THOMPSON
DORFMAN
SWEATMAN

Writer's Name	Antoine F. Hacault
Direct Telephone	204-934-2513
E-mail Address	afh@tdslaw.com
Direct Fax	204-934-0530

April 3, 2023

BY E-MAIL AND REGULAR MAIL
publicutilities@gov.mb.ca

Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba R3C 0C4

Attention: Rachel McMillin, Associate Secretary

Dear Sirs/Mesdames:

Re: Manitoba Hydro 2023/24
and 2024/25 General Rate Application
Filing Intervener Evidence for MIPUG
Our Matter No. 0194440 AFH

We attach the Pre-Filed Testimony of Patrick Bowman dated April 3, 2023, which is being filed on behalf of the Manitoba Industrial Power Users Group.

Thank you.

Yours truly,

THOMPSON DORFMAN SWEATMAN LLP

Per: Antoine F. Hacault

Antoine F. Hacault*

AFH/av
Encl.
cc: Board Counsel (all via e-mail)
Manitoba Hydro, and Interveners

*Services provided through A. F. Hacault Law Corporation

In the Matter of Manitoba Hydro 2023/24 and 2024/25 General Rate Application

Pre-Filed Testimony of Patrick Bowman

Submitted to: Manitoba Public Utilities Board

On behalf of: Manitoba Industrial Power Users Group

April 3, 2023

InterGroup

CONSULTANTS

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APPENDICES

1.0 INTRODUCTION

This testimony has been prepared for the Manitoba Industrial Power Users Group ("MIPUG") by Patrick Bowman.[1] This testimony reviews the Manitoba Hydro ("Hydro") 2023/24 and 2024/25 General Rate Application ("GRA" or "Application") filed November 15, 2022 with the Manitoba Public Utilities Board ("PUB" or "Board") and updated December 9, 2022.

With respect to the testimony contained herein, Mr. Bowman notes the following:

- Mr. Bowman is an independent witness, and his Resume is provided in Appendix A.
- Mr. Bowman's scope on this assignment was to review the Application taking into account normal regulatory principles for electric utility rate setting. The scope of review focuses particularly on matters of interest to large power users in Manitoba.
- Mr. Bowman acknowledges his role is to provide opinion evidence to the Board that is fair, objective and non-partisan.
- Mr. Bowman has endeavoured to ensure all factual assumptions and specific information relied upon are expressly cited in the testimony that follows.

Mr. Bowman has participated and provided testimony in every major Manitoba Hydro proceeding before the Board since the 2001 Status Update, including the various Cost of Service ("COS") reviews (2005 and 2016) and the Need for and Alternatives To ("NFAT") proceeding in 2013.

Mr. Bowman has not had access to materials deemed confidential related primarily to the export market. As a result, pending review of the evidence of the Board's independent expert, Daymark, issues related to export markets are generally not addressed in this submission.

References to the Application materials (Tabs and Appendices) generally refer to the December 9, 2022 amended filing (Tab 8 at December 21) unless specifically referenced to the November 15, 2022 version.

1.1 SUMMARY OF RECOMMENDATIONS

Based on the analysis summarized in this report, the following findings and recommendation are provided:

Recommendation 1: Hydro's proposal to finalize the 3.6% rate increase from January 1, 2022, and impose average 2% increases in each of 2023/24 (September 1, 2023) and 2024/25 (April 1, 2024) are justified based on the financial projections presented.

Recommendation 2: The Board may want to consider delaying the April 1, 2024 increase to September 1, 2024, to help mitigate the impact of multiple rate increases within the same 12 month period.

[1] Services provided by Bowman Economic Consulting Inc.

Recommendation 3: 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 4: Balances in the Conawapa deferral account, the Loss on Disposal account related to discontinued operations, and the Asset Removal cost deferral account, totalling approximately $382 million, should be written-off to income in 2022/23. The Board should ensure the necessary Orders are provided in time for this transaction to be recorded in the 2022/23 fiscal year.

Recommendation 5: 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.

Recommendation 6: 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 7: 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 8: 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 9: There should not be a new IFRS Phase-In Deferral created nor needed to adopt appropriate depreciation practices at this time.

Recommendation 10: The Change in Depreciation Method Deferral, totalling $327 million at year-end 2022/23, should be discharged as an offset to accumulated depreciation, by account.

Recommendation 11: The Board should continue to apply its finding from Order 59-18 that Export revenues should be a reduction to allocated class costs.

Recommendation 12: The Board should rely on the net export revenue and net income assumptions in PCOSS24 for the purposes of establishing differentiated rates in this proceeding.

Recommendation 13: PCOSS analyses should ensure 20% of the cost of wind generation cost is classified to demand, while the remaining 80% is classified to energy.

Recommendation 14: DSM costs should be functionalized to generation and transmission and distribution in proportion to the marginal values used to justify the programming, or approximately 75%, 10%, 15% respectively.

Recommendation 15: The PCOSS Coincident Peak allocator should be calculated on the eight-year average of the highest single hour, or at most a very limited number of hours each year (e.g, 4-6 hours per year). The current approach based on 50 hours each year includes far too much averaging of relatively high load hours, and fails to recognize the true driver of peak capacity costs, which is the highest load that must be served.

Recommendation 16: Differential rate increases should be implemented based on an amended PCOSS24 reflecting the Board's direction from this proceeding. Rate proposals should be based on achievement of the outer range of the ZOR by 2027/28, if not sooner.

Recommendation 17: The change to industrial rates to recognize on-peak demand rather than demand at any time is an improvement to the price signals and should be approved. There is no need to further adjust the demand charge for the approximately 1% in lost revenue when the industrial classes are already paying well above costs. Further, the 10% cap on off-peak usage is not justified at this time.

2.0 OVERVIEW OF HYDRO'S APPLICATION AND STATUS OF THE UTILITY FINANCES

2.1 CONTEXT FOR CURRENT REVIEW

The current application is a culmination of a series of Manitoba Hydro proceedings over the past decade that has refined the organization, starting with the 2012/13 and 2013/14 GRA, as follows[2]:

- 2012/13 and 2013/14 GRA ("2012 GRA") – Comprehensive GRA. Transition to IFRS, including depreciation methodology proposals; Board directed a quantitative probabilistic review of risks in support of financial targets.
- 2013 NFAT – Decision to proceed with development plan, including Keeyask but not Conawapa. Assessment included impacts of financial implications of Bipole III.
- 2014/15 and 2015/16 GRA ("2015 GRA") – Comprehensive Revenue Requirement Review (no COS). Erosion in financial conditions for new projects, added capital spending and DSM, continued review (rejection) of Hydro's depreciation methodology proposals. No assessment of quantitative probabilistic review of risks was provided.
- 2016 COS Review – Establishment of new methods for COS.
- 2017/18 and 2018/19 GRA ("2017 GRA") – Major review of a limited scope, driven by Hydro proposal for complete overhaul of financial targets (rejected). Material increases in capital spending on new projects, reduction in export prices. Initial focus on probabilistic risk review (filed but not generally used by Hydro to ser financial targets).
- 2018 Technical Conference on Financial Targets – Now terminated Board-directed process (Order 59/18, Directive 9) for cooperative review of rule-based or other approaches to reserves or financial targets (including probabilistic). Board eventually concluded efforts had become an "adversarial process" … "not conducive to accomplishing the Board's intended goals of dialogue and education". (Order 126-18)
- 2019/20 Electric Rate Application ("2019 ERA") – Limited scope review of rate increases for 2019/20. No long-term forecasts provided. No update on probabilistic risks assessment.
- 2021 Consumers Coalition Application for Status Update – Truncated process to test whether Hydro's rates were just and reasonable and address outstanding "unfinished business"[3]. Process not completed, in favour of 2021 Interim Rate Application
- 2021 Interim Rate Application ("2021 IRA") – Limited scope review focused on "immediate and pressing"[4] then-occurring acute water flow issues (Hydro application also relied heavily on Keeyask coming into service to justify rate increases).

[2] Does not generally include interim rate reviews.
[3] Consumer's Coalition Application, March 26, 2021, page 3.
[4] Hydro Application, November 15, 2021, Cover Letter.

In short, the history of Hydro regulation over the last decade indicates the last comprehensive review was the 2012 GRA, though the 2015 GRA was comprehensive from the perspective of Revenue Requirement. The record indicates a longstanding but as yet incomplete attempt to establish probabilistic risk assessment for the purposes of setting financial targets and rate increases.

The last long-term financial forecasts were provided in the 2017 GRA, however these forecasts were generally based on a proposed set of revised financial targets that were rejected by the PUB. The most relevant baseline closely reflecting the Board's decisions in Order 59/18 was Manitoba Hydro Exhibit #93 from that proceeding[5], which is further reviewed in this submission.

Since the 2017 GRA, the most notable development has been the passage of Bill 36, the *Manitoba Hydro Amendment and Public Utilities Board Amendment Act*.[6] These amendments are not yet in force for rate setting, but will begin to apply to any determination of rates for any period after April 1, 2025.[7] This presumably captures the next Hydro GRA, and will impact primarily certain key areas including rate caps, the setting of financial targets, the scope of matters the Board can consider in setting rates, and the requirement for rates for each class to reflect costs. The current application has not been framed specifically to respond to Bill 36, but the interests of ratepayers for long-term rate stability and predictability suggests the coming effects of Bill 36 should not be completely ignored.

Therefore, the current review, as a full-scope GRA, is a positive and long-delayed development. Hydro's filing appears relatively comprehensive and thorough, outside of materials unavailable for review due to confidentiality. One material omission appears to be advancement of the comprehensive probabilistic risk assessment (and potential inclusion in a rules-based financial target regime) that was started with the 2017 GRA, but otherwise appears to have been sidelined[8].

2.2 OUTLINE OF HYDRO'S APPLICATION

Hydro's initial Application filing on November 15, 2022 requested final approval of the 3.6% interim rate increase granted effective January 1, 2022[9]; a rate increase of 3.5% effective September 1, 2023; and a subsequent 3.5% rate increase effective April 1, 2024 (with further 3.5% annual increases projected through the 2032/33 year, followed by 0.5%/year thereafter). At that time, Hydro did not provide the specific rate increases broken out by class.

Hydro's traditional long-term financial projection had been known as an Integrated Financial Forecast ("IFF"), prepared for each fiscal year. Hydro now avoids the use of this term, in favour of the Financial Forecast Scenario ("FFS"), though the key product is nearly identical. The FFS filed with the November 15, 2022 Application illustrated a 20-year scenario that was largely based around the financial targets in the recently passed Bill 36. Those targets are as follows:[10]

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[5] Order 59/18 page 173.
[6] S.M. 2022, c.42.
[7] S.M. 2022, c.4, s.65.
[8] PUB/MH-I-21a.
[9] Granted in Order 140/21.
[10] Received Royal Assent November 3, 2022.

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

(d) subject to the policy objectives set out in clauses (a) to (c) and to the extent practicable, rates or changes in rates should be stable and predictable from year to year.

The FFS filed November 15, 2022 achieved the 70% debt-to-equity ratio one year early, by March 31, 2039 and had exceeded the achievement of the March 31, 2035 target by reaching 76%. However, the FFS as of November 15, 2022 failed to achieve the other key constraint of Bill 36, namely the rate cap:

39.2(1) Despite sections 39 and 39.1, the general rate increase for all grid customers for any fiscal year within a rate period, expressed as a percentage increase from year to year, must not exceed the lesser of 5% and the maximum determined according to the following formula and expressed as a percentage:

$$\text{Max} = (CPI_1/CPI_2) - 1$$

In this formula,

CPI_1 is the Consumer Price Index, determined in accordance with subsection (2), for the 12-month period ending on September 30 of the calendar year immediately preceding that fiscal year;

CPI_2 is the Consumer Price Index, determined in accordance with subsection (2), for the 12-month period immediately preceding the 12-month period referred to in the description of CPI_1.

In short, subsection 39.2(1), which takes precedence over the financial targets set out in subsection 39.1(1), requires that rates do not increase by more than annual inflation or 5%, whichever is lower[11]. For the 2023/24 year, where rate increases applied only to a portion of the year, and the previous year of inflation data was high, this test may have been met. However, for

[11] The legislation sets out the CPI should be measured September 30, based on Manitoba All-Items CPI for each month of the previous 12 months divided by 12.

the remainder of the forecast period, Hydro forecast annual inflation at 2.3% or below[12], well below the level of the rate increases assumed in the FFS. Hydro provides extensive discussion of its determination to ignore the rate cap required under Bill 36[13] in preparing the November 15, 2022 version of the FFS, but in doing so did not address the key requirement that the financial targets were subservient to the rate cap under Bill 36. It would appear Hydro's rationale focused primarily on what the utility viewed as its prudent course of debt retirement, which it asserts would have not been possible under the legislated rate cap, even though the rate cap would have prevailed. In short, the November 15, 2022 FFS was not a credible scenario for future rates or financial projections.

Following the announcement by the Government of Manitoba on November 23, 2022 that it would reduce government charges for the Debt Guarantee Fee ("DGF") and Water Rentals by one-half, on a permanent basis starting April 1, 2022, the above conflict became moot. Hydro refiled the Application documents on December 15, 2022 with an updated FFS (Appendix 4.1) that reflects an expectation of compliance with both the rate cap and debt:equity targets set out in Bill 36. In making its announcement, the Government specified that "(t)he savings from these reductions are to be applied annually to Hydro's debt."[14] Based on the updated FFS scenario as compared to the previous November 15, 2022 FFS (but assuming the rate caps in Bill 36 were met as required[15]), this outcome of accelerated debt reduction appears to be achieved[16].

The December 15, 2022 Application was supplemented on December 21, 2022 by materials on class-specific rate requests and limited rate design changes, reflecting the output of a new Prospective Cost of Service Study for 2023/24 (PCOSS24) and consideration of improving price signals to customers[17].

2.3 IMPLICATION OF DECEMBER 15, 2022 FINANCIAL FORECAST

As noted earlier in this submission, Hydro has proceeded through multiple recent proceedings (2019 ERA, 2021 IRA) without providing a new long-term financial forecast. Throughout these proceedings, there were multiple factors highlighted that suggested Hydro was facing improved financial conditions that should indicate positive financial outcomes compared to past expectations for the period following Keeyask in-service. For example, interest rates have been lower than expected for a number of years, Hydro had been directed to reduce its operating and maintenance ("O&M") spending to comply with Provincial fiscal constraints, and new export contracts had been signed with Saskatchewan.

