IN THE MATTER OF
MANITOBA HYDRO

Review of Order 140/21 Interim rate increase and 2023/24 and 2024/25 GRA

INDEX

PART 1

INTRODUCTION

1. This submission should be read in conjunction with the **Issue papers** prepared with respect to various issues relevant to MIPUG's intervention in this proceeding. The **Issue papers** are appended to this submission.

2. This may be the last GRA where the historical approach of the PUB to setting just and reasonable rates continues to apply.

3. There are two positions with respect to the need by the PUB to consider post April 1, 2025 legislative policies and principles in setting the rate path for this GRA. For clarity we refer to these approaches as the "Blinders" approach (the transition provisions require the Board to be blind to changes that are coming after 2025) or the "Outlook" approach (the Board can still remain attentive to the changes coming after 2025 and include them in its outlook).

4. As will be submitted in further detail, the result under both approaches can be the same.

PART 2

RECOMENDATONS

Recommendation 1: MIPUG recommends that the Board implement a 0% average rate increase for 2023/24 and an increase for 2024/25 that is less than 2% overall on April 1, 2024, as outlined in Recommendation 3, and confirm the 3.6% interim increase from Order 140/21.

Recommendation 2: Assuming the PUB adopts the Blinders approach and rejects the Outlook approach, the Board should implement immediate differential rate adjustments to at minimum achieve the outer band of 95 – 105 by 2027/28 based on PCOSS24.

Recommendations 1 and 3 should put Hydro on pace to achieve this objective.

Under the Outlook approach, the pending provisions for reflecting properly allocated revenue requirements to each class would suggest an even more dramatic rate differentiation is merited.

Recommendation 3: With respect to differentiated rates:

- No further rate adjustments be implemented with respect to the 3.6% rate increase from 2021;
- For the test year 2023/24, the following classes, (GSS ND, GSL 30-100kV, GSL >100kV and Area and Roadway Lighting) which are above the ZOR, have no rate increases (i.e., 0%). This would apply irrespective of whether the PUB grants to other classes a rate increase, or whether the PUB does not grant rate increase in 2023/24 as per MIPUG's Recommendation 1;
- For the test year 2024/25, the following classes, (GSS ND, GSL 30-100kV, GSL >100kV and Area and Roadway Lighting) which are above the ZOR, have no rate increases (i.e., 0% change to unit rates; this includes no increase to the demand charge related to the change in definition of billing demand for GSL 30-100kV and GSL >100kV – which reduces Hydro's revenues by about $0.9 million). The remaining classes would receive the rate increases as proposed by MH in its Application.

Recommendation 4: The Board should continue to apply its finding from Order 59-18 that Export revenues should be a reduction to allocated class costs.

Recommendation 5: The Board should rely on the net export revenue and net income assumptions in PCOSS24 for the purpose of establishing differentiated rates in this proceeding.

DEPRECIATION RECOMMENDATIONS

Recommendation 6: Hydro should adopt the Average Service Life ("ASL") procedure for all depreciation calculations, whether for regulatory purposes or financial reporting. The ASL procedure is sound, well-accepted throughout North America, and leads to an appropriate recognition of the service value being provided by the assets providing service to customers. As such, ASL is the approach most consistent with just and reasonable rates.

This is consistent with Alternative 2 in the Depreciation Issues document.

Recommendation 7: In order to achieve reasonable and fair depreciation rates and expense, Hydro should determine the level of componentization required regardless as to the group procedure used. The Equal Life Group ("ELG") procedure is not an alternative to proper componentization.

Recommendation 8: Some of the accounts developed by Alliance appear to be reasonable refinements on Hydro's account structure. Others appear trivial and of no materiality. The review of componentization by Hydro should be a continuing activity, consistent with capital asset tracking within any utility as part of maintaining accurate capital asset accounts.

Recommendation 9: The booking of gains and losses on disposals (other than terminal retirements) is redundant and inconsistent with group depreciation. If for some reason the booking of gains and losses is to be continued as part of Hydro's IFRS asset accounting, then the gains and losses recorded should be broken out by asset account, included in a regulatory deferral account, and amortized to income over the weighted average remaining life of the assets in that account.

Recommendation 10: There should not be a new IFRS Phase-In Deferral created nor needed to adopt appropriate depreciation practices at this time.

Recommendation 11: The Change in Depreciation Method Deferral, totaling $327 million at year-end 2022/23, should be discharged as an offset to accumulated depreciation, by account. Alternatively, this balance should be amortized over the remaining life of the assets as part of Alternative 2 of the Depreciation Issues document. The mathematical outcome for setting rates of the two options is the same.

Recommendation 12: Industrial Billing Demand Definition

The update to the definition of industrial billing demand, to focus only on the on-peak period, should be approved, with two adjustments.

First, there should be no revenue enhancement to the demand rate included, given the class is paying well above the ZOR. The Board can achieve this outcome by revising downward the overall average increase for revenue requirement to permit there to be no rate increase for this factor.

Second, there should be no off-peak cap of 10% above on-peak before the off-peak period becomes the basis for demand charges. While no limit is required, Hydro has accepted that a less constraining cap (such as allowing the on-peak billing units to be as low as 75% of the off-peak peak), which is a reasonable compromise and should be adopted while the new rate is being put into place.

At the earliest reasonable opportunity, the rate design should also be applied to GSL 0-30 kV customers who are of sufficient size and have appropriate metering.

Recommendation 13: Manitoba Hydro should be directed to study the customer homogeneity in the GSL 750 V – 30 kV rate class and report back to the PUB at the next GRA on alternatives to improve the homogeneity of the class.

Recommendation 14: Reliability
MIPUG recommends that the Board direct Manitoba Hydro to establish a metric for unserved energy based on industry best practice engagement of customers to establish a reasonable estimate of customer cost for reliability events, both momentary and non-momentary.

Recommendation 15: Hydro should resume updating of the Uncertainty Analysis tool, to provide probabilistic assessments of the likelihood of reaching future financial targets considering overlapping risks, and to support future rate increases.

Recommendation 16: The Board should direct a one-year amortization of amounts related to the Conawapa deferral account, and the Selkirk loss on disposal and cost of removal balances, in the earliest available fiscal year. This decision should be explicitly linked to finalizing the 3.6% interim rate from 2021.

APPROACHES AND JURISDICTION OF THE PUB IN THIS GRA

5. MIPUG has approached this hearing in an environment of uncertainty. On the one hand, the scope and procedures followed a normal GRA consistent with past practice. On the other, forecasts beyond the test years of 2023/24 and 2024/25 are burdened with the need to interpret information through the lens of *The Manitoba Hydro Amendment and Public Utilities Board Amendment Act*, S.M. 2022, c. 42 ("*The Amendment Act*") including the transition provisions. That lens is, to say the least, murky.

6. In this submission, MIPUG has attempted to address not only the contents of the hearing, about which the Board has heard extensive testimony, but also the legal framework for the decisions the Board will need to make. Unlike the financial forecasts and market projections, etc., the Board has received relatively little in terms of legal interpretations of the framework for the upcoming decision.

7. No witness who testified had the expertise or provided analysis about how the Board should or must take into account *The Amendment Act*. Every witness testimony therefore must be considered not only at face value, but also through the lens of the legislation. This includes all the accountants, economists, and engineers, including MIPUG's own witness, Mr. Bowman. As the Board is aware, Mr. Bowman provided evidence that in his expert opinion, taking into account a number of caveats – first and foremost his reading of *The Amendment*

Act as an economist – Manitoba Hydro's basic case for finalizing the interim 3.6% increase and implementing a further average increase of 2% and 2%, in 2023/24 and 2024/25 respectively, was sound.

8. In MIPUG's view, *The Amendment Act* has a number of relevant sections that must be relied upon to come to a final decision in this case, including in interpreting Mr. Bowman's evidence. First and foremost is the transition provision.

9. The relevant portions of the explanatory note to *The Amendment Act*, which is written as a reader's aid and is not part of the law provide:

> ELECTRICITY AND GAS RATES
>
> Currently, the Public Utilities Board (the "PUB") regulates electricity rates under Part 4 of *The Crown Corporations Governance and Accountability Act* and Manitoba Hydro's gas utility under *The Public Utilities Board Act*.
>
> Under the new framework, both electricity rates and gas rates are regulated under *The Manitoba Hydro Act*.
>
> *Electricity rates*
>
> **The existing legislative framework continues to apply to the determination of electricity rates until March 31, 2025.** (emphasis added)
>
> The new legislative framework applies to the determination of electricity rates for each three-year rate period beginning after March 31, 2025.
>
> When approving rates, the PUB is to be guided by
>
> > Treasury Board-approved capital expenditure programs and government directives issued to Manitoba Hydro, and

the debt-to-capitalization targets set out in the Act and any additional financial targets established by regulation.

…

APPLICATION

The Manitoba Hydro Act, *The Public Utilities Board Act* and Part 4 of *The Crown Corporations Governance and Accountability Act* **continue to apply to the determination of electricity rates for any period ending before April 1, 2025, as if those Acts had not been amended.** (emphasis added)

10. The issue which arises in reading the explanatory note and *The Amendment Act*, is the lack of any additional explicit guidance which respect to the PUB's longstanding approach to also consider the longer-term outlook, as one element, in arriving at the appropriate rates for the test years. This long-term approach was especially important when Hydro was going through its decade of investment. Without a long-term approach, Manitobans would have faced a rate shock when depreciation and interest expenses for these large projects needed to be absorbed into rates.

11. Section 65 of *The Amendment Act* reads as follows:

Transitional

65 Despite Part 1 and sections 23 and 64 of this Act, the following Acts or provisions, as they read immediately before the enactment of this Act, continue to apply to the determination of rates for the retail supply of power under **The Manitoba Hydro Act** for any period ending before April 1, 2025:

(a) Part 4 of **The Crown Corporations Governance and Accountability Act**;

(b) **The Manitoba Hydro Act**;

(c) section 2 of **The Public Utilities Board Act**.

12. The French version, which has equal authority, [1]reads as follows:

Disposition transitoire

65 Par dérogation à la partie 1 et aux articles 23 et 64 de la présente loi, les lois ou dispositions qui suivent, telles qu'elles étaient libellées juste avant l'édiction de la présente loi, continuent de s'appliquer à la fixation des tarifs de fourniture d'énergie au détail prévue par la **Loi sur l'Hydro-Manitoba** pour toute période prenant fin avant le 1er avril 2025 :

a) la partie 4 de la **Loi sur la gouvernance et l'obligation redditionnelle des corporations de la Couronne**;

b) la **Loi sur l'Hydro-Manitoba**;

c) l'article 2 de la **Loi sur la Régie des services publics**.

13. Subsection 10(2) of *The Interpretation Act* provides the following guidance:

Expiry or lapse at the end of the day

10(2) When an Act or regulation is expressed to expire, lapse or otherwise cease to have effect on a particular day, it ceases to have effect at the end of that day.

Cessation d'effet à la fin du jour prévu

10(2) La loi ou le règlement qui prévoit sa date de cessation d'effet, notamment par caducité, cesse d'avoir effet à vingt-quatre heures à cette date.

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[1] See *The Interpretation Act*, s. 7. **Bilingual versions**
7 The English and French versions of Acts and regulations are equally authoritative, in accordance with section 23 of the *Manitoba Act, 1870*

14. Any interpretation of legislation starts with the general meaning of words. In the transition provision, the word "despite" is used as a preposition. In English, a synonym to "despite" is "notwithstanding". According to the online Merriam-Webster dictionary,[2] the definition is "without being prevented by".

15. In <u>Legal and Legislative Drafting</u>, Salembier, Paul, LexisNexis, 2009, at p. 443, in discussing plain language alternatives, the author recommends the use of "despite" instead of "notwithstanding". Other plain language alternatives are "as an exception to, although".

16. In the French version, the noun "dérogation" is used. According to the leading online French dictionary, Larouse,[3] this noun is derived from the verb "déroger". It expresses the concept of not needing to comply with a law. The antonym is to observe or respect a law.

17. Both the English and the French versions of s. 65 therefore require the PUB to ignore the following parts of *The Amendment Act*:

(a) Part 1 which includes all the new framework and policies which become part of *The Manitoba Hydro Act* (the *Hydro Act*);

(b) Section 23 of *The Amendment Act* which amends parts of section 2 of *The Public Utilities Board Act* (the *PUB Act*) which currently set forth the PUB jurisdiction on setting rates (this is done to implement the new framework in *The Hydro Act* applicable as of April 1, 2025);

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[2] 145 Synonyms & Antonyms of DESPITE | Merriam-Webster Thesaurus
[3] Définitions : déroger - Dictionnaire de français Larousse

(c) Section 64 of *The Amendment Act* which amends the applicability of existing regulatory framework under *Part 4 of The Crown Corporations Governance and Accountability Act* (the *Crown Act*). In particular s. 25 is amended to remove reference to Manitoba Hydro being subject to that framework. Again, this is done to implement the new framework in *The Hydro Act* applicable as of April 1, 2025

18. Section 65 of *The Amendment Act* requires the PUB to apply the existing framework under:

(a) Part 4 of ***The Crown Corporations Governance and Accountability Act****;*

(b) ***The Manitoba Hydro Act****;*

(c) section 2 of ***The Public Utilities Board Act****.*

19. Part 4 of The Crown Corporations Governance and Accountability Act provides, in part,:

Hydro and MPIC rates review

25(1) Despite any other Act or law, rates for services provided by Manitoba Hydro and the Manitoba Public Insurance Corporation shall be reviewed by The Public Utilities Board under *The Public Utilities Board Act* and no change in rates for services shall be made and no new rates for services shall be introduced without the approval of The Public Utilities Board.

Application of Public Utilities Board Act

25(3) *The Public Utilities Board Act* applies with any necessary changes to a review pursuant to this Part of rates for services.

Factors to be considered, hearings

> 25(4) In reaching a decision pursuant to this Part, The Public Utilities Board may
>
> (a) take into consideration….
>
> (viii) any compelling policy considerations that the board considers relevant to the matter, and
>
> (ix) any other factors that the Board considers relevant to the matter;
>
> **Éléments à considérer**
>
> 25(4) Afin de prendre une décision en vertu de la présente partie, la Régie des services publics peut :
>
> a) tenir compte :
>
> (viii) des considérations de principe importantes qu'elle estime pertinentes à l'affaire,
>
> (ix) des autres éléments qu'elle estime pertinents à l'affaire;

20. In obiter, at para. 71, in a 2020 decision, the Manitoba Court of Appeal[4] noted:

> [71] It is interesting to note that the French language version of section 25(4)(a)(viii) states the PUB may consider "des considérations de principe importantes qu'elle estime pertinentes à l'affaire". In my view, the French translation permits consideration of "important policy considerations", which could arguably influence the interpretation of the phrase "compelling policy considerations" found in the English version. However, as the matter was not argued before us, I will not comment further on this observation.

[4] Manitoba (Hydro-Electric Board) v Manitoba (Public Utilities Board) et al, 2020 MBCA 60 (CanLII), <https://canlii.ca/t/jb2kz>

> [72] While the PUB has broad authority to make orders approving or setting rates for Manitoba Hydro that are not unjust, unreasonable or discriminatory, the **PUB is clearly constrained by the prohibition contained in section 43(3) of the *Hydro Act***. (emphasis added)

21. The question arises whether, in exercising its discretion under subsection 25(4), the PUB is constrained by the specific statutory direction in s. 65 of *The Amendment Act* to apply the existing regulatory framework and ignore the new legislative framework and policies which will be in effect as of April 1, 2025.

22. The issue of the PUB exercising its discretion in a manner inconsistent with a specific statutory directive is what led to the Court of Appeal overturning the PUB's decision with respect to the creation of an on-reserve class.[5]

23. As a creature of statute, the PUB's jurisdiction is created by and limited by the statute.

S. 39.1(1)(a) of the *Hydro Act* – properly allocating revenue requirements to classes

24. Similar to the question on whether the future financial targets in *The Amendment Act* should guide the Board's decision in this proceeding, there is the question of how the future constraints on cost allocation should apply.

[5] 2020 MBCA 60 (CanLII) | Manitoba (Hydro-Electric Board) v Manitoba (Public Utilities Board) et al | CanLII at para. 98.

25. If the PUB is to be blind to the future constraints that will apply under *The Amendment Act*, then there is no need to take into account the constraints that also will apply to cost allocation.

26. However, should the PUB endorse the Outlook approach which does take into account the future constraints that will apply under *The Amendment Act*, we submit that it is also appropriate for the PUB to consider the policy expressed in s. 39.1(1)(a) which reads as follows:

> **Electricity and rates policies**
>
> **39.1(1)** It is hereby declared to be the policy of the government that
>
> (a) the rates charged by the corporation to each class of grid customers in Manitoba **are to be based** on the revenue requirements **<u>properly allocated</u>** to that class;
>
> **Politiques tarifaires en matière d'électricité**
>
> **<u>39.1(1)</u>** Il est par les présentes déclaré que le gouvernement du Manitoba a pour politique :
>
> a) de veiller à ce que les tarifs facturés par la Régie à toute catégorie de clients branchés au réseau du Manitoba **soient fondés** sur des besoins en revenus **<u>correctement associés</u>** aux clients de cette catégorie; (emphasis added)

27. Considering both the English and French versions and the ordinary meaning of the words and reading the legislative framework as a whole, we submit that s. 39.1(1)(a) expresses the legislative intent that rates are required to reflect causation, without a Zone of Reasonableness.

28. A synonym for "properly" is "correctly" [6] In French, the ordinary meaning of "correctement" is "done correctly, in conformity with rules."[7]

29. Subsection 39(5) of the *Hydro Act* (added by *The Amendment Act*) provides in part as follows:

> **Rules for approving or varying rates**
>
> **39(5)** The following rules apply to the approval or variation of rates by the regulator:
>
> 1. The regulator must base its order or decision about rates on the revenue requirements for the rate period.
> 2. When reviewing the revenue requirements, the regulator **must** take into account and be guided by
>
> (a) the policies set out in section 39.1

30. There is nothing in the new framework which specifies that "Revenues that are within the zone of reasonableness are **deemed to** represent full cost recovery" (MH argument at p. 243, lines 23 and 24).

31. The new framework will require the PUB to "take into account and be guided by" the requirement that classes only pay for revenue requirements caused by them. If the legislature's intention was to deem compliance if RCC was within a ZOR, it could easily have said so. There are numerous instances where the legislature includes "deeming" provisions in the legislation. This is not one of those instances.

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[6] 36 Synonyms & Antonyms of PROPERLY | Merriam-Webster Thesaurus
[7] Définitions : correctement - Dictionnaire de français Larousse

32. Rates charged for the "rate period" cannot be "properly allocated" to a class if the class pays in excess of the revenue requirement caused by the class for that rate period. Referring to the French version, it would be "incorrect" to allocate costs to a class which are not "associated" to the customers in that class.

33. At page 243 of its written submission, MH confuses cost allocation "methods" or "rate design" (s. 39(5) number 4. of the *Hydro Act*) with a zone of reasonableness. A zone of reasonableness is not a method. Cost allocation methods are allocation methods like "Coincident Peak" etc.

34. Rate design is the art of designing rates to recover costs, whether they be customer costs, demand costs or energy costs. A zone of reasonableness is not a rate design.

35. The legislative intent of not requiring customers to pay for more than the services provided to them is implicit in s. 39(5) number 6. which reads as follows:

> 6. Rates within a class may differ based on the type, level
> or combination of services provided to the customer.

36. Number 6. recognizes that if a customer in a class uses a different type (e.g., 3 phase instead of 2 phase) or level of service there may be a different rate charged to that customer. Again, this is a cost causation concept.

The Strict Compliance Approach (Blinders as to the future framework and policies.)

37. If the Board considers the appropriate interpretation of *The Amendment Act* to be the Blinders approach, the question becomes what evidence does the Board have regarding the rate increases required? The most critical context for this approach was provided by Mr. Bowman as follows:

> In my evidence, I inserted a table that was noting for the record that, if it weren't for Bill 36 -- and as we sit here today, as much as Hydro put in a case about its debt levels and about the challenges it faces -- we need to recognize where we are in the investment cycle with Manitoba Hydro. We are at a place that no one dreamed, I would say. We have quite spectacular performance with regard to the period after in-service of the major projects, as this table noted, and I find the negative net income column perhaps the most persuasive. When these projects were being approved and even in periods after they were approved, it had always been expected that there would be a difficult period with many years of forecast negative net income, you know, even at average water, many years and in many cases nine (9) figures, hundreds of millions, almost a billion in one case, of negative net income after the projects came in. And that was part of the plan.
>
> We're not in that situation today. We are so much better off than that, it's stunning. And I think if this information -- this type of forecast had been available earlier, I think people would have found it surprising. [Tr. pp. 3974-3975]

38. Mr. Bowman went on to indicate his position that Hydro's rationale for 2 percent rate increases had no merit absent *The Amendment Act*:

> On the legal question, if I'm wrong, then I would submit, based on the last two (2) slides, there's actually no basis for 2 percent increase today. I think rate -- ratepayers have faced significant increases as we've been bringing the projects into service. We have time to absorb those projects. And we are outperforming financially what we ever dreamed that we would be today, and there's time to absorb that if it weren't for the fact that we now need to get on to the next job, which is dealing with the Bill 36 rate targets -- or debt/equity targets. [Tr. p. 3979]

39. Mr. Bowman did not put into his evidence a specific recommendation that would apply under the Blinders approach, beyond his conclusions that there was "no basis" for the Hydro 2%/2% rate proposal absent *The Amendment Act* (while also noting that any such recommendation had to take into account that Hydro's performance in respect of reliability must improve in relation to issues experience by some MIPUG members[Tr. pp.3979-3980]).

40. The only specific rate recommendations the Board has received from experts who made conclusions based roughly on the Blinders approach are Mr. Rainkie and Mr. Colaiacovo.

41. Indeed Mr. Rainkie's "Analytical Perspective #1" which focuses on the test years parallels Mr. Bowman's conclusion that there is no basis for a rate increase in either test year based on test year-specific data. Mr. Rainkie similarly finds no basis for a rate increase under his "Analytical Perspective #3" which uses a very long-term focus (30 years) reflecting that rates today already include

projections of the costs of the major new projects from the past few hearings (akin to Mr. Bowman's analogy of the Anaconda which has just swallowed a large meal and its time to "just give it a minute" [Tr. p. 3975]).

42. Mr. Colaiacovo concluded similarly for no rate increases, absent *The Amendment Act*, on the basis of a "do no harm" principle (CC Ex. 23 page 21).

43. If the Board is persuaded that the legal framework, and in particular the transition provisions, require a Blinders approach to *The Amendment Act* financial constraints and targets, it may want to take note of the evidence of Mr. Rainkie in regard to his proposal of average increases of 0%/1.3% for 2023/24 and 2024/25 respectively. It is acknowledged that this recommendation is sustainable (with sustained 1.3% increased into the future) only if Hydro's financial achievements exceed its current forecasts (e.g., better O&M control, a more focused capital budget, no wasteful Strategy 2040 spending, or better achievements in export markets). However, the approach permits revision to a 2% rate path in future, as an example, in the event such increases in performance are not achieved.

Taking into account the future framework of *The Amendment Act* in the exercise of discretion (Outlook approach).

44. One possible interpretation of s. 65 of *The Amendment Act* is it does not limit the scope of the PUB's discretion under s. 25(4) of the *Crown Act*. The view would be that s. 65 of *The Amendment Act* does not preclude the PUB from

taking into account anything that it deemed to be relevant to setting rates including based on forecasts taking into account *The Amendment Act*. This approach essentially mirrors that taken by Hydro, and by Mr. Bowman.

45. For simplicity, this approach will be termed the "Outlook" approach – *The Amendment Act* does not change our <u>present</u> as reflected in the conduct of this hearing, but it does affect our <u>outlook</u> for years after 2025.

Issues with the Outlook Approach

46. Notwithstanding the use of the Outlook Approach by Mr. Bowman and by Hydro, this approach gives rise to multiple notable issues.

47. The transition provision in *The Amendment Act* expressly indicates that the previous legislation and provisions "continue to apply to the determination of rates for the retail supply of power under The Manitoba Hydro Act for any period ending before April 1, 2025."

48. Manitoba Hydro's approach towards s. 65 of *The Amendment Act* is inconsistent. In its written argument page 15-16, it notes that:

> "…when establishing its projected rate path, Manitoba Hydro is guided by the following priorities that give consideration to the best interests of all Manitobans, today and in the future:
>
> 1. **<u>Compliance with legislated rate-setting regulatory framework</u> that sets the maximum general rate increase at the level of inflation or 5%, whichever is lower, to achieve debt-to-equity targets by 2035 and 2040**;

> 2. Stable and predictable rates for customers, together with keeping rates low compared to other jurisdictions (discussed in Section 3.3.2);
>
> 3. Gradually improving Manitoba Hydro's financial health over time; and
>
> 4. Ensuring system reliability and modernizing the grid through system investments funded from cash from operations where possible" (emphasis added)

49. The problem is that the PUB is not required to ensure "Compliance" with the new *The Amendment Act* framework and targets. The opposite directive is given in s. 65 of *The Amendment Act*.

50. In MH Ex. 56, presented on June 19, at Slide 15, there is also a contradictory statement by Manitoba Hydro:

> The new legislative framework, while not applicable to the determination of electric rates until April 1, 2025 is still a compelling policy consideration that cannot be ignored.

51. Either the new legislative framework is applicable (relevant and not be ignored) to the determination of rates in this proceeding or the new legislative framework is not relevant and should be ignored.

52. The same issue is highlighted in the submission of Mr. Bowman (direct examination, MIPUG Ex. 21) where he notes at slide 7 that this is "The First Bill 36 Rate Increase". It is hard to accord a finding that Bill 36 (*The*

Amendment Act) is driving rates during a period in which it is specifically excluded from applying.

53. Accountants and economists have provided expert evidence which is founded on different approaches to the exercise of the PUB's discretion under s. 25(4) of the *Crown Act*.

54. The legislature, knowing full well the PUB has a long-term approach to setting rates in a GRA with specific test years, could have added a sentence in s. 65 of *The Amendment Act* indicating that s. 65 did not limit the PUB's discretion in s. 25(4) to consider the relevance of the new framework in deciding just and reasonable rates prior to April 1, 2025. It did not do so.

55. The failure to do so may cause practical issues noted by Mr. Bowman: "I don't think anybody would design a credible financial forecast that did not build in the law of the land as they understand it will apply at the time they're making the financial forecast for." (Tr. p. 4065).

56. However, it is not the PUB's role to re-write the transition provision (s. 65 of *The Amendment Act*).

Cautionary Approach

57. Out of an abundance of caution to deal with the possibility of a jurisdictional challenge, the PUB may decide to endorse the Blinders interpretation with the result this entails and, in the alternative, advise of its finding using the

Outlook approach. We submit that the evidence adduced in this GRA would allow the PUB to reach the same conclusion on the appropriate rate determinations.

The Alternative of the Outlook Approach

58. If the Board is of the view that the Blinders approach is not required under *The Amendment Act* framework, then the primary evidence for assessment of the rate proposals stem from Hydro and Mr. Bowman. Both these views conclude that a stable and predictable path towards *The Amendment Act* targets is advisable. However, it must be acknowledged that both these conclusions are explicitly and inevitably the "First Bill 36 Rate Increase" as outlined by Mr. Bowman.

59. Despite a confluence of views regarding the appropriateness of rate increases today under the Outlook Approach, MIPUG submits that through the course of the hearing, a key flaw in this approach has been highlighted. This flaw revolves around two conclusions:

60. The rate path is oriented towards achievement of the 70:30 ratio by 2040 and ignores the more imminent target of 80:20 by 2035 which is far exceeded. (The financial forecast scenario provided by Hydro in Appendix 4.1 achieves 76:24 by 2035)

61. The period from 2035-2040 reflects material capital spending on Major Generation (Figure 3.29, Tab 3) totalling on the order of $1.4 billion, which is related to the yet to be announced (and expressly out of scope) Integrated

Resource Plan. This spending is driving the need for 30% equity (over $400 million in added net income requirements) which is a material upwards driver of the rate path to get to 70:30 by 2040.

62. Combined, these two factors reflect material issues with the approach to the legislation, and the scope of this proceeding.

63. First, the scope of this proceeding excludes integrated resource planning. Setting rates to achieve a debt target in 2040 that is driven heavily by resources that are tied to that out-of-scope IRP, and hence were not tested, is problematic.

