	566	632
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	21.90%	24.34%	26.82%	29.36%	31.95%	34.59%	37.28%	40.02%	42.82%	45.68%

Figure 28: Electric Operations Projected Balance Sheet: Alternative 2 – IFRS-ALG – 2022/23 to 2031/32

ELECTRIC OPERATIONS PROJECTED BALANCE SHEET
Alternative 2 - IFRS-ALG
(In Millions of Dollars)

For the year ended March 31	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**
ASSETS										
Plant in Service	28 814	29 416	30 089	30 739	31 593	32 345	33 112	33 929	34 789	35 693
Accumulated Depreciation	(3 525)	(4 083)	(4 638)	(5 186)	(5 776)	(6 415)	(7 052)	(7 715)	(8 398)	(9 104)
Net Plant in Service	25 288	25 333	25 451	25 553	25 817	25 929	26 059	26 214	26 390	26 589
Construction in Progress	470	512	472	484	319	328	336	343	350	357
Current and Other Assets	2 222	1 513	1 631	1 688	1 551	1 638	1 738	1 604	1 698	1 900
Goodwill and Intangible Assets	1 034	1 006	981	954	921	887	853	817	780	744
Total Assets before Regulatory Deferral	29 014	28 364	28 535	28 678	28 607	28 783	28 985	28 977	29 219	29 591
Regulatory Deferral Balance	1 389	1 419	1 490	1 561	1 596	1 635	1 674	1 713	1 711	1 699
	30 403	29 783	30 025	30 239	30 203	30 418	30 660	30 689	30 929	31 290
LIABILITIES AND EQUITY										
Long-Term Debt	22 408	21 912	21 747	21 494	21 186	21 078	21 977	21 440	21 958	22 750
Current and Other Liabilities	3 931	3 389	3 440	3 742	3 861	4 089	3 336	3 783	3 379	2 748
Provisions	67	65	63	61	59	56	54	52	51	50
Deferred Revenue	626	683	755	830	891	917	945	973	1 004	1 038
Retained Earnings	3 575	4 037	4 327	4 477	4 606	4 673	4 742	4 836	4 932	5 098
Accumulated Other Comprehensive Income	(371)	(402)	(404)	(413)	(401)	(396)	(394)	(394)	(394)	(394)
Total Liabilities and Equity before Regulatory Deferral	30 236	29 685	29 927	30 190	30 203	30 418	30 660	30 689	30 929	31 290
Regulatory Deferral Balance	166	98	98	49	0	0	0	0	0	0
	30 403	29 783	30 025	30 239	30 203	30 418	30 660	30 689	30 929	31 290

Figure 29: Electric Operations Projected Balance Sheet: Alternative 2 – IFRS-ALG – 2032/33 to 2041/42

ELECTRIC OPERATIONS PROJECTED BALANCE SHEET
Alternative 2 - IFRS-ALG
(In Millions of Dollars)

For the year ended March 31	**2032/33**	**2033/34**	**2034/35**	**2035/36**	**2036/37**	**2037/38**	**2038/39**	**2039/40**	**2040/41**	**2041/42**
ASSETS										
Plant in Service	36 672	37 680	38 768	39 910	41 171	42 495	43 923	45 182	46 564	48 003
Accumulated Depreciation	(9 824)	(10 581)	(11 343)	(12 125)	(12 946)	(13 812)	(14 708)	(15 628)	(16 558)	(17 540)
Net Plant in Service	26 848	27 099	27 425	27 786	28 225	28 683	29 214	29 554	30 006	30 463
Construction in Progress	365	373	381	492	753	662	536	826	726	569
Current and Other Assets	1 935	2 659	2 779	2 583	2 581	2 513	2 480	2 480	2 382	2 545
Goodwill and Intangible Assets	708	672	635	599	562	525	487	449	412	374
Total Assets before Regulatory Deferral	29 855	30 802	31 220	31 460	32 120	32 383	32 717	33 309	33 525	33 950
Regulatory Deferral Balance	1 690	1 680	1 669	1 657	1 645	1 634	1 623	1 613	1 619	1 623
	31 545	32 482	32 889	33 117	33 765	34 017	34 341	34 922	35 144	35 574
LIABILITIES AND EQUITY										
Long-Term Debt	22 722	23 246	22 933	22 776	22 592	22 306	22 170	21 918	21 432	21 014
Current and Other Liabilities	2 762	2 871	3 145	3 063	3 303	3 463	3 406	3 548	3 673	3 873
Provisions	49	48	47	45	44	43	42	40	39	38
Deferred Revenue	1 113	1 189	1 342	1 538	1 823	1 857	1 979	2 194	2 231	2 268
Retained Earnings	5 293	5 523	5 816	6 088	6 399	6 742	7 138	7 615	8 162	8 775
Accumulated Other Comprehensive Income	(394)	(394)	(394)	(394)	(394)	(394)	(394)	(394)	(394)	(394)
Total Liabilities and Equity before Regulatory Deferral	31 545	32 482	32 889	33 117	33 765	34 017	34 341	34 922	35 144	35 574
Regulatory Deferral Balance	0	0	0	0	0	0	0	0	0	0
	31 545	32 482	32 889	33 117	33 765	34 017	34 341	34 922	35 144	35 574