[12] Application, Tab 10, MFR 65 (Amended), Table 4.
[13] November 15 Application, Tab 3, pages 35-50.
[14] Letter from Manitoba Government to the Chair, Manitoba Hydro, provided as Attachment 1 to Hydro's November 29, 2022 Correspondence to the PUB (Exhibit MH-2).
[15] See Tab 3 from November 15, 2022, in particular Figure 3.27, as compared to Tab 4 (Amended) Figure 4.32.
[16] Tab 3 (Amended), page 9; and PUB/MH-II-8a
[17] Application, Tab 8 and related appendices

The most notable comparison between the current FFS is portrayed in relation to the long-term forecasts filed since NFAT. They key comparators are provided in Table 2-1 below:[18]

[18] All data from Exhibit MH93 from the 2017 GRA, except for the current FFS with data from Tab 10 and Appendix 4.1.

Table 2-1: Comparison of Current and Previous Long-Term Forecasts

	Long Term Rate Increase	25% Equity Ratio	Maximum Long-Term Debt	Minimum Equity	Negative Net Income	Retained Earnings at 2033/34	Maximum Net Debt
NFAT Plan 5 – High Keeyask Level 2 DSM	3.95% 2014/15; 3.99% 2015/16 to 2031/32	2031/32	$22.490 B in 2023/24	8% in 2021/22-2023/24	Total of $638 M in 8 years during 2015/16 – 2022/23	$6.659 B	$21.606 B in 2022/23
MH14 (financial forecast from 2014)	3.95% 2015/16 to 2030/31	2033/24	$24.476 B in 2028/29	10% in 2022/23 - 2026/27	Total of $977 M in 8 years during 2018/19 – 2025/26	$5.557 B	$23.227 B in 2024/25
MH15	3.95% 2016/17 to 2028/29	2031/32	$23.495 B in 2026/27	12% In 2021/22 – 2023/24	Total of $58M in 3 years during 2018/19 – 2022/23	$7.402 B	$22.589 B in 2021/22
MH Exhibit #93 (based on MH16)	3.36% 2016/17; 3.36% 2017/18; 3.57% 2018/19 to 2035/26	2035/36	$25.560 B in 2028/29	12% In 2024/25 – 2028/29	Total of $418 M in 6 years during 2022/23 – 2026/27	$5.004 B	$24.971 B in 2027/28
FFS December 15, 2022	3.36% 2016/17; 3.36% 2017/18; 3.6% 2018/19; 2.3% 2019/20; 2.9% 2020/21; 3.6% 2021/22; 0% 2022/23; 2.0% 2023/24 to 2040/41	2035/36	$24.291 B in 2021/22	13% during 2017/18 – 2021/22	Outside of 2021/22 drought - none	$5.635 B	$23.293 B in 2021/22

The data in Table 2-1 above highlights that the current FFS, by most metrics, is a significant improvement on Exhibit MH93, as well as showing an improvement in many metrics compared to the long-term financial forecasts before that dating back to NFAT. This is particularly true for net losses (which were always expected to occur after Keeyask in-service, but are no longer projected), minimum equity (previously as low as 8%-12%; now expected to hit a minimum of 13% and is already targeted to rebound to 15% by March 31, 2023[19].

Comparing specifically to Exhibit MH93 (based on IFF16 from the 2017 GRA), the rate increases since that time have been lower than projected, but despite this the maximum net debt is lower than expected (and already peaked in 2021/22) and retained earnings at 2033/34 are projected to be more than $0.6 billion higher despite lower rate increases over the period.

The comparison to Exhibit MH93 also emphasizes how much of the earlier scenario was based on very poor financial performance after Keeyask came into service, with the achievement of the long-term targets occurring only via the benefits of compounding higher annual rate increases impacting the later years of the scenario. This is no longer the case to the same degree, as shown in the following figures[20]:

Figure 2-1: Figures comparing Hydro Exhibit #93 (2017) to current Financial Forecast

Figure 1 – Debt Ratio **Figure 2 - Retained Earnings** **Figure 3 – Net Debt**

The above three figures from Hydro's materials indicate that under the previous forecast, for the first 10 years after Keeyask came into service the debt ratio, retained earnings, and net debt were projected to be materially worse than exhibited in the current FFS.

It is also important to note that much of the same financial performance for the current FFS was also true for the FFS from November 15, 2022 before the reduction in government charges. The largest change between the two FFS from this hearing is that the rate projection is lower in the most recent FFS. In other words, under Hydro's two separate FFS from this proceeding, both exhibit improvements over past forecasts, indicating it is not the Government charge relief that is the defining difference[21].

[19] Application, Tab 10, MFR 20 (Amended).
[20] Coalition/MH-I-27b. note that some MH93 values have been reclassified for consistency by Hydro, but the effects on the above figures is expected to be small.
[21] Assuming no Bill 36 rate caps.

The above information confirms MIPUG submissions in the 2019 ERA[22] and 2021 IRA[23] regarding positive developments that had not yet been factored into any Hydro long-term forecast. From the current FFS, it is now clear that the implementation of Keeyask has not resulted in trends significantly different than projected at the NFAT proceeding. Costs for the projects were higher, and in-service dates were delayed. Consequently, debt is somewhat higher for longer; however, so is the total equity at in-service. Despite debt levels being higher, Hydro can still sustain a better net income with lower power rates, largely due to lower interest rates than had been assumed at the time of NFAT.

[22] MIPUG Exhibit 7, slides 9-10.
[23] MIPUG Final Argument, page 15.

3.0 2023/24 AND 2024/25 REVENUE REQUIREMENT

The above analysis confirms that the in-service of Keeyask, as well as Bipole III, have now been achieved with a highly positive financial condition in many respects compared to earlier forecasts. This is useful but not determinative information to assessing the reasonableness of Hydro's current rate request.

In practice, Hydro is at a unique juncture that merits multiple actions to help address trends seen in the FFS and the pending impacts of Bill 36. This includes the following:

1) A need to make determinations on the 2023/24 and 2024/25 rate request
2) Adjustments required to the March 31, 2023 regulatory accounts, affecting the opening balances for the test years
3) Resolving the approach to depreciation for regulatory purposes.

3.1 OVERALL 2023/24 AND 2024/25 RATE REQUEST

At this time, Hydro is requesting a rate increase of 2% per year, which is below the level of annual inflation presently being experienced. This is a positive development compared to past forecasts. However, it must be also noted that under the current legislation, Hydro will be limited in the future to rate requests that must be at inflation (or below inflation, if inflation were above 5%). Previous MIPUG evidence highlighted that appropriate rate policies for Hydro should balance two tools to address risk:

1) Use of reserves: Lower net income when adverse conditions arise, or experience net losses.
2) Rate response[24]: Higher than previously forecast rate adjustments when adverse conditions arise.

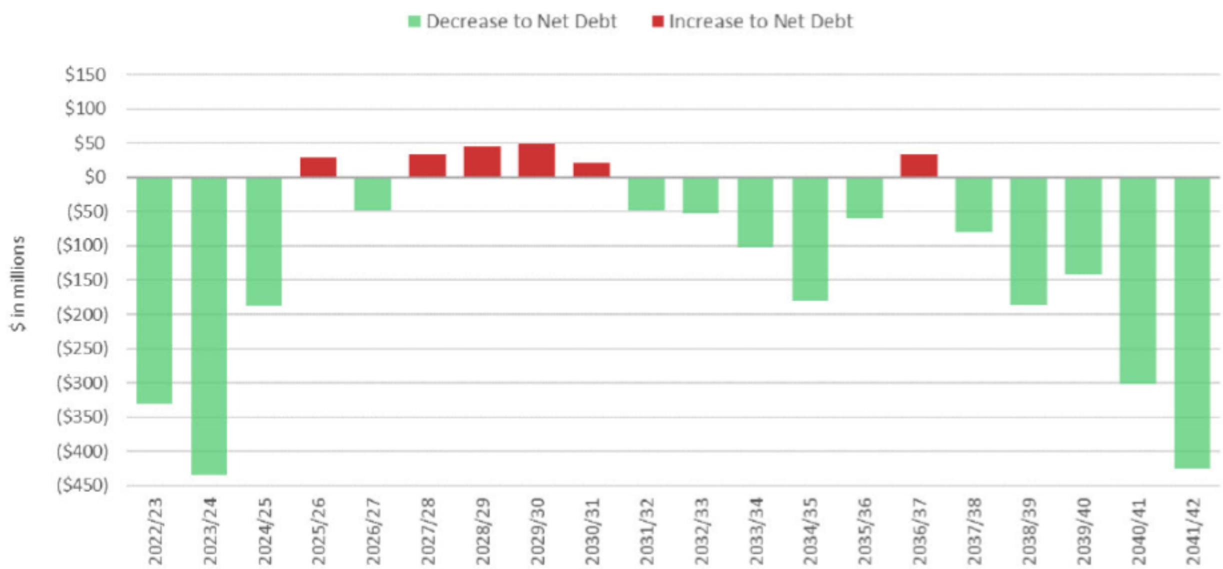
The new legislation in effect limits the potential for the rate response tool in cases where rate increases above inflation would have been merited. Unfortunately, this means an unavoidable greater reliance on reserves (i.e., retained earnings). For this reason, as Hydro prepares for the new rate setting regime, prudence would dictate caution about foregoing opportunities to build up reserves at this time.

Second, the Hydro materials indicate long-term positive trends in net income and cash flow that can have large positive effects over years 10 to 20 of the long-term financial forecast (i.e., 2032/33 to 2041/42). However, these same forecasts also indicate relatively acute challenges in the near-term after the current high reservoir levels have passed (i.e., approximately the next 3-7 years).

[24] See, for example, Background Paper C to the evidence of Patrick Bowman in the 2017 GRA, Exhibit MIPUG #15.

In respect to cash, the period starting 2024/25 shows the return to normal water flows, with significant further erosion starting 2025/26. The following figure indicates Hydro's surplus cash available for debt repayment[25]:

Figure 3-1: Hydro Surplus Cash Available for Debt Repayment

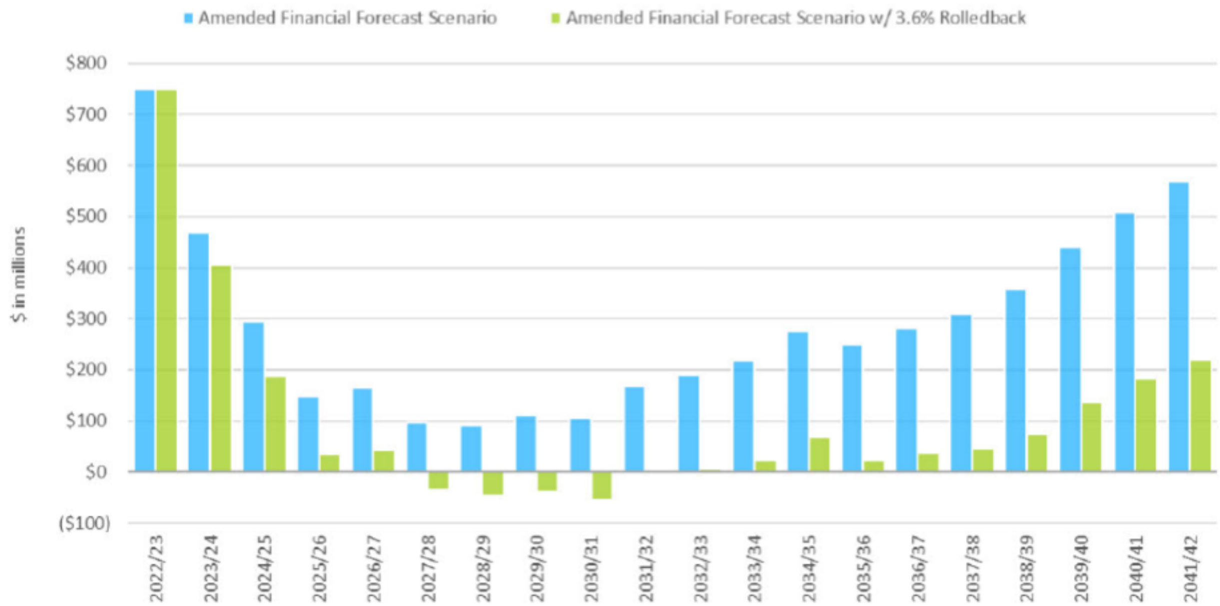


As shown in Figure 3-1 above, starting in 2025/26 Hydro has effectively a neutral cash position. This extends for approximately 6 years (2025/26 to 2030/31) before cumulative rate increases are able to drive any significant cash surpluses. The amount of surplus cash is dependent on other aspects of Hydro's FFS, such as O&M expense and in particular, sustaining capital expenditures, so the absolute values of the above forecasts may change with pressures to contain spending in these two areas. However, the basic trend is likely to be maintained – that is, rate increases are needed just to keep up with other changes occurring in the utility, and do not generally lead to improvement in cash surpluses.

In terms of net income, a similar trend is seen over the same period, as shown in the blue bars in the following figure[26]:

[25] Application, Tab 4, Figure 4.26.
[26] Application, Tab 3, Figure 3.14.

Figure 3-2: Hydro Net Income From December 15, 2022 FFS



As shown in Figure 3-2, Hydro's net income exhibits a significant reduction with the projected end of the current high water conditions and reservoir levels in 2024/25, but then enters a period of extended flat performance despite ongoing rate increases. Similar to the cash flow profile noted above, but to an even greater degree, the absolute values are dependent on a number of projections and assumptions such as O&M expenses, and regulatory treatment of such matters as cloud computing and depreciation. However, within the range of years from 2025/26 to 2030/31, the basic pattern above would likely hold even with changes in these factors.

Hydro's performance could improve significantly with aggressive cost control in the areas of O&M and sustaining capital, assuming these can be achieved without further erosion in Hydro's system reliability and customer service performance. Net income levels may also see improvement with various measures discussed below in this submission related primarily to regulatory deferrals. But these changes are not likely determinative to the conclusion that sustained and regular rate adjustments will be advisable to sustain financial performance for the period to approximately 2030/31.

These challenges arise for a number of reasons, two of which are of notable:

1) Hydro faces the end of certain significant and financially beneficial export contracts, in 2025/26 (NSP) and to a lesser degree 2026/27 (WPS)[27].

[27] Application, Tab 5, Figure 5.10.

2) From 2026/27 to 2028/29 Hydro faces refinancing of material quantities of low cost debt (more than $1 billion per year, at an average interest rates between 2.3% and 2.9%). Hydro is forecasting to refinance these debt instruments between 3.72% and 3.86%, but these interest rates are projected in an environment that continues to present unusually high uncertainty and instability.

On the first item noted, Hydro faces the end of export contracts that provide significant dependable energy sales. The FFS has these sales being largely replaced with opportunity sales, which result in lower overall revenue and more exposure to market pricing as of 2025/26. This is shown in the following figure[28]:

Figure 3-3: Reduction in Dependable Energy Sales Volumes

In terms of dollar impact, the reduction is significant, as Hydro illustrates in the following figure[29]:

[28] Application, Tab 3, Figure 3.24.
[29] Application, Tab 3, Figure 3.25.