64. Second, on the legislative front, the 2035 targets are of key importance and should be taken into account. The legislation sets out are as follows, per the amended *Manitoba Hydro Act*:

> 39.1(1) It is hereby declared to be the policy of the government that:

…

> (c) subject to section 39.2 and the regulations, the rates charged by the corporation are to provide sufficient revenue
>
> (i) to enable the corporation to achieve the following target debt-to-capitalization ratios:
>
> (A) 80% by March 31, 2035,

(B) 70% by March 31, 2040, and

(ii) to achieve or maintain any additional financial targets established by regulation; and

65. The above excerpt highlights that the operative target for the time being is 80% by March 31, 2035.

66. The Board has evidence of the rate increases required to achieve the 80% ratio by March 31, 2035. In fact, the Board has two relevant scenarios:

67. A scenario using the Hydro forecast of costs and revenues, with the rate increase adjusted from 2% to 0% in each of 2023/24 and 2024/25, and 2% in each year thereafter. This scenario is outlined in Appendix 4.4 (Amended) Sensitivity Analysis as "0% Rate Increases in 2023/24 & 2024/25".

68. Under this scenario, the 2035 debt:equity ratio is revised from 76% upwards to 80% (page 2 of 11), exactly on target for the 2035 date in the legislation (*The Amendment Act*). This scenario suffers 2 years of net losses, totalling $17 million ($8 million in 2029 plus $9 million in 2031) combined (page 4 of 11) which are immaterial compared to the expected financial performance following the in-service of the major new projects.

69. A scenario using the Coalition adjusted O&M and capital costs (CC Rate Scenario #4, per Coalition/MH-I-43a-h) achieves the debt:equity outcome with 0% increases in 2023/24 and 2024/25, followed by 0.98%/year through

2034/25 (see Attachment 1, pp. 25 – 32 of 64). That scenario suffers 3 years of net losses before 2035, totalling $47 million, but faces challenges from 2035-2040 as the new IRP resources begin to affect rates.

70. Under the Outlook Approach, there is ample evidence that 0% rate increases for 2023/24 and 2024/25 could be implemented and still meet the requirements of *The Amendment Act* as drafted, when giving meaning to section 39.1(1)(c)(i)(A) as to an 80% target by 2035. This also has the feature of not raising rates today to pay for placeholder IRP related spending after 2035, which is consistent with the Board's restricted scope in this hearing, and the appropriate way to reflect highly speculative future investments.

71. In short, taking into account *The Amendment Act*, but with a focus on the 2035 targets, the Board could readily conclude that no further rate increases are required in 2023/24 and 2024/25.

Additional Considerations

72. MIPUG has, in accordance with the PUB's expectations, avoided adducing its own overlapping expert evidence where it knew other parties would likely adequately address a particular area of evidence.

73. Under either Blinders Approach or the Outlook Approach, MIPUG recommends the Board take into account a number of factors on which MIPUG did not call specific expert evidence:

(a) The need for Hydro to improve system reliability, particularly for subtransmission customers. Along with appropriate engagement regarding the customer relationship and data sharing, investment in improved monitoring, visibility, and redundancy in transmission and subtransmission is needed.

(b) The potential that Hydro's O&M cost escalation, particularly tied to Strategy 2040, is excessive.

(c) The potential that Hydro's normal capital spending must be focused on improving outcomes for customers, taking into account the impact of interruptions on customers rather than simply Hydro's own lost revenues.

(d) The potential that Hydro's export revenue forecasts are speculative and, based on the public record, conservative forecasts.

74. The above considerations could support a small upward adjustment from the 0%/0% level (for reliability spending) or a small downward adjustment (for curtailing waste and Strategy 2040 spending).

75. Further, the Board should take note of Mr. Bowman's recommendation that multiple increases within a 12-month period should be avoided if possible.

Recommendation on rate increases

76. In light of the above, MIPUG recommends that the Board implement a 0% average rate increase for 2023/24 and an increase for 2024/25 that is less than 2% overall on April 1, 2024, as outlined in Recommendation 3, and confirm the 3.6% interim increase from Order 140/21.

77. This approach puts Hydro on a path to achieve if not exceed the 80:20 debt target for 2035, consistent with *The Amendment Act* if this is appropriately taken into account (Outlook approach). It also provides Hydro with extra funds to address added investment in reliability. However, this rate increase is also justified with reference to Mr. Rainkie's evidence under the Blinders approach.

RECOMMENDATION 1 – RATES RECOMMENDATION

Recommendation 1: MIPUG recommends that the Board implement a 0% average rate increase for 2023/24 and an increase for 2024/25 that is less than 2% overall on April 1, 2024, as outlined in Recommendation 3, and confirm the 3.6% interim increase from Order 140/21.

DIFFERENTIAL RATE INCREASES

Recommendation 2: Assuming the PUB adopts the Blinders approach and rejects the Outlook approach, the Board should implement immediate differential rate adjustments to at minimum achieve the outer band of 95 – 105 by 2027/28 based on PCOSS24. Under the Outlook approach, the pending provisions for reflecting properly-allocated revenue requirements to each class would suggest an even more dramatic rate differentiation is merited.

Recommendation 3: With respect to differentiated rates:

- No further rate adjustments be implemented with respect to the 3.6% rate increase from 2021;
- For the test year 2023/24, the following classes, (GSS ND, GSL 30-100kV, GSL >100kV and Area and Roadway Lighting) which are above the ZOR, have no rate increases (i.e., 0%). This would apply irrespective of whether

the PUB grants to other classes a rate increase, or whether the PUB does not grant rate increase in 2023/24 as per MIPUG's Recommendation 1;

- For the test year 2024/25, the following classes, (GSS ND, GSL 30-100kV, GSL >100kV and Area and Roadway Lighting) which are above the ZOR, have no rate increases (i.e., 0% change to unit rates; this includes no increase to the demand charge related to the change in definition of billing demand for GSL 30-100kV and GSL >100kV – which reduces Hydro's revenues by about $0.9 million). The remaining classes would receive the rate increases as proposed by MH in its Application..
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78. We have attached **Issue paper** 7 on the questions of:

(a) Whether it is appropriate for the Board to set differential rates at this time? And,

(b) Whether the differential rates proposed by Hydro are sufficient to address longstanding Revenue:Cost Coverage issues?

79. The table prepared by MH in response to PUB/MH I- 141b shows that if these classes identified in Recommendation 3, are to reach the zone of reasonableness in 5 years, there should be a movement which is greater than the proposed -.5% and -1% differentiated rate increases.

80. The evidence was that, based on PCOSS 24, it is estimated that the following MIPUG classes will contribute more than their measured costs by the following amounts:

(a) the 45 companies in the GSL 30 – 100 kV class will contribute more than their measured costs by $11.8 million, and

(b) the 14 companies in the GSL >100 kV class will contribute more than their measured costs by $19.4 million dollars. (Tr. pp. 3696 – 3700).

81. By definition, if a class is outside the zone of reasonableness, the rates charged to that class are unreasonable.

82. The PUB has set a 10-year timeline for classes to get to the 95 – 105 Zone of Reasonableness. There is no compelling reason to depart from that goal. Indeed, based on *The Amendment Act*, there are compelling reasons (and, eventually, requirements) to advance that goal.

83. The issue of GSL 30 – 100 kV and GSL >100 kV paying unreasonable rates goes back to at least 1996. We marked PUB Order 51/96 as MIPUG 18. The PUB, at page 61 (p. 69 of 101 of the pdf) of that Order, granted differentiated rate increases of 0% with respect to the GSL customer class and 2.84% then 2.34% for the Residential customer class.

84. If the PUB decides to apply the Outlook approach we submit that s. 39.1(1)(a) suggests a more pressing need to move to parity the 4 classes which are above the ZOR.

Use of PCOSS 24

85. **Issue paper 3** responds to the issue of:

Whether PCOSS24 reports RCC ratios that can be reliably used to set rates?

86. We submit that the measured RCC ratios in PCOSS24 are reliable and if anything may understate the persistent issue of the residential class not covering its measured costs.

Ms. Derksen's criticisms of PCOSS24 are unfounded.

87.

88. **Issue paper** 6 deals with various criticisms of Ms. Derksen with respect to the use of PCOSS 24.

89. First, we disagree that RCCs are Unstable. RCC's have been remarkably stable of the last decades.

90. Second, Ms. Derksen ignores growth in distribution costs in her analysis. One example is some $80 million between PCOSS21 and PCOSS 24.

91. Third, RCC ratios before NER is simply a backdoor attempt to attack the PUB's decision NOT TO allocate NER to distribution costs.

92. Fourth, Ms. Derksen's comments and approach to marginal costs are deeply flawed as explored in MIPUG's cross-examination of her. Hydro's evidence on the deficiencies of her analysis is compelling.

93. 20-year-old historical political speeches with respect to possible funding of Uniform Rates are not law. If the then Government or any future Government wanted to change the manner in which rates are set and export

revenues are applied, they could easily have done so through the legislation which has been referred to as *The Amendment Act*.

94. All classes pay uniform rates irrespective of the location and the fact that it may be more costly to serve a customer in a remote rural area vs. an urban area.

Speculation that RCC will be self correcting

95. We submit that there is no credible evidence that the Revenue to Cost Coverage ratios will self correct. As set out in **Issue paper** 6, there have been previous similar hypothetical and speculative assertions all of which have been unfounded.

96. Although some variables such as export revenue were isolated by Ms. Derksen to show the impact of those variables on RCC there was no evidence of what a full PCOSS analysis in the future tests years and in the future will look like.

Whether the approach to estimating NER in PCOSS24 is appropriate.

Recommendation 4: The Board should continue to apply its finding from Order 59-18 that Export revenues should be a reduction to allocated class costs.

Recommendation 5: The Board should rely on the net export revenue and net income assumptions in PCOSS24 for the purpose of establishing differentiated rates in this proceeding.

97. PCOSS24 was prepared to reflect the costs of providing electrical service in the Test Year 2023/24.[8]

98. While starting reservoir levels in PCOSS24 are above average, water inflows are set at an average level, and the effect of running a new PCOSS "normalizing" for this effect does not directionally change the conclusions from PCOSS24.

99. This "testing" of PCOSS24, therefore supports the directionality and reasonableness of PCOSS24 for setting rates, rather than undermining the conclusions.

100. Compared to PCOSS21, PCOSS24 now includes the entire cost profile of the major new generation and transmission (including Keeyask and MMTP). In PCOSS21, the test year started with no Keeyask units in service and ended with only five of seven units in service[9]. This means that a significant part of the cost of Keeyask was included in PCOSS21, but very little new revenue from the project was included.

101. Because Keeyask is now in service, and the full suite of assets that generate the substantial export revenues (Net Export Revenues, or NER) are included in Hydro's costs, there is a significant revenue offset that is needed to pay for the basic economic rationale for constructing or advancing Keeyask and other

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[8] Hydro Application. Tab 8, page 6-7.
[9] Hydro Application. Tab 8, page 7.

assets in the first place. This NER is therefore appropriately credited against the cost of the assets that generate the NER (generation and transmission).

102. While NER and Contribution to Reserves do see an upward effect from higher-than-average starting reservoirs, the added NER is allocated to generation and transmission, while the added Net Income is allocated to all assets based on average Rate Base, which still primarily consists of generation and transmission (over $22 billion out of $27 billion of Rate Base is generation and transmission)[10]. For this reason, the impact of any alleged high or unstable NER makes relatively little difference in the outcomes of the PCOSS.

GSL 30 – 100 kV and GSL >100 kV classes are further penalized when there are above average export revenues

103. What also seems to have been ignored by Ms. Derksen is that the GSL 30 – 100 kV and GSL >100 kV classes are further penalized when there are above average export revenues.

104. PUB/MH I-141a utilizes a scenario of expected export revenues in 2024/25 with average water flow and no higher reservoir starting conditions. 2024/25 is the last test year in this GRA. The RCC of GSL>100kV goes down from 113.2 % to 110.5% or a 2.7% change in RCC. On $166.6 million of class revenues this means that directionally the GSL>100kV paid ($166.6 x 2.7%)

[10] Hydro Application, Appendix 8.1 (PCOSS24), page 26.

$4.498 million over its measured costs under the projected export revenue results towards other classes – mainly the Residential class.

105. The drastic under contribution of the Residential class towards Generation and Transmission is further illustrated by Mr. Bowman's direct evidence slides at slide 24 (MIPUG Ex. 21).

106. If we assume that both Residential consumers and GSL >100kV pay 100% of their Distribution and Subtransmission costs, Residential consumers only pay 90.1% of their Generation and Transmission costs – they are approximately 5% away from the ZOR.

107. Lastly, as a cross-check, Hydro provided responses to PUB/MH-I-141(a) and Coalition/MH-I-155(a) that adjust the NER to the level expected for 2024/25 (a reduction of approximately $180 million[11] to NER and to Net Income). Despite this material decrease, the impact on the outcomes of the study (the measure of which classes are in a zone that is deemed to be potentially reasonable, and those that are outside the zone and are therefore unreasonable), does not change at all[12]. For example, the residential RCC changes only from 94.4% to 94.8%. This is positive confirmation that the Board can rely on the output of PCOSS24 for the purposes of setting rates.

DEPRECIATION ISSUES

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[11] Coalition/MH-I-155(a), reduced from $1,116.2 million to $932.5 million.
[12] MIPUG Ex. 6, Table 4-2, page 48.

Recommendation 6: Hydro should adopt the Average Service Life ("ASL") procedure for all depreciation calculations, whether for regulatory purposes or financial reporting. The ASL procedure is sound, well-accepted throughout North America, and leads to an appropriate recognition of the service value being provided by the assets providing service to customers. As such, ASL is the approach most consistent with just and reasonable rates. This is consistent with Alternative 2 in the Depreciation Issues document.

Recommendation 7: In order to achieve reasonable and fair depreciation rates and expense, Hydro should determine the level of componentization required regardless as to the group procedure used. The Equal Life Group ("ELG") procedure is not an alternative to proper componentization.

Recommendation 8: Some of the accounts developed by Alliance appear to be reasonable refinements on Hydro's account structure. Others appear trivial and of no materiality. The review of componentization by Hydro should be a continuing activity, consistent with capital asset tracking within any utility as part of maintaining accurate capital asset accounts.

Recommendation 9: The booking of gains and losses on disposals (other than terminal retirements) is redundant and inconsistent with group depreciation. If for some reason the booking of gains and losses is to be continued as part of Hydro's IFRS asset accounting, then the gains and losses recorded should be broken out by asset account, included in a regulatory deferral account, and amortized to income over the weighted average remaining life of the assets in that account.

Recommendation 10: There should not be a new IFRS Phase-In Deferral created nor needed to adopt appropriate depreciation practices at this time.

Recommendation 11: The Change in Depreciation Method Deferral, totaling $327 million at year-end 2022/23, should be discharged as an offset to accumulated depreciation, by account. Alternatively, this balance should be amortized over the remaining life of the assets as part of Alternative 2 of the Depreciation Issues document. The mathematical outcome for setting rates of the two options is the same.

108. MIPUG's submissions are further set out at pages 29 to 32 of the Depreciation Document marked as PUB-20 and in **Issue paper 1.**

109. We submit that there are a couple of keys points for the PUB's consideration of the Depreciation Issues.

110. First the only independent expert witness with 20 years of auditing and accounting experience was Dustin Madsen[13]. In addition, he is a Certified Depreciation Professional.

111. More importantly he had specific professional experience as an instructor and an IFRS project manager.

112. Conversely, Manitoba Hydro chose to not have an independent IFRS expert provide an opinion on the accounting aspect of the depreciation issues. Manitoba Hydro, also chose not to call its accounts or auditors to challenge Mr. Madsen's accounting opinions, including his opinion that further componentization was not required for an IFRS compliant ASL method. As a result, an adverse inference should be drawn that Manitoba Hydro's accountants and auditors would not support Manitoba Hydro's arguments.

113. As a further result, little or no weight should be given to Hydro's argument at pages 158 to 162 of its submission that further componentization is required under ASL but not under ELG. Although Manitoba Hydro asserts that Alliance prepared an IFRS compliant ASL study, Mr. Watson of Alliance is not an accountant, and has very limited expertise specifically related to IFRS. Further, all

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[13] See GSS-GSM -5 at p. 4.

parties agreed that Mr. Watson and his team included recommendations to initiate some examples of immaterial new componentization which is not required by IFRS[14]. The same applies to Mr. Larry Kennedy who is not an accountant and cannot opine on IFRS requirements.

114. Any Manitoba Hydro management discretion and decision should be based on appropriate accounting advice. Mr. Madsen has provided that independent advice.

115. Logically it is difficult to reconcile Manitoba Hydro's assertion that with Alliance's collaboration it produced an IFRS compliant ASL study but that it would take extensive work to implement ASL.

116. Page 6 of 199 of Appendix 9.11 (the Alliance report) indicates:

> Detailed analysis was performed in this study to calculate depreciation rates for Manitoba, split fixed asset costs into homogeneous subcomponent accounts, and develop specific depreciation rates and parameters for all of MHydro's depreciable plant by subcomponent account using IFRS compliant, average life group procedure, remaining life technique. Hence, this study fully complies with the PUB's directives.

117. A review of the record, specifically July and August, 2020 minutes of meetings entitled "Minutes ASL IFRS compliant" shows that Ms. Michelle Hooper

[14] Hydro submission, p. 159, lines 10 and 11.

was actively involved in recommending the additional componentization for the Alliance study which is allegedly an IFRS compliant ASL method.[15]

118. Contrary to the argument by Manitoba Hydro at p. 162 of 244, an accountant does not need to perform a large-scale depreciation study to understand the level of componentization. The independent IFRS expert can assess the "significance" and "materiality" of the groups chosen and resulting compliance with IFRS – whether under ELG or ALG.

119. There was no independent depreciation expert who challenged Mr. Bowman's evidence that if further componentization is required for ASL, it is also required for ELG because both are Life Group depreciation methods.

120. We therefore submit that the "extra componentization" and "extra cost" arguments are simply not credible and not based on independent accounting expert advice.

121. At a high level we submit:

(a) ASL is used by the vast majority of utilities in the US, and Canadian Crown utilities. Among the Canadian Crown utilities, only NB Power uses ELG.[16]

(b) ASL is universally agreed to lead to lower depreciation expense, to the point that Hydro acknowledges adoption of IFRS-compliant ASL can be done without a likely need to a phase-in, while ELG will

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[15] See MIPUG/MH I-91a-dd, Attachment 7 where Ms. Hooper's review & comments to Alliance are noted. For example, at p. 10 of 48 there was a proposed split in Powerhouse and Powerhouse Renovations, and it is noted that Mr. Watson (Dane) was comfortable with the proposed approach. At pp. 10 and 11 of 48 there was a split proposed for Water Control Systems and it is noted that "Dane ok with the proposed sub-componentization." There are multiple examples of proposed splits with Dane being "ok with" or "agrees".

[16] Transcript page 3141.

require a phase-in due to the adverse financial impacts.[17] The depreciation issues document estimates this at $267 million over 20 years, but this is based on the Alliance estimates which are noted by all parties to be excessively granular.[18] Mr. Bowman noted that the range could be from $267 million to $1.3 billion, and indicated that the estimate of $700 million was probably "not a bad number" based on the impact of using Mr. Kennedy's estimated lives applied to the current level of componentization.[19]

(c) The only significant rationale supporting ELG is the assertion by Hydro that it needs to do more componentization to implement ASL. However, Hydro's primary apparent concern about componentization is that it takes additional administrative and tracking effort.[20] Outside of a dispute as to whether this added componentization is in fact required (see the evidence of Mr. Madsen)[21], both Mr. Madsen[22] and Mr. Bowman[23] noted that added componentization is in fact a benefit, where merited, since it improves utility cost tracking and life analysis. Further, Hydro notes that some of the new components would be implemented even if remaining under ELG.[24]

122. Mr. Bowman and Mr. Madsen both support ASL procedure, which Hydro agrees is a viable alternative. By way of contrast, Hydro's preferred approach (ELG) is not supported by any other party in the proceeding. Mr. Madsen notes that the rate impacts of adopting the ELG approach "are significant and not warranted in this case".[25] Mr. Bowman echoes the concerns over unjustified rate pressures from ELG, and further notes that ELG, in the case of Hydro, fails to live

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[17] Hydro Argument, page 158.
[18] Transcript page 3018-3019.
[19] Transcript page 3208-3209.
[20] Transcript page 3050-3070.
[21] For example, transcript page 3068.
[22] Transcript page 3070.
[23] Transcript page 3108-3110.
[24] Transcript page 3116.
[25] PUB-20, page 32.

up to its purported benefits of accuracy[26] and it ultimately does not match the consumption of service value of a group of asset, which is the basis for determining that rates in a given year are just and reasonable.[27]

123. Ultimately, the role of the PUB is to set just and reasonable rates. The purpose of IFRS is fair presentation. It is to portray a financial condition of an organization after the fact. By way of contrast, the role of a regulator is prospective. It is to establish the rates to be charged in the future. As such it sets the economic and financial conditions within which a utility operates.

124. The mandates of regulators are not to chase interpretations of accounting standards (whether these are fixed or subject to ongoing interpretations). Rate setting on the basis of interpreting accounting standards is inappropriate in that it fails to begin with the clear legislative mandate given a regulator, and it is also contrary to the purpose of the two roles. Mr. Bowman dealt with this issue extensively in PUB/MIPUG I-7.

Depreciation Phase-in Deferral Account for ELG

125. The fact that Manitoba Hydro seeks to establish a new deferral account should the PUB approve the ELG speaks volumes of the intergenerational inequity caused by front loading depreciation costs through ELG. ELG is quite simply not aligned with accepted regulatory principles.

[26] MIPUG Ex. 6, page 25.
[27] See MIPUG Ex. 6 page 29-30 and MIPUG Ex. 15, page 5.

Industrial Billing Demand Definition

Recommendation 12: The update to the definition of industrial billing demand, to focus only on the on-peak period, should be approved, with two adjustments:

- there should be no revenue enhancement to the demand rate included, given the class is paying well above the ZOR. The Board can achieve this outcome by revising downward the overall average increase for revenue requirement to permit there to be no rate increase for this factor.
- there should be no off-peak cap of 10% above on-peak before the off-peak period becomes the basis for demand charges. While no limit is required, Hydro has accepted that a less constraining cap (such as allowing the on-peak billing units to be as low as 75% of the off-peak peak), which is a reasonable compromise and should be adopted while the new rate is being put into place.
- At the earliest reasonable opportunity, the rate design should also be applied to GSL 0-30 kV customers who are of sufficient size and have appropriate metering.

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126. Please refer to **Issue paper 8** with respect to these recommendations. The changes to the definition are directionally appropriate. However, the 90% off peak formula does not go far enough and the proposed increase in demand rate charged further penalizes the 30 -100 kV and >100kV classes by about $0.9 million when these classes have paid more than $31 million above their measured costs (per PCOSS24).

127. Given the increasing importance of demand, in addition to further exploring Time of Use Rates and allowing new entrants in the Curtailable Rate program, Hydro should also explore various rate structures and options such as those identified in Gerdau's answer to undertaking marked as MIPUG 22:

- Industrial Conservation Initiatives

- Transmission/Demand Coincident Peak (CP) Capacity Programs

- Operating Reserve, Spinning Reserve, Sync Reserve Services

- Demand Response (DR) Programs.

Rate Classification for 0 – 30 kV GSL Customers

Recommendation 13: Manitoba Hydro should be directed to study the customer homogeneity in the GSL 750 V – 30 kV rate class and report back to the PUB at the next GRA on alternatives to improve the homogeneity of the class.

128. Please refer to **Issue paper 10** for further information on this issue.

129. The differing consumption behaviors between smaller commercial customers and larger industrial customers can directly impact contributions to coincident system peak and distribution service requirements that impact PCOSS allocations, which are assumed on a class average basis in the COSS methodology used by Manitoba Hydro.

130. MIPUG proposed to Manitoba Hydro witnesses that they look at customer homogeneity in the GSL 750 V – 30 kV rate class. This proposal was viewed favourably:

> MS MARNIE VAN HUSSEN: *"And, certainly, we can – something we can take a look at. I – I will say that's, you know, will happen with all of our rate classes, you know, not all customers can be close to the average. So, certainly, to the extent that's going to happen, regardless of the – makeup of your class. But we will, we will take a look at it."* [Transcript p.3736]

131. It is also noted that the recent changes to the *Hydro Act* may limit the Board's ability to direct changes to class structure and composition in future. For this reason, MIPUG recommends that the Board direct Hydro in this GRA to complete an analysis of the GSL 0-30kV class with regard to homogeneity, and identify measures that Hydro may implement to improve the cost allocation to these customers, including restricting the class, moving customers to other classes based on their usage characteristics, or other measures that may arise from the study.

Recommendation 14: Reliability
MIPUG recommends that the Board direct Manitoba Hydro to establish a metric for unserved energy based on industry best practice engagement of customers to establish a reasonable estimate of customer cost for reliability events, both momentary and non-momentary.

132. This recommendation is dealt with in **Issue paper 9**.

133. Best practice for engagement and surveying of customers in response to reliability events was discussed at some length during cross-examination of Manitoba Hydro witnesses. Manitoba Hydro could benefit from adoption of industry best practice, using information obtained through customer engagement and surveys to establish the value of lost load (VOLL) or cost of unserved energy [Transcript 1543 – 1549].

134. It appears that Manitoba Hydro has acknowledged it could improve what it currently does. For example,

> "*MS Tanis Brako: The CSTS asks residential customers of, you know, many different topics related to the services that we offer, but there's a gap. We don't have a formal survey that goes to commercial and industrial customers that ask the same thing.*
>
> *So, we have, again, like I mentioned, identified that as a gap, this is through Strategy 2040. We know that we need to have a better understanding of the evolving needs of our customers*." [Transcript p.1490]

Recommendation 15: Hydro should resume updating of the Uncertainty Analysis tool, to provide probabilistic assessments of the likelihood of reaching future financial targets considering overlapping risks, and to support future rate increases.

135. During cross-examination and during the direct evidence of Mr. Bowman, previous Board directives on this issue were identified as well as the usefulness of probabilistic assessments.

136. See Consumers Coalition Exhibit 28 and in particular Mr. Bowman's Background Paper C (at pp. 8 to 21) on the benefits of the Uncertainty Analysis tool, its functions and how Manitoba Hydro's Uncertainty Analysis could be improved.

137. This tool would be useful for the PUB in performing its tasks. Hydro should resume using it.

Recommendation 16: The Board should direct a one-year amortization of amounts related to the Conawapa deferral account, and the Selkirk loss on disposal and cost of removal balances, in the earliest available fiscal year. This decision should be explicitly linked to finalizing the 3.6% interim rate from 2021.

138. See **Issue paper 2** for further discussion on this recommendation and in particular the desirability to deal with the mothballing of Selkirk generation and not burdening future generations with their costs.

139. The recommendation with respect to Conawapa was previously fairly extensively dealt with in written submissions.

140. At the hearing, the expert evidence reconfirmed the desirability of reducing deferral accounts. We also reviewed the history of why the Conawapa deferral account was set up.

141. Multiple years of losses were anticipated with the absorption into rates of the major capital projects. Although there was a recommendation by MIPUG and the PUB that the Province provide relief by reducing its charges, it had refused to do so.

142. In those particular circumstances, as they previously existed, the last thing ratepayers needed was to absorb approximately a $380 million dollars one time write off with respect to Conawapa which was no longer going to be built.

143. In the course of the GRA following NFAT, Manitoba Hydro indicated that it anticipated the auditors requiring a full write off of costs in 2017/18[28].

[28] See Hacault cross-examination Tr. pages 2506 to 2545.

144. In when I asked what benefits my grandchildren could possibly have in continuing to absorb deferred Conawapa amortization costs, the answer was essentially “There’s no enduring benefit at this point”[29].

145. Although regulatory certainty warrants a high threshold to change the amortization period of the Conawapa amortization account, we say that the high threshold test has been met.

146. The set of facts which led to the creation of this long-term deferral account simply no longer exist.

147. The anticipated significant ongoing losses in absorbing the major capital projects are no longer projected to occur.

148. The requested rate relief from the Province, which no one thought would occur, is now reality providing approximately $180 million annually in rate relief. At a remaining balance of some $303 million, the retroactive Provincial rate relief eliminates the adverse impact. Also, in addition to benefitting from an urgently approved 3.6% rate increase, according to expected financial results, Manitoba Hydro has benefited from outstanding revenues in 2022/23.

149. The justification for the deferral, being the need to rate smooth no longer exists. The immediate amortization has the effect of eliminating the ongoing $12.6 million reduction to net income[30].

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[29] See Hacault cross-examination Tr. Page 2545, lines 6 to 25, then pages 2546 - 2553. Quote is from line 25, p. 2553.

150. This extraordinary change in the factual underpinning justifies that the Board make a one-time decision to implement Mr. Bowman's recommendation.

CONCLUSION

151. For the reasons set in this submission and the **Issue briefs** we ask that the PUB grant the relief set out in the various recommendations.

All of which is respectfully submitted this 22nd day of June, 2023.