Figure 30: Electric Operations Projected Indirect Cash Flow Statement: Alternative 2 – IFRS-ALG – 2022/23 to 2031/32

ELECTRIC OPERATIONS PROJECTED INDIRECT CASH FLOW STATEMENT
Alternative 2 - IFRS-ALG
(In Millions of Dollars)

For the year ended March 31	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**
OPERATING ACTIVITIES										
Net Income (Loss)	755	467	296	157	137	74	76	102	104	175
Net Movement in Regulatory Deferral	(190)	(99)	(71)	(119)	(84)	(39)	(40)	(38)	2	12
Add Back:										
Depreciation and Amortization	618	632	643	657	676	694	713	733	755	777
Net Finance Expense	909	900	886	906	915	927	936	946	949	923
Adjustments for Non-Cash Items	39	13	13	12	11	10	6	2	(1)	(2)
Adjustments for Non-Cash Working Capital Accounts	(6)	82	41	43	45	46	47	48	49	50
Interest Paid	(1 064)	(834)	(935)	(941)	(936)	(946)	(962)	(978)	(979)	(950)
Interest Received	24	15	10	9	5	4	5	1	1	2
Cash Provided by Operating Activities	1 084	1 176	882	724	770	770	781	816	879	988
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	657	350	750	920	970	1 360	1 580	560	1 180	790
Retirement of Long-Term Debt	(1 103)	(1 439)	(875)	(901)	(1 183)	(1 274)	(1 468)	(680)	(1 096)	(663)
Repayments from/(Advances to) Investment Entities	22	(0)	(0)	(0)	(0)	(0)	(0)	(0)	7	11
Contributions from Non-Controlling Interests	0	0	0	0	0	0	0	0	0	0
Proceeds from Short-Term Borrowings, Net	0	0	0	0	0	0	0	0	0	0
Sinking Fund Investment Withdrawals	248	244	234	233	234	232	233	234	234	235
Sinking Fund Investment Purchases	(248)	(244)	(234)	(233)	(234)	(232)	(233)	(234)	(234)	(235)
Other	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(8)	(11)
Cash Provided by Financing Activities	(425)	(1 090)	(126)	18	(214)	86	112	(121)	84	126
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(672)	(692)	(699)	(735)	(713)	(756)	(784)	(825)	(867)	(911)
Additions to Intangible Assets	(20)	(12)	(18)	(14)	(13)	(13)	(13)	(13)	(14)	(14)
Net Contributions Received	44	72	81	83	74	38	41	45	48	53
Cash Paid for Mitigation and Major Development Obligations	(103)	(57)	(52)	(55)	(54)	(54)	(55)	(55)	(50)	(51)
Cash Paid for Transmission Rights Obligations	(21)	(20)	(19)	(19)	(18)	(17)	(16)	(15)	(15)	(14)
Other	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)
Cash Used for Investing Activities	(774)	(711)	(708)	(741)	(725)	(803)	(827)	(865)	(898)	(937)
Net Increase (Decrease) in Cash	(114)	(625)	48	0	(169)	53	65	(169)	66	177
Cash at Beginning of Year	1 047	933	308	357	357	188	242	307	137	203
Cash at End of Year	933	308	357	357	188	242	307	137	203	380

Figure 31: Electric Operations Projected Indirect Cash Flow Statement: Alternative 2 – IFRS-ALG – 2032/33 to 2041/42

ELECTRIC OPERATIONS PROJECTED INDIRECT CASH FLOW STATEMENT
Alternative 2 - IFRS-ALG
(In Millions of Dollars)