Figure 3-4: Reduction in Dependable Energy Sales Revenue

[redacted]

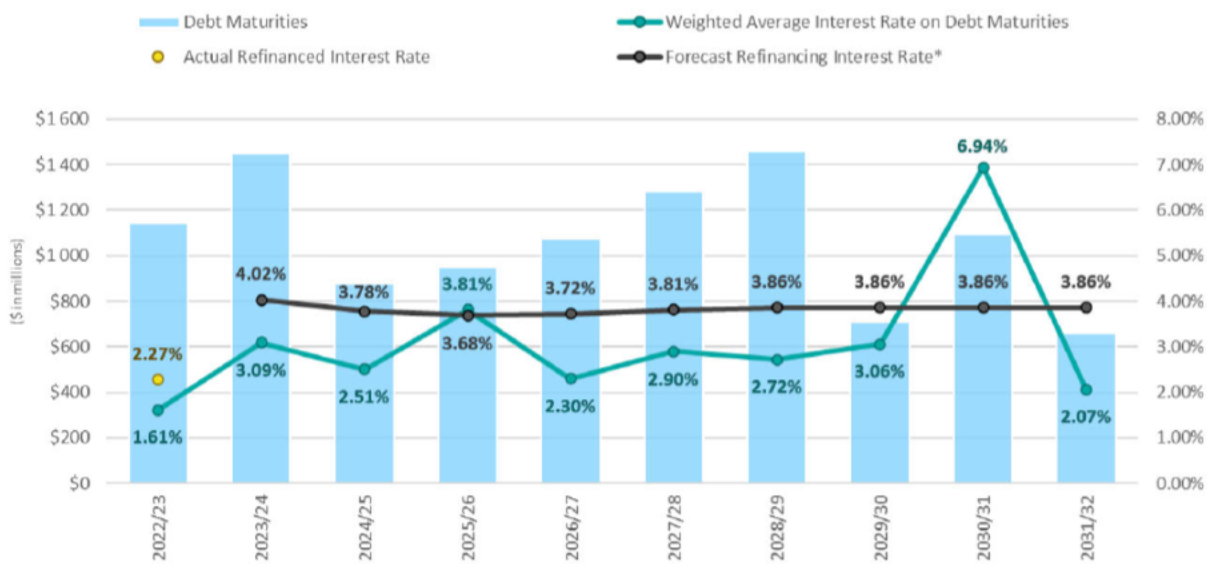
After 2025/26, the forecasts indicate a stabilizing of export revenue, however at a much lower level than before 2024/25, and with more exposure to price variability.

This factor alone represents a nearly $200 million per year reduction in revenue, which must effectively be replaced by either improved export pricing/participation[30] or added revenues from domestic customers. Export market price forecasts and marketing strategies are beyond the scope of this submission due to inability to access confidential material in Hydro's filings.

The second factor that helps drive the flat cash flow and net income performance in the years following 2025/26 is the need to refinance debt at interest rates that are likely to be higher than the debt being retired. This is shown in the following figure[31]:

[30] Hydro can help mitigate the impact by either securing better price per unit sold, or more actively engaging in market arbitrage if possible with freed up volumes and dependable capacity/energy.
[31] Application, Tab 3, figure 3.20.

Figure 3-5: Debt Refinancing and Interest Rates



*Forecast rates are a blended rate of 85% fixed rate debt and 15% floating rate debt to match model assumptions on forecasting borrowings
NOTE: Interest rates presented above exclude the Provincial Guarantee Fee

The debt instruments shown to be refinanced over the period 2026/27 to 2028/29 total more than $1 billion per year, at forecast interest rates that are 0.9-1.4% higher than the debt being retired. This will drive increases to finance expense even without a growth in the absolute level of debt. These forecast interest rates are also potentially not reflective of market conditions that will prevail at the time. The above rates are based on summer 2022 forecasts. Updated winter 2022 forecasts indicate the 85% fixed:15% floating benchmark for 2026/27 to 2028/29 have already moved from 3.72%, 3.81% and 3.86% respectively, to 3.88%, 3.92% and 4.10%[32].

Between these two factors, dependable exports and refinancing low cost debt, there is justifiable foundation for sustained predictable rate increases to address likely adverse cost movements. This is not to say it is impossible for the effects to be mitigated – it is possible interest rates will return to generationally low levels and dependable contracts will be available to replace the ending export arrangements, however neither of these should be considered likely. This is particularly true with current Bank of Canada efforts to curb inflation, and ongoing evolution in the MISO market to connect unprecedented volumes of new renewable generation, an effect that is underway even before enhanced production supports passed by the United States as part of the Inflation Reduction Act[33].

It should also be noted that the Board has previously found that Manitoba Hydro is a pure cost recovery utility[34]. This concept suggests limited priority should be given to building equity. The

[32] PUB/MH-II-10a.
[33] See, for example, Application Appendix 4.2
[34] Order 59/18, page 6.

finding indicates the need for concern if Hydro is excessively growing equity or paying down debt ahead of the depreciation of the assets which underpin the debt[35]. This finding would further suggest a need for reconsideration of the Bill 36 financial targets, and indicate concerns for the financial performance shown for the period after 2031/32 when net income climbs materially even at average water conditions. However, these concerns are not likely the key focus of rate setting for at least the next 7 years.

In summary, based on three factors noted above, Hydro's proposal to implement an overall rate increase of 2% in each of 2023/24 and 2024/25 appears prudent and reasonable. The same logic also suggests any roll-back of the 3.6% rate increase from January 1, 2022 would undermine progress towards the same overall objective. The three key factors are:

1) Limits imposed by Bill 36 on Hydro's ability in the future to raise revenue through above-inflation rate increases if required as part of rate response to adverse developments (e.g., further interest rate increases).
2) Dependable export contracts that are scheduled to end in 2025/26.
3) Required refinancing of low cost debt in 2026/27 to 2028/29.

Mitigative actions in the form of reductions in O&M spending and capital spending (to the extent these can be implemented without further reductions in reliability), an altered regulatory accounting approach, and improved export market performance could lead to improved financial performance over the period. However, for at least the next 2 years, while these improvements are sought, the imposition of 2% annual rate increases initiates a path of predictable and below-inflation increases that are justified based on the facts at this time.

The Board may want to consider delaying the April 1, 2024 increase to September 1, 2024, to help mitigate the impact of multiple rate increases within the same 12 month period.

Recommendation 1: Hydro's proposal to finalize the 3.6% rate increase from January 1, 2022, and impose average 2% increases in each of 2023/24 (September 1, 2023) and 2024/25 (April 1, 2024) are justified based on the financial projections presented.

Recommendation 2: The Board may want to consider delaying the April 1, 2024 increase to September 1, 2024, to help mitigate the impact of multiple rate increases within the same 12 month period.

It should also be noted that an alternative path which did not require the proposed rate increases could have been available under the following circumstances:

[35] It also indicates no future path should be assumed where Hydro must earn revenues to pay dividends to its shareholder.

1) Hydro had advanced the probabilistic financial modelling known as the "uncertainty analysis"[36] for updated conditions, and included the ability of the tool to apply rate response to developing conditions.

2) Bill 36 had not limited the annual rate cap to inflation or 5%, whichever is less.

Under these two conditions, and with a thorough testing of the individual items in the FFS, Hydro could have produced scenarios showing the minimum level of rate increases that could be implemented today in a manner that did not expose ratepayers to any notable risk of future rate shock. As reviewed as part of the 2017 GRA[37], a probabilistic financial modelling tool may show that in exchange for carrying a very small risk (e.g., less than 5%) of a rate increase in future at, say, 1.5 times inflation, rates today could be maintained at a level lower than the increases otherwise proposed. In this manner, quantifiable potential future rate increases become the "reserves" that allow Hydro to manage risks, rather than simply growing retained earnings and achieving arbitrary debt:equity targets.

However, with Hydro failing to update the uncertainty analysis tool, and with the new limits on rate increases above inflation, the potential to explore rate increases today below the proposed level is not possible. Notwithstanding the Bill 36 limits on rate response, resumption of work on this analytical product should be prioritized, in support of providing an advanced tool for assessing the likelihood of reaching mandated financial ratios by legislated target dates under specified conditions, rather than simply relying on deterministic scenario modelling.

Recommendation 3: 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.

3.2 MARCH 31, 2023 REGULATORY DEFERRAL BALANCES

For fiscal year 2022/23, Hydro faces three unprecedented financial factors that drive net income to record levels. These are:

1) High water flows

2) A 3.6% rate increase, implemented January 1, 2022 in response to drought, which remains in place

3) An adjustment to water rentals and debt guarantee fees retroactive to April 1, 2022, announced November 23, 2022 (more than half way into the fiscal year).

Under present projection, net income will reach $751 million[38], more than $600 million above the budget filed with the PUB in February 2022[39].

[36] PUB/MH-I-21a.
[37] Background Paper C to the evidence of Patrick Bowman in the 2017 GRA, Exhibit MIPUG #15.
[38] Application, Tab 4, Figure 4.2.
[39] Application, Tab 4, page 8.

At the same time, Hydro's regulatory accounts are carrying multiple deferred charges to customers that will require amortization to income in future years, but do not represent any enduring value to ratepayers. Among these items are the following:

1) **Conawapa planning costs**: Hydro spent $380 million on planning costs for the Conawapa generating station, which has since been cancelled. These costs were deferred to income over 30 years starting 2018/19[40]. This deferral "smooths out the impact of this one-time cost on consumers"[41], but also permits cessation of the amortization should work on the Conawapa project resume in the future. However, with the ongoing evolution of export markets and the reduced levelized costs of alternative resource options[42], the likelihood of Conawapa resuming development for domestic purposes appear to be declining. The undepreciated balance of Conawapa planning costs as of March 31, 2023 is $316 million.

2) **Selkirk and other GS loss on retirement**: The Selkirk thermal generating station ceased operation on April 1, 2021[43] This "resulted in immediate retirement of 75% of the Selkirk GS assets based on a detailed review to identify the assets which were no longer in use or useful".[44] As a result, losses on retirement of $37.1 million were recorded and deferred to the regulatory gains and losses account. Other generating station losses were also recorded for discontinued operations, bringing the total losses to $43 million. Hydro has confirmed that with respect to the Selkirk assets, no ensuring value exists from the assets now removed, and no reasonable potential exists for a future gain on disposal of the remaining assets to offset the recorded loss on the assets which were already disposed[45].

3) **Removal costs for assets that were not replaced:** Manitoba Hydro's conversion to IFRS led to the adoption of a new approach to accounting for costs of removal of retired assets. For assets removed in order to be replaced by a new asset in the same location, the cost of removal becomes part of the new asset capital costs[46]. However, for assets removed that are not replaced in the same location, the removal cost is charged to income. This was explained in the 2015 GRA, at Appendix 5.4, as follows[47]:

> Upon transition to IFRS, MH is eliminating the inclusion of negative salvage in depreciation rates as a means to offset other financial impacts associated with the transition. To the extent that it is necessary to remove an asset in order to replace it, the costs of removal of replaced assets will be capitalized as a cost component of the replacement asset. All other asset removal costs will be charged against income as incurred.

[40] Application Tab 10, MFR 16, Figure 1.
[41] Order 59/18 page 22.
[42] Conawapa Levelized Cost of Energy is now estimated at $92/MW.h, compared to wind at $56/MW.h, per the response to Coalition/MH-I-85 Attachment 1 page 23.
[43] PUB/MH-I-40a.
[44] PUB/MH-I-126b.
[45] MIPUG/MH-II-30.
[46] See Order 73/15, page 45.
[47] Hydro 2015 GRA Application, Appendix 5.4, page 32.

> Despite this description of the accounting provision (charged against income as incurred), Hydro now indicates that it is carrying $23 million in regulatory deferrals for "cost of removal for assets which were not replaced"[48] Hydro appears to link the deferral of these amounts to Order 73/15 in the response to PUB/MH-I-114; however, no such approval to defer these losses (rather than recognize in income in the year incurred) appears to be included in the decisions in PUB Order 73/15.

Taking into account the above three provisions, it appears that Hydro is carrying approximately $382 million in regulatory deferrals for which there is (i) no enduring value as they relate to discontinued operations or terminated planning costs, and (ii) in the case of removal costs, the amounts may never have been appropriate for inclusion in regulatory deferrals.

Various interrogatories explored the option of writing-off some or all of the above amounts to income in 2022/23, when net income variances would permit these matters to be extinguished and avoid burdening future ratepayers for costs on which they receive no value[49]. In each case, Hydro provided a response noting the following:

1) While writing off the amounts may affect future net income positively, it would have no effect on cash. Hydro also noted the write-offs would have minimal effect on achievement of the legislated debt:equity targets.
2) For any write-offs that were intended to take effect in 2022/23 "an Order would need to be received prior to the finalization of Manitoba Hydro's audited financial statements for 2022/23."[50]

While Hydro's comment on cash and debt:equity suggests the utility sees limited upside to write-offs, Hydro appears to have provided no rationales in direct opposition to transactions to write-off the above balances.

Given the financial projections for 2022/23, and the opportunity to eliminate from future customers the net income or revenue requirement burden associated with assets which will not be used and useful to provide service in the future, the above write-offs appear to be prudent. The Board should ensure Hydro receives the necessary Orders to permit the transactions to be recorded in the 2022/23 fiscal year.

> **Recommendation 4: Balances in the Conawapa deferral account, the Loss on Disposal account related to discontinued operations, and the Asset Removal cost deferral account, totalling approximately $382 million, should be written-off to income in 2022/23. The Board should ensure the necessary Orders are provided in time for this transaction to be recorded in the 2022/23 fiscal year.**

[48] MIPUG/MH-II-30d.
[49] For example, MIPUG/MH-II-30; PUB/MH-I-33b.
[50] PUB/MH-I-33b.

3.3 DEPRECIATION

Hydro's filing seeks changes in the area of depreciation that are structured as resolution to outstanding matters from the Board's Orders in 43/13 (from the 2012 GRA) and 73/15 (from the 2015 GRA), and to a lesser extent, 59/18 (2017 GRA). Fundamentally, since the 2012 GRA, Hydro has sought the Board's approval to implement a depreciation methodology known as the Equal Life Group procedure ("ELG") and the Board has rejected this request for rate setting purposes. Hydro elected nonetheless to implement the ELG procedure for the purposes of its IFRS financial reporting, and the current complications arise from this divergence.