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[30] Tr. Page 2551

IN THE MATTER OF
MANITOBA HYDRO

Review of Order 140/21 Interim rate increase and 2023/24 and 2024/25 GRA

SUBMISSION ON BEHALF OF Manitoba Industrial Power Users Group
("MIPUG")

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LEGAL AND LEGISLATIVE DRAFTING

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meaning, the court could eventually choose to apply the *contra proferentem* to construe ambiguous language against the interests of the party who drafted it.[20]

A lawyer drafting a legal document or a government drafter drafting a statute is therefore well advised to adopt a drafting style that places a premium on clarity and precision, even if that requires sacrificing some elements of style to achieve it. Because of this unwavering focus on precision,[21] legislative and legal drafting differs in style from other forms of writing.

THE LEGISLATIVE STYLE

In response to the challenge posed by this quest for certainty, legislation and, to a lesser extent, legal drafting, has adopted a distinct literary style. This style is highly formalized and highly stylized. It does not seek to entertain, to impress or even to explain. Ruth Sullivan describes it in the following terms:

> The current legislative style in Canada is formal, serious, and impersonal. It is often highly technical. For better or worse, it avoids most of the features that make reading a pleasurable experience — for example, wit, humour, originality, emotive and figurative language, stylistic variation, and local or personal reference. In short, the voice with which the legislature speaks is remote not only from everyday speech but from most other forms of written expression as well.[22]

The American drafting style is similar. As Donald Hirsch explains:

> The draftsman is not employed to produce a work of literature, but to express legislative policy clearly and simply.[23]

The unique literary style used in legislation — and, to a degree, in other legal instruments — owes much of its singularity to the fact that it is destined to be interpreted in accordance with the principles of statutory interpretation, and is therefore presumed to have been drafted with those principles in mind.[24] The principles that have the most impact on legislative drafting are:

- the presumption of consistent expression;
- the presumption against tautology; and
- the *expressio unius* or negative implication rule.

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20 K. Adams & A. Kaye, "Revisiting the Ambiguity of 'And' and 'Or' in Legal Drafting" (2006) 80 St. John's L. Rev. 1167 at 1193.

21 Note that precision is not the same as specificity, which is a focus on detail. One can convey a very broad idea in precise terms.

22 R. Sullivan, "Some Implications of Plain Language Drafting" (2001) 22 Stat. L. Rev. 175 at 183.

23 D. Hirsch, *Drafting Federal Law* (Washington, D.C.: Office of the General Counsel, Legislation Division, 1980) at 8.

24 R. Sullivan, *Statutory Interpretation*, 2d ed. (Concord, Ont.: Irwin Law, 2007) at 166; R. Sullivan, *Sullivan on the Construction of Statutes*, 5th ed. (Markham, Ont.: LexisNexis Canada, 2008) at 205.

The presumption of consistent expression[25] dictates that words in a statute are presumed to be used in a consistent fashion, and to carry the same meaning throughout a statute or other legal text. Ruth Sullivan explains further in *Sullivan on the Construction of Statutes*:

> It is presumed that the legislature uses language carefully and consistently so that within a statute or other legislative instrument the same words have the same meaning and different words have different meanings. ... Once a particular way of expressing a meaning has been adopted, it is used each time that meaning is intended. Given this practice, it makes sense to infer that where a different form of expression is used, a different meaning is intended.[26]

What this means for drafters is that they must avoid elegant variation: changes in the manner of expression designed to maintain interest by avoiding repetition. Once a particular word or expression is adopted, they must stick to it, regardless of how repetitious or dull it makes the text appear.[27] By way of example, Garth Thornton points out that if one provision of a statute requires notices to be *given*, other provisions should not require them to be *furnished*, *lodged*, *submitted*, *delivered* or *filed*, and that a provision referring to the *issuance* of a licence should not be followed by one referring to its *grant*.[28] Justice Blackburn summed this up with the observation that one of the clearest rules of legal drafting is "never to change the form of words unless you are going to change the meaning".[29]

The presumption against tautology[30] dictates that text is not included in a legislative or legal instrument unless it is there for a reason. As Ruth Sullivan explains:

> It is presumed that the legislature avoids superfluous or meaningless words, that it does not pointlessly repeat itself or speak in vain. Every word in a statute is presumed to make sense and to have a specific role to play in advancing the legislative purpose.[31]

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25 Also known as the presumption of uniform expression: P.A. Côté, *The Interpretation of Legislation in Canada*, 3d ed. (Toronto: Carswell, 2000) at 332; R. Sullivan, *Sullivan and Driedger on the Construction of Statutes*, 4th ed. (Toronto: Butterworths, 2002) at 164.

26 R. Sullivan, *Sullivan on the Construction of Statutes*, 5th ed. (Markham, Ont.: LexisNexis Canada, 2008) at 214-15.

27 H. Thring, *Practical Legislation*, 2d ed. (London: John Murray, 1902) at 84; R. Dick, *Legal Drafting in Plain Language*, 3d ed. (Toronto: Carswell, 1995) at 6, 86; E.A. Driedger, *The Composition of Legislation*, 2d ed. (Ottawa: Department of Justice, 1976) at 90; J. Aitken, *Piesse – The Elements of Drafting*, 9th ed. (Sydney: Law Book Company, 1995) at 19; G.C. Thornton, *Legislative Drafting*, 4th ed. (London: Butterworths, 1996) at 74; Office of Legislative Council, *Guide to Legislation and Legislative Process in British Columbia*, Part 2 (B.C. Ministry of the Attorney General, August 2003) at 3, online: <http://www.llbc.leg.bc.ca/Public/PubDocs/bcdocs/376304>; D. Hirsch, *Drafting Federal Law* (Washington, D.C.: Office of the General Counsel, Legislation Division, 1980) at 29.

28 G.C. Thornton, *ibid.* at 74.

29 *Hadley v. Perks*, [1866] L.R. 1 Q.B. 444 at 457.

30 "Tautology" is the unnecessary repetition of the same thing in different words: *Concise Oxford Dictionary*, 8th ed. (Oxford: Oxford University Press, 1990).

31 R. Sullivan, *Sullivan on the Construction of Statutes*, 5th ed. (Markham, Ont.: LexisNexis Canada, 2008) at 210.

This principle was explained by the House of Lords in *Hill v. William Hill (Park Lane) Ltd.* in the following terms:

> When the legislature enacts a particular phrase in a statute the presumption is that it is saying something which has not been said immediately before. The rule that a meaning should, if possible, be given to every word in the statute implies that, unless there is a good reason to the contrary, the words add something which would not be there if the words were left out.[32]

Drafters must therefore resist the urge to repeat something already said in a statute for emphasis, or to ease the transition to a new topic.[33] The presumption against tautology provides a good reason for drafters to avoid doublets and triplets — such as *null and void* and *give, devise and bequeath* — because their use invites the court to attribute a new and different meaning to the second and subsequent words in these expressions — something that those using them do not intend.

The interpretive presumption embodied in the maxim *expressio unius est exclusio alterius* is that where legislation sets out some things expressly but does not mention other things of the same class, it intends to exclude the latter. It is also referred to as the *negative implication*[34] or *implied exclusion*[35] rule. Ruth Sullivan explains the rule in *Statutory Interpretation* as follows:

> if the legislature had intended to include all possible members or things, it would have mentioned them all or described them using general terms; it would not have mentioned one or some while saying nothing of the others, for that would be irrational and disorderly. Legislation is supposed to be drafted in a coherent and orderly way. It thus follows from sound drafting practice that a partial enumeration of like things is meant to be exhaustive, and anything left off the list is by implication meant to be excluded.[36]

The rule reflects normal expectations of rational communication. If an advertisement for an apartment states that "cats are permitted", readers will normally assume that dogs are not, or they would otherwise have been mentioned. Because cats are specifically mentioned and the advertisement is silent on other pets, it is rational to conclude that other pets were deliberately excluded.

The *expressio unius* rule also applies to exceptions: if a statute makes certain exceptions to a general rule, other exceptions will not be read into it.[37] It has application to patterns of reference as well. Because of the presumption of consistent expression, once a particular expression such as *right or interest* has been adopted to convey a particular idea, any subsequent departure from that pattern — like a

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32 [1949] A.C. 530 at 546 (H.L.).

33 R. Sullivan, "Some Implications of Plain Language Drafting" (2001) 22 Stat. L. Rev. 175 at 184.

34 R. Dickerson, *The Interpretation and Application of Statutes* (Boston: Little, Brown & Co., 1975) at 234.

35 R. Sullivan, *Sullivan on the Construction of Statutes*, 5th ed. (Markham, Ont.: LexisNexis Canada, 2008) at 244.

36 R. Sullivan, *Statutory Interpretation*, 2d ed. (Concord, Ont.: Irwin Law, 2007) at 190-91.

37 *Canada (Canadian Private Copying Collective) v. Canadian Storage Media Alliance*, [2004] F.C.J. No. 2115, [2005] 2 F.C.R. 654 at 693 (F.C.A.).

reference to *interest* alone — will be presumed to be intentional, and to therefore have been intended to convey a different idea.[38]

For drafters, the *expressio unius* presumption permits a degree of concision that would not otherwise be possible; when providing for something expressly, it obviates the need to provide that other things are not included. It is also, however, a trap for the unwary; drafters must take care that by specifically mentioning some members of a class they do not implicitly exclude others.

These interpretive presumptions — the presumption of consistent expression, the presumption against tautology, and the *expressio unius* rule — all have an impact on the legislative style. Complying with the presumption of consistent expression lends a certain repetitiousness to legislation, while it and the presumption against tautology militate against the use of rhetorical flourishes. The *expressio unius* rule, on the other hand, gives legislation a certain crisp succinctness that some find discomfiting. Though the legislative style and the presumptions that underlie it may be foreign to some readers, drafters accept them as the necessary cost of being as precise as possible.

Because drafters are expected to draft with the principles of statutory interpretation in mind,[39] when they produce a draft for their clients they are implicitly assuring them that the text will operate effectively when those principles are factored in. As the British Columbia drafting guide advises:

> In drafting legislation, Legislative Counsel are not merely putting words to proposed government policy. We are also giving a legal opinion, based on the application of the principles of statutory interpretation, that the words we are writing will have the intended legal effect.[40]

Because the goal in drafting a legislative or legal document is to maximize certainty, a drafter will always sacrifice eloquence at the altar of accuracy and clarity.[41] A lack of literary flair is simply the price paid by the legislative style in the quest for certainty. As Garth Thornton explains:

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38 R. Sullivan, *Sullivan on the Construction of Statutes*, 5th ed. (Markham, Ont.: LexisNexis Canada, 2008) at 246-47.

39 R. Sullivan, *Statutory Interpretation*, 2d ed. (Concord, Ont.: Irwin Law, 2007) at 166; R. Sullivan, *Sullivan on the Construction of Statutes*, *ibid.* at 205.

40 Office of Legislative Council, *Guide to Legislation and Legislative Process in British Columbia*, Part 2 (B.C. Ministry of the Attorney General, August 2003) at 1, online: <http://www.llbc.leg.bc.ca/Public/PubDocs/bcdocs/376304>.

41 Hansard Society Commission, *Making the Law: Report of The Hansard Society Commission on The Legislative Process* (London, U.K.: Hansard Society for Parliamentary Government, 1993) at 56, para. 221, cited in P. Conway, "Syntactic Ambiguity" (Paper published by the Law and Justice foundation of New South Wales, 2002) at 2, online: <http://xml.lawfoundation.net.au/ljf/site/9f2043ee7ccfa2ddca256f1200115808/63b6c5e2abb6a511ca25714c000cff37/$FILE/syntactic.pdf>; R. Ramage, "Effective Draftsmanship – Part 4" (2005) 155 New L.J. 166 at 166; I. Turnbull, "Problems of Legislative Drafting" (1983) 13 Queensland Law Society Journal 225 at 229; J. Aitken, *Piesse – The Elements of Drafting*, 9th ed. (Sydney: Law Book Company, 1995) at 19; Office of Legislative Council, *Guide to Legislation and Legislative Process in British Columbia*, Part 2 (B.C. Ministry of the Attorney General, August 2003) at 2, online: <http://www.llbc.leg.bc.ca/Public/PubDocs/bcdocs/376304>.

> Writing in an artificial form, whether it be the drafting of a law or the composition of a sonnet, requires the acceptance and adoption of the conventions of the form.[42]

COMPLAINTS ABOUT DRAFTING

Though the call for precision can make the legislative or legal style a bit bland and matter-of-fact, it need not be opaque, convoluted or long-winded. Yet it is a recurring complaint about laws and legal documents that they are uncommonly difficult to read. The description given in a Statute Law Society report typifies this perception:

> The literary style is one of most frequent complaints about legislation, since it is one of the principal factors which affect comprehensibility. This style, legalistic, often obscure, and circumlocutious requires a certain type of expertise in order to gauge its proper meaning. Sentences are long and involved, the grammar is obscure, and archaisms, legally meaningless words and phrases, tortuous language, the preference for the double negative over the single positive, abound.[43]

Five years later, the Renton Committee espoused similar views:

> We have discovered that even [judges] often find it difficult to understand the intention of legislation passed by Parliament. If this is so, it is likely that practising lawyers find that the way in which the law is drafted presents at times an impenetrable barrier to understanding it; and we have indeed had evidence to this effect.[44]

The courts have hardly been more charitable in their views. In *Winchester Court Ltd. v. Miller*, Lord Justice Mackinnon expressed his perplexity at the impenetrability of the writing:

> He must be a bold, if not a conceited man who can feel confidence in forming, or expressing, an opinion on any one of the innumerable problems that arise out of what may be cited together as "the Rent and Mortgage Interest Restrictions Acts, 1920 to 1939", but having once more groped my way about that chaos of verbal darkness, I have come to the conclusion, with all becoming diffidence, that the county court judge was wrong in this case. My diffidence is increased by finding that my brother Luxmoore has groped his way to the contrary conclusion.[45]

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[42] G.C. Thornton, *Legislative Drafting*, 4th ed. (London: Butterworths, 1996) at 175.

[43] Statute Law Society, *Statute Law Deficiencies: Report of the Committee appointed by the Society to examine the failings of the present Statute Law System* (London: Sweet & Maxwell, 1970) at 34.

[44] The Renton Committee, *The Preparation of Legislation: Report of a Committee appointed by the Lord President of the Council*, Cmnd. 6053 (London: H.M.S.O., 1975) at 37.

[45] [1944] K.B.734 at 744.

the hope that they will escape parliamentary scrutiny.[112] Aside from the fact that it undermines democratic principles, this practice should be discouraged because it contravenes the organizing principle that rules related to the same subject-matter should be placed together.

Offence Provisions

While some may suggest that a provision stating that a breach of a statutory rule constitutes an offence and setting the penalty for that offence is best placed immediately after the rule to which the offence relates, the practice in a number of jurisdictions[113] is to place all offence provisions together after setting out the substantive provisions of the statute.

Regulation-Making Powers

In many jurisdictions,[114] regulation-making powers are grouped together and placed near the end of a statute. While this has the advantage of making the regulation-making powers easier to find, it has the disadvantage in some cases of separating them from the statutory provisions to which they relate. For this reason, drafters will sometimes ignore this organizational guideline and will sprinkle regulation-making powers throughout the statute, placing them just after the substantive provisions to which they relate. Though it makes them harder to find, it can be effective, particularly when the purpose of the regulation-making power is to provide an exception to the substantive rule in question.

Transitional Provisions

Transitional provisions are provisions that facilitate the transition from an existing legal regime to a new legal regime being put in place by the statute in question. They therefore usually operate for a short time only. Transitional provisions are placed after the permanent provisions of the statute so that, once they have their effect and become spent, they can be dropped from consolidations of the statute without affecting the continuity of its numbering.

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112 The Statute Law Society's *Statute Law Deficiencies: Report of the Committee appointed by the Society to examine the failings of the present Statute Law System* (London: Sweet & Maxwell, 1970) at 21.

113 This is the practice at the federal level in Canada and in British Columbia: Office of Legislative Counsel, *Guide to Legislation and Legislative Process in British Columbia*, Part 2 (B.C. Ministry of the Attorney General, August 2003) at 9.

114 At the federal level in Canada and in British Columbia: *Guide to Legislation and Legislative Process in British Columbia*, *ibid.* at 9.

Where a statute is being replaced, transitional provisions might provide that actions taken under the former statute are deemed to have been done under the new statute, as in the following example:

> 8 – Every decision, order, determination and declaration made by the former Board is deemed to have been made by the new Board and may be enforced as such.[115]

A transitional provision can also provide for the continuation in office of persons holding office under a regime replaced by a new statute:

> 9 – The person occupying the position of Registrar of Firearms on the day on which section 82 of the Act, as enacted by subsection (1) of this Act, comes into force is deemed, as of that day, to be appointed as Registrar of Firearms under the *Public Service Employment Act* and continues to occupy that position until another person is appointed or deployed as the Registrar of Firearms under that Act.[116]

Because transitional provisions in amending statutes are not normally consolidated with the text of the statute being amended, drafters should exercise caution in putting rules into transitional provisions that will be operative for more than a short period. Because they are not consolidated, users of the consolidated statute will quickly forget them, and the continued application of long-term transitional provisions could cause problems years later. If a transitional amendment will potentially apply for more than a short period, then consideration should be given to including it as a substantive provision that will then find its way into the consolidated version. The benefit of doing so will have to be balanced against the complicating effect this has on the substantive provisions of the statute being amended.[117]

Keep in mind that the Interpretation Acts of many jurisdictions[118] contain standard transitional rules that apply to the introduction of new statutory regimes, and that these may render a transitional provision unnecessary. These are discussed further in Chapter 10, "Using an Interpretation Act".[119]

Consequential Amendments

In a new statute, consequential amendments are amendments to other statutes that are necessary to properly give effect to the new statute. In an amending statute, they are amendments to statutes other than the primary target statute that are needed to give effect to the amending statute.

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115 *Public Service Modernization Act* (Canada), S.C. 2003, c. 22, s. 47.

116 *An Act to amend the Criminal Code (firearms) and the Firearms Act* (Canada), S.C. 2003, c. 8, s. 49(2).

117 D. Hirsch, *Drafting Federal Law* (Washington, D.C.: Office of the General Counsel, Legislation Division, 1980) at 27.

118 *Interpretation Act* (Canada), R.S.C. 1985, c. I-21, s. 44; *General Clauses Act, 1897* (Bangladesh), s. 24; *Interpretation Act* (British Columbia), R.S.B.C. 1996, c. 238, s. 36.

119 Under the heading "Advantages of an Interpretation Act".

truck or bus". By virtue of this interpretive rule, a drafter can use the defined term in another definition:

> 22 – "hearse" means an **automobile** used exclusively for carrying caskets.

Because the concept of *a four-wheeled motor vehicle, other than a truck or bus* is built into the definition of *automobile* it is not necessary to repeat it in the new definition. The result is a shorter, cleaner definition of *hearse* than would otherwise be the case.

Interpretive rules can be of real value where changes in drafting style are being introduced, such as changes related to plain language drafting. If features such as examples or administrative notes are going to be included in some or all new statutes, an Interpretation Act can set out rules on how the new features are to be treated. The Australian *Acts Interpretation Act 1901*, for example, provides that where a statute uses examples to illustrate how a provision operates, if the example is poorly chosen and is not in fact consistent with the provision, the provision (and not the example) will be decisive of the meaning.[111] The British Columbia *Interpretation Act* provides that italicized text in square brackets, added for convenience to describe the subject-matter of a cross-reference, is not part of the statute in which it is used.[112] An Interpretation Act might also provide that examples or administrative notes are not to be considered part of the statute, and could provide a different process by which they may be amended.[113]

Standard Transitional Rules

The way in which statutes operate in time — including the way in which they come into force and are repealed or replaced — is one of the more conceptually difficult aspects of statutory interpretation. As a result, without appropriate rules governing the transition from an existing legal regime to a new one, the government's management of its statute book would be complicated, and citizens (including judges and lawyers) would find it difficult to determine what laws are in force at any given time.

A well-drafted Interpretation Act can smooth the process by which statutes come into force and are amended, replaced and repealed, and make that process more transparent to the public. An Interpretation Act will typically contain rules about how statutes take effect, how amendments operate, and what happens when a statute is repealed or otherwise ceases to have effect.

Interpretation Act provisions relating to how statutes take effect may provide, for example:

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111 Section 15AD. See also *Interpretation Act* (Singapore), s. 7A.

112 R.S.B.C. 1996, c. 238, s. 11(2).

113 For a further discussion of these features and of interpretive rules applicable to them, see Chapter 11, "Plain Language Drafting".

- that if no date of coming into force or commencement[114] is stated, a statute takes effect when it receives assent;[115]
- that where a statute contains a provision stating that any of its provisions, or the statute as a whole, is to come into force on a particular day, the coming into force provision itself is considered to have come into force on the day the statute received royal assent, without having to expressly provide for this;[116]
- that where a statute is stated to commence on a particular day, it will be considered to commence at the start of that day;[117]
- that where a statute is to terminate on a particular day, it will be considered to terminate at the end of that day;[118] and
- that orders, regulations and appointments may be made after a statute receives royal assent but before it comes into force, if those orders, regulations and appointments are necessary to permit the statute to function properly from the outset.[119]

Interpretation Acts typically also set out rules regarding the operation of amendments that replace a provision in an existing statute (*the former provision*) with a new provision (*the new provision*). The essence of these rules is to ensure that unchanged elements of the former provision carry through under the new provision, so that the amendment causes a minimum of disruption. These rules also apply to the replacement of an entire statute with a new one. Typical provisions provide that:

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[114] The expressions *come into force* and *commence* are used interchangeably to refer to the time when a statute takes effect.

[115] *Interpretation Act* (Canada), R.S.C. 1985, c. I-21, s. 6(2)(*a*); *General Clauses Act, 1897* (Bangladesh), s. 5(1)(a). Under s. 6(2)(*b*) of the *Interpretation Act* (Canada), regulations come into force at the start of the day on which they are registered.

[116] *Interpretation Act* (Canada), *ibid.*, s. 5(3); *Interpretation Act 1984* (Western Australia), s. 22; and *Interpretation Act* (Northern Territory), s. 6(3).

[117] *Interpretation Act* (Canada), *ibid.*, s. 6(1); *Acts Interpretation Act 1901* (Australia), s. 3(2); *General Clauses Act, 1897* (India), s. 5(3); *General Clauses Act, 1897* (Bangladesh), s. 5(3); *Interpretation Act* (Singapore), s. 10(1); *Interpretation Act, 2005* (Ireland), ss. 16 and 17; model *Interpretation Act* (Uniform Law Conference of Canada). The fact that this gives statutes and regulations a retroactive application has been the subject of some comment: Office of the Legislative Counsel (Australia), *Review of the Commonwealth Acts Interpretation Act 1901* (1998) at 27-28; and P. Salembier, "Designing Regulatory Systems: A Template for Regulatory Rule-making – Part II" (2003) 24 Stat. L. Rev. 1 at 12.

[118] *Interpretation Act* (Canada), *ibid.*, s. 6(1); *Interpretation Act* (Uniform Law Conference of Canada), s. 5(2). The repeal of a statute, which in Canada is done by way of the enactment of a repealing statute, is governed by s. 6(2), which provides that the time of commencement of the repealing statute, and hence the time of repeal of the former statute, is at the *beginning* of the day on which the repealing statute comes into force. See *R. v. Allan*, [1979] O.J. No. 406, 45 C.C.C. (2d) 524 at 527 (Ont. C.A.).

[119] *Interpretation Act* (Canada), *ibid.*, s. 7; *General Clauses Act, 1897* (Bangladesh), s. 22; *Acts Interpretation Act 1901* (Australia), s. 4; *General Clauses Act, 1897* (India), s. 22; *Legislation Act, 2006* (Ontario), S.O. 2006, c. 21, Sch. F, s. 10; *Interpretation Act, 2005* (Ireland), s. 17; model *Interpretation Act* (Uniform Law Conference of Canada), s. 6.

- appointments made under the former provision continue in place;[120]
- regulations, orders and other instruments issued under the former provision continue to have effect to the extent that they are consistent with the new provision;[121]
- references in other statutes to the former provision will be read as references to the new provision after the amendment;[122]
- proceedings commenced under the former provision are to continue under the procedure established by the new provision, as far as possible;[123] and
- citizens are to have the benefit of any reduction in punishments, fines or forfeitures effected by the new provision.[124]

The Canadian *Interpretation Act* also provides that the fact that an amendment has been made is not of itself to be taken as an indication that the law has been changed from what it was before the amendment, or what the previous law was.[125] This addresses situations where, after an amendment, the substance of the new provision is essentially the same as the former provision, but has been reorganized or modernized. The Australian *Acts Interpretation Act 1901* also provides that changes in style — including a move to clearer language — are not to be taken to embody a change in the law.[126]

A third area in which Interpretation Acts play an important role in managing transition in statute law is in setting out rules for what happens when a statute is repealed or otherwise ceases to have effect.[127] Typical of such provisions are those that provide that the repeal of a statute does not:

- revive any law or instrument that the repealed statute itself repealed or replaced;[128]

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120 *Interpretation Act* (Canada), *ibid.*, s. 44(*a*); *General Clauses Act, 1897* (Bangladesh), s. 24; *Interpretation Act* (British Columbia), R.S.B.C. 1996, c. 238, s. 36(1)(*a*).

121 *Interpretation Act* (Canada), *ibid.*, s. 44(*g*); *General Clauses Act, 1897* (Bangladesh), s. 24; *Interpretation Act* (British Columbia), *ibid.*, s. 36(1)(*e*).

122 *Interpretation Act* (Canada), *ibid.*, s. 44(*h*); *General Clauses Act, 1897* (Bangladesh), s. 8(1).

123 *Interpretation Act* (Canada), *ibid.*, s. 44(*e*); *Interpretation Act* (British Columbia), R.S.B.C. 1996, c. 238, s. 36(1)(*b*).

124 *Interpretation Act* (Canada), *ibid.*, s. 44(*c*); *Interpretation Act* (British Columbia), *ibid.*, s. 36(1)(*d*).

125 Sections 44(*f*) and 45(2) and (3).

126 Section 15AC.

127 Some statutes contain sunset clauses providing that they will automatically expire on a certain date, or on the happening (or non-happening) of a certain event.

128 *Interpretation Act* (Canada), R.S.C. 1985, C. I-21, s. 43(*a*); *Acts Interpretation Act 1901* (Australia), s. 7; *General Clauses Act, 1897* (India), s. 6(a); *Interpretation Act* (Singapore), s. 16(1)(a); *Legislation Act, 2006* (Ontario), S.O. 2006, c. 21, Sch. F, s. 57; *Interpretation Act, 2005* (Ireland), s. 27(1)(a); model *Interpretation Act* (Uniform Law Conference of Canada), s. 31(a). Section 6A of the Bangladesh *General Clauses Act, 1897* expands upon this by providing that the repeal of an amending statute does not affect the amendments made by that statute. Section 7 of that Act goes on to confirm, perhaps unnecessarily, that an express mention must be made in order to effect the revival of a statute or provision that has earlier been repealed.

- affect the previous operation of the repealed statute, or any action taken or liability incurred under it;[129] or
- affect any offences committed under the repealed statute, which can continue to be prosecuted as if the statute had not been repealed.[130]

One aspect of transition that Interpretation Acts in general do not adequately address is the manner in which spent provisions, or entire spent statutes, are to be treated. A statute or provision is considered to become "spent" when it ceases to have ongoing effect. The most commonly occurring example of a spent provision is an amending provision. Once an amending provision comes into force, the amendment made by the amending provision takes effect, and the statute being amended ("the target statute") is changed accordingly. The amending provision then ceases to operate; it has done its work and its usefulness has come to an end. It is spent. When all of the provisions in an amending Act have come into force, the Act as a whole will become spent.

A provision will eventually also become spent if it provides that it is to apply only for a limited period of time. Consider, for example, the following provision:

> 23 – No person may import linen goods without a permit before January 1, 2010.

It becomes spent at midnight of December 31, 2009.

Spent provisions constitute an exception to the rule that "the law is always speaking". Most statutory provisions are of ongoing application, such as:

> 24 – Every person who commits murder is guilty of an offence.

These apply anew to each fact situation as it arises. Spent provisions, on the other hand, operate on a single occasion or for a limited time only, and then cease to have effect.

An amending provision that is spent can no longer be amended.[131] Any attempt to use a further amendment to the amending statute to change the effect of an earlier amendment on the target statute will be ineffectual if it is made after the first amendment has taken effect.[132] For a further discussion of this, see Chapter 8, "Amendments".

Most Interpretation Acts deal with the issue of spent provisions inadequately, or not at all. Some Interpretation Acts partly address the issue by providing that

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[129] *Interpretation Act* (Canada), *ibid.*, s. 43(*b*); *Acts Interpretation Act 1901* (Australia), s. 8; *General Clauses Act, 1897* (India), ss. 6(b) and (c); *Interpretation Act* (Singapore), ss. 16(1)(b) and (c); *Legislation Act, 2006* (Ontario), *ibid.*, ss. 51(1)(*b*) and (*c*); *Interpretation Act, 2005* (Ireland), ss. 27(1)(b) and (c); model *Interpretation Act* (Uniform Law Conference of Canada), ss. 31(b) and (c).