For the year ended March 31	**2032/33**	**2033/34**	**2034/35**	**2035/36**	**2036/37**	**2037/38**	**2038/39**	**2039/40**	**2040/41**	**2041/42**
OPERATING ACTIVITIES										
Net Income (Loss)	205	242	306	285	323	356	411	494	566	632
Net Movement in Regulatory Deferral	10	10	11	12	12	12	10	10	(6)	(4)
Add Back:										
Depreciation and Amortization	799	825	851	878	906	940	975	1 005	1 041	1 077
Net Finance Expense	926	927	929	914	904	899	892	875	862	852
Adjustments for Non-Cash Items	(3)	(4)	(6)	(9)	(13)	(14)	(15)	(18)	(20)	(21)
Adjustments for Non-Cash Working Capital Accounts	51	52	53	54	55	57	58	59	60	61
Interest Paid	(957)	(957)	(966)	(959)	(948)	(945)	(936)	(925)	(913)	(898)
Interest Received	4	4	8	7	5	5	4	8	7	7
Cash Provided by Operating Activities	1 035	1 098	1 186	1 183	1 244	1 309	1 399	1 509	1 596	1 706
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	(50)	570	(40)	(10)	150	160	200	170	0	200
Retirement of Long-Term Debt	0	20	(49)	(275)	(150)	(338)	(449)	(339)	(425)	(488)
Repayments from/(Advances to) Investment Entities	9	10	11	12	12	12	12	15	16	16
Contributions from Non-Controlling Interests	0	0	0	0	0	0	0	0	0	0
Proceeds from Short-Term Borrowings, Net	0	0	0	0	0	0	0	0	0	0
Sinking Fund Investment Withdrawals	236	235	241	240	238	238	236	234	232	228
Sinking Fund Investment Purchases	(236)	(235)	(241)	(240)	(238)	(238)	(236)	(234)	(232)	(228)
Other	(11)	(12)	(13)	(14)	(14)	(15)	(14)	(18)	(19)	(20)
Cash Provided by Financing Activities	(52)	588	(91)	(287)	(2)	(180)	(251)	(171)	(428)	(291)
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(993)	(1 010)	(1 109)	(1 270)	(1 517)	(1 218)	(1 294)	(1 539)	(1 297)	(1 286)
Additions to Intangible Assets	(14)	(15)	(15)	(16)	(16)	(16)	(17)	(17)	(18)	(18)
Net Contributions Received	95	98	186	232	322	73	163	257	81	84
Cash Paid for Mitigation and Major Development Obligations	(51)	(50)	(50)	(51)	(50)	(51)	(52)	(53)	(54)	(55)
Cash Paid for Transmission Rights Obligations	(13)	(12)	(12)	(11)	(10)	(10)	(9)	(9)	(1)	0
Other	(0)	0	0	0	0	0	0	0	0	0
Cash Used for Investing Activities	(977)	(989)	(1 001)	(1 117)	(1 271)	(1 223)	(1 209)	(1 361)	(1 290)	(1 276)
Net Increase (Decrease) in Cash	7	697	94	(221)	(29)	(94)	(60)	(24)	(121)	140
Cash at Beginning of Year	380	386	1 083	1 177	956	927	833	773	749	628
Cash at End of Year	386	1 083	1 177	956	927	833	773	749	628	768

Figure 32: Electric Operations Projected Direct Cash Flow Statement: Alternative 2 – IFRS-ALG – 2022/23 to 2031/32

ELECTRIC OPERATIONS PROJECTED DIRECT CASH FLOW STATEMENT
Alternative 2 - IFRS-ALG
(In Millions of Dollars)