At its core, it is critical that the Board continue to exercise its mandate to establish just and reasonable rates, including through establishing methods of depreciation appropriate for this end. Most matters of depreciation methodology do not at present appear to have any notable differences between the approaches used by Manitoba Hydro and approaches that have consistently been recommended by intervening parties and accepted by the Board, including:

- The use of a straight-line method (where the costs of assets are intended to be recovered generally equally over the course of the asset life, in equal increments each year)
- The use of group procedures, where Hydro combines its individual assets into groups and largely accounts for the depreciation characteristics across the entire account.
- Accounting for the costs of removal of assets as part of the capital cost of the replacement asset for interim retirements (where there is a replacement asset on the same site, as the need for the asset continues) and as an expense[51] for terminal retirements (where no replacement asset is required).

The key matters requiring attention at this time relate to two methodological areas:

1) The **group procedure** to be used in calculating depreciation expense. In this regard, "procedure" refers to a set of methods to turn estimates of the service life of assets (sometimes referred to as life and dispersion estimates, or Iowa curves) into an annual expense. Two such procedures have been the focus since 2012; namely the ELG procedure and a second procedure known as either Average Life Group ("ALG") or Average Service Life ("ASL"). For simplicity, and to help distinguish from the similarly acronymed ELG, this submission refers to the second procedure as ASL.
2) The treatment of what is termed as **gains and losses on disposal**. This relates to the accounting treatment upon the actual realization of the life of an asset (not an estimate) which is now known to have varied from the average life estimated earlier.

Having addressed the above two questions of methodology, in light of the best alignment with what is needed to achieve just and reasonable rates, the second major set of questions to be

[51] Note that the previous section of this evidence does address the regulatory deferral treatment of net salvage costs, which earlier Board decisions appear to accept will be expensed, but to this point Hydro appears to have included in regulatory deferrals.

addressed in this proceeding relates to transition provisions to achieve these methods, including disposition of the deferral accounts that have accrued since the 2012 GRA.

3.3.1 Group Procedure in Previous Board Orders

On the matter of group procedure, there is a lengthy and comprehensive record on the matter of a comparison between the two key procedures in Orders 43/13 and 73/15 (as well as 59/18 directing continuation of the ASL procedure for rate setting). The Board made numerous findings that rejected the use of the ELG procedure for rate setting, noting evidence in the proceeding that:

- Both ELG and ASL are acceptable for IFRS purposes.[52]
- Gains and losses on disposal, if greater under ASL than ELG, can be amortized into income over a defined period under rate regulated accounting.[53]
- ASL is used by the vast majority of North American utilities, "particularly Canadian Crown utilities and hydro-based operations".[54]

The Board also noted one other issue with ELG, namely the rate impact[55].

> …the Board, at this time, is not prepared to determine Manitoba Hydro's revenue requirement for rate-setting purposes based on a switch from the ASL methodology to the ELG procedure.
>
> Under either ASL or ELG, Manitoba Hydro is eventually made whole, since by the time an asset is decommissioned, the entire capital cost has been recovered by Manitoba Hydro from ratepayers. However, there is no doubt that over the next twenty years (the timeframe for Manitoba Hydro's integrated financial forecast), a switch to ELG would increase Depreciation Expense in every single year. Furthermore, Manitoba Hydro was unable to advise the Board at which point ratepayers should expect a "crossover point" at which the increased Depreciation Expense recovered in the early years reduces Depreciation Expense in the later years. As such, the Board must assume that during the entirety of the foreseeable 20 year planning horizon, a switch to ELG would increase the amount of Depreciation Expense consumers are expected to fund through their rates.
>
> For purposes of rate-setting, the Board orders Manitoba Hydro to continue to determine Depreciation Expense based on its existing ASL methodology at this time.

In that decision, the Board noted that Hydro did not accept that the ASL estimates before the Board were accurate for what it said would be the version of ASL required under IFRS. Hydro indicated it would have to do an "IFRS-compliant" version of ASL that included more components of assets, and so the comparison of ELG versus ASL costs that were before the Board at that time

[52] Order 73/15, page 39.
[53] Order 73/15, page 40.
[54] Order 73/15, page 40.
[55] Order 73/15, page 45.

was not accurate. The Board provided an opportunity for Manitoba Hydro to demonstrate that ASL procedure under IFRS would in fact be close to the costs of ELG[56], and to demonstrate the cross-over point at which the ELG procedure would become cheaper than ASL.

Hydro has now filed what it considers to be the study to fulfill that requirement, in Appendices 9.11 and 9.12.

3.3.2 Group Procedure (ELG versus ASL)

The ASL procedure applies a set of mathematics that is intuitively aligned with the expectations of a group of assets having a clearly estimated average service life. For example, The ASL depreciation rate, in its simplest form, for an asset with a 40 year life is 2.5%/year (or 1/40th). This 2.5%/year rate continues to be operative throughout the asset's life, whether it lasts 20 or 40 or 60 years.

Inherent in the use of the ASL Group Procedure is the concept of an asset group. This classification ("componentization") entails taking the utility's assets and grouping them with like assets who are expected to have similar average lives. Every group depreciation methodology requires such componentization or else the very concepts of average lives and actuarial analysis cannot be completed.

In order to know if an asset group is performing according to the estimate, the depreciation study will provide both an average life (i.e., 40 years), and a dispersion. The dispersion addresses the characteristics as to how the asset is expected to perform in relation to its average life. For example, a symmetrical dispersion of high mode will portray that the asset group will see many retirements between years 35 and 45, while a low mode may portray that the assets will see more retirements at 20 and 60 years (i.e., the retirement probability curve would have larger shoulders). Depreciation practice assigns these dispersions a value to indicate the degree of modality (or tightness) exhibited, typically from 0 to 5. Asymmetrical dispersions are also possible, skewed either to the right or left. Thus, a life estimate could be 40-S4, indicating a 40 year average service life, with a symmetrical dispersion and a relatively high mode. This nomenclature is sometimes known as an "Iowa curve" due to the origination at Iowa State University.

For the ASL procedure, the selection of a dispersion is typically of very limited importance. The dispersion is mostly needed to indicate if the asset group is showing excess early or late retirements, so that this variance can be quantified. The variance can then be amortized if desired, typically over the remaining life of the assets in the group.

It must be noted that the ASL procedure inherently includes recognition that some assets will retire earlier than the 40 year average, and some later, and this is not, in and of itself, an indictment of the 40 year life estimate, nor is it a "loss on retirement". It is simply a component of the estimation approach. The ASL procedure inherently does what Hydro now seeks to do with its deferred gains and losses account – that is, the impact of early retirements are effectively amortized over the remaining life of the assets in the group.

[56] Order 73/15, page 46.

The ELG procedure is a significantly more complicated refinement on the ASL procedure noted above. Just as ASL is applied to a group of assets, ELG first slices each group of assets into tiers that are expected to have equal lives. So, while ASL has a group for Wood Distribution Poles, ELG implicitly creates a group for Wood Distribution Poles expected to live 1 year, and a separate group for Wood Distribution Poles expected to live 2 years, and so on. ELG then creates a separate rate for each of these subgroups of theoretical equal life.

One complication arises in knowing how to slice the overall asset investment in a class into the differing estimated lives. The answer is reliance on the Iowa curve. The Iowa curve can indicate, say for a 40 year average life asset, what percentage should be assumed to retire in year 1, and in year 2, etc. up to years 70 or higher. However, this introduces a new and significantly more sensitive set of assumptions into the preparation of depreciation estimates – not only does the utility require a good estimate of how long the assets will live on average, but it also requires a detailed knowledge of just how the retirements will vary around the average. Solid estimates can be made of dispersion and the appropriate Iowa curve for assets with very good actuarial data, however this requires the data to be sound in multiple ways that is not typical of Hydro's assets:

1) First, the data generating the actuarial analysis has to include a large enough set of individuals. This may be true in some accounts (e.g., transmission towers, of which Hydro has thousands) but is not true for most of Hydro's generating accounts, where there is a very limited set of, for example, spillways or turbines or gates (i.e., dozens).
2) Second, the data has to be relatively complete through a large part of the asset's life cycle (e.g., for a 60 year life asset, one would need records over about 100 years to capture the dispersion experience). For most utility assets that are relatively long-lived, this is not typically available. It can be achieved with assets like trucks and computers, for example, which have shorter life cycles.
3) Third, the data from the past record has to be representative of future performance. Again, with longer life cycles, and changing technology, this can be difficult to achieve. Consider wood distribution poles. Hydro has a long history of experience with wood distribution poles; however, the technology of pole treatments and practices for stubbing, etc. have changed notably in recent years. Similarly Hydro's capital management approach may have also changed, leading to more or less repairs of damaged poles and a corresponding change in the rate of replacements – this also changes the life and dispersion parameters. Also, new poles are typically of different species and quality than older poles which often came from old growth trees.

It can be challenging enough to review asset performance under the above limitations to come up with reasonable estimates of average asset lives. The confidence related to knowing the correct dispersion as well is far more challenging. Some approaches can be used to help correct for this issue, including looking at peers to effectively broaden the set of data being considered, but this too introduces its own imprecision, as the peers may have different climate, maintenance practices, types of assets, etc. For this reason, the purported greater degree of accuracy under ELG, dependent upon selecting the correct dispersion, is not well-founded for most utility asset classes.

In terms of the mathematics of calculating the costs under each procedure, Hydro has presented a comparison of the costs of ASL and ELG, as follows[57]:

[57] PUB/MH-I-109.

Figure 1 Difference between ALG (ASL) and ELG Depreciation

Assumptions:

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

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

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

In the example above Hydro considers 3 assets of average age of 3, under both the ELG and ASL procedures. Hydro's portrayal attempts to indicate that the costs of these three assets to revenue requirement under ASL ($200,000; $100,000; $0) is more unstable and front-end loaded than under ELG ($183,000; $83,000; $33,000). However, the portrayal is deeply flawed for two reasons:

1) The analysis portrays a sort of terminal account, where there is no turnover or reinvestment.

2) The analysis books a loss on disposal under the ASL procedure, despite the assets performing exactly as intended in the depreciation estimates, and no loss on disposal has actually occurred. Absent this loss in disposal problem, the analysis indicates that customers in the first year would have experienced the services of three pieces of the sample equipment, at a cost of $150 ($50/piece of equipment/year). In year 2 the cost would be $100 for the services of two pieces of the equipment (again, $50/piece of equipment/year), and in year 3, the cost would be $50 for the services of one piece of the equipment. This is the inherent fairness to customers in the ASL procedure, and underlines why the apparent "loss" on disposal that Hydro attempts to book in year one, purportedly to protect customers in years 2-3 from carrying the costs of a piece of equipment they no longer use, is not supported by the mathematics. Customers in year 2 or 3, paying $50/piece of equipment/year, are not being burdened as a result of the early retirement on the first unit. In contrast, under the ELG procedure, the cost of services from three pieces of equipment in year 1 is $183 ($61 per piece of equipment/year), in year 2 it is two pieces for $83 ($41.50 per piece of equipment/year) and in year 3 it is $33 for the service of one piece of equipment, even though in each case the unit is providing one unit-year of service. This is a clear portrayal of the front loading of costs associated with the ELG procedure. This also emphasizes why ELG does not lead to just and reasonable rates for different generations of customers.

Hydro further introduces flaws into their description of the above figure by noting[58]:

> Had the assets in Group A been divided into three separate component groups based on their service lives, as is required under IFRS, then the annual depreciation expense would have been equal to the expense determined under the ELG procedure.

This mixes entirely the concept of group depreciation with componentization. Hydro attempts to imply that at the outset there are 3 assets which are already known to have differing lives, and the scenario simply tries to lump the assets into the same non-homogenous class. This is not a correct description whatsoever of asset dispersion. The concept of 3 assets in a class are that at the outset they are not distinguishable. They are, for example, 3 distribution poles of the same quality and composition. One may be hit by a car in year 1, but we do not know whether this will occur, or which one. One may be struck by lightning in year 2, and one may fail due to rot in year 3. At the outset one could never break these poles into their own classes. All one knows at the beginning is that the poles will live an average of 2 years, with a symmetrical dispersion (and even this is an estimate). It is important to note that this is true under ASL or ELG – all grouping of assets must be done with like assets in a group, and there is no exemption for kludging non-alike assets into the same class just because the ELG procedure is being used.

[58] PUBub/MH-I-109, page 4.

In order to address the above concerns, a more appropriate example of a continuing property account the following example is provided:

Table 3-1: Depreciation Expense ELG versus ASL

Depreciation Expense for 4 Trucks, at 2.5 year average life, over 5 years.

			Capital spent						
	year		0	1	2	3	4	5	
Truck number				unit 1 replaced at end of year	unit 2 replaced	unit 3 replaced	unit 4 replaced	all retire at end of year	
1	retires 1, 5		100,000.00	100,000.00					
2	retires at 2, 5		100,000.00		100,000.00				
3	retired at 3, 5		100,000.00			100,000.00			
4	retires at 4, 5		100,000.00				100,000.00		
2.5 yr average life									
Depreciation expense									Total
	ASL	Gross Book		400,000.00	400,000.00	400,000.00	400,000.00	400,000.00	
				40%	40%	40%	40%	40%	
	ASL depreciation			160,000.00	160,000.00	160,000.00	160,000.00	160,000.00	800,000.00
	ELG	GBV 1 year old		400,000.00	100,000.00	100,000.00	100,000.00	100,000.00	
		rate		52.08%	52.08%	52.08%	52.08%	52.08%	
		GBV 2 year old		-	300,000.00	100,000.00	100,000.00	100,000.00	
		rate		36.11%	36.11%	36.11%	36.11%	36.11%	
		GBV 3 year old		-	-	200,000.00	100,000.00	100,000.00	
		rate		29.17%	29.17%	29.17%	29.17%	29.17%	
		GBV 4 year old		-	-	-	100,000.00	100,000.00	
				25.00%	25.00%	25.00%	25.00%	25.00%	
	ELG depreciation			208,333.33	160,416.67	146,527.78	142,361.11	142,361.11	800,000.00
Added Cost of ELG									
	NBV ASL		400,000.00	340,000.00	280,000.00	220,000.00	160,000.00	0	
	NBV ELG		400,000.00	291,666.67	231,250.00	184,722.22	142,361.11	0	
	cumulative added cost of ELG			48,333.33	48,750.00	35,277.78	17,638.89	0	

Development of rates	
ASL rate	
1/2.5=	**40%**
ELG rate	
age of vehicle	
1	100%
	50%
	33 3%
	25%
	208 3%
	/4
	52.1%
2	50%
	33 3%
	25%
	108 3%
	/3
	36.1%
3	33 3%
	25%
	58 3%
	/2
	29.2%
4	**25.0%**

In the above example, the asset in question that is providing service to customers is a fleet of four trucks, with an average service life of 2.5 years. Hence, to provide service for 5 years, eight individual trucks will ultimately be required. At the time of retirement, each asset is replaced with a new truck, because the utility requires four trucks at a time to fulfill its service to customers. The example ignores inflation and mid-year calculations for simplicity.