[130] *Interpretation Act* (Canada), *ibid.*, s. 43(*d*); *General Clauses Act, 1897* (India), ss. 6(d) and (e); *Interpretation Act* (Singapore), ss. 16(1)(d) and (e); *Legislation Act, 2006* (Ontario), *ibid.*, s. 51(1)(*d*); *Interpretation Act, 2005* (Ireland), ss. 27(1)(d) and (e); model *Interpretation Act* (Uniform Law Conference of Canada), ss. 31(d) and (e).

[131] At least without using a retroactive amendment: for a discussion of the use of retroactive provisions, see P. Salembier, "Understanding Retroactivity: When the Past Just Ain't What It Used To Be" (2003) 33 Hong Kong L.J. 99.

[132] An amending provision can always be amended before it has taken effect: *Potter Distilleries Ltd. v. British Columbia*, [1981] B.C.J. No. 1278, 132 D.L.R. (3d) 190 (B.C.C.A.).

the repeal of an amending statute does not affect the amendments made by that statute, and that an express mention must be made in order to revive a statute or provision that has earlier been repealed.[133]

The Canadian *Interpretation Act* does not address spent provisions directly, but it does unintentionally confuse the issue. Subsection 2(2) of that Act provides that:

> 25 (2) For the purposes of this Act, ... an enactment that has expired, lapsed or otherwise ceased to have effect is deemed to have been repealed.

Although the opening words of the provision indicate that it is intended to apply only to the use of the word *repealed* in the *Interpretation Act* itself, this provision is often incorrectly interpreted to say that a spent provision in any statute is automatically repealed. Reliance on this erroneous interpretation has led to re-enactments of expired provisions without repealing the expired — but still existing — provision, leading to an unintended duplication.[134]

Adding appropriate provisions to an Interpretation Act regarding the inoperability of spent provisions generally would no doubt provide some useful clarity in this area.

LIMITS ON THE USEFULNESS OF INTERPRETATION ACTS

There are inherent limitations in what an Interpretation Act can achieve, including the caveat that it can never achieve absolute certainty. In addition to the limits discussed above in relation to attempts to codify common law rules of statutory interpretation,[135] there are a number of other areas in which an Interpretation Act is likely to be less effective in achieving legislative efficiencies and certainty than other available alternatives.

The first and foremost limit to acknowledge is that no single Interpretation Act can anticipate all possible circumstances in which the terminology it standardizes or the standard rules it sets out might be applied. Similarly, no single set of grammatical rules and definitions can be realistically expected to rationalize all the differing modes of expression that will inevitably exist in any large body of statute law. Because it is not feasible to try to impose unchangeable, standardized meanings across the entire body of statute law, most Interpretation Acts provide that their standard definitions apply only if no contrary intention is apparent — in other words, unless a different meaning is apparent from the manner in which the term is used in the particular statute.[136] This reflects the common law rule of statutory interpretation regarding the applicability of definitions as well.[137]

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133 *General Clauses Act, 1897* (Bangladesh), s. 7; *General Clauses Act, 1897* (India), s. 6A.

134 Having two section 8s in the same statute, for example.

135 Under the heading "Standard Rules of Interpretation".

136 See *Interpretation Act* (Canada), R.S.C. 1985, c I-21, s. 3(1); *General Clauses Act, 1897* (Bangladesh), ss. 3, 4, and 4A(1). See also A.B. Srivastava & S.H.S. Abidi, *Swamikamu's Commentaries on General Clauses Act (Central and States)*, 4th ed. (Allahabad: Law Publishers (India) Pvt. Ltd., 2004) at 99. Cases applying the Canadian provision include *Dhak v. Canada*

speakers use *have to* (which has its own problems). And so most drafters fall back on *shall*, treating it more or less as a term of art.[156]

Kenneth Adams, another American drafter, makes the same point, noting that in the "stylized and limited" language of contracts *shall* does not seem terribly out of place.[157]

Most plain language advocates also recommend replacing doublets and triplets with single terms. This was discussed in Chapter 3, "Reducing Complexity", and a list of common doublets and triplets, with suggested shorter replacements, is set out there.

Changes in average word length can be measured using readability formulas, which can be applied using software designed for that purpose. This makes progress in simplifying vocabulary easy to measure.

The following chart incorporates recommendations for simplifying terminology gleaned from a number of sources:[158]

Recommended Simplifications

ab initio	from the start, from the beginning
abovementioned *x*, aforementioned *x*	*x* mentioned above
accordingly	so, therefore, consequently
acquire	get, buy, win, obtain
adduce	give, present, submit as proof
adjacent to	next to
advise	tell, inform, state, say, mention, notify
affix	attach
aggregate	total, sum
allocate	give, divide, set apart, designate, assign, distribute

156 T. Dorsey, *Legislative Drafter's Deskbook: A Practical Guide* (Washington, D.C.: TheCapitol.Net, 2006) at 192.

157 K. Adams, "Making Sense of 'Shall'" *New York L.J.* (October 18, 2007).

158 J. Erasmus, "Plain Language Drafting Meets Interpretive Principles and Rules – A Drafter's Perspective" (Paper presented to CIAJ conference, "Legislative Drafting, Getting Results", November 1998) at 3, online: <http://www.ciaj-icaj.ca/english/publications/LD71erasmus.pdf>; *Legistics*, "If, Where and When", online: <http://www.justice.gc.ca/eng/dept-min/pub/legis/n17.html>; *Legistics*, "Pursuant To", online: <http://www.justice.gc.ca/eng/dept-min/pub/legis/n31.html>; R. Ramage, "Effective Draftsmanship – Part 4" (2005) 155 New L.J. 166 at 168; A.C.T. Parliamentary Counsel's Office, *Words and Phrases: A Guide to Plain Legal Language* (October 2006).

arising out of	resulting from
ascertain	find out, decide, determine, work out, calculate, learn
attain	reach, achieve, become, turn, obtain
attempt	try
body corporate	corporation
bona fide	in good faith, genuine, honestly, sincerely
by reason of, by virtue of	because of
by reason only	only because
calendar month	month
chattels	goods, personal property
commence	begin
comprise	consist of, composed of, include, contain, made up of, have, formed of, constitute, is
concerning	about
covenant	contract under seal, contract, agreement, condition
deemed	taken, treated as, regarded as, considered, thought
deliver	give, provide, supply
demised premises	property
determine	terminate, end
discontinue	stop, end, finish, cease
disburse	pay out, pay
duly	properly
dwelling-house	house
endeavour	try
enjoin	direct, require
ex officio	automatically, without further appointment

ex parte	without notice to any other person, by one party in the absence of and without notice to the other
expended	paid
expiration, expiry	end
first-mentioned	first
fix	establish, set
forenoon	a.m. (as in 10 a.m.), morning
forthwith	promptly, immediately, without delay, at once
furnish	give, provide, tell
gainfully employed	employed, working
has the power to	may
have knowledge of	know, be aware of
henceforth	from now on
herein	in this document
heretofore	up to now, until now, to this time
howsoever	by whatever means, to whatever extent, no matter how, however
including without limiting the generality of the foregoing	including, for example, in particular
in connection with	about
in consequence of	because of
in lieu of	in place of, instead of
in personam	against the person
in question	concerned, being considered, in dispute, in issue
in relation to	about
in rem	against the thing, against the world at large, in the matter of
in respect of	about, in relation to
in specie	in kind

inter alia	among other things
in the event of, in the event that	if
irrespective of	whether or not, even if
is desirous of	wishes to
jointly and severally	collectively and separately, each of them
lessee	tenant
lessor	landlord
make application	apply
make payment	pay
medical practitioner	doctor
mutatis mutandis	with the necessary changes, with the appropriate changes
necessitate	require
not being	other than, except
notwithstanding	despite, as an exception to, although, however (when referring to the preceding provision)
on account of	for, because
on the ground that	because
other than	except
over and above	in addition to
per annum	for each year, per year, annually
per capita	for each person, per person
provided nevertheless that	but
preceding	last
preclude	prevent, exclude, leave out
predecease	die before
prior to	before
pro rata	proportionately, in proportion
purchase	buy

Incremental Increase/(Decrease) from Financial Forecast Scenario Debt Ratio (%) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**85%**	**83%**	**82%**	**82%**	**81%**	**81%**	**80%**	**80%**	**79%**	**79%**	**78%**	**77%**	**76%**	**75%**	**73%**	**72%**	**71%**	**70%**	**68%**	**66%**
5 Year Drought beginning in 2025/26	0%	0%	0%	1%	3%	4%	5%	6%	6%	7%	7%	7%	7%	8%	8%	8%	8%	8%	9%	9%
7 Year Drought beginning in 2025/26	0%	0%	0%	1%	1%	2%	3%	6%	8%	9%	9%	9%	9%	10%	10%	10%	11%	11%	11%	12%
Above Average Water Flows (2025/26 to 2034/35)	0%	0%	0%	0%	-1%	-1%	-1%	-2%	-2%	-3%	-3%	-4%	-4%	-4%	-4%	-4%	-5%	-5%	-5%	-5%
Below Average Water Flows (2025/26 to 2034/35)	0%	0%	0%	0%	1%	1%	1%	2%	2%	2%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%
High Electricity Price Forecast Sensitivity	0%	0%	-1%	-1%	-2%	-2%	-3%	-4%	-4%	-5%	-6%	-7%	-7%	-8%	-9%	-10%	-12%	-12%	-14%	-15%
Low Electricity Price Forecast Sensitivity	0%	0%	1%	1%	1%	2%	2%	2%	3%	3%	4%	4%	5%	5%	6%	6%	7%	7%	8%	9%
High Interest Rate Sensitivity	0%	0%	0%	0%	0%	0%	1%	1%	1%	2%	2%	2%	3%	3%	4%	4%	5%	5%	6%	6%
Low Interest Rate Sensitivity	0%	0%	0%	0%	0%	0%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-3%	-4%	-4%	-4%	-5%
Business Operations Capex increase by 10% per year	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	2%	2%	2%	3%	3%	3%	4%	4%	5%
Business Operations Capex decrease by 10% per year	0%	0%	0%	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-3%	-3%	-4%	-4%	-5%	-5%
2% Rate Path with Government Fees Unchanged	1%	1%	2%	3%	4%	4%	5%	6%	7%	8%	9%	10%	11%	12%	12%	14%	15%	16%	17%	18%
0% Rate Increase in 2023/24	0%	0%	0%	0%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%	3%	3%	3%	4%	4%	4%
0% Rate Increases in 2023/24 & 2024/25	0%	0%	0%	1%	1%	1%	2%	2%	2%	3%	3%	4%	4%	5%	5%	6%	6%	7%	8%	8%
3.6% Interim rolled back on Sept 1/23, 2.0% in 2024/25	0%	0%	1%	1%	1%	2%	2%	3%	3%	4%	5%	5%	6%	7%	7%	8%	9%	10%	11%	12%

Debt Ratio (%) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	**85%**	**83%**	**82%**	**82%**	**81%**	**81%**	**80%**	**80%**	**79%**	**79%**	**78%**	**77%**	**76%**	**75%**	**73%**	**72%**	**71%**	**70%**	**68%**	**66%**
5 Year Drought beginning in 2025/26	85%	83%	82%	83%	84%	85%	85%	86%	86%	85%	85%	84%	83%	82%	81%	80%	79%	78%	77%	75%
7 Year Drought beginning in 2025/26	85%	83%	82%	82%	82%	83%	84%	86%	87%	87%	87%	86%	85%	84%	83%	83%	82%	81%	79%	78%
Above Average Water Flows (2025/26 to 2034/35)	85%	83%	82%	81%	80%	79%	79%	78%	77%	76%	75%	74%	72%	71%	69%	68%	67%	65%	63%	61%
Below Average Water Flows (2025/26 to 2034/35)	85%	83%	82%	82%	82%	82%	82%	81%	81%	81%	81%	80%	79%	78%	77%	76%	75%	74%	72%	71%
High Electricity Price Forecast Sensitivity	85%	83%	81%	80%	79%	78%	77%	76%	75%	74%	72%	71%	69%	66%	64%	62%	60%	57%	54%	52%
Low Electricity Price Forecast Sensitivity	85%	84%	83%	82%	82%	82%	82%	82%	82%	82%	82%	81%	80%	80%	79%	79%	78%	77%	76%	75%
High Interest Rate Sensitivity	85%	83%	82%	82%	81%	81%	81%	81%	81%	80%	80%	80%	79%	78%	77%	77%	76%	75%	74%	73%
Low Interest Rate Sensitivity	85%	83%	82%	81%	81%	80%	80%	79%	78%	78%	76%	75%	74%	72%	70%	69%	68%	66%	64%	62%
Business Operations Capex increase by 10% per year	85%	83%	82%	82%	81%	81%	81%	81%	80%	80%	79%	79%	78%	77%	76%	75%	75%	73%	72%	71%
Business Operations Capex decrease by 10% per year	85%	83%	82%	81%	81%	80%	80%	79%	79%	78%	77%	76%	74%	72%	71%	69%	68%	66%	63%	61%
2% Rate Path with Government Fees Unchanged	86%	85%	84%	84%	84%	85%	85%	86%	86%	87%	87%	87%	87%	86%	86%	86%	86%	85%	85%	84%
0% Rate Increase in 2023/24	85%	83%	82%	82%	81%	81%	81%	81%	81%	80%	80%	79%	78%	77%	76%	75%	75%	73%	72%	71%
0% Rate Increases in 2023/24 & 2024/25	85%	83%	82%	82%	82%	82%	82%	82%	82%	82%	81%	81%	80%	79%	79%	78%	78%	77%	76%	75%
3.6% Interim rolled back on Sept 1/23, 2.0% in 2024/25	85%	84%	83%	83%	82%	83%	83%	83%	83%	83%	83%	83%	82%	81%	81%	81%	80%	79%	79%	78%

Incremental Increase/(Decrease) from Financial Forecast Scenario Net Income (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	$ 751	$ 469	$ 295	$ 149	$ 166	$ 97	$ 92	$ 111	$ 105	$ 169	$ 190	$ 219	$ 277	$ 250	$ 282	$ 309	$ 358	$ 439	$ 507	$ 569
5 Year Drought beginning in 2025/26	0	0	0	(370)	(474)	(273)	(300)	(294)	(75)	(78)	(81)	(84)	(88)	(92)	(97)	(100)	(106)	(110)	(114)	(120)
7 Year Drought beginning in 2025/26	0	0	0	(239)	(120)	(183)	(419)	(728)	(455)	(275)	(105)	(110)	(115)	(120)	(126)	(132)	(138)	(142)	(149)	(156)
Above Average Water Flows (2025/26 to 2034/35)	0	0	0	99	100	105	111	115	121	127	133	139	143	50	51	56	60	62	64	67
Below Average Water Flows (2025/26 to 2034/35)	0	0	0	(83)	(88)	(92)	(95)	(99)	(104)	(108)	(112)	(118)	(124)	(44)	(47)	(49)	(52)	(53)	(56)	(58)
High Electricity Price Forecast Sensitivity	0	126	93	127	154	153	174	184	199	210	221	228	256	307	343	360	358	350	387	378
Low Electricity Price Forecast Sensitivity	0	(97)	(57)	(76)	(89)	(107)	(107)	(118)	(124)	(128)	(126)	(136)	(151)	(178)	(190)	(205)	(209)	(200)	(224)	(230)
High Interest Rate Sensitivity	0	2	(9)	(14)	(31)	(48)	(65)	(85)	(96)	(116)	(122)	(125)	(130)	(138)	(147)	(155)	(167)	(178)	(190)	(200)
Low Interest Rate Sensitivity	0	1	9	16	28	41	57	70	77	94	99	100	100	102	105	110	119	128	131	135
Business Operations Capex increase by 10% per year	0	(1)	(5)	(10)	(15)	(21)	(27)	(35)	(41)	(48)	(56)	(65)	(73)	(83)	(95)	(105)	(116)	(126)	(138)	(150)
Business Operations Capex decrease by 10% per year	0	1	5	10	14	19	26	32	40	48	58	66	73	80	88	98	110	123	132	142
2% Rate Path with Government Fees Unchanged	(183)	(189)	(191)	(197)	(209)	(219)	(229)	(242)	(255)	(266)	(277)	(294)	(317)	(328)	(346)	(363)	(380)	(396)	(413)	(432)
0% Rate Increase in 2023/24	0	(24)	(40)	(41)	(45)	(48)	(51)	(56)	(59)	(63)	(66)	(72)	(77)	(83)	(90)	(97)	(104)	(111)	(120)	(128)
0% Rate Increases in 2023/24 & 2024/25	0	(24)	(77)	(82)	(87)	(94)	(100)	(107)	(114)	(121)	(130)	(140)	(149)	(161)	(176)	(189)	(203)	(217)	(233)	(250)
3.6% Interim rolled back on Sept 1/23, 2.0% in 2024/25	0	(65)	(108)	(114)	(122)	(131)	(139)	(149)	(160)	(170)	(183)	(195)	(208)	(226)	(245)	(263)	(284)	(303)	(325)	(348)

Net Income (in millions of $) Fiscal Year Ending March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Amended Financial Forecast Scenario	$ 751	$ 469	$ 295	$ 149	$ 166	$ 97	$ 92	$ 111	$ 105	$ 169	$ 190	$ 219	$ 277	$ 250	$ 282	$ 309	$ 358	$ 439	$ 507	$ 569
5 Year Drought beginning in 2025/26	751	469	295	(221)	(308)	(176)	(209)	(184)	30	91	108	134	189	158	185	209	253	329	393	449
7 Year Drought beginning in 2025/26	751	469	295	(90)	46	(86)	(327)	(617)	(350)	(106)	84	108	162	130	156	177	220	297	358	413
Above Average Water Flows (2025/26 to 2034/35)	751	469	295	248	266	202	203	226	226	296	323	357	419	299	333	365	418	501	571	636
Below Average Water Flows (2025/26 to 2034/35)	751	469	295	66	78	5	(3)	11	1	61	77	101	153	205	235	261	307	386	451	512
High Electricity Price Forecast Sensitivity	751	595	387	277	320	250	266	295	304	379	410	447	533	557	625	669	716	789	894	947
Low Electricity Price Forecast Sensitivity	751	372	238	73	76	(10)	(15)	(7)	(19)	41	63	82	126	72	92	104	149	239	284	340
High Interest Rate Sensitivity	751	471	286	135	135	49	27	26	9	53	67	93	147	112	135	154	191	261	318	369
Low Interest Rate Sensitivity	751	470	304	165	193	137	148	181	182	263	289	319	377	352	387	420	478	567	638	704
Business Operations Capex increase by 10% per year	751	469	289	139	151	76	65	76	64	121	133	154	204	167	188	204	242	313	369	419
Business Operations Capex decrease by 10% per year	751	470	300	159	180	116	118	143	145	217	247	285	350	330	370	407	469	562	639	711
2% Rate Path with Government Fees Unchanged	568	281	104	(48)	(44)	(122)	(137)	(131)	(150)	(97)	(87)	(76)	(40)	(78)	(63)	(54)	(22)	43	94	137
0% Rate Increase in 2023/24	751	446	255	108	120	49	41	55	46	106	123	147	199	167	192	212	254	329	388	441
0% Rate Increases in 2023/24 & 2024/25	751	446	218	67	78	3	(8)	3	(9)	48	59	79	127	89	106	120	155	222	275	319
3.6% Interim rolled back on Sept 1/23, 2.0% in 2024/25	751	405	187	35	44	(34)	(47)	(39)	(55)	(1)	7	23	68	24	37	46	75	137	183	221

d) CC Rate Scenario #4: Confirmation of the 3.6% 2021/22 interim rate increase, 0% rate increases in 2023/24 and 2024/25 and even annual rate increases from 2025/26 onward to achieve a 80% Debt ratio by 2034/35;

e) CC Rate Scenario #5: CC rate scenario #1 with 50% of the reductions to payments to government between 2022/23 and 2024/25 deferred into the Major Capital Projects deferral account, with the resulting balance to be amortized over 10 years from 2025/26 to 2034/35;

f) CC Rate Scenario #6: CC rate scenario #2 with 50% of the reductions to payments to government between 2022/23 and 2024/25 deferred into the Major Capital Projects deferral account, with the resulting balance to be amortized over 10 years from 2025/26 to 2034/35;

g) CC Rate Scenario #7: CC rate scenario #3 with 50% of the reductions to payments to government between 2022/23 and 2024/25 deferred into the Major Capital Projects deferral account, with the resulting balance to be amortized over 10 years from 2025/26 to 2034/35; and

h) CC Rate Scenario #8: CC rate scenario #4 with 50% of the reductions to payments to government between 2022/23 and 2024/25 deferred into the Major Capital Projects deferral account, with the resulting balance to be amortized over 10 years from 2025/26 to 2034/35.

RESPONSE:

Below is a brief commentary on the key assumptions underpinning this request:

i. *Cash flows for regulatory deferrals such as cash paid for DSM expenditures, ineligible overhead, regulatory costs as well as interest costs on the City of Winnipeg perpetual obligation are classified as investing activities* – as indicated in the response to Coalition/MH I-35d, the reclassification of these items to investing activities does not impact or change the annual or the cumulative total cash surplus/deficit, net debt balance or the annual change to the net debt balance.

ii. *O&A escalates at 2% each year over the 20-year forecast period based on the projected 2022/23 O&A of $589 million* - Compared to the O&A forecast included in the Amended Financial Forecast Scenario, this O&A sensitivity is $1.1 billion (on average $60 million per year) lower over the 2023/24 to 2041/42 forecast period. This O&A assumption is

CC Rate Scenarios #2 and #6 contain even annual rate increases of 0.8% from 2024/25-2034/35 followed by 2% annual rate increases to the end of the forecast period. These scenarios achieve a debt equity ratio of 80% by 2034/35 however the debt ratio only improves by 1% to 79% by 2041/42 (latest date for achieving the 70% debt ratio target prescribed under the new legislative framework is March 31, 2040). Despite the $2.9 billion in lower spending assumed in this IR, these scenarios both contain several years of net losses and cash deficits persist throughout much of the forecast period totaling $1.7 billion. Although the new legislative framework specifies the latest achievement date of the 80% debt ratio to be March 31, 2035, annual inflationary rate increases of 2% (from 2035/36 to 2039/40), are not enough to reduce the debt ratio from 80% to 70% by March 31, 2040 as required under the new legislative framework.

CC Rate Scenarios #3 and #7 contain even annual rate increases of 1.4% from 2025/26-2041/42 which results in a debt ratio of 75% by 2041/42. Net income is positive in all years of the forecast in these scenarios however there are cumulative cash deficits totaling approximately $600 million during the second decade of the planning horizon.

CC Rate Scenarios #4 and #8 contain even annual rate increases of 1.0% from 2025/26-2034/35 followed by 2% annual rate increases to the end of the forecast period. These scenarios achieve a debt equity ratio of 80% by 2034/35, however, the debt ratio only improves by 2% to 78% by 2041/42 which fails to achieve the 70% debt ratio target by 2039/40 prescribed in the new legislative framework. Despite the $2.9 billion in lower spending assumed in these hypothetical scenarios, both hypothetical scenarios contain several years of net losses and cash deficits persist throughout much of the forecast period totaling $1.5 billion. Although the new legislative framework requires the 80% debt ratio to be achieved by March 31, 2035, annual inflationary rate increases of 2% (from 2035/36 to 2039/40), are not sufficient to reduce the debt ratio from 80% to 70% by March 31, 2040 as required under the new legislative framework.

Please see Attachment 1, for the projected financial statements and Attachment 2, for the detailed calculations of the financial metrics for the hypothetical scenarios a) through h) in this response.

ELECTRIC OPERATIONS PROJECTED OPERATING STATEMENT
COAL-MH-I-43d - CC Rate Scenario #4
(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	-	-	-	18	36	55	75	95	116	138
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	3 028	2 845	2 691	2 719	2 729	2 755	2 803	2 866	2 916
EXPENSES										
Operating and Administrative	589	601	613	625	638	650	663	677	690	704
Net Finance Expense	909	899	883	900	908	919	928	940	945	923
Depreciation and Amortization	618	631	641	653	663	680	697	715	735	756
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	161	163	165	165	167	168	169	171	172
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	2 626	2 615	2 679	2 703	2 750	2 797	2 842	2 901	2 898
Net Income before Net Movement in Reg. Deferral	565	403	230	11	16	(21)	(42)	(39)	(35)	18
Net Movement in Regulatory Deferral	190	106	77	118	114	62	57	50	4	(12)
Net Income	755	509	307	129	130	41	16	11	(31)	6
Net Income Attributable to:										
Manitoba Hydro	**751**	**504**	**301**	**123**	**122**	**35**	**8**	**2**	**(40)**	**(4)**
Wuskwatim Investment Entity	4	5	6	7	7	7	7	8	9	9
Keeyask Investment Entity	0	0	0	0	0	0	0	0	0	0
Total Non-Controlling Interests	4	5	6	7	7	7	7	8	9	9
	755	509	307	129	130	41	16	11	(31)	6
Percent Increase	0.00%	0.00%	0.00%	0.98%	0.98%	0.98%	0.98%	0.98%	0.98%	0.98%
Cumulative Percent Increase	0.00%	0.00%	0.00%	0.98%	1.96%	2.96%	3.96%	4.98%	6.00%	7.04%

ELECTRIC OPERATIONS PROJECTED BALANCE SHEET
COAL-MH-I-43d - CC Rate Scenario #4
(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	29 362	29 979	30 567	31 357	32 036	32 728	33 467	34 244	35 062
Accumulated Depreciation	(3 525)	(4 082)	(4 635)	(5 179)	(5 761)	(6 389)	(7 014)	(7 664)	(8 332)	(9 021)
Net Plant in Service	25 288	25 279	25 344	25 388	25 596	25 647	25 715	25 803	25 912	26 041
Construction in Progress	470	512	472	484	319	328	336	343	350	357
Current and Other Assets	2 222	1 611	1 787	1 684	1 561	1 658	1 747	1 570	1 596	1 707
Goodwill and Intangible Assets	1 034	1 006	981	954	925	896	866	836	805	774
Total Assets before Regulatory Deferral	29 014	28 408	28 584	28 509	28 401	28 529	28 664	28 552	28 663	28 879
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	29 834	30 087	30 081	30 039	30 229	30 420	30 359	30 474	30 677
LIABILITIES AND EQUITY										
Long-Term Debt	22 408	21 922	21 757	21 314	21 006	20 908	21 817	21 280	21 808	22 610
Current and Other Liabilities	3 931	3 389	3 439	3 739	3 858	4 084	3 332	3 778	3 375	2 747
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	4 079	4 380	4 502	4 624	4 659	4 668	4 670	4 630	4 627
Accumulated Other Comprehensive Income	(371)	(402)	(404)	(413)	(401)	(396)	(394)	(394)	(394)	(394)
Total Liabilities and Equity before Regulatory Deferral	30 236	29 737	29 989	30 033	30 039	30 229	30 420	30 359	30 474	30 677
Regulatory Deferral Balance	166	98	98	49	0	0	0	0	0	0
	30 403	29 834	30 087	30 081	30 039	30 229	30 420	30 359	30 474	30 677

ELECTRIC OPERATIONS PROJECTED INDIRECT CASH FLOW STATEMENT
COAL-MH-I-43d - CC Rate Scenario #4
(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	509	307	129	130	41	16	11	(31)	6
Net Movement in Regulatory Deferral (1)	-	-	-	-	-	-	-	-	-	-
Add Back:										
Depreciation and Amortization	618	631	641	653	663	680	697	715	735	756
Net Finance Expense	909	899	883	900	908	919	928	940	945	923
Net Movement Impacts (1)	(9)	17	31	42	50	59	67	75	99	111
Adjustments for Non-Cash Items (1)	37	72	95	48	50	99	97	94	94	95
Adjustments for Non-Cash Working Capital Accounts (1)	(82)	3	(41)	(42)	(42)	(43)	(44)	(45)	(46)	(47)
Interest Paid (2)	(1 048)	(818)	(919)	(921)	(912)	(922)	(938)	(955)	(958)	(929)
Interest Received	24	16	13	10	5	3	5	2	1	1
Cash Provided by Operating Activities	1 204	1 330	1 009	819	852	836	827	837	839	915
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	657	360	750	730	970	1 370	1 590	560	1 190	800
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	232	230	231	232	233	234
Sinking Fund Investment Purchases	(248)	(244)	(234)	(233)	(232)	(230)	(231)	(232)	(233)	(234)
Other	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(8)	(11)
Cash Provided by Financing Activities	(425)	(1 080)	(126)	(172)	(214)	96	122	(121)	94	136
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(672)	(639)	(644)	(674)	(649)	(684)	(709)	(747)	(785)	(826)
Additions to Intangible Assets	(20)	(12)	(18)	(14)	(13)	(13)	(13)	(13)	(14)	(14)
Additions to Regulatory Deferral Balances (1)	(103)	(103)	(107)	(111)	(115)	(121)	(124)	(125)	(103)	(98)
Net Contributions Received	44	72	81	83	74	38	41	45	48	53
Cash Paid to the City of Winnipeg (2)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
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	(893)	(777)	(776)	(807)	(792)	(868)	(893)	(928)	(935)	(966)
Net Increase (Decrease) in Cash	(114)	(527)	107	(160)	(154)	64	56	(212)	(2)	86
Cash at Beginning of Year	1 047	933	406	513	353	199	263	318	107	105
Cash at End of Year	933	406	513	353	199	263	318	107	105	190