For the year ended March 31	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 174	3 039	2 907	2 772	2 822	2 853	2 899	2 971	3 060	3 139
Cash Paid to Suppliers and Employees	(1 049)	(1 044)	(1 099)	(1 116)	(1 121)	(1 141)	(1 161)	(1 178)	(1 203)	(1 202)
Interest Paid	(1 064)	(834)	(935)	(941)	(936)	(946)	(962)	(978)	(979)	(950)
Interest Received	24	15	10	9	5	4	5	1	1	2
Cash Provided by Operating Activities	1 084	1 176	882	724	770	770	781	816	879	988
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	657	350	750	920	970	1 360	1 580	560	1 180	790
Retirement of Long-Term Debt	(1 103)	(1 439)	(875)	(901)	(1 183)	(1 274)	(1 468)	(680)	(1 096)	(663)
Repayments from/(Advances to) External Entities	22	(0)	(0)	(0)	(0)	(0)	(0)	(0)	7	11
Contributions from Non-Controlling Interests	0	0	0	0	0	0	0	0	0	0
Proceeds from Short-Term Borrowings, Net	0	0	0	0	0	0	0	0	0	0
Sinking Fund Investment Withdrawals	248	244	234	233	234	232	233	234	234	235
Sinking Fund Investment Purchases	(248)	(244)	(234)	(233)	(234)	(232)	(233)	(234)	(234)	(235)
Other	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(8)	(11)
Cash Provided by Financing Activities	(425)	(1 090)	(126)	18	(214)	86	112	(121)	84	126
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(672)	(692)	(699)	(735)	(713)	(756)	(784)	(825)	(867)	(911)
Additions to Intangible Assets	(20)	(12)	(18)	(14)	(13)	(13)	(13)	(13)	(14)	(14)
Net Contributions Received	44	72	81	83	74	38	41	45	48	53
Cash Paid for Mitigation and Major Development Obligations	(103)	(57)	(52)	(55)	(54)	(54)	(55)	(55)	(50)	(51)
Cash Paid for Transmission Rights Obligations	(21)	(20)	(19)	(19)	(18)	(17)	(16)	(15)	(15)	(14)
Other	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)
Cash Used for Investing Activities	(774)	(711)	(708)	(741)	(725)	(803)	(827)	(865)	(898)	(937)
Net Increase (Decrease) in Cash	(114)	(625)	48	0	(169)	53	65	(169)	66	177
Cash at Beginning of Year	1 047	933	308	357	357	188	242	307	137	203
Cash at End of Year	933	308	357	357	188	242	307	137	203	380

Figure 33: Electric Operations Projected Direct Cash Flow Statement: Alternative 2 – IFRS-ALG – 2032/33 to 2041/42

ELECTRIC OPERATIONS PROJECTED DIRECT CASH FLOW STATEMENT
Alternative 2 - IFRS-ALG
(In Millions of Dollars)

For the year ended March 31	**2032/33**	**2033/34**	**2034/35**	**2035/36**	**2036/37**	**2037/38**	**2038/39**	**2039/40**	**2040/41**	**2041/42**
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 219	3 327	3 456	3 505	3 627	3 780	3 905	4 019	4 152	4 285
Cash Paid to Suppliers and Employees	(1 231)	(1 276)	(1 313)	(1 371)	(1 439)	(1 531)	(1 574)	(1 593)	(1 649)	(1 688)
Interest Paid	(957)	(957)	(966)	(959)	(948)	(945)	(936)	(925)	(913)	(898)
Interest Received	4	4	8	7	5	5	4	8	7	7
Cash Provided by Operating Activities	1 035	1 098	1 186	1 183	1 244	1 309	1 399	1 509	1 596	1 706
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	(50)	570	(40)	(10)	150	160	200	170	0	200
Retirement of Long-Term Debt	0	20	(49)	(275)	(150)	(338)	(449)	(339)	(425)	(488)
Repayments from/(Advances to) External Entities	9	10	11	12	12	12	12	15	16	16
Contributions from Non-Controlling Interests	0	0	0	0	0	0	0	0	0	0
Proceeds from Short-Term Borrowings, Net	0	0	0	0	0	0	0	0	0	0
Sinking Fund Investment Withdrawals	236	235	241	240	238	238	236	234	232	228
Sinking Fund Investment Purchases	(236)	(235)	(241)	(240)	(238)	(238)	(236)	(234)	(232)	(228)
Other	(11)	(12)	(13)	(14)	(14)	(15)	(14)	(18)	(19)	(20)
Cash Provided by Financing Activities	(52)	588	(91)	(287)	(2)	(180)	(251)	(171)	(428)	(291)
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(993)	(1 010)	(1 109)	(1 270)	(1 517)	(1 218)	(1 294)	(1 539)	(1 297)	(1 286)
Additions to Intangible Assets	(14)	(15)	(15)	(16)	(16)	(16)	(17)	(17)	(18)	(18)
Net Contributions Received	95	98	186	232	322	73	163	257	81	84
Cash Paid for Mitigation and Major Development Obligations	(51)	(50)	(50)	(51)	(50)	(51)	(52)	(53)	(54)	(55)
Cash Paid for Transmission Rights Obligations	(13)	(12)	(12)	(11)	(10)	(10)	(9)	(9)	(1)	0
Other	(0)	0	0	0	0	0	0	0	0	0
Cash Used for Investing Activities	(977)	(989)	(1 001)	(1 117)	(1 271)	(1 223)	(1 209)	(1 361)	(1 290)	(1 276)
Net Increase (Decrease) in Cash	7	697	94	(221)	(29)	(94)	(60)	(24)	(121)	140
Cash at Beginning of Year	380	386	1 083	1 177	956	927	833	773	749	628
Cash at End of Year	386	1 083	1 177	956	927	833	773	749	628	768