In the top of the table, the pattern of replacements is noted. As one truck retires at the end of year 1, it is replaced by a second, which is assumed to last for 4 years. Similarly, the second truck retires at the end of year 2, and replaced with a truck that lasts 3 years, etc. By the end of 5 years, the full fleet is retired, all trucks lasted an average of 2.5 years, and all original cost will have been recovered. Note that this is a valid group of assets – similar equipment grouped with an equivalent estimated service life, and with a pattern of dispersion about the average life.

On the right-hand side are the calculations of the depreciation rates. For ASL the rate is simple – it is 40% (1 / 2.5 years). For ELG, the rate depends on the age or vintage of the vehicle. For vehicles in their first year, the rate would be 52.1%. This is because they will have a 25% slice assumed to retire at year 1 (100% depreciation rate), a 25% slice that retires at year 2 (50% depreciation rate needed), a 25% slice that retires at year 3 (33.3% depreciation rate) and a 25% slice that retires at year 4 (25% depreciation rate). The composite rate then for a first year vehicle is 52.1% ((100%+50%+33.3%+25%) / 4).

If the vehicle survives to year 2, then there is a 1/3 chance of retiring when it is 2 years old (a 50% rate) a 1/3 chance of retiring when it is 3 years old (a 33.3% rate) and a 1/3 chance of retiring when it is 4 years old (a 25% rate) leading to a composite depreciation rate for vehicles in their second year of 36.1%.

The same pattern applies to vehicles in their third and fourth year. Note that to properly apply ELG then, it is important to calculate the depreciation rate <u>annually</u> to suit the vintage of the assets in service. Under Hydro's approach, this is not done. Hydro only periodically updates the depreciation study and also further hybridizes the ELG depreciation rates by age to a single rate applied to the entire group of assets – a further oversimplification which serves to undermine the purported accuracy of the ELG procedure.

Taking these rates and applying them to the fleet of trucks shown in the table, the ASL approach leads to customers facing depreciation expenses of $160,000 per year. This same value is maintained throughout the 5 years. The result is fair for rate setting since each year of customers received the same overall service (the service of 4 trucks).

Under ELG however, the depreciation expense declines from $208,333 in the first year to $142,361 in the final 2 years. This decline occurs despite the same level of service being provided in each year noted (4 trucks worth of service).

As to the concept of a crossover point, as requested by the PUB, the bottom of the page shows that although there is a crossover on depreciation expense (by year 3 the expense is lower under ELG than ASL), the overall investment by customers in the early years of the ELG approach is not brought back to zero until the entire account is retired in year 5. In other words, the concept of paying more now to pay less later does not yield net benefits, just front-end loaded charges.

Finally, one simplification made in the example further underlines the disadvantage of ELG for customers. Each new truck is amortized under ELG at 52.1% in its first year versus 40% under ASL. If this were a growing account (and particularly with inflation), with the size of the truck fleet being increased each year, then the ELG estimates could very well indicate a higher total expense in <u>every year</u>. In other words, the ELG proposition for customers is not to pay more now in order to pay less later – it can easily be pay more now to pay more later[59]. Indeed, every ELG study of utility property I have reviewed, from any utility, has shown a higher expense for ELG than for ASL using the same life and dispersion estimates, regardless as to the status of the utility in its asset life curves or maturity.

A further observation from the above table is that the ASL procedure results in $160,000 of depreciation in the first year, with a $100,000 retirement at the end of the first year. Under group depreciation, $100,000 of asset value, and $100,000 of accumulated depreciation would be retired at the end of year 1 leaving no gains and losses. Hydro effectively claims that this would result in only $60,000 in accumulated depreciation being recorded at the end of year 1 (depreciation of $160,000 less $100,000 of disposal), which is asserted to be insufficient for the 3 remaining trucks. Hydro's mathematics would indicate that there remain 3 trucks which have survived one year, out of a 2.5-year life (40% depreciation rate) so there should be $120,000 in accumulated depreciation (hence, a $60,000 loss on retirement of unit one should be recorded rather than charged to accumulated amortization). However, this is not accurate for a group procedure. The $60,000 in accumulated depreciation at the end of year one is precisely in line with the estimates for the account according to the depreciation study. There is no loss, and there is no revision to estimates required as the estimates remain in line with the projections.

In the alternative, if Hydro had recorded a $60,000 loss at the end of year 1, and maintained a $120,000 in accumulated depreciation, the account would eventually accrue excessive accumulated depreciation. This is because the ASL procedure is already recognizing this early retirement as part of the dispersion, and inherently amortizing it over the remaining life of the assets. For Hydro to either recognize the loss to income, or to recognize the loss to a regulatory deferral account and amortize it over the life of the asset, is to pancake a second method of addressing purported gains and losses on top of the already internally consistent ASL approach. No other utility which uses ASL that I am aware of attempts to short-circuit or pancake such a methodology as a regulatory deferral on top of the ASL procedure, which is already achieving the same objective.

Based on the above considerations, it remains appropriate for Hydro to use the ASL procedure for calculation of depreciation expense.

> **Recommendation 5: 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.**

[59] This is confirmed as an adverse effect of ELG in the depreciation literature, for example at NARUC, Public Utility Depreciation Practices, August 1996, page 178: "In a growing account however, a crossover point may never occur."

3.3.3 Componentization

As to the issue of componentization, at a simple level, the degree of componentization should not be permitted to be excessively coarse simply because of some concept that ELG will adjust for the attendant inaccuracies. This is simply not true. ELG will slice any group of assets in subgroups of equal life regardless as to how componentized the account may be – but if there are material 20-year average life assets (e.g., insulators) mixed into an account with 60-year assets (e.g., conductors), neither ELG nor the actuarial analysis on which it heavily relies, can properly remediate for the inconsistent data.

The componentization recommended in the Alliance study is suggested to only be required if the ASL procedure is used. This is not accurate, as it suggests ELG can readily mix material assets of different average service lives in the same accounts, which is not appropriate depreciation practice.

It should also be noted that the extra accounts which were recommended by Alliance were intended to address material groups of assets that were too coarsely componentized in Hydro's current accounts. Hydro claims that it worked with Alliance to "combine asset components of immaterial or insignificant results."[60] However, it does appear that many of the accounts created by Alliance may not meet a reasonable threshold for materiality. For example, In the Concentric study, the account 5000R captures Communication assets for Power System Control, totalling $10,268,504[61] with average service lives of 17 years. The Alliance study broke this account into three classes, as follows[62]:

5000R-02	Communication - Power System Control - Digital	992,757
5000R-03	Communication - Station Control & Monitoring - Analog/Mechanical	227,223
5000R-04	Communication - Station Control & Monitoring - Digital	9,048,523

The two new classes, at less than $1 million each, represent trivial components of Hydro's asset base (0.0045% and 0.0010% respectively). It appears highly unlikely that without this componentization of less than $1 million in assets, Hydro's accounts would not be IFRS compliant. There are multiple examples in the Alliance report where new accounts have been created with $5-10 million or less in assets, which would not appear to be material to the overall depreciation estimates.

The evidence of Hydro in respect of the Alliance study also appears to overstate the conclusions that Alliance has reached. Hydro notes[63]:

[60] PUB/MH-I-131a; also see PUB/MH-I-139b.
[61] Application, Tab 10, MFR 95 Attachment, pdf page 77.
[62] GSS-GSM-MH-II-1, Excel supporting file.
[63] Application, Appendix 4.3, page 21.

> The IFRS-compliant ASL study as compiled by Alliance determined that Manitoba Hydro would require 410 additional asset components to comply with the degree of granularity required for determining total depreciation expense (including gains and losses) under IFRS-compliant ASL. (emphasis added).

However, Alliance does not so characterize their work as establishing a requirements, as follows[64]:

> [Q:] Does Alliance indicate that anything less than 410 new accounts would not be IFRS compliant? If so, please provide a detailed description why this is the case.
>
> [A:] No, although Alliance believes that the additional groups represent their best estimate for creating groups with homogeneous lives, Alliance does not indicate that using anything less than 410 new accounts would not be IFRS compliant.

The evidence also indicates that although Alliance has completed approximately 100 depreciation studies in the last 5 years, only 3 of these studies were for utilities that use IFRS[65].

In short, the support for an absolute requirement for 410 new accounts is weak.

It should also be noted that the Alliance study adds approximately 20 accounts to the major hydraulic generation stations[66], and there are 15 such hydro sites. This accounts for approximately 300 of the 410 new accounts. However, these are not unique individual accounts. These accounts are simply a location code added to an asset class, with their own unique depreciation rate that is easily calculated to reflect individual hydro site life spans. There is no need to complete the same degree of actuarial analysis and monitoring of each of these accounts as their would be if they represented unique types of assets. As such, the additional work implied to manage this breakdown is overstated.

If the evidence of Hydro is that more componentization is needed to properly group like assets with like, and such componentization is needed to have an IFRS-compliant account structure, then there should be no relief from implementing this account structure simply because ELG is used as the depreciation procedure. There should also be no relief permitted by the Board in order to ensure ratepayers are paying appropriate provisions for depreciation, which would not be achieved with an inadequate componentization.

> **Recommendation 6: 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 7: 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**

[64] MIPUG/MH-I-91i.
[65] MIPUG.MH-I-91a-dd Attachment 2 (updated).
[66] Per Appendix 9.11 page 167 Alliance is recommending 34 accounts per site including depreciated and amortized plant; per MFR-95 Attachment 1, Concentric routinely uses approximately 14 accounts per site.

continuing activity, consistent with capital asset tracking within any utility as part of maintaining accurate capital asset accounts.

3.3.4 Gains and Losses on Disposal

On the matter of gains and losses, Hydro has indicated that it must book gains and losses under both ELG and ASL where retirements occur that have a realized life different than the average service life. Further comment is provided below regarding the specific mathematical approach taken by Hydro to calculating and recognizing gains and losses, and why it is problematic. At a high level though, the concept of gains and losses as expressed by Hydro is inconsistent with group depreciation at its core. The retirement of an asset is not to be judged on its own performance, comparing the accumulated depreciation on the asset to the original cost retired. This is the practice one would apply under unit accounting, where each asset is treated in effect as its own account. Hydro does not use unit accounting.

Indeed, in group depreciation, there is no specific accumulated deprecation of each asset – there is only the accumulated depreciation of the group. Any calculation, much less financial recognition of a gain or loss is a corruption of the vary nature of group depreciation. If the truck that retired at year one in the above example was transacted with a loss due to it not performing to the 2.5 year average, then the booking of that loss outside of normal depreciation accounts would undermine the concept of the 40% depreciation rate being applied to the remainder of the continuing group. Taking the loss onto the income statement would drive large surpluses in the accumulated depreciation for the group, since the 40% rate being charged to assets at, for example, year 4 would no longer be necessary. As noted in the Manual on Public Utility Depreciation Practices published by NARUC[67]:

> Under group depreciation, no gain or loss is recognized for retirement of individual assets. Upon retirement of an asset from the group, the cost of the asset is debited to the accumulated depreciation account and credited to the asset account. Any gross salvage received for the retired asset is credited to the accumulated depreciation account and any cost of removal is debited to the accumulated depreciation account. Under group depreciation, since the accumulated depreciation relates to the entire group rather than to specific assets within the group, no gain or loss is recognized.

The expected outcome of booking gains and losses will almost universally be losses, as the largest value assets will almost always be the newest assets due to inflation, and it is these assets that are presently exposed to retirement before their average age has been reached (since they are young)[68]. Booking losses to regulatory deferrals will drive surpluses in accumulated depreciation. Indeed, this effect is what is seen in Hydro's depreciation studies. The latest Concentric studies

[67] National Association of Public Utility Commissioners, Public Utility Depreciation Practices, August 1996, page 49.
[68] The so-called gains on 100 year old Pointe du Bois turbines may match so-called losses on Pointe du Bois turbines from 1930, but due to their asset value, any possible recent gains on Pointe du Bois turbines will never offset a potential concurrent loss on a Limestone turbine at a young age, if they occurred in the same year.

show that under ELG, Hydro has surplus accumulated depreciation of $857 million[69] while under ASL the surplus is $1.262 billion[70]. At 2014, the equivalent amounts were $607 million for ELG[71] and $1.024 billion for ASL[72], a growth of approximately $250 million. The growth would reflect in part changes to average service lives (mostly lengthening) but also the fact that Hydro is booking gains and losses out of accumulated depreciation, despite the fact that Hydro's depreciation rates already inherently include amortization of these gains and losses. Note that in each past Concentric depreciation study, the estimated surpluses that then existed were already scheduled to be amortized to income and therefore should have declined over time, not have grown.

Despite the above considerations rejecting the concept of recognizing gains and losses on disposal as being inconsistent with group depreciation, it is noted that Hydro may be in a position where such recognition is required by Hydro's auditors. In this case, largely the same mathematical outcome can be achieved so long as the following conditions are met:

(a) The gains and losses should be tracked by account (not at the Corporate level).

(b) Gains and losses in each account are amortized over the average remaining life of the assets in the account (calculated consistent with the ASL procedure).

(c) Depreciation studies continue to be completed on a whole life basis, with accumulated depreciation variances similarly amortized over the average remaining life of the assets in the account.

Under this approach, Hydro may need to rely on regulatory deferrals to ensure the IFRS and regulatory books remain consistent.

It would be highly inferior to combine the gains and losses transactions into a single account across multiple asset types that is averaged over the remaining life of all of Hydro's assets. This approach is excessively coarse and would not be appear to be required if the transactions can be tracked to each group account in the first place.

> **Recommendation 8: 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.**

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[69] Application, MFR 95 Attachment, pdf page 62 at $846 million for Manitoba Hydro, plus Wuskwatim at pdf page 64, at $11 million.
[70] Application, MFR 95 Attachment, pdf page 92 at $1.249 billion for Manitoba Hydro, plus Wuskwatim at pdf page 94, at $13 million.
[71] Hydro 2015 GRA Application, Appendix 5.6, pdf page 89, at $603 million for Manitoba Hydro, plus Wuskwatim at pdf page 91 at $4 million.
[72] MIPUG/MH-I-22b from the 2015 GRA, Manitoba Hydro at $1.015 billion at page 20, and Wuskwatim at $9 million at page 22.