(1) Cash flows for Regulatory Deferrals reclassified from Cash Provided by Operating Activities to Cash Used for Investing Activities
(2) Interest Costs on City of Winnipeg reclassified from Cash Provided by Operating Activities to Cash Used for Investing Activities

ELECTRIC OPERATIONS PROJECTED DIRECT CASH FLOW STATEMENT
COAL-MH-I-43d - CC Rate Scenario #4
(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	3 016	2 832	2 677	2 705	2 714	2 736	2 782	2 845	2 894
Cash Paid to Suppliers and Employees (1)	(945)	(884)	(917)	(946)	(946)	(958)	(975)	(992)	(1 049)	(1 051)
Interest Paid (2)	(1 048)	(818)	(919)	(921)	(912)	(922)	(938)	(955)	(958)	(929)
Interest Received	24	16	13	10	5	3	5	2	1	1
Cash Provided by Operating Activities	1 204	1 330	1 009	819	852	836	827	837	839	915
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	657	360	750	730	970	1 370	1 590	560	1 190	800
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	232	230	231	232	233	234
Sinking Fund Investment Purchases	(248)	(244)	(234)	(233)	(232)	(230)	(231)	(232)	(233)	(234)
Other	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(8)	(11)
Cash Provided by Financing Activities	(425)	(1 080)	(126)	(172)	(214)	96	122	(121)	94	136
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(672)	(639)	(644)	(674)	(649)	(684)	(709)	(747)	(785)	(826)
Additions to Intangible Assets	(20)	(12)	(18)	(14)	(13)	(13)	(13)	(13)	(14)	(14)
Additions to Regulatory Deferral Balances (1)	(103)	(103)	(107)	(111)	(115)	(121)	(124)	(125)	(103)	(98)
Net Contributions Received	44	72	81	83	74	38	41	45	48	53
Cash Paid to the City of Winnipeg (2)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
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	(893)	(777)	(776)	(807)	(792)	(868)	(893)	(928)	(935)	(966)
Net Increase (Decrease) in Cash	(114)	(527)	107	(160)	(154)	64	56	(212)	(2)	86
Cash at Beginning of Year	1 047	933	406	513	353	199	263	318	107	105
Cash at End of Year	933	406	513	353	199	263	318	107	105	190

(1) Cash flows for Regulatory Deferrals reclassified from Cash Provided by Operating Activities to Cash Used for Investing Activities
(2) Interest Costs on City of Winnipeg reclassified from Cash Provided by Operating Activities to Cash Used for Investing Activities

ELECTRIC OPERATIONS PROJECTED OPERATING STATEMENT
COAL-MH-I-43d - CC Rate Scenario #4
(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	161	186	212	265	322	383	448	517	591	668
Extraprovincial	754	762	783	707	693	705	682	643	615	588
Other	41	43	45	49	53	56	58	61	64	65
	2 967	3 042	3 136	3 172	3 280	3 417	3 524	3 621	3 736	3 849
EXPENSES										
Operating and Administrative	718	732	747	762	777	793	809	825	841	858
Net Finance Expense	932	939	947	943	944	952	958	954	956	963
Depreciation and Amortization	777	800	825	850	876	910	946	975	1 011	1 048
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	173	178	178	180	182	185	186	188	190	192
Other Expenses	86	89	91	94	97	100	104	107	111	113
Corporate Allocation	1	1	1	1	1	1	1	1	1	1
	2 957	3 033	3 101	3 180	3 275	3 408	3 487	3 523	3 617	3 692
Net Income before Net Movement in Reg. Deferral	10	10	36	(8)	5	9	37	98	119	157
Net Movement in Regulatory Deferral	(15)	(21)	(26)	(33)	(37)	(42)	(40)	(39)	(23)	(24)
Net Income	(5)	(11)	9	(40)	(33)	(33)	(3)	59	97	133
Net Income Attributable to:										
Manitoba Hydro	**(16)**	**(23)**	**(3)**	**(53)**	**(46)**	**(45)**	**(18)**	**42**	**78**	**114**
Wuskwatim Investment Entity	10	11	12	12	13	13	16	17	18	19
Keeyask Investment Entity	0	0	0	0	0	0	0	0	0	0
Total Non-Controlling Interests	10	11	12	12	13	13	16	17	18	19
	(5)	(11)	9	(40)	(33)	(33)	(3)	59	97	133
Percent Increase	0.98%	0.98%	0.98%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	8.08%	9.14%	10.20%	12.41%	14.66%	16.95%	19.29%	21.67%	24.11%	26.59%

ELECTRIC OPERATIONS PROJECTED BALANCE SHEET
COAL-MH-I-43d - CC Rate Scenario #4
(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	35 950	36 866	37 861	38 909	40 073	41 299	42 627	43 785	45 065	46 400
Accumulated Depreciation	(9 723)	(10 460)	(11 201)	(11 961)	(12 758)	(13 601)	(14 475)	(15 372)	(16 279)	(17 239)
Net Plant in Service	26 227	26 406	26 659	26 948	27 315	27 699	28 153	28 414	28 786	29 161
Construction in Progress	365	373	381	492	753	662	536	826	726	569
Current and Other Assets	2 026	2 585	2 500	2 480	2 416	2 478	2 537	2 426	2 357	2 523
Goodwill and Intangible Assets	743	713	683	652	622	592	562	532	502	472
Total Assets before Regulatory Deferral	29 361	30 077	30 224	30 573	31 106	31 432	31 787	32 198	32 371	32 725
Regulatory Deferral Balance	1 783	1 763	1 736	1 704	1 666	1 625	1 585	1 546	1 523	1 499
	31 145	31 839	31 960	32 276	32 772	33 056	33 372	33 743	33 894	34 224
LIABILITIES AND EQUITY										
Long-Term Debt	23 002	23 536	23 233	23 486	23 502	23 636	23 900	23 878	23 792	23 774
Current and Other Liabilities	2 764	2 873	3 147	3 069	3 313	3 478	3 428	3 570	3 695	3 895
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	4 611	4 588	4 585	4 532	4 486	4 441	4 423	4 465	4 543	4 657
Accumulated Other Comprehensive Income	(394)	(394)	(394)	(394)	(394)	(394)	(394)	(394)	(394)	(394)
Total Liabilities and Equity before Regulatory Deferral	31 145	31 839	31 960	32 276	32 772	33 056	33 372	33 743	33 894	34 224
Regulatory Deferral Balance	0	0	0	0	0	0	0	0	0	0
	31 145	31 839	31 960	32 276	32 772	33 056	33 372	33 743	33 894	34 224

ELECTRIC OPERATIONS PROJECTED INDIRECT CASH FLOW STATEMENT
COAL-MH-I-43d - CC Rate Scenario #4
(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)	(5)	(11)	9	(40)	(33)	(33)	(3)	59	97	133
Net Movement in Regulatory Deferral (1)	-	-	-	-	-	-	-	-	-	-
Add Back:										
Depreciation and Amortization	777	800	825	850	876	910	946	975	1 011	1 048
Net Finance Expense	932	939	947	943	944	952	958	954	956	963
Net Movement Impacts (1)	121	130	138	147	154	162	164	166	153	157
Adjustments for Non-Cash Items (1)	96	96	96	96	94	93	94	93	93	94
Adjustments for Non-Cash Working Capital Accounts (1)	(48)	(49)	(50)	(51)	(52)	(53)	(54)	(55)	(56)	(57)
Interest Paid (2)	(944)	(953)	(963)	(965)	(968)	(978)	(978)	(985)	(987)	(986)
Interest Received	5	4	5	5	5	5	6	5	4	4
Cash Provided by Operating Activities	934	958	1 007	984	1 021	1 059	1 133	1 212	1 271	1 356
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	370	580	(30)	400	350	580	600	400	400	600
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	234	237	243	242	244	246	248	250	250	250
Sinking Fund Investment Purchases	(234)	(237)	(243)	(242)	(244)	(246)	(248)	(250)	(250)	(250)
Other	(11)	(12)	(13)	(14)	(14)	(15)	(14)	(18)	(19)	(20)
Cash Provided by Financing Activities	368	598	(81)	123	198	240	149	59	(28)	109
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(903)	(919)	(1 017)	(1 176)	(1 421)	(1 122)	(1 195)	(1 438)	(1 196)	(1 183)
Additions to Intangible Assets	(14)	(15)	(15)	(16)	(16)	(16)	(17)	(17)	(18)	(18)
Additions to Regulatory Deferral Balances (1)	(106)	(109)	(111)	(114)	(117)	(120)	(123)	(127)	(131)	(133)
Net Contributions Received	95	98	186	232	322	73	163	257	81	84
Cash Paid to the City of Winnipeg (2)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
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	(1 009)	(1 023)	(1 035)	(1 153)	(1 309)	(1 262)	(1 249)	(1 404)	(1 335)	(1 321)
Net Increase (Decrease) in Cash	292	533	(110)	(46)	(90)	38	32	(133)	(92)	144
Cash at Beginning of Year	190	483	1 016	906	860	771	809	841	707	616
Cash at End of Year	483	1 016	906	860	771	809	841	707	616	760

(1) Cash flows for Regulatory Deferrals reclassified from Cash Provided by Operating Activities to Cash Used for Investing Activities
(2) Interest Costs on City of Winnipeg reclassified from Cash Provided by Operating Activities to Cash Used for Investing Activities

ELECTRIC OPERATIONS PROJECTED DIRECT CASH FLOW STATEMENT
COAL-MH-I-43d - CC Rate Scenario #4
(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	2 944	3 018	3 110	3 143	3 247	3 382	3 487	3 581	3 693	3 806
Cash Paid to Suppliers and Employees (1)	(1 071)	(1 112)	(1 145)	(1 199)	(1 263)	(1 349)	(1 382)	(1 389)	(1 439)	(1 468)
Interest Paid (2)	(944)	(953)	(963)	(965)	(968)	(978)	(978)	(985)	(987)	(986)
Interest Received	5	4	5	5	5	5	6	5	4	4
Cash Provided by Operating Activities	934	958	1 007	984	1 021	1 059	1 133	1 212	1 271	1 356
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	370	580	(30)	400	350	580	600	400	400	600
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	234	237	243	242	244	246	248	250	250	250
Sinking Fund Investment Purchases	(234)	(237)	(243)	(242)	(244)	(246)	(248)	(250)	(250)	(250)
Other	(11)	(12)	(13)	(14)	(14)	(15)	(14)	(18)	(19)	(20)
Cash Provided by Financing Activities	368	598	(81)	123	198	240	149	59	(28)	109
INVESTING ACTIVITIES										
Additions to Property, Plant and Equipment	(903)	(919)	(1 017)	(1 176)	(1 421)	(1 122)	(1 195)	(1 438)	(1 196)	(1 183)
Additions to Intangible Assets	(14)	(15)	(15)	(16)	(16)	(16)	(17)	(17)	(18)	(18)
Additions to Regulatory Deferral Balances (1)	(106)	(109)	(111)	(114)	(117)	(120)	(123)	(127)	(131)	(133)
Net Contributions Received	95	98	186	232	322	73	163	257	81	84
Cash Paid to the City of Winnipeg (2)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
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	(1 009)	(1 023)	(1 035)	(1 153)	(1 309)	(1 262)	(1 249)	(1 404)	(1 335)	(1 321)
Net Increase (Decrease) in Cash	292	533	(110)	(46)	(90)	38	32	(133)	(92)	144
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(1) Cash flows for Regulatory Deferrals reclassified from Cash Provided by Operating Activities to Cash Used for Investing Activities
(2) Interest Costs on City of Winnipeg reclassified from Cash Provided by Operating Activities to Cash Used for Investing Activities

WRITTEN ARGUMENT – EXPERT EVIDENCE

1. During the cross-examination by Mr. Czarnecki of Mr. Patrick Bowman on the depreciation panel there appeared to be a suggestion that Mr. Bowman's evidence with respect to depreciation ought to be given little or no weight because he did not write the Exam of the Society of Depreciation Professionals and obtain a Certificate as a Certified Depreciation Professional from that American Society (June 5, 2023, Tr. p. 3266) and implied that greater weight should be placed on the evidence filed by Mr. Kennedy and Mr. Watson.

2. MIPUG retained Mr. Patrick Bowman to provide expert testimony to the Board on issues of cost of service, rate design, revenue requirement and depreciation.

3. There is generally no dispute that Mr. Bowman is qualified to provide expert evidence on cost of service, rate design and revenue requirement. For the foregoing reasons, MIPUG respectfully submits that Mr. Bowman ought to be accepted by this Board as an expert in matters of deprecation (and in particular, his review of depreciating studies for rate setting purposes) and that his evidence on depreciation be given commensurate weight.

The laws of expert evidence

4. A properly qualified expert is shown to have acquired special or peculiar knowledge through study or experience in respect of matters on which he or she or they undertake to testify. (See: **Anderson, G: *Expert Evidence* (2nd ed.) (LexisNexis Canada Inc. 2009) (*excerpt*), TAB 1, page 91**).

5. Judges have held that knowledge and experience of an expert can be gained through practical experience and observation. Experts are not disqualified merely because others are more qualified. (***Expert Evidence*, TAB 1, pp. 91-92)**

6. In other words, expert evidence is not a battle of CVs. The person with the more impressive CV ought not to be given more weight. Rather, that the Board should weigh the evidence on the whole, including the inputs and reasoning applied by the experts, and decide which it prefers.

Evidence with respect to Mr. Bowman's Qualifications

7. Mr. Bowman's CV details his extensive experience in utility rate regulation and in particular is experience in matters of depreciation. His CV is attached as **Appendix A to MIPUG – 6**, **InterGroup Intervener Evidence – April 3, 2023 – Redacted**.

8. Mr. Bowman confirmed as follows through his oral testimony on June 9, 2023 (**June 9, 2023 Transcript, pages 3940 to 4150**) that:

a. Bowman Economic Consulting is a member of the society of depreciation professionals (Tr. page 3948, lines 22 – 25);

b. Mr. Bowman has approximately 24 years of experience with InterGroup Consultants, which experience includes preparing evidence and expert testimony for regulatory hearings (Tr. page 3949, lines 1 – 9);

c. For approximately the past decade, Mr. Bowman was mentored by Patricia Lee who is a trainer with the Society of Depreciation Professionals and faculty member of the National Association of Regulatory Commissioners, Regulatory Studies Program. Mr Bowman stated that he has worked very closely with Pat Lee in respect of matters of depreciation for about a decade (Tr. page 3949, lines 22-25; page 3950, lines 1-6);

d. He has participated in over 80 regulatory hearings on behalf of parties ranging from utilities, to interveners, to regulators (page 3950, lines 6 – 17). He has testified in utility proceedings involving Crown Corporations or other government owned utilities such as BC Hydro, Northwest Territories Power Corporation, Yukon Energy and New Brunswick Power (ongoing) and Newfoundland Hydro (Tr. page 3952, lines 10 – 23);

e. Mr. Bowman's first proceeding where he had a significant role in depreciation was in 2005, some 17 or 18 years ago, wherein he coordinated Yukon Energy's depreciation filing and testified to it (Tr. page 3950, lines 19-25; page 3951, lines 1 – 22);

f. Since 2005, Mr. Bowman has provided evidence in relation to depreciation proceedings involving Northwest Territories Power Corporation, Newfoundland Hydro, BC Hydro, a number of utilities in Alberta and Enbridge Gas (Ontario – ongoing) (Tr. page 3951, lines 23 – 25; Tr. page 3952, lines 1 – 9);

g. Mr. Bowman has testified at every major Manitoba Hydro hearing since 2001 (when there was an opportunity for oral testimony) (Tr. page 3953, lines 6 – 13);

h. He provided evidence in the Manitoba Hydro 2012/13 and 2013/14 GRA, which evidence was with respect to the issues of equal life group versus average service life and removal of net salvage value from depreciation (Tr. page 3953, lines 19 – 25);

i. Together with Pat Lee, he submitted evidence and testified to matters of depreciation in the Manitoba Hydro 2015/16 GRA, and that his evidence formed part of the record in that proceeding and which the Board referenced and used in its final decision (Tr. page 3954, lines 2 – 20); and

j. Since the Manitoba Hydro 2015/16 GRA, he has participated in over nineteen (19) additional hearings dealing specifically with depreciation (Tr. page 3954, lines 21 – 25; Tr. page 3955, line 1).

9. Leading up to this hearing, Mr. Bowman participated in the three technical conferences on depreciation as the independent expert on behalf of MIPUG. 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. (**PUB-20 – Depreciation Issues Document – May 10, 2023**).

10. Finally, MIPUG entered into evidence the Society of Depreciation Professionals ("SDP") criteria for obtaining a certified depreciation professional

designation (see **MIPUG-16 – SCP Certification main page – June 5, 2023**). In summary, the criteria are:

a. Active membership in the SDP;

b. At least 5 years of professional depreciation experience, at least 2 of which must be in an area related to depreciation administration. Three years experience may be in a related field such as […] planning, regulation, and regulator consulting. Depreciation administration comprises any of the following activities: […] the review of depreciation studies […];

c. College degree or equivalent;

d. Successful passage of CDP exam within 5 years prior to CDP application; and

e. Completed application and references.

11. MIPUG submits that Mr. Bowman meets all of the criterial for obtaining a certified depreciation professional designation other than having taking the exam and completing the application.

12. MIPUG also submits that Mr. Bowman's lack of a certified depreciation professional designation does not disqualify him as an expert. When asked in cross-examination whether he planned to become a certified depreciation professional, the following exchange occurred:

> MR. PATRICK BOWMAN: I doubt it. My focus has been on rate setting and how depreciation fits into that for purposes of saying [sic] just and reasonable rates. It's not my – not my interest to do depreciation studies for utilities and so that – that hasn't been the – the – the area where I've looked to focus.
>
> MR. BRENT CZARNECKI: Yeah, understood. And we recognize your experience.
>
> **June 5, 2023 transcript, page 3266, lines 12-20**

British Columbia Utilities Commission ("BCUC")

13. Mr. Bowman's testimony in matters of depreciation was recently given weight in **British Columbia Hydro and Power Authority Fiscal 2023 to Fiscal 205 Revenue Requirements Application, Decision and Order G-91-23 (April 21, 2023) (*excerpt*) TAB 2.**

14. In that case, Mr. Bowman gave evidence on behalf of the Association of Major Power Customers of British Columbia ("AMPC").

15. The expert retained by BC Hydro (Mr. Kennedy of Concentric Advisors) stated that Mr. Bowman was not a depreciation expert. While BC Hydro did not seriously dispute the expertise of Mr. Bowman, it argued that Mr. Kennedy's evidence was preferred on account of his credentials.

16. AMPC argued that Mr. Bowman provided detailed rationale for each of his recommendations, with all supporting rationales. It also argued that Mr. Bowman "carefully stays within his expertise and only comments on the outputs of the depreciation study". AMPC also noted that the Commission should not give more weight to the

evidence provided by the person with a more impressive CV, but weigh the evidence as a whole, including the inputs and reasoning applied. (**TAB 2**, **page 117**) MIPUG respectfully adopts these same submissions in the instant proceeding.

17. Similar to AMPC's submission in the BC proceeding, MIPUG also submits that the fact that Mr. Bowman has not completed a depreciation study is irrelevant as his expertise is relevant to reviewing depreciation studies, methodologies and principles to determine the rate implications therefrom. (**TAB 2, page 117**)

18. In any event, with respect to BC Hydro's expert, Mr. Kennedy, the BCUC found that "[t]he Panel gives little weight to Mr. Kennedy's certified depreciation professional designation, which is not a requirement to complete a depreciation study." (**TAB 2, page 119)** [Emphasis added]

19. With respect to Mr. Bowman, the BCUC found as follows:

> The Panel gives weight to Mr. Bowman's evidence on the use of depreciation studies by rate-regulated utilities. The Panel recognizes Mr. Bowman's work in public utility regulation since 1988 and his testimony in 40 proceedings before regulators in six jurisdictions in Canada.
>
> The Panel recognizes that Mr. Bowman has never created a depreciation study himself, and that his experience is not as extensive as that of Mr. Kennedy. Further, like Mr. Kennedy, Mr. Bowman is not an expert in any of the fields that contribute technical substance to them. However, the Panel is satisfied that Mr. Bowman has sufficient experience and expertise to provide evidence that challenges the results of the Depreciation Study. Mr. Bowman provided clear explanations of his opinions, and he responded comprehensively to questions posed during the oral hearing.
>
> **TAB 2, pages 119-120**

Manitoba Hydro's Position

20. Manitoba Hydro does not appear to be seriously contesting the characterization of Mr. Bowman as an expert witness with respect to matters of depreciation or otherwise. It did not provide oral or written argument on this point.

21. We note that in **Exhibit MH-3 - MB to PUB re 2023 GRA Comments on Applications for Intervener Status Applications for the MH 2023 General Rate Application – November 30, 2022**, Manitoba Hydro notes as follow's with respect to Mr. Bowman, at page 4:

> As part of its proposed intervention, MIPUG intends to engage five technical advisors, including two unidentified, "highly specialized advisors" in the areas of depreciation and export markets without providing any clarification on which specific issues it intends to address in these areas or the purpose of same, which according to MIPUG, are expected to be quite costly. <u>There appears to be potential duplication in the advisors included by MIPUG. The curriculum vitae of Mr. Patrick Bowman indicates that his areas of experience include "Utility regulation and Rates, including Depreciation", and he is a member of the Society of Depreciation Professionals</u>.
>
> <u>To the extent that MIPUG requires a consultant to assist it with depreciation matters, given that Mr. Bowman has experience in the area of depreciation, including appearing as a witness for MIPUG on depreciation in previous PUB proceedings, Manitoba Hydro questions whether it is necessary for MIPUG to engage a second, and presumably more costly technical advisor on depreciation matters</u>. Manitoba Hydro also notes that GSS/GSM intends to address depreciation as part of its proposed intervention, and intends to engage one technical advisor, Mr. Dustin Madsen, who is a Certified Depreciation Professional. [Emphasis added]

22. While Manitoba Hydro is careful to state that Mr. Bowman has "experience" in depreciation, by contesting MIPUG's retainer of another expert in depreciation on the

basis of Mr. Bowman's participation, MIPUG respectfully submits that Manitoba Hydro has implicitly accepted Mr. Bowman as an expert in depreciation.

23. Moreover, Manitoba Hydro has adopted Mr. Bowman's evidence numerous times throughout the course of this proceeding.

24. Manitoba Hydro recognized Mr. Bowman's evidence numerous times in its oral submissions (**June 19, 2023 Transcript**):

a. Adopting Mr. Bowman's comments that what we have here is "spectacular performance" (page 4159, lines 17-22 & page 4219, lines 14-19);

b. Adopting Mr. Bowman's evidence as it relates to interim rate increases and whether the Board should consider rolling back that rate increase (pages 4175-4176 & page 4234); and

c. Adopting Mr. Bowman's evidence as it relates to the characterization of retained earnings (page 4206, lines 6-18).

25. Manitoba Hydro has also adopted Mr. Bowman's evidence in several areas of its Written Argument, **MH-57 – MH Final Written Argument – June 19, 2023**:

a. In support of its submission that it is entirely reasonable and appropriate for Manitoba Hydro to plan now for the regulatory framework contained in Bill 36. (See page 17 of 244, lines 1-14, wherein it noted that a similar position was taken by Mr. Bowman);

b. In support of its position that changes to export contracts and interest rates support rate increases in the test years, at page 25 of 244, lines 1-3:

> Notably, Mr. Bowman also identified the end of the NSP system sales agreement and the refinancing of debt as reasons why he supported the proposed 2% rate increases in the Test Years: […]

c. In support of its position that, if the granting of the interim rate relief was not just and reasonable at the time, the least preferred option is a retroactive rollback. See page 32 of 244, lines 1-3:

> Manitoba Hydro concurs with the pragmatic opinion offered by Mr. Bowman regarding the importance of looking forward when considering the potential retroactive adjustment to any interim rate, if warranted: […]

d. Manitoba Hydro agrees with Mr. Bowman's evidence that in future GRAs, an uncertainly analysis could be a useful tool for assessing the likelihood of reaching the legislated financial targets under specified conditions, rather than assessing the targets themselves. See page 38 of 244, lines 9 -12;

e. In support of its position that the Board now has sufficient information to opine on depreciation matters. See page 154 of 244, at lines 10-24:

> Manitoba Hydro submits that the information now on the record is sufficient to allow the Board to make a determination on the depreciation issues. The information placed on the record in this proceeding has demonstrated how the potential treatment of the depreciation issues would impact customers and that the alternatives recommended for the Board's consideration do not negatively impact customers. Any alternative that defers full resolution of the depreciation issues, including Alternative 3 and Alternative 4, as

> presented in Depreciation Issues Document, should be rejected.
>
> Mr. Bowman and Mr. Madsen both indicate that extensive information has been provided on the record. By recommending one of the two alternatives which allow for full resolution of the depreciation matters, Mr. Bowman and Mr. Madsen have indicated that they believe the depreciation matters can be resolved during this proceeding. In contrast, Mr. Rainkie is the only party who has indicated that a Board decision should be deferred to a future proceeding on the basis that Manitoba Hydro has not met the requirements of the outstanding depreciation Directives.

26. While some of the areas in which Manitoba Hydro adopted Mr. Bowman's evidence were not with respect to depreciation matters; we respectfully submit that Manitoba Hydro should not have the benefit of adopting some of Mr. Bowman's evidence for the purpose of supporting its case and not giving commensurate weight to his evidence with respect to depreciation matters, particularly as the other areas of Mr. Bowman's expertise are complimentary to and inform his opinions with respect to depreciation. In other words, Manitoba Hydro should not get to have its "pie" and eat it too.

EXPERT EVIDENCE

Second Edition

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ility. The Court's admissibility
desperate need for an explana-
ng the nature of the children's
vise incredible behaviour could
ssing their credibility".[29] Justice
n. The Court did not appear to
an's testimony.

took another look at the admis-
ing child complainants in *R. v.*
or who tendered the evidence.
nent. This time, the Court ruled
lmissible.

nt alleged that the accused had
rior to reporting the abuse. After
vn called Dr. Marshall, a child
lay in alleging sexual abuse did
r. Marshall did not examine the
rshall provided a general expla-
l children, namely, that delayed
asons and did not prove anything
Marshall's evidence was admissi-
ity criteria. The Ontario Court of
dmissible because it was neither
rejudicial effect outweighed its

Dr. Marshall's evidence was in-
ority of four to three, expressed
ed, "*Mohan* expressly states that
to warrant accepting the dangers
vidence."[31] He added that, "the
l in this case was not unique or
e proper subject for a simple jury
ssion was not necessary".[32]

issenting opinion, found that Dr.
en might delay reporting sexual
whether the complainant's delay
her.[33] The dissenting justices were

. 40 (S.C.C.).

f the Court.

of the view that the testimony was necessary because it went beyond the ordinary knowledge and experience of the jury. In citing the probative value versus prejudicial effect factor, McLachlin C.J. reasoned:

> Dr. Marshall testified in a clear and straightforward manner. ... His evidence was easy to understand and well within the ability of the jury to evaluate. ... I cannot conclude that the trial judge erred in holding that the probative value of Dr. Marshall's evidence outweighed its prejudicial effects.[34]

The decisions of the Courts of Appeal and the Supreme Court of Canada in *R. v. R. (D.)* and *R. v. D. (D.)* illustrate that the application of the rules regarding the admissibility of expert testimony requires a careful analysis of the testimony in the context of the circumstances of the case. In *R. v. R. (D.)*, the psychological testimony for the defence was ruled admissible; whereas in *D. (D.)* the Crown's testimony was inadmissible. The different admissibility rulings might be due to several reasons: (1) a more rigorous application of the *Mohan* criteria in 2000 than in 1996; (2) a permissive application of the cost benefit analysis for the admissibility of the criminal defendant's expert in order to give effect to an accused's entitlement to fully defend himself; or (3) a more rigorous application of the *Mohan* criteria on Crown experts to protect accused persons from wrongful convictions. Six years later, a majority judgment of the Supreme Court would call for careful scrutiny of evidence presented against an accused.[35]

Although it is unclear whether there is a trend to apply the necessity criterion with increased rigour, an increased concern about the dangers of expert evidence might account for an increased consciousness of its usefulness. In *Chartier v. Greaves*, a decision of Ontario Superior Court of Justice in 2000, Power J. saw "a trend in the law recently with respect to expert testimony, the trend being to question its usefulness to the extent that the Courts were using it".[36]

(c) A Properly Qualified Expert

While the *Mohan* Court did not explain what degree of study or experience would meet its properly qualified expert criterion, judges have subsequently added that knowledge and experience can be gained through

34 *Ibid.*, at para. 41.
35 *R. v. Trochym*, [2007] S.C.J. No. 6, 2007 SCC 6 at para. 1 (S.C.C.).
36 [2000] O.J. No. 5520, 15 C.P.C. (5th) 65 at para. 18 (Ont. S.C.J.).

practical experience or observation.[37] Experts are not disqualified merely because others are more qualified.[38]

Courts have followed the traditional approach of evaluating a witness' qualifications by assessing credentials in a field of expertise in light of the matter to be opined upon. Witnesses might be properly qualified to provide an opinion on one issue but not on another in the same field. In *R. v. Terceira*, Finlayson J.A. wrote that trial judges must consider whether the expert "had the necessary expertise to enable her to express an opinion in this field".[39] Courts have consistently underscored the need for trial judges to carefully assess and identify the scope of the expertise of an expert witness in advance of him or her testifying.[40]

Although it has been often stated that deficiencies of expertise go to the weight and not admissibility, courts have excluded expert testimony under the properly qualified expert criterion where experts were not properly qualified to opine on the issue for which they are proffered and where there were concerns about unreliable evidence or expert bias. Expert testimony has been excluded on the basis of the properly qualified expert criterion in circumstances where opposing counsel did not challenge the experts' qualifications and where a witness had been qualified as an expert in a previous proceeding. These decisions might represent a trend to apply this *Mohan* criterion with increased rigour.