Figure 34: Electric Operations Key Financial Measures: Alternative 2 – IFRS-ALG

ELECTRIC OPERATIONS KEY FINANCIAL MEASURES
Alternative 2 - IFRS-ALG

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Annual Rate Increases	0.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Rate Increases	0.00%	2.00%	4.04%	6.12%	8.24%	10.41%	12.62%	14.87%	17.17%	19.51%	21.90%	24.34%	26.82%	29.36%	31.95%	34.59%	37.28%	40.02%	42.82%	45.68%
Net Income/(Loss)	$751	$462	$289	$151	$129	$67	$69	$94	$95	$166	$195	$230	$293	$272	$310	$344	$396	$477	$548	$613
Net Income/(Loss) before Net Movement in Reg. Deferral	$565	$368	$224	$38	$53	$35	$36	$64	$106	$187	$215	$251	$316	$296	$335	$368	$422	$505	$560	$628
Retained Earnings	$3 575	$4 037	$4 327	$4 477	$4 606	$4 673	$4 742	$4 836	$4 932	$5 098	$5 293	$5 523	$5 816	$6 088	$6 399	$6 742	$7 138	$7 615	$8 162	$8 775
Total Equity	$4 030	$4 504	$4 870	$5 044	$5 207	$5 316	$5 422	$5 546	$5 671	$5 871	$6 140	$6 447	$6 894	$7 365	$7 959	$8 337	$8 855	$9 547	$10 131	$10 783
Net Debt	$22 963	$22 529	$22 341	$22 371	$22 322	$22 355	$22 400	$22 449	$22 468	$22 420	$22 366	$22 262	$22 081	$22 020	$22 052	$21 972	$21 786	$21 644	$21 342	$20 917
Change in Net Debt - Inc/(Dec)	($330)	($435)	($187)	$29	($49)	$33	$45	$49	$20	($48)	($54)	($105)	($181)	($61)	$32	($81)	($186)	($142)	($302)	($425)
Cash Provided by Operating Activities	$1 084	$1 176	$882	$724	$770	$770	$781	$816	$879	$988	$1 035	$1 098	$1 186	$1 183	$1 244	$1 309	$1 399	$1 509	$1 596	$1 706
Cash Used for Investing Activities	($774)	($711)	($708)	($741)	($725)	($803)	($827)	($865)	($898)	($937)	($977)	($989)	($1 001)	($1 117)	($1 271)	($1 223)	($1 209)	($1 361)	($1 290)	($1 276)
Cash Surplus/(Deficit)	$310	$465	$174	($17)	$45	($33)	($47)	($49)	($18)	$51	$59	$109	$185	$66	($27)	$86	$191	$148	$307	$430
Self Financing Ratio	140%	165%	125%	98%	106%	96%	94%	94%	98%	105%	106%	111%	119%	106%	98%	107%	116%	111%	124%	134%
Cash Flow to Net Debt	4.7%	5.2%	3.9%	3.2%	3.5%	3.4%	3.5%	3.6%	3.9%	4.4%	4.6%	4.9%	5.4%	5.4%	5.6%	6.0%	6.4%	7.0%	7.5%	8.2%
Net Finance Expense	$909	$900	$886	$906	$915	$927	$936	$946	$949	$923	$926	$927	$929	$914	$904	$899	$892	$875	$862	$852
Debt Ratio	85%	83%	82%	82%	81%	81%	81%	80%	80%	79%	78%	78%	76%	75%	73%	72%	71%	69%	68%	66%
Interest Paid	$1 064	$834	$935	$941	$936	$946	$962	$978	$979	$950	$957	$957	$966	$959	$948	$945	$936	$925	$913	$898
EBIT Interest Coverage Ratio	1.80	1.50	1.32	1.16	1.14	1.07	1.07	1.10	1.10	1.18	1.21	1.24	1.31	1.29	1.33	1.37	1.43	1.53	1.61	1.70
EBITDA Interest Coverage Ratio	2.48	2.21	2.06	1.92	1.95	1.89	1.91	1.95	1.99	2.12	2.18	2.24	2.34	2.36	2.44	2.53	2.64	2.79	2.92	3.07
Capital Coverage Ratio	2.26	2.23	1.61	1.20	1.21	1.08	1.06	1.06	1.08	1.16	1.16	1.22	1.29	1.27	1.32	1.37	1.43	1.53	1.59	1.66