3.3.5 Transition Provisions re: Regulatory Deferral Accounts

Regardless as to the ultimate methodology selected, Hydro seeks approval for transition provisions to address the following:

1) **IFRS Phase-in Deferral:** A new account to phase-in the impacts of adoption of a final permanent depreciation procedure. Hydro recommends that this be the IFRS ELG that it has sought since the 2012 GRA. Hydro recommends that the impact, which is estimated at $70 million per year and growing[73], be phased-in through increases of approximately $5 million per year until fully implemented[74] (by 2036/27) and that the balance be amortized to income over 30 years. Depending on the definition of the amortization period, it appears this would lead to amortization of the deferral continuing to either the 2053/54 or the 2065/66 year.
2) **Change in Depreciation Method Deferral:** This account has been in place to capture the difference between the depreciation expense that Board has deemed fair and reasonable for rate setting purposes (ASL), and the more aggressive depreciation expense that Hydro elected to implement for financial reporting purposes upon transition to IFRS (ELG). The balance in the account at year-end 2022/23 is projected at $329 million[75]. Hydro has proposed that this amount be amortized to income starting September 1, 2023, over a period of 30 years for Manitoba Hydro assets, 42 years for Wuskwatim Power LP ("WPLP") assets, and 62 years for Keeyask Hydro LP assets ("KHLP")[76]. These time periods are reported to reflect the average remaining life of the assets in each entity.
3) **Loss on Retirement or Disposal of Assets:** Hydro is seeking approval to amortize $67 million recorded in the regulatory deferral for loss on retirement or disposal of assets. Hydro seeks amortization over a period of 26 years for Hydro, 27 years for WPLP, and 58 years for KHLP, reflecting the weighted average probable remaining life of the assets that contributed to the deferral balance. However, as noted above, almost the entirety of this account relates to either discontinued operations of to salvage expenses that were meant to be expensed. The preferred outcome for these accounts is to be written-off in 2022/23.

For the **IFRS phase-in** (proposed new account), explicit amortization over an excessive period does not appear reasonable and does not mitigate the issue of ELG being an inappropriate depreciation procedure for a Crown-owned hydro-based long-lived asset utility. Further, the transition to ELG is not an enduring benefit that should be deferred so future customers can pay extra to amortize the deferred amount. The Board should make a determination as to the preferred depreciation approach, and this methodology should be fully reflected in the utility's accounts to ensure accurate portrayal of the consumption of the assets in service. No deferral should be used or needed. Also note that the deferral would be a non-cash effect, so of somewhat limited value.

[73] Application, Appendix 4.3, page 30. Corrected Feb 2, 2023.
[74] Application, Appendix 4.3, page 31. Corrected Feb 2, 2023.
[75] Application, Tab 10, MFR 16, Figure 1.
[76] Application, Appendix 4.3, page 31.

In respect of the $329 million **Change in Depreciation Method Deferral** (existing), the portrayal that customers are somehow underpaid on depreciation runs counter to the findings of every depreciation analysis filed in this proceeding. In each of the depreciation studies in this proceeding, the analysis indicates Hydro's asset base is in fact significantly over-depreciated compared to current estimates (i.e., there is an accumulated depreciation surplus). In each study, whether ASL or ELG, and whether using Concentric or Alliance componentization and life estimates, the degree of surplus far exceeds the balance in the depreciation methods deferral account, as shown in the following Table 3-2:

Table 3-2: Accumulated Depreciation Surplus ($M) Under Four Studies

Accumulated Depreciation Surplus ($M)
as at March 31, 2019

	ELG		ASL	
	Concentric	Alliance	Concentric	Alliance
Hydro	845.5	736.2	1249.0	1216.9
WPLP	11.2	4.1	12.9	3.0
Total	856.7	740.3	1261.9	1219.9
reference:	MFR-95	MIPUG/MH-II-28a-g Attachment 1	MFR-95	MIPUG/MH-II-28a-g Attachment 2

As noted in Table 3-2 above, depending on the methods selected, the current depreciation estimates put the level of calculated accumulated depreciation below what Hydro presently has recorded somewhere between $740 million and $1.261 billion (i.e., a large surplus). Given this degree of variance, there would appear to be potential for discharging the entire balance in the Change in Depreciation Method Deferral as an offset to accumulated depreciation, by account. This is possible because the Depreciation Method Deferral arose from a set of calculations at the account level, so should be readily credited to each existing account. Mathematically, this would have a similar effect as proposed by Hydro (i.e., deferral over remaining life), as it would reduce the degree of variance that is presently being amortized into rates over the remaining life of the assets implicitly as part of the derivation of the amortization of reserve differences or "true-up".

In short, there does not appear to be the need for any special transition accounts to implement a set of appropriate depreciation parameters and methods consistent between the regulatory accounts and the IFRS accounts.

> **Recommendation 9: There should not be a new IFRS Phase-In Deferral created nor needed to adopt appropriate depreciation practices at this time.**
>
> **Recommendation 10: The Change in Depreciation Method Deferral, totalling $327 million at year-end 2022/23, should be discharged as an offset to accumulated depreciation, by account.**

3.3.6 Issues Arising from Hydro's Response to Depreciation Directives

In addition to the above considerations supporting the recommendations in this submission, comment is merited on a number of claims made in the Hydro materials regarding depreciation.

Does the Alliance study confirm that a more componentized ASL is of equivalent cost to ELG?

No. Alliance provides a comparison of ASL and ELG under a more componentized framework in MIPUG/MH-II-28a-g Attachments 1 and 2. The data indicates that under the more componentized account structure, annual depreciation under ASL for Hydro (including WPLP but excluding KHLP) is $458.5 million[77], while under the more componentized ELG, annual depreciation is $474.7 million[78] (KHLP would significantly add to this divergence). As noted earlier in this submission, each of these procedures is entirely internally comprehensive with respect to the handling of gains and losses, so can be directly compared without further adjustment.

Does the Alliance study confirm that a more componentized ASL is of equivalent cost to ELG as applied by Manitoba Hydro?

No. The Alliance study cannot be compared to the Concentric ELG study performed for Hydro as they use a different approach to life estimation, with Alliance electing to be generally more aggressive.

For example, Concentric considers the entirety of the account 2000L Overhead Conductors and Devices to merit an average life of 85 years (85-R3). Concentric notes "These assets are rarely retired except to increase load"[79]. Concentric relied on the actuarial data to estimate the 85-year life, noting it had a better Residual Measure (i.e., curve fit) than the previous 80-year life.[80] Concentric also calculated that on an ELG basis, this account had accumulated depreciation of $173 million but only required $125 million at an 85-year life estimate[81]. In other words, this account was already outperforming the ELG estimates by $48 million, leading to a large surplus accumulated depreciation (under ASL the surplus was even larger, at $59 million)[82].

Alliance however componentized this account into two parts – 2000L-01 (Overhead Conductors and Devices) representing approximately 90 per cent of the investment and 2000L-02 (Spacer Dampers) representing approximately 10 per cent[83]. The first category received an 85 year life (85-R4), while the second received a 20 year life (20-S6)[84].

In fact, data indicates that half of the retirements in the account to date are of spacer dampers, not conductor[85] even though these assets make up only 10% of the account. Under actuarial life

[77] MIPUG/MH-II-28a-g Attachment 2 pages. MIPUG/MH-II-28d notes: "Attachment 2 provides Average Life Group depreciation schedules and rates determined by applying the whole-life technique and depreciation parameters identified in the IFRS-compliant ASL Depreciation Study (Appendix 9.11). The included schedules separately identify the portion of depreciation expense associated with life and with amortization of the accumulated depreciation variance."

[78] MIPUG/MH-II-28a-g Attachment 1 pages 12 and 14. MIPUG/MH-II-28c notes: "Attachment 1 provides Equal Life Group depreciation schedules and rates determined by applying the whole-life technique and the depreciation parameters set out in Appendix 9.12 Attachment 1 and provided in MIPUG/MH I-91cc, which reflect equivalent service lives to those in use in the IFRS-Compliant ASL Depreciation Study (Appendix 9.11)."

[79] Tab 10, MFR 95 Attachment, pdf page 18-19.

[80] Tab 10, MFR 95 Attachment, pdf page 19.

[81] Tab 10, MFR 95 Attachment, pdf page 60.

[82] Tab 10 MFR 95, Attachment, pdf page 90.

[83] GSS/GSM-II-1 Excel supporting document.

[84] PUB/MH-I-128a-f Attachment 1 page 15.

[85] MIPUG/MH-I-91a-dd Attachment 8 page 27.

analysis, Concentric has already accounted for the shorter life of spacer dampers in determining an 85-year average life.

The reason for Alliance's ASL study leading to higher depreciation expense than Concentric's ASL study is because Alliance is more aggressive with lives. Alliance concurs with Concentric's 85-year average for the conductors, but then removed the shortest average life assets that were key to the Concentric actuarial analysis, making up 50% of experienced retirements. For a fair comparison of the effects of componentization, it would be necessary to adopt the shorter life for Spacer Dampers (which may be justified as a new componentized account) but also adjust the average life of the remaining balance to address that the shortest-lived components are now removed.

Absent this adjustment, the Alliance report simply adopted an effective life for the overall 2000L account that is indicated to be equivalent to an 80-R3[86]. Any study that shortens lives will indicate a higher depreciation expense. This is not a function of componentization.

A similar effect occurs on account 000D Spillways, per MIPUG/MH-I-91v. Concentric uses a 90-R3.5, while the composite Alliance life for the account is 86 years. Further, Concentric's notes indicate that Hydro staff report "there may continue to be an extension of the service life for this account"[87] which was not taken into account in the Alliance report[88].

This is not to minimize the Alliance finding regarding spacer dampers. The fact that over $80 million of assets that typically last 20 years were being depreciated as if they last 85 years is problematic, and likely merits a new component. This is true under ELG or ASL. The difference in annual depreciation expense on this asset is material, at approximately $3 million ($80 million divided by 20, versus $80 million divided by 85). The net effect would likely be much smaller, as the remaining conductor likely merits a longer life, such as 90 years, to maintain the Concentric average rooted in actuarial analysis.

Does IFRS-compliant ASL better track retirements than CGAAP ASL?

Not materially. Hydro provides a comparison of the two ASL approaches in PUB/MH-II-39, indicating that under the Alliance IFRS-ASL the gains and losses in the test years would be $28 million per year, while under the CGAAP-ASL the gains and losses would be $23 million per year (this compares to Hydro's calculation that under ELG the gains and losses would be $3 million per year[89]). However, this comparison is misleading for two reasons:

First, the differences between Concentric's ASL gains and losses and Alliance's is not due to componentization, it is due to the fact that Alliance has been more aggressive in setting service lives. Any method that drives higher depreciation expense will drive less computed so-called gains and losses (which, as noted above, is a misnomer when it occurs consistent with the ASL estimates).

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[86] MIPUG/MH-II-28a-g Attachment 1, page 9.
[87] Tab 10, MFR 95 Attachment, pdf page 14.
[88] MIPUG/MH-I-91v.
[89] Appendix 9.12, Figure 7.

In any event, the purported benefits of a far more componentized account structure to reduce recorded gains and losses, which only serves to reduce the gains and losses by $5 million, underlines why this exercise has not yielded the results intended by Hydro.

Is Hydro's calculation of Gains and Losses on disposal appropriate?

No.

The language Hydro uses to explain the adjustments that it provides each year for the regulatory deferral is that it captures "gains and losses on retirement of assets"[90]. Hydro provides a detailed database showing how the value is calculated in PUB/MH-I-130 Excel supporting file.

In that Excel file, Hydro provides lengthy lists of retirement transactions and compares each to the respective ELG or ASL curves to determine if each transaction led to a gain or loss on retirement. Hydro does not appear to apply a materiality threshold – in some cases gains and losses of tens of dollars or less are recorded[91]. Issues with this approach under a group accounting method are already addressed above.

An additional issue arises in reviewing the data however, in that Hydro routinely records what it considers to be gains on retirement when there was in fact no retirement of assets. This is explored further in MIPUG/MH-II-28f where Hydro confirms one example (of many) where there was no retirements whatsoever in a year, but the utility recorded a $153,505.91 gain. In that case, the transaction is from the 2014/15 transaction database for Great Falls GS. Hydro provides no accounting standards that permit such recognition of a gain, only noting that[92]:

> The accounting standards do not provide explicit direction with the respect use of the ELG depreciation procedure and as such professional judgement is required in the application. The determination of a gain for a year in which no retirements occur for a given account is an indication that the account has been depreciated too quickly, and the assets which were predicted for retirement have become fully depreciated without being retired. As such, recognition of a gain in this circumstance serves as a correction to depreciation expense.

First, this response indicates an obvious issue with classifying the transaction as a gain on retirement. There was no retirement.

Second, the accounting basis for recording a gain tied to a non-event raises issues that would appear to poorly fit the basis of a realized event requiring recognition.

Third, at best the transaction described is not a retirement-related transaction, it is an updated estimate of asset performance. This is the very function of a depreciation study, conducted periodically (or a limited analysis termed a "technical update" by depreciation professionals). Hydro has in effect created an entire second level of depreciation studies occurring annually to mimic (and effectively undermine) the entire function of a depreciation study analysis. As a result, the entire scheme of gains and losses that has been created appears to be an unprecedented construct

[90] Appendix 4.3, page 5.
[91] See PUB/MH-I-130 Excel file, tab "Actual ELG G-L by Acct for examples, in column Q.
[92] MIPUG/MH-II-28f.

that duplicates the purpose of accumulated depreciation and group accounting. For this reason, elimination of the use of booking gains and losses outside of accumulated depreciation requires revision.

Adoption of the approaches set out in this submission, relying on industry standard depreciation practices, is merited.

Does the ELG approach closely track retirements?

No. The retirement data in PUB/MH-I-130 Excel attachment provides the actual retirements by year, versus the ELG predicted retirements. As noted in the response to MIPUG/MH-II-27i and j, the ELG method predicts that Hydro will experience $686.1 million in retirements over the period 2015-2022. Instead, Hydro only experienced $581.9 million in retirements[93], over $100 million in difference, or almost 20%. This is a common characteristic of ELG – the use of Iowa curves can generate predictions of small but not immaterial retirements of assets at young ages that typically do not occur. As these assets are the highest value assets on the system, the ELG procedure can often drive depreciation expense higher based on expectations of retirements that are uncommon. In this way, the ELG procedure has not better tracked retirements and gains and losses than other procedures, it has simply front-loaded the accrual of accumulated depreciation.

Any approach that front-loads depreciation will appear to minimize the so-called losses on retirement that Hydro calculates. However, this is not a desirable criterion for developing appropriate depreciation expense, or fair rates that reflect the service value received from all assets serving customers. This is part of the reason why ELG is poorly suited to setting fair rates.

[93] MIPUG/MH-II-27i and j.