(d) Probative Value versus Prejudicial Effect

R. v. Mohan included the probative value versus prejudicial effect analysis in its relevance and necessity criteria.[41] The balancing process lies at the core of the determination of the admissibility of expert testimony:

> The balancing process which lies at the core of the determination of the admissibility of this kind of evidence is not unique to expert opinion evidence. It essentially underlies all our rules of evidence. It is, however, necessarily case-specific. The probative value of the proposed evidence and its potential prejudicial effect can only be assessed in the context of a particular trial.[42]

---

37 *R. v. Rayner*, [2000] N.S.J. No. 399, 2000 NSCA 143 (N.S.C.A.).

38 *Saskatchewan Hospital Association (c.o.b. Saskatchewan Association of Health Organizations) v. Parker*, [2001] S.J. No. 267, 2001 SKCA 60 at para. 172 (Sask. C.A.).

39 [1998] O.J. No. 428, 38 O.R. (3d) 175 at para. 33 (Ont. C.A.), affd [1999] S.C.J. No. 74, [1993] 3 S.C.R. 866 (S.C.C.).

40 *Vigoren v. Nystuen*, [2006] S.J. No. 293, 2006 SKCA 47 at para. 67 (Sask. C.A.).

41 [1994] S.C.J. No. 36, [1994] 2 S.C.R. 9 (S.C.C.), revg [1992] O.J. No. 743, 8 O.R. (3d) 173 (Ont. C.A.).

42 *R. v. K. (A.)*, [1999] O.J. No. 3280, 45 O.R. (3d) 641 at para. 76 (Ont. C.A.).

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British Columbia Hydro and Power Authority

Fiscal 2023 to Fiscal 2025 Revenue Requirements Application

Decision
and Order G-91-23

April 21, 2023

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

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Executive summary

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

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

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

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

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

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

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

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

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

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

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

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

e. Filing for approval of the TIRR and the DARR annually in filings separate from its RRA filings.

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

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

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

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

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

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

Based on its most recent reliability results, BC Hydro continues to strive to strike an appropriate balance between affordability and system performance and risk, by increasing expenditures where needed, and deferring investments where prudent to do so, as reflected in its Capital Plan for the Test Period.[655] Notwithstanding our observation above, we are concerned that while BC Hydro's normalized reliability indices results for F2012 to F2021 have improved slightly in F2021 in comparison to F2020, they remain below the average of major electricity utilities in Canada, which suggests that additional efforts on the part of BC Hydro to improve reliability may still be warranted.

As for the NIA, the Panel shares Zone II RPG's continued concerns about the reliability disparity of the NIA as compared to the rest of BC Hydro's service territory. As Zone II RPG correctly points out, this disparity is particularly concerning in light of BC Hydro's caution that "feasible targeted improvements are expected to improve reliability but may not provide reliability performance comparable to less remote and more dense areas that are not subjected to the same uncontrollable elements."[656]

The Panel acknowledges that BC Hydro has recently undertaken initiatives to improve reliability in the NIA including the following: upgrades to communication and control systems; increased efforts on root cause analysis for outages; improvements in operator training; replacement of automated reclosers; and, prioritization of capital spending on the worst performing circuits, although the results of these initiatives are not reflected in this Application. The Panel supports these efforts as a good starting point. The Panel also acknowledges that the remoteness of the NIA poses particular challenges to maintaining reliability for this region, but notes that Zone II RPG flagged the need for improvement two RRAs ago, and despite the recent initiatives undertaken, this still appears not to be fully resolved more than three years later. The Panel urges BC Hydro to consider further actions to address this problem on a more timely basis, should reliability in the NIA continue to be an issue. Additional efforts in this regard would also be consistent with BC Hydro's stated commitment, as reiterated in this proceeding, to implementing reconciliation, given the prevalence of Indigenous communities within the NIA.

In the meantime, **the Panel directs BC Hydro to report on the NIA customer satisfaction index on reliability as part of its next RRA.**

Having regard to all of the above, the Panel recommends that the BCUC continue to closely scrutinize BC Hydro's asset health information, sustainment capital spending, reliability performance and customer satisfaction in future RRAs, as trends may emerge over time which may require additional remedial action.

4.6 Depreciation

BC Hydro states that the forecast amortization expense within the revenue requirement includes the amortization of property, plant and equipment in service.[657] In response to Directive 36 of the BCUC's decision in the F2020-F2021 RRA, BC Hydro engaged Concentric Advisors, ULC (Concentric) to perform a depreciation study (Depreciation Study) that reviewed existing depreciation rates and positive salvage percentages. BC Hydro is seeking approval from the BCUC to implement the recommendations from the Depreciation Study for ratemaking purposes beginning in F2022.[658]

The following sections will address:

- Concentric's Depreciation study and Intervener Evidence

[655] Exhibit B-2, p. 6-14.
[656] Zone II RPG Final Argument, p. 19 ; Exhibit B-7, BCUC IR 83.4
[657] Exhibit B-2, Section 8.3, p. 8-3.
[658] Exhibit B-2, Section 8.3.1, pp. 8-5 – 8-6.

- The revised positive salvage percentages recommended by Concentric
- The changes to vehicle asset classes recommended by Concentric
- The contested average service life recommendations made by Concentric and the interveners
- Other issues

4.6.1 Adoption of Revised Average Service Lives

In its Depreciation Study, Concentric recommends an increase to the average service lives of 52 asset classes, a decrease to the average service lives of 45 asset classes, and no change to the average service lives of 217 asset classes.[659]

Both Mr. Bowman, on behalf of AMPC, and Midgard Consulting (Midgard), on behalf of RCIA, submitted evidence that raises concerns over the lack of historical data available for the completion of the actuarial analysis and the selection of peer utilities used in the peer analysis.[660] Mr. Bowman and Midgard recommend BC Hydro adopt alternative average service life estimates which differ from Concentric's recommendations for various accounts.[661]

The Panel addresses the following issues:

- The weight to give the experts' evidence;
- Concentric's Depreciation Study;
- Bowman's alternative;
- Midgard's alternative; and
- Contested average service lives.

4.6.1.1 Expert Evidence

BC Hydro retained Mr. Kennedy, from Concentric Advisors, to prepare the Depreciation Study. BC Hydro states Mr. Kennedy is an expert in depreciation based on his vast experience conducting depreciation studies including:[662]

1. Over 40 years experience in the energy field including conducting approximately 300 depreciation studies, of which about 145 have resulted in either written or oral testimony before regulatory bodies
2. Proving oral testimony approximately 145 times and has been accepted as a depreciation expert
3. Appearing before regulators in every Canadian province and territory except Prince Edward Island, and in nine US states, and has appeared before the Canadian Energy Regulator and the Federal Energy Regulatory Commission
4. Holding a certified depreciation professional (CDP) designation and being a member and former president of the Society of Depreciation Professionals
5. Regularly attending and speaking at depreciation conferences, and reviewing the depreciation studies conducted by other experts

659 Exhibit B-2, Section 8.3.1.2, p. 8-9.
660 Exhibit C7-11, Section 2.2, pp. 11 – 14; Exhibit C8-7, Sections 5.3 and 5.5, pp. 21 – 23 and 24 – 26.
661 Exhibit C7-11, Section 1.1, pp. 3 – 5; Exhibit C8-25, BCUC IR 5.1, Appendix A, Table 6.
662 Exhibit B-2-1, Appendix T, Attachment A, pp. 722 – 734; Exhibit B-36, Appendix A, Section II, A17, p. 17; 2022-09-20 Oral Hearing Volume 2 AM, p. 164 Line 13 to p. 166 line 9 and p. 204 line 9 to p. 205 line 3.

AMPC submitted evidence prepared by Mr. Bowman. AMPC states Mr. Bowman is an expert in utility rate regulation with specific expertise in depreciation and net salvage based on the following:[663]

1. Working in public utility regulation since 1998 on behalf of utilities, interveners, governments and regulators[664]
2. Testifying before regulators in six jurisdictions across Canada, across 40 proceedings, including filing evidence or testifying on depreciation and net salvage-related matters[665]
3. Coordinating Yukon Energy's 2005 depreciation filing[666]
4. Testifying in multiple Manitoba Hydro-Electric Board (Manitoba Hydro) proceedings and "six or seven" proceedings in Alberta on depreciation[667]
5. Providing evidence with respect to average service lives in prior BC Hydro RRA[668]
6. Testifying with and being mentored by Patricia Lee, former president of the Society of Depreciation Professionals[669]
7. Experience in matters related to overall utility economics, planning and project design[670]

Concentric states that Mr. Bowman is not a depreciation expert with experience limited to the review of depreciation practices and policies, the testing of the reasonableness of depreciation methods and the testing of the reasonableness of proposed depreciation lives for the purposes of regulatory rate setting. As such, Mr. Bowman's recommendations must be reviewed in the context that Mr. Bowman has a high level and general understanding of the impact of depreciation expense on the revenue requirement.[671]

Concentric states that depreciation is a highly specialized field that requires an understanding that extends past the engineering underlying the physical life of assets. It is essential to understand the manner in which the physical life and the accounting life of assets are similar or different. There are many depreciation concepts and theories that need to be understood fully in order to understand a depreciation study.[672] For example, Concentric submits that Mr. Bowman has a factually and theoretically wrong understanding about the construction of the Observed Life Tables which can lead to inaccurate average service life recommendations. Additionally, the Hydro One peer data utilized by Mr. Bowman has the same limitations in the retirement data as BC Hydro.[673]

BC Hydro states that although Mr. Bowman's evidence was accepted as part of Manitoba Hydro's 2012-2013 and 2013-2014 RRA, the Manitoba Public Utilities Board never accepted Mr. Bowman as an expert in depreciation.[674] Moreover, in the Manitoba Hydro 2014-2015 and 2015-2016 RRA, another consultant, Patricia Lee, was retained to be the depreciation expert by the industrial customer group Mr. Bowman was representing. Mr. Bowman did not have experience in the review of average service lives until the mid 2010s.[675]

[663] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 406 lines 16 – 19.
[664] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 399 line 18 to p. 401 line 6.
[665] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 401 lines 7 – 18.
[666] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 402 line 7 to p. 403 line 3.
[667] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 403 line 26 to p. 405 line 3.
[668] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 406 lines 6 – 15.
[669] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 404 line 18 to p. 405 line 17.
[670] Exhibit C7-11, Appendix A.
[671] Exhibit B-36, Appendix A, Section III, A16, pp. 16 – 17.
[672] Exhibit B-36, Appendix A, Section III, A18, pp. 17 – 18.
[673] Exhibit B-36, Appendix A, Section III, A18, pp. 18 – 19.
[674] 2022-09-20 Volume 2 PM, p. 449 line 6 to p. 453 line 6.
[675] 2022-09-20 Volume 2 PM, p. 453 line 7 to p. 456 line 6.

RCIA submitted evidence from Midgard, prepared by Mr. Helland and Mr. Oakley. RCIA states Mr. Oakley is an expert in utility rate regulation and Mr. Helland is an expert in general asset and risk management.[676] Specifically, RCIA states Mr. Oakley is a qualified expert in utility rate regulation based on the following expertise: [677]

1. Possessing a bachelor's degree in electrical engineering from the University of Calgary[678]
2. Working in the utility energy business for over 36 years[679]
3. Co-founding principal of Midgard Consulting in 2009[680]
4. Possessing experience with revenue requirement proceedings, rate design applications, cost of service proceedings, resource plan reviews and facility need and citing proceedings with expertise in utility capital planning and development, asset management plans and resource plans[681]
5. Performing work for regulators, utilities and customer groups including testifying before tribunals like the BCUC 20 times, among other things[682]

RCIA states Mr. Helland is an expert in general asset and risk management based on the following expertise: [683]

1. Possessing a bachelor's degree in systems engineering, master's degree in applied science, a master's degree in business administration and certificate in asset management[684]
2. Co-founding principal of Midgard Consulting in 2009 and serving as its CEO from its founding until the end of 2022[685]
3. Serving as the current director of RCIA[686]
4. Possessing experience with revenue requirement proceedings, rate applications, cost of service proceedings and resource plans with expertise in engineering, regulatory and business consulting[687]
5. Performing work for customer groups, regulators and utilities including asset management and risk management work for over 15 Canadian distribution and transmission utilities[688]

Concentric states that although Midgard has broad experience in utility asset management and asset health, the contributing authors have virtually no experience in the determination of average service life estimates nor hold a CPD designation. There are several differences between an asset's maximum life expectation used for asset management and the average service life of a group of assets within an asset class.[689]

For example, Concentric states Midgard makes basic errors which would have been avoided if Midgard's evidence was provided by a qualified CDP including:[690]

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676 2022-09-20 Volume 2 PM, p. 490, lines 17 – 20.
677 Exhibit C8-14. Appendix A, pp. 13 – 20; 2022-09-20 Volume 2 PM, p. 491 line 6 to p. 497 line 18.
678 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 491 lines 6 – 10.
679 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 491 lines 11 – 13.
680 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 491 lines 14 – 17.
681 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 492 lines 6 – 16.
682 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 402 line 17 to p. 497 line 18.
683 Exhibit C8-25, pp. 14 – 16; 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 498 line 24 to p. 502 line 20.
684 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 498 line 24 to p. 499 line 13.
685 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 499 lines 22 – 26.
686 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 500 line 16.
687 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 500 lines 1 – 21.
688 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 500 line 22 to p. 502 line 20.
689 Exhibit B-36, Appendix A, Section IV, A39, p. 44.
690 Exhibit B-36, Appendix A, Section IV, A41, p. 46 – 47.

1. Misuse of the Retirement Experience Index and Bauhan's Scale
2. Determining the maximum life estimates are comparable to average service life estimates
3. Inclusion of Hydro One in Midgard's peer analysis

In the opening statement during the oral testimony, Mr. Helland states that Midgard's role is an independent witness providing opinion evidence to the BCUC that is fair, objective and non-partisan.[691] Mr. Andrews, representing BCSEA, states that Midgard is an acting agent for RCIA which is an advocate in this proceeding. Mr. Helland states that as a professional engineer, he is bound by a code of ethics to act in the public interest and not advocate for one party or another.[692]

Positions of the Parties

BC Hydro submits that its depreciation proposals are based on the recommendations of Mr. Kennedy of Concentric, "an independent expert with vast experience in depreciation studies." BC Hydro submits that the relative experience and depth of analysis warrants the BCUC giving greater weight to Mr. Kennedy's evidence on issues where there are disagreements.[693]

BC Hydro submits that Mr. Bowman's expertise is significantly more limited as he does not conduct depreciation studies, is not a CDP, and was determined not to be a recognized expert in depreciation by the Manitoba Public Utilities Board in 2013.[694]

BC Hydro submits that Mr. Helland and Mr. Oakley, of Midgard, are not certified depreciation professionals and "do not have any formalized training in the area of depreciation theory or practice." BC Hydro notes that the only experience on their CVs with respect to depreciation concerns the hydroelectric facilities for Boralex Ocean Falls Limited Partnership[695] which they confirm has a very small rate base and for which they did not conduct a depreciation study.[696]

BC Hydro further submits that Midgard "is not an 'independent expert' on any reasonable interpretation of that concept" and that Midgard's role is to act as an advocate for residential consumers as an agent of RCIA. BC Hydro notes that Mr. Helland is a director of the RCIA and "retained himself and Midgard to provide evidence."[697]

BCSEA submits that the BCUC should prefer the opinions of BC Hydro's experts over those of RCIA and AMPC, for the reasons BC Hydro sets out in its final argument.[698]

AMPC submits that the BCUC should decide which expert opinion to prefer "based on its views of the substance of the opinions expressed on each point in dispute" rather than through a "global assessment of weight." AMPCsubmits that the BCUC can only weigh the evidence put before it, and to accept expert opinion as reliable, the BCUC must be able to understand the analysis and complete reasoning that led to the formation of the opinion and test its foundation.[699]

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[691] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 504 lines 20 – 23.
[692] 2022-09-20 Oral Hearing Transcript Volume 2 PM, p. 509 line 24 to p. 511 line 10.
[693] BC Hydro Final Argument, pp. 147–148.
[694] BC Hydro Final Argument, p. 149.
[695] BC Hydro uses the term "Boralex Falls" in its Final Argument.
[696] BC Hydro Final Argument, p. 150.
[697] BC Hydro Final Argument, p. 151.
[698] BCSEA Final Argument, p. 31.
[699] AMPC Final Argument, pp. 5-2 to 5-3.

AMPC submits that caution must be taken when receiving evidence from "expert generalists", noting the *Johnson v. Milton (Town)* decision, where the Honourable Mr. Justice Moldaver stated:[700]

> …trial judges who fail to properly perform their gatekeeper function run the risk of having their decision-making function usurped or severely eroded by "expert generalists" who profess to know something about everything and who are only too willing to provide the court with a ready-made solution for any contentious issue that might exist. The problem with such witnesses is that while they appear knowledgeable and generally come across well, upon closer scrutiny, their opinions may well turn out to be little more than concoctions consisting of guesswork, speculation, commonplace information and junk science, with a hint of valid science thrown in for good measure.
>
> Courts must be vigilant to guard against such impermissible evidence. It is trite law that expert witnesses should not give opinion evidence on matters for which they possess no special skill, knowledge or training…

In reply, BC Hydro submits that it has not suggested that the BCUC should "blindly" accept Mr. Kennedy's evidence due to his significant experience, but rather that the BCUC should give greater weight to his evidence on issues where there are disagreements.[701]

AMPC submits that, in contrast to Mr. Kennedy's evidence, Mr. Bowman provides detailed rationales for each service life recommendation that he makes, with all supporting rationales. Further, AMPC submits that BC Hydro's criticism that Mr. Bowman was "selective" in his views ignores his explanations for his approach, and that Mr. Kennedy likewise engaged in a selective review.[702]

AMPC submits that BC Hydro's challenge to Mr. Bowman's evidence "misses the mark," and that Mr. Bowman's evidence "carefully stays within his expertise and only comments on the outputs of the depreciation study and where in his view the available data support longer service lives," which BC Hydro does not dispute. AMPC submits that Mr. Bowman has "special skill and knowledge with depreciation-related matters" and his evidence should be given weight. AMPC submits that the BCUC should not give more weight to the evidence provided by the person with the more impressive CV, but rather weigh the evidence as a whole, including the inputs and reasoning applied by the experts.[703]

AMPC submits that Mr. Bowman's qualifications to testify on asset service lives are "no longer in question." AMPC notes Mr. Bowman's work in public utility regulation since 1988, his specific experience with depreciation since 2005, and his testimony in 40 proceedings before regulators in six jurisdictions across Canada. In response to BC Hydro's criticisms of Mr. Bowman's qualifications, AMPC submits that:[704]

- It is not relevant that Mr. Bowman has not completed a depreciation study because his work is with utilities includes reviewing and supervising the work of different depreciation experts.
- The relevance of Mr. Bowman's lack of a certified depreciation professional designation is unclear, because there is no evidence that this designation is of any relevance to establishing expertise in depreciation.
- Mr. Bowman was not put forward as an expert in depreciation in the 2013 Manitoba Public Utilities Board proceeding, and he was accepted as qualified to provide evidence "analyzing depreciation studies for rate-setting purposes" which is his role in this proceeding.

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[700] AMPC Final Argument, pp. 5-6 to 5-7; *Johnson v. Milton (Town)*, 2008 ONCA 440 at paras. 49-50.
[701] BC Hydro Reply Argument, p. 88.
[702] AMPC Final Argument, pp. 5-2, 5-4.
[703] AMPC Final Argument, p. 5-8.
[704] AMPC Final Argument, pp. 5-8 to 5-11.

In reply, BC Hydro submits that Mr. Bowman's experience and qualifications "do not demonstrate any specialized skill or knowledge in determining average service lives for depreciation purposes" and that the BCUC should assign more weight to Mr. Kennedy's evidence in cases of disagreement. In particular, BC Hydro submits that Mr. Bowman testified that his experience with depreciation did not really start until the mid-2010's, and has been "more focused on general utility regulation and policy matters related to depreciation and net salvage, with less focus on actually reviewing depreciation studies and average service lives, and no experience conducting such studies." BC Hydro disagrees with AMPC's view that Mr. Bowman's lack of a certified depreciation professional designation is irrelevant, and submits that if Mr. Bowman had the designation, it would at least indicate that he had the minimum qualifications to testify on depreciation matters, whereas contrary to AMPC's assertion, it is not apparent to BC Hydro that Mr. Bowman has the required experience in the field to qualify for the designation. BC Hydro further submits that in 2013 the Manitoba Public Utilities Board found that Mr. Bowman was not a depreciation expert, "despite counsel seeking that he be recognized as an 'expert on the appropriate regulatory approach to reflecting the outcome of depreciation studies'."[705]

BCOAPO shares AMPC's concern regarding the weight to be given to Mr. Kennedy's evidence, in particular his heavy reliance on "practices of peers while limiting that data pool to only those for whom Mr. Kennedy has prepared reports" and on his own judgment "without sufficient transparency behind it to inform an evaluation of its strength, reliability and value." BCOAPO is also concerned that Mr. Kennedy has strayed into "numerous areas where he is not an expert, in some cases to override the input received from [BC] Hydro's own subject matter experts."[706]

RCIA submits that the Midgard experts did not claim standing as experts in depreciation studies, but rather in respect of utility rate regulation (Mr. Oakley) and in general asset management and risk management (Mr. Helland). RCIA notes that BC Hydro did not argue that Mr. Oakley and Mr. Helland were not experts in the fields in which they claimed standing. RCIA submits it is apparent that Mr. Oakley and Mr. Helland have "considerable background knowledge in utility asset management in general, transmission, distribution, and generation assets, having been responsible for planning, designing, constructing, maintaining, and operating such assets throughout their careers" and that weight should be given to their evidence on the factors that determine utility asset lives.[707]

In reply, BC Hydro submits that the evidence of Mr. Oakley and Mr. Helland on depreciation "is not informed by any expertise in depreciation and did not follow accepted practices," and should therefore be assigned little weight.[708]

RCIA is also concerned that the BCUC is being asked to trust that depreciation experts are "perfect, and consequently do not need to explain themselves." RCIA notes Mr. Kennedy's comments in the oral hearing:[709]

> "MR. KENNEDY: A: We did write up a more detailed explanation for some of the larger accounts. We did not on that one because it would have been very difficult to write up for all 300 accounts. So we -- that one didn't quite make the cut in terms of size for the write up.
>
> MR. MANHAS: Q: And you'll agree with me that if someone were looking to independently understand how your judgment was applied, they would likely face challenges in doing so, correct?
>
> MR. KENNEDY: A: Well, this is where there's an expectation, I guess maybe of myself, of other independent experts understanding the process that once you're taking completing studies. And this is a challenge when we have people that have never completed studies, and don't understand, have never

[705] BC Hydro Reply Argument, pp. 90–91.
[706] BCOAPO Final Argument, pp. 63–64.
[707] RCIA Final Argument, p. 18.
[708] BC Hydro Reply Argument, p. 92.
[709] RCIA Final Argument, pp. 29–30.

> gone through that process. So, sir, I don't know that we necessarily have to explain that in detail what you would do to properly do a depreciation study. That's why we have depreciation professionals, is that's a common, standard practice within depreciation professionals to go through that series of judgement.
>
> MR. MANHAS: Q: Okay, but if the BCUC were wanting to review and understand, given their oversight of BC Hydro's depreciation accounts how you come to your conclusions, there's nothing in your report that would allow them to do that, correct?
>
> MR. KENNEDY: A: In the report itself, no. There is the opportunity through IRs and through the discussion we're having at this very moment. [emphasis added]"

RCIA submits that Mr. Kennedy's stance is that only if supplementary exploration is pursued by interveners is information made available to independently understand his judgements and actual process, and that at best, this approach poses a significant regulatory barrier to meaningful intervener participation, and at worst is an unnecessary erosion of regulatory oversight based on a "trust me" argument.

Panel determinations

The Panel gives weight to Mr. Kennedy's evidence on depreciation studies. The Panel recognizes the value of his 40 years' experience, 300 depreciation studies and his provision of oral testimony on 145 occasions. The Panel gives little weight to Mr. Kennedy's certified depreciation professional designation, which is not a requirement to complete a depreciation study.

That said, the Panel shares the concerns expressed by AMPC, BCOAPO and RCIA regarding the lack of sufficient explanations for Mr. Kennedy's recommendations. Some of Mr. Kennedy's proposed changes to average service lives come with no explanation at all, such as the change from 20 to 25 years for recreational facilities, the first change proposed on the list in Appendix T Table 1. The ones that are explained each contain between a third and half a page of text, most of which pertains to the relevant historical asset retirement data, to which Mr. Kennedy himself assigns low weight.

The Panel is also concerned with Mr. Kennedy's view, expressed in his oral testimony, that "I don't know that we necessarily have to explain that in detail what you would do to properly do a depreciation study." In the Panel's view, that is precisely what an expert is expected to do. From the perspective of regulatory efficiency, it is preferable that expert reports provide sufficient explanations for their opinions without the BCUC and interveners having to resort to information requests to supplement that evidence.

The Panel is mindful of the caution of Justice Moldaver to be vigilant to guard against the "impermissible evidence" of "expert generalists." While Mr. Kennedy has prepared and defended many depreciation studies, he is not an expert in any of the fields that contribute direct technical knowledge or substance to them.

To the extent that Mr. Kennedy's views differ from those of more qualified experts on matters such as engineering, including the evidence provided by BC Hydro's own subject matter experts, it is critical that he can justify these differences.

The Panel gives weight to Mr. Bowman's evidence on the use of depreciation studies by rate-regulated utilities. The Panel recognizes Mr. Bowman's work in public utility regulation since 1988 and his testimony in 40 proceedings before regulators in six jurisdictions in Canada.

The Panel recognizes that Mr. Bowman has never created a depreciation study himself, and that his experience is not as extensive as that of Mr. Kennedy. Further, like Mr. Kennedy, Mr. Bowman is not an expert in any of the fields that contribute technical substance to them. However, the Panel is satisfied that Mr. Bowman has

sufficient experience and expertise to provide evidence that challenges the results of the Depreciation Study. Mr. Bowman provided clear explanations of his opinions, and he responded comprehensively to questions posed during the oral hearing.

The Panel gives weight to the evidence of Mr. Oakley in respect of utility rate regulation. The Panel notes Mr. Oakley's degree in electrical engineering and 36 years' experience working with energy utilities, and his contributions to more than 20 proceedings before the Ontario Energy Board, among others.

The Panel recognizes that Mr. Oakley has never created a depreciation study himself. However, unlike Mr. Kennedy, Mr. Oakley has qualifications and experience in the engineering and other factors that are inputs into a depreciation study.

The Panel gives weight to the evidence of Mr. Helland in respect of general asset management. The Panel notes Mr. Helland's degree in systems engineering, master's degree in applied science and certificate in asset management, and his asset management and risk management work for over 15 Canadian distribution and transmission utilities.

The Panel shares BC Hydro's concern regarding the independence of Midgard's experts, given that Midgard also acts as an advocate for residential consumers as an agent of RCIA. The Panel does not consider this sufficient reason to disqualify Midgard's experts from testifying, but the Panel will be cautious in weighing their opinions.