4.0 COST OF SERVICE AND RATE DESIGN

4.1 OVERVIEW

Manitoba Hydro has provided an updated Prospective Cost of Service Study ("PCOSS") for the 2023/24 fiscal year (PCOSS24) in Appendix 8-1. Manitoba Hydro indicates PCOSS24 reflects the directives from the last major COS review in 2016 (Order 164/16) as well as minor refinements ordered in the one GRA proceeding since that time (Order 59/18)[94].

In this GRA, Hydro seeks approval for one additional change, related to LED lighting, which has minimal impact on most customer revenue:cost coverage ratios ("RCC"s) for most classes outside of lighting. RCCs are the key output of a cost-of-service study, indicating if each customer class is paying fair rates. The Board has accepted that reasonable rates arise if the RCC for a class is generally varying between 95% to 105%[95]. Otherwise, updates applied by Hydro are reflective of small revisions and responses to outstanding directives from the Board.

Hydro's application highlights that the impact of the methodology changes directed since Order 164/16 are of very small magnitude on RCC ratios (0.7% or less[96]), other than for the LED lighting class. However, there is one exception related to Directive 27 from Order 59/18, regarding the approach used by Hydro to address export revenues, which is addressed in this submission.

The PCOSS otherwise largely follows the approved methodology from the 2016 review.

In a few specific cases, the facts regarding Hydro's system or precedent for COS practice (i.e., the recent Centra review) have evolved since the 2016 review, necessitating important updates to individual methodological elements of the Hydro PCOSS study. These are addressed below.

4.2 EXPORT REVENUE TREATMENT

In preparing the COS study, Hydro will first include all costs to operate the system, and compare these costs with the revenues from each class of domestic customer. As is to be expected, this approach will show a material shortfall, as up to this stage the analysis ignores export revenues which pay for a significant portion of the generation and transmission system (i.e., matches <u>all</u> costs with only <u>domestic</u> revenue).

In order to include the export revenues in the COS analysis, Hydro is required to provide a projection of the export revenues and include these as an offset to the costs of generation and transmission (generally, the "offset approach"). Hydro has at times instead credited the export revenues to the individual classes, as if these revenues were a supplement to the revenues paid by the class, rather than an offset to the system costs. The Board reviewed the offset approach (which it termed the "alternative methodology") in the previous GRA, and explained the rationale for adopting this approach in Order 59/18, as follows[97]:

[94] Hydro Application, Tab 8, page 7.
[95] Order 59/18, page 197.
[96] Hydro Application, Tab 8, page 8.
[97] Order 59/18, page 197.

> Further, the Board finds that the alternative methodology is consistent with cost causation. As stated by the Board in Order 164/16, "export revenues are not a 'dividend' that can be assigned or based on considerations other than cost causation". The domestic customer classes incur costs to facilitate Manitoba Hydro's export business. Treating export revenues as a reduction of allocated costs in the Revenue to Cost Coverage ratio aligns with the economic justification for major capital projects such as Keeyask, which is based on using the full quantum of export revenues to lower the cost of new generation and transmission.

The offset approach is also consistent with the literature on COS, such as the National Association of Regulatory Utility Commissioners (NARUC), which notes[98]:

> In addition, revenues collected from non-firm opportunity sales or coordination type sales, are normally treated in the same manner as other operating revenues. The retail service customers are normally given credit for these revenues through a reduction in their revenue requirements since they are produced through the use of plant or utility personnel, the expenses of which are borne by the utility's retail service customers.

It must also be noted that the above two differing treatments of export revenue (the approved offset approach and the dated revenue allocation approach) make no difference whatsoever to the dollar value of distinction between what a customer class pays, and what costs they are allocated[99]. For example, PCOSS24 shows that Residential customers pay a total of $831.6 million in revenues, and are allocated $1352.4 million of costs before export revenues are included in the study. This would indicate a shortfall of $520.8 million; however, this result is not meaningful. The result only becomes meaningful once an export credit of $471.2 million is applied to this class, yielding a shortfall of $49.6 million. Under either approach, this shortfall will be $49.6 million.

The distinction arises considering whether the $471.2 million is applied against the cost otherwise allocated to the class ($1352.4 million) or as an adder to the class revenues ($831.6 million). While the shortfall remains $49.6 million, the calculated RCC ratio will differ, as shown in the following table:

[98] National Association of Regulatory Utility Commissioners (NARUC), (January, 1992), Electric Utility Cost Allocation Manual, Chapter 2: Overview of Cost of Service Studies and Cost Allocation, page 31.
[99] Coalition/MH-I-156a.

Table 4-1: Comparison of Export Revenue Treatment Approaches

$millions		Costs		Revenues	Surplus/(Shortfall)	RCC ratio
Offset Approach		$1,352.4				
(approved)	less:	$471.2				
	total	$881.2		$831.6	$49.6	94.4%
Revenue Approach				$831.6		
(previous)			plus:	$471.2		
		$1,352.4	total	$1,302.8	$49.6	96.3%

As indicated in Table 4-1 above, the shortfall of $49.6 million remains the same regardless as to the approach. However, under the previous approach, the RCC ratio is obfuscated to appear as if the class is closer to 100% (only 3.7% away, at 96.3%) than merited. The reason this occurs is that by using the previous approach, the export revenues make the cost and revenue figures appear bigger, which reduces the apparent import of the $49.6 million shortfall.

However, this obfuscation is apparent when comparing the $49.6 million shortfall against the revenues actually paid by the class, $831.6 million. In other words, to fully close the gap, a rate increase of $49.6 million is needed on a class with revenues of $831.6 million. The required $49.6 million increase divided by the $831.6 million in existing rates yields a 5.96% rate increase requirement to reach full cost recovery, solely for the purposes of fair cost allocation (assuming no other changes in Hydro's costs). This 5.96% requirement is clearly outside the concept of a ZOR of 95% to 105%. Under the previous revenue approach, the reported RCC would inaccurately portray that the customer class is within the ZOR.

Hydro has indicated that the approach to export revenue allocation is a major change in the PCOSS24 RCC ratios, as indicated in the third column from the following table (re: Directive 27) taken from the Application[100]:

[100] Hydro Application, Tab 8, page 8.

Figure 8.2 RCC Impact of Methodology Changes

Customer Class	Directives 24-26 (NT Transmission, GSL Customer Service, Service Drop, Common Costs)	A&RL LED DSM	Directive 27 (NER in RCC Calculation)	Total
Residential	-0.2%	0.1%	-1.9%	-2.0%
GSS Non-Demand	0.0%	0.1%	3.5%	3.6%
GSS Demand	0.1%	0.1%	0.6%	0.8%
GSM	0.0%	0.1%	0.1%	0.2%
GSL 750V-30kV	-0.1%	0.1%	-0.9%	-0.9%
GSL 30-100kV	0.6%	0.1%	5.8%	6.5%
GSL >100kV	0.7%	0.1%	6.3%	7.1%
A&RL	-0.2%	-11.8%	0.8%	-11.2%

However, the impacts noted above are primarily a function of how far each class is from the 100% RCC ratio. The table does not indicate a change in the degree of shortfall, nor in the magnitude (all negative values are associated with classes that are presently underpaying, and all positive values are associated with classes that are presently overpaying). The table only indicates a change in the degree of urgency with which the Zone of Reasonableness should be interpreted to require rate action to achieve fairness. In other words, maintaining the methodology change helps ensure customer classes which are far from 100% (particularly GS Small Non-Demand, GSL 30-100 kV and GSL >100kV) receive timely relief.

Recommendation 11: The Board should continue to apply its finding from Order 59-18 that Export revenues should be a reduction to allocated class costs.

4.3 USE OF 2023/24 FORECASTS

PCOSS24 is based on the forecast cost and revenue values for fiscal 2023/24. Under the Hydro approach to COS modelling, the entire PCOSS model always balances – costs equal revenues at the system-wide level. This is done by including Net Income as a cost that must be paid for by customers. In 2023/24, Net Income in the PCOSS year is anomalously large ($474 million), so this Net Income must be included in the PCOSS24 costs and recovered from customers[101].

The reason for the anomalously large Net Income is due to somewhat high starting reservoirs for the 2023/24 fiscal year. Although reservoirs are projected to be high to start the year, the majority

[101] Appendix 8.1, PCOSS24, page 22.

of the annual hydrological resource comes from precipitation within the year, which is forecast at typical levels, so the impact of high starting reservoirs is largely muted[102]. Nonetheless, there is a small effect from the high starting reservoirs.

At the same time that a relatively high net income is included for 2023/24, there is also a relatively high export revenue projection compared to normal water flows.

Manitoba Hydro provided its assessment of the robustness of PCOSS24 for rate setting purposes as follows[103]:

> Manitoba Hydro's PCOSS has been developed with a deliberate effort to avoid and eliminate variability wherever possible. The second test year is used for the study in part because it includes average export revenues that consider a range of flow data and is also less likely to be impacted by abnormal levels of water in storage compared to the first test year. Other inputs that help minimize variability include the use of weather normalized customer load, and load research that is averaged over eight years to develop normalized estimates of class demand. A PCOSS prepared on this basis is the appropriate benchmark to use to guide gradual adjustments to rates in order to achieve target RCCs over the long term.

As compared to PCOSS21, both generation assets and export revenues are up significantly, as the Keeyask generation is now in service (PCOSS21 included zero units of Keeyask at the start of the year, and only 5 of 7 units by the end of the year[104] and with little export revenue arising from Keeyask in the year due to this staged in-service). PCOSS21 provides very limited value as for comparison purposes for this reason.

The data inputs to PCOSS24 appear to be properly prepared and reasonable reflections of the GRA financial forecast scenario. For this reason, outside of methodological issues noted in this submission re: revenue requirement preparation or COS methods, the results of PCOSS24 can and should be applied to rate setting at this time.

It is noted that future PCOSS analyses may show different results owing to changes to water flows. Arguably, the PCOSS scenario could be normalized for water flow variances. However, this would open a substantial debate about which other factors are appropriate to normalize in preparing the PCOSS. As a test of the potential impact of any such normalization, a comparison was made of the PCOSS24 results with a hypothetical PCOSS for 2024/25 where water flows are based on the 100+ year record and are not driven by any 2023 spring reservoir balances. The results showed no difference in the distribution of classes that merit rate relief or adjustment for being outside of the 95%-105% ZOR, as follows[105]:

[102] Tab 5, page 35.
[103] Coalition/MH-I-131e(Revised).
[104] PCOSS21, page 3, in PUB-MFR-20, Attachment 1 from the 2021 Interim Rate Application.
[105] PUB/MH-I-141a and Coalition/MH-I-155a.

Table 4-2: RCC ratios from PCOSS24 versus PCOSS24 using 2024/25 export revenues

	RCC ratio			
	PCOSS24		adjusted to 2024/25 Net Export Revenue	
		ZOR		ZOR
Residential	94.4%	below	94.8%	below
GS Small Non-Demand	109.7%	above	110.0%	above
GS Small Demand	101.8%	w/in	102.1%	w/in
GS Medium	100.3%	w/in	100.3%	w/in
GS Large 0-30 kV	97.9%	w/in	97.4%	w/in
GS Large 30-100 kV	112.4%	above	110.2%	above
GS Large 100+ kV	113.2%	above	110.5%	above
Area and Roadway Lighting	108.2%	above	112.0%	above

As noted in the above Table 4-2, the use of export revenues (and net income) normalized for water flows made no difference to which classes were above, below or within the ZOR. The RCC ratios moved to a degree, but it would be expected that Hydro's relative rate proposals would still be of relevance and be appropriate to retain under either scenario.

> **Recommendation 12: The Board should rely on the net export revenue and net income assumptions in PCOSS24 for the purposes of establishing differentiated rates in this proceeding.**

4.4 CLASSIFICATION OF WIND GENERATION

Consistent with the directives from Order 164/16, wind generation costs continue to be classified 100% to energy. The Board set out its reasoning on this classification issues as follows[106]:

> Wind generation is subject to prevailing wind conditions and thus Manitoba Hydro cannot count on wind generation at any specific point in time. For example, Manitoba Hydro cannot call on wind generation to meet its winter peak demand. Since wind generation does not contribute to the winter peak capacity, it should be classified 100% as Energy. (emphasis added)

The issue of wind classification was also addressed in Order 59/18 where the Board noted that "as a resource, wind is transacted on an energy basis through contracts with suppliers. Manitoba Hydro does not invest in wind assets in order to serve peak demand. This supports the continued classification of wind as 100% energy."[107]

[106] Order 164/16 page 49.
[107] Order 59/18, page 187.

On this matter, it is clear that the facts regarding wind capacity are becoming less consistent with the Board's underlying findings.

First, Manitoba Hydro has specifically stated that wind generation is of capacity value[108]:

> Manitoba Hydro continues to assume the existing wind generation has a firm capacity value of 20% for long term resource adequacy analysis. The ownership of the wind generation facility does not change the firm capacity value assumptions.

Second, the Supply and Demand table used for resource planning attribute a material capacity value to wind, as follows[109]:

Table 4-3: Hydro Resource Plan for Capacity (MW)

Fiscal Year		2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Supply							
New Power Resources							
1 **Total New Hydro**		0	0	0	0	0	0
2 **Total New Thermal**		0	0	0	0	0	0
3 **Total New Wind**		0	0	0	0	0	0
4 **Total New Non-Utility Generation**		0	0	0	0	0	0
5 **Total New Power Resources**	1+2+3+4	**0**	**0**	**0**	**0**	**0**	**0**
Base Supply Power Resources							
Existing and Committed Hydro		5768	5768	5768	5791	5842	5852
Existing Thermal		278	278	278	278	278	278
Existing Non-Utility Generation		52	52	52	52	31	31
Supply Side Enhancements		0	0	0	0	0	25
Scheduled Outages		-135	-135	-135	-150	-150	-150
Contracted Imports		600	600	600	250	250	200
6 **Total Base Supply Power Resources**		**6563**	**6563**	**6563**	**6221**	**6251**	**6236**
7 **Total Power Resources @ Point of Supply**	5+6	**6563**	**6563**	**6563**	**6221**	**6251**	**6236**

In the above resource planning tables, Hydro notes 52 MW of Existing Non-Utility Generation, declining to 31 MW in 2026/27. Manitoba Hydro clarifies that this generation is primarily comprised of wind utility purchases[110].

Third, Manitoba Hydro shows an increasing reliance on purchases of wind generation starting in 2033/34, which is similarly given a capacity value in system planning.

In short, the facts today are clearly no longer consistent with the Board's findings that wind is an energy-only resource that does not contribute to winter peak capacity.