4.6.1.2 Basis of Concentric's Average Service Life Recommendations

Concentric states the recommended average service life estimates for each asset class are based on the following four drivers:

1. An analysis of BC Hydro's retirement data (data driven)[710]
2. Discussions with BC Hydro management and operations representatives[711]
3. Peer comparison analysis, including Ontario Power Generation, Manitoba Hydro, Newfoundland and Labrador Hydro Corporation and FortisBC Inc. (FBC)[712]
4. Concentric's professional judgement[713]

RCIA provides the following table summarizing the frequency of the drivers used to derive the recommended changes to the average service life estimates as part of the current Depreciation Study which was confirmed by Concentric to be accurate:[714]

Table 41: Average Service Life Recommendation Drivers

	BC Hydro Data Driven	BC Hydro Management Driven	BC Hydro Data & Management Driven	BC Hydro Operational Interviews	Peer Data Driven (Non-BC Hydro)	Concentric Driven
Low	98	98	98	42	39	3
Medium	0	0	0	15	37	86
High	0	0	0	41	22	9

[710] Exhibit B-2-1, Appendix T, pp. 9 – 11.
[711] Exhibit B-2-1, Appendix T, p. 11.
[712] Exhibit B-2-1, Appendix T, pp. 11 – 12.
[713] Exhibit B-2-1, Appendix T, p. 12.
[714] Exhibit B-20, RCIA IR 145.1.

ISSUE TOPIC #1:

ISSUE: HYDRO'S DEPRECIATION PROPOSALS

Are Hydro's depreciation proposals reasonable for implementation, as a final decision on the outstanding depreciation matters?

MIPUG SUMMARY AND/OR RECOMMENDATION:

The Issues Document cooperatively prepared on depreciation sets out four alternatives for depreciation methods. MIPUG supports Alternative 2, for the reasons set out by Mr. Bowman in his position outline in that document (page 29-32).

This alternative is premised on a final resolution of all methodological issues for depreciation today, followed by an implementation period culminating at the next GRA (solely related to developing new asset components).

If the Board is not prepared to make a final decision today, MIPUG supports Alternative 4, with Hydro being directed to complete componentization permitting adoption of ASL for financial reporting purposes as soon as practical. This has the features of permitting convergence with Alternative 2 within a short period.

DISCUSSION AND SUPPORT:

Manitoba Hydro has been working to address depreciation methodology issues for over a decade. The first significant consideration of depreciation methodology was in the 2012 GRA, and has led to lengthy and contentious debates between the parties before the PUB.

Evolution of this issue has been significant, to the point that all parties were able to cooperate on the production of a joint issues document (PUB Ex. 20). Although this issues document covered multiple overlapping issues raised by the PUB, Mr. Bowman contextualized that it was Issue #2 (the use of the ELG or ASL procedure) that centered the remainder of the issues. On this matter, Mr. Madsen and Mr. Bowman expressed a strong preference for ASL, and Manitoba Hydro noted that ASL was a "viable alternative"[1] and met Hydro's top priority, which was resolution of the policy and methodology debates regarding depreciation coming out of this proceeding.

[1] Hydro Argument, page 158.

It is not practical to fully expound on the full range of considerations made by Mr. Bowman and Mr. Madsen in determining that ASL was the preferred approach. However, a few notable facts should be highlighted:

- ASL is used by the vast majority of utilities in the US, and Canadian Crown utilities. Among the Canadian Crown utilities, only NB Power uses ELG.[2]
- ASL is universally agreed to lead to lower depreciation expense, to the point that Hydro acknowledges adoption of IFRS-compliant ASL can be done without a likely need to a phase-in, while ELG will require a phase-in due to the adverse financial impacts.[3] The depreciation issues document estimates this at $267 million over 20 years, but this is a coarse based on the Alliance estimates which are noted by all parties to be excessively granular.[4] Mr. Bowman noted that the range could be from $267 million to $1.3 billion, and indicated that the estimate of $700 million was probably "not a bad number" based on the impact of using Mr. Kennedy's estimated lives applied to the current level of componentization.[5]
- The only significant rationale supporting ELG is the assertion by Hydro that it needs to do more componentization to implement ASL. However, Hydro's primary apparent concern about componentization is that it takes additional administrative and tracking effort.[6] Outside of a dispute as to whether this added componentization is in fact required (see the evidence of Mr. Madsen)[7], both Mr. Madsen[8] and Mr. Bowman[9] noted that added componentization is in fact a benefit, where merited, since it improves utility cost tracking and life analysis. Further, Hydro notes that some of the new components would be implemented even if remaining under ELG.[10]

Based on the above, MIPUG submits there is ample evidence that Alternative #2 (ASL) is justified. This will permit full resolution of the depreciation methodology issues today, with a time-limited implementation period to achieve the benefits of some added componentization.

As to the remaining issues of deferrals, upon implementation of the ASL procedure at the next GRA a number of deferral accounts would begin to be amortized. Mr. Bowman made

[2] Transcript page 3141.
[3] Hydro Argument, page 158.
[4] Transcript page 3018-3019.
[5] Transcript page 3208-3209.
[6] Transcript page 3050-3070.
[7] For example, transcript page 3068.
[8] Transcript page 3070.
[9] Transcript page 3108-3110.
[10] Transcript page 3116.

it clear that for the purposes of rate setting, regulatory depreciation deferrals are simply a different presentation of the annual depreciation expense, and deferral balances are simply a different presentation of the accumulated amortization balance. Deferring these balances over the remaining life of the assets is entirely consistent with their nature as simple variances in the amount of accumulated depreciation recorded. This includes deferrals for the change in methodology, and for the purported gains and losses.

In contrast to the ASL procedure, which Mr. Bowman and Mr. Madsen support, and Hydro notes is a viable alternative, Hydro's preferred approach (ELG) is not supported by any other party in the proceeding. Mr. Madsen notes that the rate impacts of adopting the ELG approach "are significant and not warranted in this case".[11] Mr. Bowman echoes the concerns over unjustified rate pressures from ELG, and further notes that ELG, in the case of Hydro, fails to live up to its purported benefits of accuracy[12] and it ultimately does not match the consumption of service value of a group of asset, which is the basis for determining that rates in a given year are just and reasonable.[13]

Finally, on the matter of accumulated depreciation variance, all parties who testified to the issue of Hydro's current surpluses noted for the Board that these should, at present, be amortized over the remaining life of the assets. This includes Ms. Hooper[14], Mr. Bowman[15], Mr. Madsen[16] and Mr. Watson[17]. However, in the face of material depreciation variances (i.e., a measure that some degree of excess depreciation was recorded in the past compared to current estimates), the adoption of a more aggressive form of depreciation driving increased revenue requirements appears unmerited.

As a result of the above considerations, the Board is strongly encouraged to resolve the issues with depreciation today, in the form of Alternative 2.

However, in the event the Board is still unsatisfied that there is a sufficient record to complete its assessment of ASL versus ELG, the Board is encouraged to adopt Alternative 4 (status quo) while Hydro implements all needed added componentization providing for immediate transition to the ASL procedure for the first test year of the next GRA.

[11] PUB-20, page 32.
[12] MIPUG Ex. 6, page 25.
[13] See MIPUG Ex. 6 page 29-30 and MIPUG Ex. 15, page 5.
[14] Transcript page 3194.
[15] Transcript page 3196.
[16] Transcript page 3195.
[17] Transcript page 3201 [erroneously attributed to Mr. Madsen].

ISSUE TOPIC #2:

ISSUE: AMORTIZATION SCHEDULES FOR CERTAIN REGULATORY DEFERRED COSTS (E.G., CONAWAPA)

Should the amortization schedules for certain regulatory deferred costs (e.g., Conawapa) be adjusted to one year? Should amortization be established on an expedited basis of one-year for deferred costs related to Selkirk GS and terminal retirements?

MIPUG SUMMARY AND/OR RECOMMENDATION:

In general, deferral accounts that are only about rate smoothing, and do not represent any ongoing cost matching or enduring value of investments, should be avoided where possible.

Given the recent financial performance and the evidence that the 3.6% interim rate increase to finance drought in 2021 was not ultimately needed for this purpose in 2022/23 or 2023/24, this may provide an opportunity to revise amortization periods to help clean up the regulatory deferrals, most notably Conawapa planning costs. These costs do not represent enduring value to ratepayers, as Conawapa is not in Hydro's resource planning scenarios.

With respect to Selkirk loss on disposal and reclamation costs, these remain in regulatory deferrals with no established amortization period. Selkirk is no longer producing power, and rapid amortization of these costs (e.g., one-year) will help ensure future ratepayers are not burdened with costs to discharge regulatory deferrals tied to a plant that, by then, will not have produced power or yielded benefits for many years.

DISCUSSION AND SUPPORT:

In the evidence of Mr. Bowman[1], provided recommendations that certain regulatory deferral balances be "written off" in 2022/23. This proposal was clarified in MIPUG Exhibit 9 to constitute a revised amortization period for the regulatory deferrals of one-year. This revised amortization period was a change from the current period for Conawapa planning costs (30 years) and for Selkirk GS loss on retirement and removal costs (currently not being amortized).

[1] MIPUG Ex. 6

Key to the recommendation was the fact that rates for the year in question (2022/23) remain interim and refundable. As noted in Exhibit MIPUG-10, the rationale for the adjustment ties to interim rates:

> The primary driver is the fact that 2022/23 rates remain interim, and the facts have materially changed since the rates were first set on an interim basis. The use of interim rates may readily lead to adjustments to the level of interim rates charged (e.g., retroactive refunds to customers) or other regulatory conditions affecting the year. Manitoba Hydro, and the readers of Manitoba Hydro's financial statements, are aware (or ought to be aware) that any financial situation reported is subject to revision and adjustment by the Board, as was made clear in Order 137/21, as follows (page 12):
>
>> Any interim rates approved must be the subject of a further public hearing process before the Board to alter or finalize such interim rates. The process to finalize the interim rates approved in this hearing process will follow in a separate proceeding before the Board in 2022.
>>
>> …
>>
>> This increase recognizes the financial consequences of the drought and the Board's objective to avoid rate shock by smoothing the rate increases required to address the costs of major capital projects entering service.
>
> Consequently, MIPUG submits that the primary driver of the MIPUG proposal is not simply that Hydro has high net income in 2022/23 – it is that interim rates as enacted are poorly matched to the year in question due to multiple material changes in circumstances from the time the rates were set. MIPUG would not be making the submission absent interim rates for 2022/23.

More specifically, MIPUG noted that[2]:

> 1) Hydro's rates were made interim as of January 1, 2022 (Order 137/21)
>
> 2) The conditions underlying the interim order changed materially.

[2] Exhibit MIPUG-10, page 3.

> 3) One of the changes (a reduction in government charges) was linked to previous Board recommendations to Government about how to deal with Conawapa costs.
>
> 4) The other material change (a revision from drought conditions to high water conditions) was integral to the decision to set interim rates at a 3.6% increase.

It is key that the Board address the change as a recovery of the costs (not a failure to recover the costs) tied to the interim 3.6% rate increase.

Hydro rejects the proposal in its Argument on the basis that any revision will be a non-cash impact, and going forward it is effectively only cash that will result in changes to rates to meet the Bill 36 debt targets.[3] This is an incomplete rationale, as there is a clear and important aspect to regulating Hydro today, and presumably into the future, tied to net income, not only cash generation. Indeed, Hydro acknowledges as much in their Argument where they note a concern that taking losses on disposal to net income as a routine matter could undermine rate stability: "As discussed in Section 15.7 above, terminal losses can cause deterioration in net income if significant, and the continued deferral of costs related to discontinued operations likely still has merit from a rate smoothing perspective."[4] It would appear that amortizing the full amount of today's loss on disposal and site clean-up balance for Selkirk, which is not being amortized to income at all (and hence is not smoothing rates in any notable way), would enhance the potential for future rate stability from having no further balance to address, rather than having an ongoing amortization expense.

The Board should read these comments in conjunction with the submissions contained in MIPUG Exhibits 9 and 10, which remain valid.

MIPUG acknowledges the Board's decision in Order 57/23 in regards to Conawapa that: "An account with an approved amortization period is an asset to a regulated utility in the same manner as an account receivable. It forms part of a utility's revenue requirement and should not be interfered with lightly."[5] MIPUG did not approach the recommendation lightly. The Board faces a significant challenge with a 3.6% interim rate increase that was implemented for a period that is now known to have record and continuing high net income, where the rate increase was not ultimately required for the test year in question. Further, the one-year amortization of the Conawapa deferral account does not undermine Hydro's right to recovery – it enhances it, since the cash is already in hand. Rather than

[3] Hydro Argument, page 172.
[4] Hydro Argument, page 173.
[5] Order 57/23, page 10.

leaving Conawapa as a future recovery, it can be recorded as an amount already recovered. This does not undermine or increase risk – it increases certainty for Hydro.

Based on the above considerations, MIPUG submits that the Board should direct a one-year amortization of amounts related to the Conawapa deferral account, and the Selkirk loss on disposal and cost of removal balances, in the earliest available fiscal year. This decision should be explicitly linked to finalizing the 3.6% interim rate from 2021.

ISSUE TOPIC #3:

ISSUE: IS PCOSS24 RELIABLE AND APPROPRIATE FOR USE TO SET RATES, INCLUDING THE USE OF FORECAST NET EXPORT REVENUE?

> Does PCOSS24 reflect a reasonable estimate of the costs to provide service to each class in the test years?

MIPUG SUMMARY AND/OR RECOMMENDATION:

> PCOSS24 reflects a reasonable estimation of the costs to provide service and is reliable for use to set differential rate increases. While PCOSS24 reflects some small unique characteristics of the year in question, in each of the last two Hydro rate hearings that had a PCOSS (2017 and 2021), the Board has relied on the then-current PCOSS best available estimate of costs from the fully detailed PCOSS, and PCOSS24 is no different (if anything it is more reliable than past examples, like PCOSS21).

> While starting reservoir levels in PCOSS24 are above average, water inflows are set at an average level, and the effect of running a new PCOSS "normalizing" for this effect does not directionally change the conclusions from PCOSS24. This therefore supports the directionality and reasonableness of PCOSS24 for setting rates, rather than undermining the conclusions.

DISCUSSION AND SUPPORT:

PCOSS24 was prepared to reflect the costs of providing electrical service in the Test Year 2023/24.[1] Compared to PCOSS21, PCOSS24 now includes the entire cost profile of the major new generation and transmission (including Keeyask and MMTP). In PCOSS21, the test year started with no Keeyask units in service and ended with only five of seven units in service[2]. This means that a significant part of the cost of Keeyask was included in PCOSS21, but very little new revenue from the project was included.

Because Keeyask is now in service, and the full suite of assets that generate the substantial export revenues (Net Export Revenues, or NER) are included in Hydro's costs, there is a significant revenue offset that is needed to pay for the basic economic rationale for constructing or advancing Keeyask and other assets in the first place. This NER is therefore appropriately credited against the cost of the assets that generate the NER (generation and transmission). The Board has confirmed this approach is appropriate in

[1] Hydro Application. Tab 8, page 6-7.
[2] Hydro Application. Tab 8, page 7.

Order 164/16[3] and accepted the methodology in 59/18.[4] Hydro has correctly applied this methodology in PCOSS24.

Similarly, Hydro has correctly included in PCOSS24 the expected export revenues from the test year in question.

On the matter of hydro generation volumes, Hydro has clarified in Argument that PCOSS24 uses average inflows for 2023/24 to determine the quantity of exports available for sale in PCOSS24[5]. Hydro also notes that PCOSS24 uses above average starting reservoir levels, consistent with the financial forecast for the test year. This is appropriate.

It is important to recognize the net effect of higher starting reservoir levels is a matched increase in NER and an offsetting equal increase in Net Income (called "Contributions to Reserves" in the PCOSS, as a cost item[6]).

While NER and Contribution to Reserves do see an upward effect from higher-than-average starting reservoirs, the added NER is allocated to generation and transmission, while the added Net Income is allocated to all assets based on average Rate Base, which still primarily consists of generation and transmission (over $22 billion out of $27 billion of Rate Base is generation and transmission)[7]. For this reason, the impact of any alleged high or unstable NER makes relatively little difference in the outcomes of the PCOSS.

For example, as a cross-check, Hydro provided responses to PUB/MH-I-141(a) and Coalition/MH-I-155(a) that adjust the NER to the level expected for 2024/25 (a reduction of approximately $180 million[8] to NER and to Net Income). Despite this material decrease, the impact on the outcomes of the study about ZOR (the measure of which classes are in a zone that is deemed to be potentially reasonable, and those that are outside the zone and are therefore unreasonable), does not change at all[9]. For example, the residential RCC changes only from 94.4% to 94.8%, both of which are in the range that is considered unreasonable. This is positive confirmation that the Board can rely on the output of PCOSS24 for the purposes of setting rates.

Mr. Bowman separately highlighted three methodological issues with PCOSS24 that should be viewed as being of growing importance in coming years. These are addressed further in Issue Topic #5. Outside of this, Mr. Bowman noted that PCOSS24 is "appropriate

[3] Order 164/16, page 93.
[4] Order 59/18, page 186.
[5] Hydro Argument, page 220
[6] Hydro Application, Appendix 4.1, page 24
[7] Hydro Application, Appendix 8.1 (PCOSS24), page 26.
[8] Coalition/MH-I-155(a), reduced from $1,116.2 million to $932.5 million.
[9] MIPUG Ex. 6, Table 4-2, page 48.

for use".[10] Whether the methodological updates proposed by Mr. Bowman are adopted or not, they are items of merit into the future. The changes will tend to improve the reflection of the costs of peak demand, which will lead to more costs being appropriately allocated to lower load factor classes (e.g., residential) and less to high load factor customers (e.g., industrial) as the high load factor customers impose less relative peak demand on the system. For this reason, the methodological updates before the Board would tend to support the contention that PCOSS24, if anything, is insufficiently allocating costs to smaller customers.

Outside of Ms. Derksen and Mr. Bowman, no other intervening party took issue with the specific accuracy or methods used in PCOSS24.

Based on the above, PCOSS24 is broadly accurate and reasonable for the test years, absent small revisions to methodology addressed in Issue Topic #5.

[10] Transcript page 3991.

ISSUE TOPIC #4:

ISSUE: IS PCOSS24 SKEWED BY ITS APPROACH TO REFLECTING THE REDUCTION IN GOVERNMENT CHARGES?

Is PCOSS24 skewed by its approach to reflecting the reduction in government charges?

MIPUG SUMMARY AND/OR RECOMMENDATION:

PCOSS24 appropriately reflects the reduction in government charges for debt guarantee fees and water rentals as they affect the test year.

DISCUSSION AND SUPPORT:

PCOSS24 was prepared to reflect the costs of providing electrical service in the Test Year 2023/24.[1]

On the matter of government charges, the Board may take notice of the advocacy provided by Ms. Derksen of the Coalition in her opinion that PCOSS24 has been modelled to give a disproportionate benefit of the reduced provincial Water Rental fees and Debt Guarantee fees to large customers, and that small customers will actually face a rate increase as a result of the fee reductions[2]. Ms. Derksen described it as “the Residentials lose”.[3]

Put simply, Ms. Derksen is wrong. Hydro provided clear evidence in response to a Coalition information request that the reduction in fees from government will result in an average 5.5% <u>reduction</u> in revenue requirement per year, and that the effects of the debt guarantee fee portion of the reduction will be shared precisely equally among the classes in the PCOSS in relation to their use of all assets.[4]

As to the water rental fee reduction, this change will lead to a non-linear benefit among the classes, as water rental fees in the first place are not allocated on a linear basis but rather only to generation. By applying the reduction in water rental fees to the same classes that pay the fees in the first place, the average net benefit of 5.5% now varies from 2.8% for the lighting class, to 5.1% for the residential class, and 7.5% for the GS Large >100kV class. In short, Ms. Derksen’s definition of “lose” appears to not accord with a 5.1% revenue requirement benefit to her target residential class.

[1] Hydro Application. Tab 8, page 6-7.
[2] Transcript page 3782, line 12-21.
[3] Transcript page 3922, line 3.
[4] Coalition/MH-I-138(f) and (h).

PCOSS24 appropriately models the reduction in government charges and the Board should rely upon this modelling for the purposes of assessing the overall fairness of rates via RCCs.

ISSUE TOPIC #5:

ISSUE: PCOSS24 METHODS

Are updated PCOSS24 methods required?

MIPUG SUMMARY AND/OR RECOMMENDATION:

PCOSS24 uses a sound and reasonable methodology that is consistent with previous Board direction, and mostly reflects the cost drivers on Hydro's system. However, over time, small tweaks to the methodology for cost of service should be considered to reflect changing conditions facing the utility.

At this time, the key focus of change is the growing importance of demand in structuring the utility costs and investment, and the waning influence of energy. Relatedly, peak demand drivers of the wires investment, particularly distribution, are becoming more important cost drivers as lower load factor loads grow.

PCOSS methods that merit attention due to this factor are:

- Allocation of a portion of DSM costs to distribution, to reflect the benefits derived from DSM on the distribution system.
- Classification of a portion of wind generation to demand, consistent with the benefits the wind brings to the system.
- Updating the coincident peak demand allocator to focus on the most acute peaks, rather than an average of 50 top hours each year (which itself is averaged over 8 years). Use of far fewer peak hours would more precisely reflect the customer class contribution to this peak-related cost driver.

The Board should direct Hydro to update the PCOSS methodologies for the above factors, including in the compliance filing PCOSS24 where possible, or in updated studies for future PCOSS studies where the approach cannot be implemented today.

In particular, the Board should direct implementation of the DSM adjustment and wind adjustment in PCOSS24 as part of the compliance filing process for this GRA, and direct Hydro to bring forward load research regarding reducing the number of peak hours used for load analysis as part of the next GRA.

DISCUSSION AND SUPPORT:

In his pre-filed testimony, Mr. Bowman separately highlighted three methodological issues with PCOSS24 that should be viewed as being of growing importance in coming years.[1] The updated methodologies reflect that demand is becoming the driver of many of Hydro's future costs, as meeting winter peak loads is becoming more challenging while meeting energy loads is becoming increasingly low cost. This is a significant change from past periods.

Factors driving this change including the following:

- Hydro has lost access to diversity agreements with northern US utilities, with which it previously traded winter capacity for summer capacity. This has caused an advancement in the dates at which Hydro must invest in new capacity resources.[2]
- The availability of new capacity sources is questionable, as the primary default capacity resources (combustion turbines) are carbon emitting and are increasingly under regulatory pressure (including federal) to avoid, or potentially prohibit, new investment in carbon emitting technologies.
- Added electrification of the energy system will lead to increases in the amount of energy used for charging electric cars and for heating, such as air-source heat pumps. These loads are low load factor over the course of a day or year and will drive material increases in Hydro's peak loads. Increased electric space heating in particular is expected to be a needed component of decarbonization, but is not yet factored into Hydro's load forecast.

The precise timing for the various methodological updates may vary. Movement towards better reflecting peak (less than top 50 hours) can be achieved in the next PCOSS update, as addressed by Hydro in its Argument[3].

Similarly, wind generation was highlighted in Hydro's argument as meriting a revised approach in future. However, Hydro noted wind is best modelled as a component of system resources, and as such the costs of wind could be simply included in the cost pool allocated by way of the system load factor[4]. This is an acceptable alternative that could and should be implemented today, in PCOSS24 as revised in a compliance filing.

[1] MIPUG Ex. 6, sections 4.4 to 4.6
[2] Application, Tab 5 (amended), page 38.
[3] Hydro Argument, page 215-216.
[4] Hydro Argument, page 208-209.

Finally, on the allocation of DSM, there appears to be no dispute that conservation activities yield benefits in terms of reduced load on the distribution system. No party took issue with Mr. Bowman's finding in this regard. However, Hydro does not support allocating DSM costs to distribution. This runs contrary to the Board's previous findings of principle that all benefits should be recognized in making a determination on allocation, Notably, Order 164/16 states as a discussion of principles[5]:

> … cost causation could consider a utility's most recent planning studies or the planning done to justify assets when originally placed in service. Additionally, cost causation could consider solely the primary benefit of a given asset, or all the benefits, even if all the benefits were not necessary to justify purchasing, retaining, or building the asset.

After this discussion, the Board makes the following finding[6]:

> The Board also finds that cost causation requires consideration of <u>all</u> the uses and benefits of an asset, to recognize that both primary and secondary benefits influence the planning and justification of assets. (emphasis added)

The situation with respect to DSM spending and an allocation to distribution precisely reflects the Board's principle-based finding above. This allocation could be made today, as part of the PCOSS24 compliance filing.

These changes all relate to items of increasing merit into the future, and will tend to improve the reflection of the costs of peak demand. The effect will be to have more costs being appropriately allocated to lower load factor classes (e.g., residential) and less to high load factor customers (e.g., industrial) as the high load factor customers impose less relative peak demand on the system, and do not use the distribution system. This will improve the accuracy of RCC measures in the PCOSS study.

[5] Order 164/16 page 25.
[6] Order 164/16 page 27.

ISSUE TOPIC #6:

ISSUE: USE OF REVENUE:COST COVERAGE ("RCC") RATIOS TO SET RATES

Does PCOSS24 report RCC ratios that can be reliably used to set differential rate increases?

MIPUG SUMMARY AND/OR RECOMMENDATION:

PCOSS24 reports RCC ratios that are appropriate to use for setting rates. Alternative RCCs provided by the Coalition are premised on errors in interpretation of the data, and in use of methodologies that have been rejected by the Board.

DISCUSSION AND SUPPORT:

PCOSS24 was prepared to reflect the costs of providing electrical service in the Test Year 2023/24.[1]

The primary output of PCOSS24 is a ratio between the revenues and costs for each class (the Revenue:Cost Coverage ratio, or "RCC"). This metric is reported as a test as to whether the current rates are fair. There are two different methods that have been used to calculate the ratio over the past decades. The current approach reports the costs to serve each class (net of export revenues) as compared to the revenues paid, and this approach is both sound and consistent with Board direction[2].

Ms. Derksen indicated a concern that the RCC ratios may skew the measure of costs and rates because they are net of export revenues. Her evidence calculates an RCC ratio before net export revenues, which is problematic because it assumes the domestic classes have to pay for the full cost of the generation fleet even though they are only using a portion of the fleet, and even though the fleet in question was approved for construction on the basis that there would be export revenues as an offset. Ms. Derksen also commits a methodological error by comparing these RCC ratios in way that is "normalizing" the ratios.[3] In doing this comparison, Hydro correctly notes that Ms. Derksen's contrived RCC ratio is effectively simply allocating export revenues to all functions, including distribution, which is contrary to the logic of export revenues and contrary to the Board's previous

[1] Hydro Application. Tab 8, page 6-7.
[2] Previous approaches considered the ratio of total costs to the sum of domestic revenues plus export revenues. The issues with this approach are outlined in Mr. Bowman's evidence, Exhibit MIPUG-6, at Section 4.2.
[3] Coalition Ex. 27, page 18.

Orders, particularly 164/16. For this reason, Ms. Derksen's reporting of RCCs before Net Export Revenues should be rejected.

The appropriate measurements of RCC ratios are included in the PCOSS24, noting that residential customers pay 94.4% of the costs to serve them, while the largest industrials pay 113.2%. Other classes are within this range (between 94.4% and 113.2%), some closer to 100% than others. This range is excessive and indicates inherent unfairness in rates, beyond the degree to which such variances can be seen as reasonable.

Mr. Bowman further commented on the degree to which Ms. Derksen's assertions of uncertainty in the reported RCC ratios are unfounded [Tr. pages 4002-4003].

> Cost of service is imperfect. You've heard that. This argument supports the idea there is a zone of reasonableness and that outside of that zone, rates are not reasonable - what the reasonableness part of that quote would mean.
>
> Within the zone the Board can consider balancing competing priorities, such as stability. For example, just because someone is at 101, we don't move them down to 100 so that next time they're at 99 and we've got to move them up again. Stability is one (1) of the considerations you would balance against the range of possible reasonable rate outcomes within the zone of reasonableness.
>
> I also note that does -- the question of: Does imperfection in a Cost of Service study mean you need a bigger range of reasonableness, and the answer to that would be, No.
>
> Imperfection in the Cost of Service study means you should try all the more to get to 100, because you have uncertainty about the extent to which that centre actually reflects the measured costs. You know, if I'm going to the shooting range with a rifle that's -- I don't, it doesn't shoot straight, I'm going to have to all the more aim for the middle of the target to know that I'm going to hit the target somewhere.
>
> If I had a sniper rifle with all the laser site, I probably don't have to aim as precisely, because I can hit the target where I'm aiming. But if you're -- with that imperfection would suggest all the more focus on trying to get to unity. And the zone of reasonableness is not a free pass to sit at 95 percent forever.

In short, the measured RCC ratios are reliable, but the ZOR, to the extent there is an allegation of uncertainty or instability, should be interpreted to require even more of a focus on heading for unity, or 100%.

If an alternative RCC calculation is merited, it is the approach set out by Mr. Bowman in his direct testimony (MIPUG Ex.21), at slide 24. In this exhibit, Mr. Bowman demonstrated that a large part of the RCC measured for residentials is based on the assumption that this class can avoid paying for a significant portion of distribution costs, as well as avoiding paying for generation and transmission. There is no submission before the Board that indicates each class should not pay their own distribution costs – these costs are not discretionary, or subject to any allegation of "instability", nor are there policy-related decisions regarding export allocation affecting the measure of costs. If the RCC is calculated such that residential rate revenues are first allocated to pay 100% of the costs of distribution, the remaining residential revenue only covers 90.1% of the generation and transmission costs. This ratio is well outside any range of reasonableness adopted by the Board since it first applied 95-105% in the 1990s.

The PCOSS24 reported RCC ratios are reliable for use in setting rates, and if anything may understate the degree of issue related to the persistent residential undercollection of the costs to serve that class.

ISSUE TOPIC #7:

ISSUE: ARE DIFFERENTIAL RATE ADJUSTMENTS APPROPRIATE AT THIS TIME?

Is it appropriate for the Board to set differential rates at this time? Are the differential rates proposed by Hydro sufficient to address longstanding Revenue:Cost Coverage issues?

MIPUG SUMMARY AND/OR RECOMMENDATION:

The Board has established the Zone of Reasonableness (ZOR), noting that rates outside of the 95%-105% range are not reasonable. Expedited actions are required to address these unreasonable rates.

The Board directed in Decision 59/18 that class rates should be within the range of reasonableness within 10 years (by 2027/28). Hydro's proposals do not achieve this outcome. Further, this targeted outcome only achieves the outer range of the 95%-105% band, not progress towards 100%, nor any consideration of the appropriate balancing of priorities that may lead to a class varying about 100% (above and below) over time.

The Board should implement immediate differential rate adjustments to make progress towards the outer band by 2027/28 or sooner based on PCOSS24. However, this is insufficient to achieve fair rates. The appropriate measure should be all classes varying at about 100% (sometimes above and sometimes below) while other rate design criteria are balanced with RCCs.

To the extent the Board takes a reading of Bill 36 into account, it is MIPUG's position that Section 39.1(1) of the Manitoba Hydro Act requires for each rate period that the Board seeks to bring classes to about 100% RCC. This would further support expedited action today.

DISCUSSION AND SUPPORT:

Hydro has proposed that the Board implement differentiated rates by rate class, for the purposes of moving each rate class towards the Zone of Reasonableness ("ZOR"). However, Hydro's proposals are insufficient to achieve even the absolute outer band of the ZOR by 2027/28, the date the Board set to address this fairness problem.[1]

No party has directly challenged or appealed the Board's direction re: a 10-year transition, completed by 2027/28. Manitoba Hydro, however, in argument has underlined that its

[1] Decision 59/18, page 198.

reading of subsection 39.1(1) of the revised Manitoba Hydro Act will require that all classes be within the Zone of Reasonableness by the third fiscal year after the new legislation comes into effect (April 1, 2025).[2] This interpretation is more than a target or guideline – it is Hydro's interpretation that achieving the ZOR by 2028 is a necessity. It is not clear that the Act should be relied upon in this proceeding, as set out elsewhere in this submission, but if it were the basis for rate changes, there would not appear to be any clause in 39.1(1) that could be read to say this should only be achieved by the end of each three-year rate period. Indeed, the specific allocation mentioned in s.39.1(1)(a) is regarding the annual revenue requirement, which does not apply to a rate period but to each fiscal year. If the new Act is applied to govern rates, then it is MIPUG's interpretation of subsection that the ZOR should be reached by the first revenue requirement fiscal year under the new Act (2025/26).

MIPUG does not conclude that the new Act is intended to govern rate setting at this time, but to the extent the Board may want to help manage future rate instability, a more highly differentiated rate at this time may be merited for this factor.

Use of PCOSS24

The implementation of differentiated rates should be based on PCOSS24 (subject to other comments regarding methodology in this written submission), and on achieving reasonable rates (i.e., within the ZOR) within a short remaining time period. This reflects in part that the issue for many classes has been outstanding for decades[3], and resolution should not be further delayed.

The only party who appears to advocate that achievement of the ZOR should not be a goal is Ms. Derksen, on behalf of the Coalition. Ms. Derksen effectively rejects use of PCOSS24 to set differential rates, and further rejects the idea of a ZOR and its associated prioritization of fairness.

Ms. Derksen's criticism of using PCOSS24 and of differential rate changes are numerous and appear directly related to the desire to avoid having above average increases applied to the residential class. However, upon even a brief analysis, none of Ms. Derksen's advocacy bears out in fact.

1) **RCCs are Unstable:** Ms. Derksen asserts that the PCOSS results are "unstable" due to NER. This is not correct. Indeed, the PCOSS results over time have been remarkably, even stubbornly, stable over decades in their persistence above or

[2] Hydro Argument, section 19.8.
[3] MIPUG Ex.6, Figure 4-1, page 56.

below the ZOR range[4]. Ms. Derksen further claims that it is export revenues that drive the instability (what she terms "Dramatic RCC Volatility")[5]. However, Ms. Derksen's own evidence highlights that this is patently not the case for the largest class of customers (residentials) for which she advocates. In particular, Ms. Derksen runs a series of PCOSS scenarios including PCOSS21, PCOSS24, and an extreme version of PCOSS24 using export revenues of $700 million (equivalent to about $650 million in NER, which Mr. Gawne noted was the level of pure dependable revenue in the test years with no opportunity revenue[6] – i.e., this is an extreme scenario not representative of anything projected for the test years in question). Even under this dramatic range of scenarios, the residential RCCs remain within a tight band of 95%.[7] Other classes see slightly more variation, but even with the extreme export revenue assumptions no class sees their RCC move from outside the ZOR to within the band.

2) **Residentials pay more when mines close or other factors for which they are the "catch-basin"[8]:** Ms. Derksen indicates that from PCOSS21 to PCOSS24 the share of costs borne by the residential customers increased due to mines closing, implying a reallocation of generation and transmission costs to the residential class. This is not correct. In fact, the total costs to serve the residential customers in PCOSS21 for Generation and Transmission was $507.4 million[9], and in PCOSS24 it is $502.7 million.[10] In other words, despite adding billions of dollars in added Keeyask costs, and the purported deficit caused by the alleged closing of mines, plus 3 years of added inflation and cost growth, the residential class share of generation and transmission costs went <u>down</u> by approximately $5 million (or less than 1%). Ms. Derksen conveniently ignores that the largest issue for residential customers is in fact the growth in other costs for lower voltage services (e.g., distribution) which increased $80 million from PCOSS21 to PCOSS24, a net impact of 10% on overall costs (from $800.5 million to $881.2 million) and increased far more as a percentage of the distribution share of costs.[11] If residential customers faced rate increases ONLY for the growth in distribution

[4] MIPUG Ex.6, Figure 4-1, page 56.
[5] Coalition Ex. 27, page 13.
[6] Transcript page 3585.
[7] Coalition, Ex 27, page 15.
[8] Transcript page 3795.
[9] Per PCOSS21, the residential share of generation costs totalled $426.2 million and transmission at $81.2 million net of NER. Provided in Manitoba Hydro's 2021/22 Interim Rate Application, PUB MFR-20 Attachment 1, page 23 of 65.
[10] Per PCOSS24, generation costs totalled $431.7 million and transmission at $71 million, Appendix 4.1, page 20 of 63.
[11] Ibid.

costs over the past 3 years, there would be no RCC shortfall today. Note that this clear conclusion stands in stark contrast to Ms. Derksen's claim that distribution costs are perpetually "current" as they are continually being "churned" and that changes in costs are less "impactful".[12]

3) **RCC ratios before NER (normalized) show different classes within the ZOR than PCOSS24:** This matter is more fully addressed in Issue Topic #6. In short, Ms. Derksen has adopted a unique and obfuscated approach to calculating RCC ratios that is nothing more than a back door approach to allocating export revenues to distribution customers. The calculations are not meaningful, and the conclusions Ms. Derksen draws from the analysis should be rejected.

4) **Comparison of Rates to Marginal Costs:** Ms. Derksen makes a simplistic comparison of the rates paid by domestic customers in relation to the marginal costs she reports for serving those customers. Ms. Derksen's comments and approach to marginal costs are deeply flawed, in three ways.

- First, Ms. Derksen fails to properly reflect that the Board expressly rejected the use of marginal costs for the purposes of cost-of-service and of determining the fairness of rates across classes (the ZOR)[13]. Marginal costs can be useful in the rate design step (e.g., in determining whether Ms. Derksen's residential class should have inclining or declining block rates) but are of no relevance to assessing fairness across classes.
- Second, Ms. Derksen uses marginal cost estimates that are entirely incorrect for the purposes of the calculation she performs. This includes the failure to reflect the fact that generation marginal costs vary with the load factor (Ms. Derksen uses the same generation marginal costs for each class, even though their load factors are widely varying), the failure to reflect the impact of system losses (Ms. Derksen uses the same marginal costs for high voltage customers as low voltage customers, without taking into account the impact of losses) and the failure to account for multiple costs that are not included in the marginal cost assessment. Manitoba Hydro provided Ms. Derksen with a long list of reasons in IR responses that the marginal cost assessment was not valid[14] including that they do not include any operating costs or customer service costs, and do not include subtransmission. Oddly, Ms. Derksen relies on the data from this response

[12] Transcript page 3855-3856.
[13] Board Order 164-16, page 53.
[14] Coalition/MH-II-57(d)

but studiously avoids noting Hydro's express cautions on interpreting the results.

- Third, although Ms. Derksen appears to want to rely on the conclusion that differential rate adjustments are not required because GSL >100 kV customers are paying below their measured marginal costs (ignoring all the problems above associated with measuring those costs), she fails to highlight that the present ratio (97.5%) is in fact very high by historical standards. Indeed, as of the 2017 GRA, the ratio was 58.1%, and the Board still saw fit to award GSL >100 kV customers a lower than average rate increase.[15]

5) **Self-Correcting:** Finally, Ms. Derksen provides hypothetical, speculative and deeply flawed scenarios that she indicates represent the potential situation as of 2027/28, showing that RCC ratios may be somewhat self-correcting. This is not the first time that allegations have been made that RCC ratios will self-correct without intervention. For example, in the 2017 GRA, the Board noted in Decision 59-18 the position of the Coalition that "even with the current zone of reasonableness of 95% to 105%, the result of Bipole III entering service will be to move the Residential class well within the zone"[16] Hydro also argued in the 2019 RRA proceeding that Bipole III would cause: "the Revenue to Cost Coverage ratios of the General Service Large class are significantly decreased, with the 30-100kV and >100kV sub-classes moving into the zone of reasonableness without any further rate differentiation"[17]. Also note that Ms. Derksen's definition of "largely self correct"[18] appears to indicate no material improvement in the residential class RCC from the 95% level (and also leaves the GSL >100 kV class still above the upper range of the ZOR). In short, even using dubious mathematics to support the claim, the claim is not supported.

6) **Uniform Rates:** Ms. Derksen appears to recommend a policy related adjustment to RCCs from the adoption of uniform rates over 20 years ago. The broad considerations recommended by Ms. Derksen, as a justification for residential customers perpetually underpaying their costs to serve, have already been expressly rejected by the Board.[19] Further, Ms. Derksen conveniently fails to note that every other class also has uniform rates, and indeed industrials pay the same rates whether they are located in Thompson immediately next to the major

[15] Hydro 2017/18 GRA Application, Tab 8, Figure 8.14, page 31.
[16] Order 59/18, page 195.
[17] Order 69/19, page 32.
[18] Coalition Ex. 27 page 15.
[19] Order 164/16, page 41.

> generation, or in Brandon or Winnipeg. It would be patently unfair to have other classes pay for the incremental costs to deliver power to Brandon to serve industrials, rather than the industrial customer class that is being served. A Uniform Rates Adjustment for residentials is equally unreasonable and unfair.

Ms. Derksen also highlighted numerous other dubious rationales in support of her contention that her preferred residential customer class should receive a permanent subsidy from all of the other classes. While only six are addressed above the remainder are even more unprecedented and unfounded than the six highlighted, and do not merit specific comment.

Ms. Derksen is careful to portray her evidence not as a rejection of the Board's reliance on the ZOR or cost of service, but rather as a separate step, the rate design complement to the setting of the ZOR. Ms. Derksen submission is deeply flawed and distorts widely accepted regulatory principles. As described by Mr. Bowman:

> … as Hydro noted, the revenue requirement portion will define the size of the pie. The Cost of Service study will determine the size of the slices of the pie that each class needs to be responsible for.
>
> Rate design, on the other side, is considering how you take that size of the pie and collect it from customers. And in most places, rate design is an important and actively debated topic. And here, we have very little discussion on it.
>
> Somehow, here, when we talk rate design, it's like a back door to re-debate Cost of Service and whether people should really pay the slice of the pie that is allocated to them. [Transcript page 3985].

We note that no party, not even the Consumers' Coalition challenged Mr. Bowman with respect to his description of these widely accepted regulatory principles.

Ms. Derksen is welcome to investigate appropriate measures for rate design. If her concern is marginal cost signals, she may want to consider proposing residential inclining or declining block rates, or seasonal rates that reflect that costs are higher in winter than in summer. Ms. Derksen may also want to advocate for other rate design changes for the residential class, such as changing the fixed customer charge. None of these, however, are a rationale to have other classes pay for costs that are driven by and caused by the residential class. The residential RCC, once it achieves 100%, can be collected by many different rate designs, and these deserve proper debate and attention, rather than what is effectively a distraction from achieving intraclass fairness and efficiency by Ms. Derksen finding new ways to simply have other classes pick up the tab for more years.

ISSUE TOPIC #8:

ISSUE: INDUSTRIAL BILLING DEMAND DEFINITION

Should Hydro's proposed change to the GSL 30-100 kV and >100 kV billing demand definition be adopted for 2024/25, inclusive of the increase to the demand charge to make the change revenue-neutral?

MIPUG SUMMARY AND/OR RECOMMENDATION:

The update to the definition of industrial billing demand, to focus only on the on-peak period, should be approved, with two adjustments.

First, there should be no revenue enhancement to the demand rate included, given the class is paying well above the ZOR. The Board can achieve this outcome by revising downward the overall average increase for revenue requirement to permit there to be no rate increase for this factor.

Second, there should be no off-peak cap of 10% above on-peak before the off-peak period becomes the basis for demand charges. While no limit is required, Hydro has accepted that a less constraining cap is possible as a compromise (such as allowing the on-peak billing units to be as low as 75% of the off-peak peak), which is a reasonable compromise and should be adopted, for now, while the new rate is being put into place.

Further, expedited application of the new rate should be considered for GSL 0-30 kV customers who have metering that can support the required data collection.

DISCUSSION AND SUPPORT:

Manitoba Hydro has proposed a change to the Definition of Billing Demand for the GSL 30 – 100 kV and GSL 100 kV rate classes. This change reflects Hydro's general concern about the advancing need date for capacity resources in its generation and transmission system.

MIPUG expects the change to be of some value to customers and to the system, however ultimately quite limited.

No party opposed the proposal in evidence.

The rate proposal, as presented, introduces ”peak” and “non-peak” considerations to the billing demand calculation, giving greater consideration to the coincidence between GSL customer demand peaks and the overall system peak. This price signal could, over time, help manage the system peak demand requirements.

In principle, the proposal responds to some of the issues raised by industry over the past decade regarding alternative rate designs that reflect potential cost savings to both Manitoba Hydro and ratepayers, while providing customers to whom the specific alternative rates apply with the opportunity to manage their energy costs. Appropriate price signals that allow for a modified consumption behavior response, can be beneficial to the utility and its ratepayers if they support lower overall costs for the utility, the general rate base, and individual customers in the long-term.

In implementing the rate, Hydro has proposed a rate increase to the demand rate charged to each class, to effectively make up what is anticipated to otherwise be approximately $0.9 million in lost revenue. This lost revenue reflects the fact that some customers already have a lower on-peak demand than off-peak, and by changing the billing demand metric, Hydro would immediately lose revenue even without any load response from customers. This is a fallacious logic on the part of Hydro. The fact that there are customers who already peak in system off-peak times is a benefit to Hydro, not the basis for a penalty charge.

Further, per PCOSS24, these two classes are paying more than $31 million above their measured costs – a hypothetical lost revenue of $0.9 million is not a reasonable basis for an extra rate increase on the class.

As to the degree of off-peak load permitted, the Hydro proposal is directionally sound, but as described by Mr. Bowman "timid"[1] in a manner that "kneecaps the opportunities provided by the change before it even -- before customers can even get started using it"[2]. The main criticism is the fact that Hydro is incenting customer to make use of more off-peak capacity (and to use less on-peak capacity) but is limiting the spread between the two to 10% of peak. As a result, while load shifting is communicated to be a positive action, the utility is equally communicating that it should not be pursued with much vigour.

Hydro provided a thoughtful response to these concerns once raised, noting in oral testimony that adjusting the ratio such that on-peak demand would remain the value for billing purposes even if it were only 80% or 75% of off-peak demand would not "make or break our proposal"[3]. This is a positive development that the Board should accept.

[1] Transcript, page 3983.
[2] Transcript, page 4009.
[3] Transcript, page 3473.

ISSUE TOPIC #9:

ISSUE: Reliability

Is Manitoba Hydro's reliability adequate for the needs of its customers?

MIPUG SUMMARY AND/OR RECOMMENDATION:

MIPUG recommends that the Board direct Manitoba Hydro to establish a metric for unserved energy based on industry best practice engagement of customers to establish a reasonable estimate of customer cost for reliability events, both momentary and non-momentary.

Reliability is an important priority for MIPUG members. Customer costs associated with outages and a failure to provide reliable service (often referred to as the cost of unserved energy) should be a key consideration when making capital investments in the Manitoba Hydro system.

Firstly, Manitoba Hydro's application clearly illustrates a trend of declining performance for transmission and sub-transmission that if left unchecked, will negatively impact transmission and sub-transmission customers (and distribution customers, who are also served through transmission and sub-transmission facilities).

Secondly, customer presentations provided by TC Energy and Chemtrade illustrate that SAIDI and SAIFI metrics are inadequate for determining the full impact and cost of poor reliability as these metrics do not include the frequency or impact of momentary outages, which have a direct impact to industrial operations.

Thirdly, the Midgard assertion that Manitoba Hydro's system is overbuilt to provide superior reliability to ratepayers as measured by SAIDI and SAIFI metrics does not recognize the degrading reliability in the Manitoba Hydro system, as illustrated by Manitoba Hydro in Tab 5. Manitoba Hydro's reliability is trending downwards to the detriment of customers and must be improved.

Finally, the Midgard assertion that "ratepayers have not clearly indicated they want to pay for a superior reliability system" is noted. MIPUG recommends that Manitoba Hydro improve its engagement and tools for assessing and recording the impact of reliability events on customer operations, and then use this information to establish a relevant metric for the cost of unserved energy as outlined in the Boston Report and industry best practice. The cost of unserved energy can be an important consideration for assessing the economic benefits and prioritization of capital and operating investment in the Manitoba Hydro system.

DISCUSSION AND SUPPORT:

Presentations by MIPUG members identified the costs and disruptions of reliability events as a major consideration for industrial operations in Manitoba. The presentation by TC Energy comparing reliability performance of the utility grid in Manitoba relative to other jurisdictions showed Manitoba Hydro's reliability performance to be subpar when compared to other Canadian or US jurisdictions in which the company operates. The customer presentations noted that momentary power outages (less than one minute) are as disruptive to operations as the longer duration outages tracked by Manitoba Hydro in its SAIDI and SAIFI metrics.

While an important indicator, industry standard SAIDI and SAIFI metrics do not consider momentary outages (less than one minute) that often serve as important indicators of deteriorating system performance. Momentary outages are often indicative of declining performance in aging equipment and lagging maintenance activities (tree trimming, dirty insulators) that are extremely disruptive to industrial operations as they often occur on a more frequent basis than recorded outages. Manitoba Hydro appears to have limited insight and monitoring in respect to the frequency and impact of momentary outages on its transmission and sub-transmission system. The lack of visibility on the sub-transmission system is particularly acute based on customer experience (TC Energy) and Manitoba Hydro testimony [Transcript 1532 - 1543].

> *"Mr. Cyril Patterson: Currently, unless there's that technology I spoke to earlier where we can actually see intermittent power outages on breaker operations, that there's the constant turning on and turning off of the power line for various reasons, we do very little tracking on intermittence."* [Transcript p.1542]

> *Mr. Cyril Patterson: Today, we have limited ability to track and report on that information but, in the future, that's what our grid modernization program is, to try to give us that visibility and insight into the customer's experience, in conjunction with also AMI technology, to whether or not – because that real time provides immediate data tracking and feedback on the status of a customer as to whether or not they're experiencing a – a lengthy interruption or an intermittent interruption, less than a minute."* [Transcript p.1542 - 1543]

Best practice for engagement and surveying of customers in response to reliability events was discussed at some length during cross-examination of Manitoba Hydro witnesses. Manitoba Hydro could benefit from adoption of industry best practice, using information obtained through customer engagement and surveys to establish the value of lost energy (VOLL) or cost of unserved energy [Transcript 1543 – 1549].

> "*MS Tanis Brako: The CSTS asks residential customers of, you know, many different topics related to the services that we offer, but there's a gap. We don't have a formal survey that goes to commercial and industrial customers that ask the same thing.*
>
> *So, we have, again, like I mentioned, identified that as a gap, this is through Strategy 2040. We know that we need to have a better understanding of the evolving needs of our customers*." [Transcript p.1490]

In response to questioning about whether Manitoba Hydro uses "before-outage surveys for the industrials with respect to the value of lost load" [Transcript p.1550-1551], Manitoba Hydro responded in the negative. A similar response was obtained when asked whether surveys were conducted after outage events.

In examining the use of Copperleaf, Manitoba Hydro indicated that standard industry values were used to reflect unserved energy costs, but it was emphasized that this information is not based on actual customer data. [Transcript p.1555] In keeping with this consideration, MIPUG would welcome a Board directive instructing Manitoba Hydro to develop a Manitoba-relevant metric to reflect the cost of unserved energy, that could be used in Copperleaf and other tools for prioritizing capital and maintenance investments in support of reliability improvements.

Midgard evidence suggests that Manitoba Hydro's performance metrics should be considered after adjustment for major events (generally weather-related). While this approach does highlight the reliability impact of equipment failures, it also tends to minimize the necessary emphasis on resilience in the face of climate change and the increasing frequency and severity of weather events. Customers rely on Manitoba Hydro to construct and maintain a system that is sufficiently robust and resilient to withstand a broad range of weather events.

ISSUE TOPIC #10:

ISSUE: Rate Classification for 0 – 30 kV GSL Customers

Is the GSL 0–30 kV rate class an appropriately homogenous group, or should it be redesigned to improve homogeneity?

MIPUG SUMMARY AND/OR RECOMMENDATION:

The 0-30 kV GSL rate class includes customers with a wide variety of uses, load profiles and sizes. Some of these likely more closely match those of the GSL 30 – 100 kV rate class. Others may be more similar to GS Medium customers.

The current classification provides little recognition for differences in consumption behavior, load types, customer sector (agricultural, commercial, industrial) or system interconnection.

Manitoba Hydro should be directed to study the customer homogeneity in the GSL 750 V – 30 kV rate class and report back to the PUB at the next GRA on alternatives to improve the homogeneity of the class.

DISCUSSION AND SUPPORT:

Current GSL rate classifications rely exclusively on the primary utility voltage supplied to the customer-owned transformation used to serve their operations. This means that all customers who own their own transformation (which makes them GS Large) and are served at voltages from 750V to 30 kV are included in a single class.

Customers in the GSL 750 V – 30 kV rate class have significant diversity with peak customer demand loads, varying from 200 kVA and upwards to more than 15 MVA, with smaller customers have a greater need for distribution poles and wires, and larger customers being supplied from dedicated utility assets located in close proximity to their operations, drastically reducing requirements for distribution poles and wires.

MIPUG/MH 1-118 a) requested information regarding the composition of the General Service rate classes. Manitoba Hydro's response referenced MIPUG/MH 1-62 c), which provided information from the 2021/22 fiscal period that is summarized in the tables below:

	MIPUG/MH 1-62b	MIPUG/MH 1-62c		MIPUG/MH 1-62c		MIPUG/MH 1-62c	
Fiscal Year	Total	Agriculture		Commercial		Industrial	
2021/22	Customers	Customers	Share	Customers	Share	Customers	Share
(rate class)	(#)	(#)	(%)	(#)	(%)	(#)	(%)
GSSND	53,906	2326	4.4%	46,398	87.0%	4,577	8.6%
GSSD	14,039	1500	11.3%	10,182	76.8%	1,584	11.9%
GSM	2,109	208	10.0%	1,540	73.9%	336	16.1%
GSL<30	366	69	20.2%	178	52.2%	94	27.6%
GSL30 - 100	45		0.0%	11	22.9%	37	77.1%
GSL >100	21		0.0%		0.0%	17	100.0%
Total	70,486	4103	5.9%	58,309	84.4%	6,645	9.6%

	MIPUG/MH 1-62b		MIPUG/MH 1-62c			MIPUG/MH 1-62c			MIPUG/MH 1-62c		
Fiscal Year	Total		Agriculture			Commercial			Industrial		
2021/22	Usage	Usage/Cust	Usage	Share	Avg Use	Usage	Share	Avg Use	Usage	Share	Avg Use
(rate class)	(GWh)	(GWh)	(GWh)	(%)	(GWh/Cust)	(GWh)	(%)	(GWh/Cust)	(GWh)	(%)	(GWh/Cust)
GSSND	1,719	0.032	94	5.6%	0.040	1,452	86.0%	0.031	142	8.4%	0.031
GSSD	2,132	0.152	290	13.7%	0.193	1,595	75.5%	0.157	227	10.7%	0.143
GSM	2,978	1.412	278	9.3%	1.337	2,168	72.8%	1.408	531	17.8%	1.580
GSL<30	1,753	4.790	181	10.3%	2.623	719	41.0%	4.039	854	48.7%	9.085
GSL30 - 100	1,851	41.133		0.0%		100	5.4%	9.091	1,751	94.6%	47.324
GSL >100	3,808	181.333		0.0%			0.0%		3,807	100.0%	223.941
Total	14,241		843	5.9%	0.205	6,034	42.5%	0.103	7,312	51.5%	1.100

It is clear from the summary tables (above and below) that the larger GSL classes are dominated by industrial customers, both in customer count and energy consumed.

The summary tables clearly illustrate that the GSL 750 V – 30 kV rate class exhibits significantly greater diversity between agricultural, commercial, and industrial, which have significantly greater variation in average consumption than the two higher voltage GSL rate classes. These customers can have materially different load profiles than industrial customers:

> Mr. Antoine HACAULT: then if we go – and the bottom chart of this page, we'll see that GSL - - the usage characteristics are different for the different categories of agriculture, commercial, and industrial. Would you agree with that
>
> MS MARNIE VAN HUSSEN: Yes, I would agree with that [transcript p.3733]

The differences in average annual consumption between commercial and industrial customers within the GSL 750 V - 30 kV rate class were raised in cross examination of the Manitoba Hydro panel [Transcript p.3731 – 3736] and may arise from important differences in consumption behavior between smaller commercial and larger industrial consumers, including load factors and seasonality.

The differing consumption behaviors between smaller commercial customers and larger industrial customers can directly impact contributions to coincident system peak and distribution service requirements that impact PCOSS allocations, which are assumed on a class average basis in the COSS methodology used by Manitoba Hydro.

> MS MARNIE VAN HUSSEN: You know, utilities typically will set up their customer classes to reflect where customers connect on the system similar to Manitoba Hydro or they use usage or consumption profiles. Some use end-use, so it depends on the level of granularity that you're looking at and so you kind of make assumptions around your class size. [Transcript p.3735]

MIPUG proposed to Manitoba Hydro witnesses that they look at customer homogeneity in the GSL 750 V – 30 kV rate class. This proposal was viewed favourably:

> MS MARNIE VAN HUSSEN: *"And, certainly, we can – something we can take a look at. I – I will say that's, you know, will happen with all of our rate classes, you know, not all customers can be close to the average. So, certainly, to the extent that's going to happen, regardless of the – makeup of your class. But we will, we will take a look at it."* [Transcript p.3736]

It is also noted that the recent changes to the Manitoba Hydro Act may limit the Board's ability to direct changes to class structure and composition in future. For this reason, MIPUG recommends that the Board direct Hydro in this GRA to complete an analysis of the GSL 0-30kV class with regard to homogeneity, and identify measures that Hydro may implement to improve the cost allocation to these customers, including restricting the class, moving customers to other classes based on their usage characteristics, or other measures that may arise from the study.