This finding is also consistent with the treatment of wind generation in other recent utility cost of service decisions. The most notable example is Newfoundland and Labrador Hydro, which proposed and had accepted in a settlement agreement the following COS method[111]:

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108 MIPUG/MH-I-115c.
109 Manitoba Hydro Appendix 5.6, page 1.
110 PUB/MH I-43a-e (Updated). At 20%, this is consistent with 260 MW of wind, which is approximately the generation installed at St. Leon and St. Joseph.
111 Newfoundland and Labrador Board of Commissioners for Public Utilities, Decision P.U.37 (2019), page 2, and Schedule A page 3.

> The Parties agree that Power Purchase costs for wind on the Island Interconnected System shall be 22% demand and 78% energy.

For Newfoundland, this was similarly a change from a previous 100% energy classification.

For Nova Scotia Power, the recent 2022-2024 Rate Application also noted the utility continues to support COS methods regarding wind capacity, as follows[112]:

> In the Cost of Service supporting this rate application, wind generation costs are classified 82 percent to energy and 18 percent to demand.

Given the above considerations, wind generation should be classified 20% to demand, with the remaining 80% to energy.

> **Recommendation 13: PCOSS analyses should ensure 20% of the cost of wind generation cost is classified to demand, while the remaining 80% is classified to energy.**

4.5 DEMAND SIDE MANAGEMENT FUNCTIONALIZATION

Demand Side Management (DSM) costs comprise a significant part of the costs allocated via the PCOSS. Through the amortization of net movement balances, the costs of amortizing DSM programming totals $57.2 million in the 2023/24 preliminary budget[113].

DSM costs are presently functionalized 100% to generation, based on findings in Order 164/16[114]:

> The Board finds that DSM costs should be functionalized as 100% Generation. … The Board finds that DSM is a Generation resource: it avoids Generation costs, <u>rather than the costs of Transmission and Distribution</u>. (emphasis added)

These findings by the Board pre-date the establishment of Efficiency Manitoba ("EM"), and DSM programming being delivered closely tied to the marginal value of the energy (and capacity) being saved. The programming for EM has now been through its first public review, in 2019-2020. In that proceeding, the Board found[115]:

> With respect to the electric DSM portfolio, the marginal value is based on the value to Manitoba Hydro of the electricity conserved by the DSM programs. Manitoba Hydro receives value from conserved electricity by having more electricity available to export, potentially under long-term firm contracts, as well as due to the deferral of <u>future transmission and distribution investments</u> as a result of reduced load growth and consequent reduced capacity requirements. (emphasis added)

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[112] Nova Scotia Power 2022-2024 Rate Application, January 27, 2022, page 88 of 128.
[113] MIPUG/MH-I-115b.
[114] Order 164/16, page 85.
[115] PUB Report on Efficiency Manitoba's 2020/21 to 2022/23 Efficiency Plan Submission, page 65.

This finding is a marked change from the earlier rationale applied by the Board, that DSM was solely of value as a generation function.

The Board's finding in the EM proceeding follows the clear evidence of EM that the value of DSM is spread across all 3 functions, generation, transmission, and distribution. This is highlighted in the EM response to Daymark/EM I-20a from that proceeding, which notes[116]:

> Manitoba Hydro provides Efficiency Manitoba with a forecast of 30 years of generation, transmission, and distribution marginal values. The generation marginal values for each year are broken out between marginal energy values and marginal capacity values that are then each differentiated between summer and winter seasons. Transmission marginal values are forecast on the basis of winter capacity for each of the 30 years. Distribution marginal values are also forecast on the basis of winter capacity for each of the 30 years.

It is important to recognize as well that this blended marginal value is used by EM throughout the programming assessment. The marginal values then cited by EM were 7.33 cents/kWh[117] comprising a combined generation, transmission, and distribution benefit. However, this is not necessarily comparable to the marginal values typically cited by Hydro, as Hydro's marginal values are for a hypothetical defined load shape, while the EM values are for the specific load characteristics of the programs proposed, which would be expected to skew towards higher value periods. It is helpful to note that the last publicly available Marginal Values from Manitoba Hydro as of the EM hearing were from the 2017/18 & 2018/19 GRA:[118]

30 Year Levelized Marginal Values
[cents/kWh]

Components	Used in 2016 DSM Plan		2017/18 Marginal Value in 2017 $	Change From 2015/16 to 2017/18
	2015/16 Marginal Value in 2016 $	2015/16 Marginal Value in 2017 $		
Generation	6.34	6.34	4.39	- 32%
Transmission	0.56	0.57	0.57	0.0%
Distribution	0.87	0.89	0.78	-12%
Total	7.77	7.94	5.75	-28%

The use of these values indicated a potential distribution of DSM benefits of approximately 10% to transmission, 15% to distribution, and 75% to generation. The marginal values have now been updated for this proceeding, as follows[119]:

[116] Daymark/EM I-20a.
[117] Efficiency Manitoba Three-Year Plan, pdf page 134 of 591.
[118] PUB/MH II-57 (Revised) dated 2017-12-18 from the 2017/18 & 2018/19 GRA.
[119] PUB/MH-I-43d (Updated).

30 Year Levelized Marginal Values (Cents/kWh, CAD)		
Dollar Year	2021$	2022$
Generation	4.85	4.94
Transmission	0.29	0.30
Distribution	0.54	0.55
Total	5.69	5.80

However, it must be noted that the 30 year levelized values are reported by Hydro based on a 100% load factor, which is not the load profile of the typical DSM program operated by EM (and funded by Hydro). A further illustration of this effect is shown in the following table from Hydro[120]:

	Marginal Cost (cents/kWh @ 100% LF)			Class CP LF from	Marginal Cost Trans & Dist @ Class LF (cents/kWh)			
Class	Gen	Trans	Dist	PCOSS24	Gen	Trans	Dist	Total
Residential	4.94	0.30	0.55	50.9%	4.94	0.59	1.08	6.61
GSS ND	4.94	0.30	0.55	59.7%	4.94	0.50	0.92	6.36
GSS D	4.94	0.30	0.55	62.6%	4.94	0.48	0.88	6.30
GSM	4.94	0.30	0.55	73.0%	4.94	0.41	0.75	6.10
GSL 0-30	4.94	0.30	0.55	80.3%	4.94	0.37	0.69	6.00
GSL 30-100	4.94	0.30		91.8%	4.94	0.33		5.27
GSL >100	4.94	0.30		94.4%	4.94	0.32		5.26

As noted in the above table, the marginal values relevant to the classes that use the distribution system comprise 10-15% of the total marginal values used to establish DSM cost effectiveness, and a further 5-10% for transmission.

Note that this conclusion does not differ markedly from the conclusions at the time of the EM hearing, that in respect of the 2017/18 values, only 76% of the marginal value came from avoided generation (which would include generation-linked transmission such as HVDC). The grid transmission marginal value made up a further 10% while distribution was responsible for the remaining 15%.

This means that Efficiency Manitoba's programs, contrary to the earlier PUB finding, are not only avoiding generation cost, they are also designed and justified specifically on the basis that they will avoid material transmission and distribution costs.

Hydro similarly recognizes the relevance of DSM spending to benefits on each functionalized system – generation, transmission and distribution, when discussing the proposed changes to LED

[120] Coalition/MH-II-57d.

lighting. Hydro indicates that assigning DSM costs to all customers is generally sound as the benefits of DSM relate to systems used by all customers. Hydro applies this rationale when supporting a proposal to specifically allocate a small share of DSM costs to the lighting class as these specific costs do not benefit other customers, as follows[121]:

> The costs of group and spot lamp replacements are part of the Operating costs that are directly assigned to the A&RL class in the PCOSS, so a reduction in these costs does not benefit any other class. This is unique compared to avoided Generation, Transmission and other Distribution costs which are the typical benefit of DSM programs, and which will also benefit the non-participating classes through a reduction in allocated costs. (emphasis added)

The above excerpt makes clear that Hydro views the typical benefit of DSM to be to all 3 systems – generation, transmission, and distribution.

The conclusion is further supported by the parallel logic being applied to Area and Roadway Lighting ("ARL"). In that case, Hydro has proposed to directly allocate a portion of the DSM spending on LED lights to the ARL class, as this spending was justified by O&M savings on the lights themselves, and not on the broad generation-related benefits to the remainder of customers. Hydro proposes that 38% of the LED spending be directly allocated to ARL. The same situation applies for distribution system savings and transmission system savings as justifications for DSM spending.

For these reasons, it is appropriate that DSM costs be functionalized to generation and transmission and distribution in proportion to the marginal values used to justify the programming.

> **Recommendation 14: DSM costs should be functionalized to generation and transmission and distribution in proportion to the marginal values used to justify the programming, or approximately 75%, 10%, 15% respectively.**

4.6 USE OF TOP 50 WINTER HOURS

PCOSS24 continues a longstanding approach to establishing the allocator for peak demand costs, based on the top 50 hours each winter, calculated as an average over 8 years. The rationale for this approach was set out in Order 164/16[122]:

> The Board finds that the Demand component of Generation costs should be allocated by the top 50 Winter Coincident Peak hours. Allocating Demand costs by Winter Coincident Peak reflects the shape of the domestic customer class loads during the high demand winter months in Manitoba.

While the Board was clear that the intent is to capture the relative contribution to the winter peak, Order 164/16 provided no rationale for using the Top 50 hours, versus the top hour or some smaller subset of top hours.

Since the time of Order 164/16, this issue has been more fully canvassed in respect of Centra's Cost of Service review in 2022. The Board's decision in that review noted that Coincident Peak

[121] Appendix 8.1, PCOSS24, page 12, footnote 2.
[122] Order 164/16, page 8.

allocation based on the highest design peak was supported by the utility as being the most cost causal approach for cost allocation. Summarizing Centra's evidence, the Board noted[123]:

> Centra supports Atrium's recommendation to eliminate the existing peak and average methodology for the Demand portion of Centra's Transmission and Distribution functions and replace it with a coincident peak methodology based on a design day peak allocator. According to Centra, the peak day methodology directly reflects cost causation, while the peak and average methodology includes non-cost-causal factors. Consideration of the average load of a customer class, which is recognized in the peak and average method, mutes responsibility related to the true cost driver of Centra's transmission and distribution plant, which is the coincident peak demand. The design day allocator corresponds to the highest coincident system peak conditions that the system is designed to meet.

The Board accepted this proposal from Centra[124].

The situation with Manitoba Hydro is nearly identical to Centra, in that winter peak is the highest load on the system, and the single peak hour must be capable of being served. Hydro must make investment in the system not just to meet the average of all of the peak-like hours over the course of a winter, but the worst single hour (plus contingencies and load forecast uncertainties).

The data for the top 50 hours are provided in the Excel attachment for MIPUG/MH-I-115c, which notes that in 2022 for example, the highest domestic load hour was 4519 MW. The 50th hour was 4294 MW, a full 225 MW lower than the peak hour. Further, the Top 50 hours in 2022 covers more than 16 different calendar days[125], in some cases months apart.

The impact of averaging many peak hours, such as the 50 used by Hydro, is that lower load factor classes are protected from being allocated the full costs of the peaks that they drive on the system. This is illustrated by the Excel files provided in response to MIPUG/MH-II-12b. Looking at the specific classes, the residential class 50th peak hour is only 90.79% as high as the residential peak hour. For GSL >100 kV, the 50th peak hour is approximately 97%[126]. Of course, the PCOSS uses the 50th highest peak hour for the system, which may not be the residential 50th highest peak hour, so the residential contribution to the 50th hour may be even less than 90.79% of the peak they impose on the system.

Following the precedent of the Centra COS review, there would appear to be no good rationale for retaining the top 50 hour averaging approach in Hydro's COS. In addition, Hydro's GRA makes clear that capacity-related costs are an important and growing component of the price signals that need to be considered in setting a fair COS methodology.

[123] Order 164/16, page 42.
[124] Order 164/16, page 46.
[125] Jan 5, 6, 7, 9, 10, 19, 20, 25, Feb 2, 3, 4, 17, 22, 23, 24, Dec 7.
[126] 97.6% for GSL >100 kV curtailable, and 96.7% for non-curtailable.

In order to capture some of the potential load diversity that can occur at peak, it is likely appropriate to retain Hydro's 8 year averaging of the peak load contribution. It is not apparent that more than the peak hour in each year need be included, however, an annual averaging over a small number of hours, such as 4-6 hours per year, may help address a limited set of anomalies (such as whether streetlights happen to be on or off at peak in a given year). Beyond this, the approach is simply permitting classes with low load factors to avoid being allocated the costs their loads impose on the system.

Recommendation 15: The PCOSS Coincident Peak allocator should be calculated on the eight-year average of the highest single hour, or at most a very limited number of hours each year (e.g, 4-6 hours per year). The current approach based on 50 hours each year includes far too much averaging of relatively high load hours, and fails to recognize the true driver of peak capacity costs, which is the highest load that must be served.

4.7 DIFFERENTIATED RATE INCREASES

In respect of overall class rate adjustments, Hydro has proposed differentiated rate adjustments by class intended to reflect the relative RCC ratios, as follows[127]:

Table 4-4: Differentiated Rate Increases versus RCC ratios

	PCOSS24 RCC ratio	Rate Increase Proposal per year
Residential	94.4%	2.4%
GS Small Non-Demand	109.7%	1.0%
GS Small Demand	101.8%	2.1%
GS Medium	100.3%	2.1%
GS Large 0-30 kV	97.9%	2.1%
GS Large 30-100 kV	112.4%	1.5%
GS Large 100+ kV	113.2%	1.5%
Area and Roadway Lighting	108.2%	1.0%

Directionally, the Hydro proposals are justified by the results of PCOSS24.

On the matter of the specific rate adjustments, Hydro's proposals do not sufficiently address persistent issues with certain customer classes being outside the ZOR, or indeed above or below

[127] PCOSS RCC ratios from Appendix 8.1. Rate increase proposals form Tab 8, Figure 8.1.

100%. It should be noted that a ZOR is a concept to address imperfections and estimation within the cost of service study. It is not a blanket justification for maintaining any specific customer class consistently at 105% or 95% in perpetuity.

Hydro's approach to COS has focused on classes that are above or below the ZOR, to attempt to bring these classes to the edge of the ZOR as a first priority. However, consistent with other rate design principles such as gradualism and avoiding rate shock, Hydro has tended to propose modest adjustments to rates rather than more significant adjustments to solve the ZOR issues more quickly. This approach has been largely unsuccessful over many decades, as shown in the below figure summarizing Hydro's approved PCOSS studies since 1991. Note that the figure omits PCOSS21 due to the methodological issues noted earlier in this section (i.e., the study is internally inconsistent by including Keeyask costs but largely excluding Keeyask-related revenues).

Figure 4-1: Manitoba Hydro PCOSS RCC results since 1991

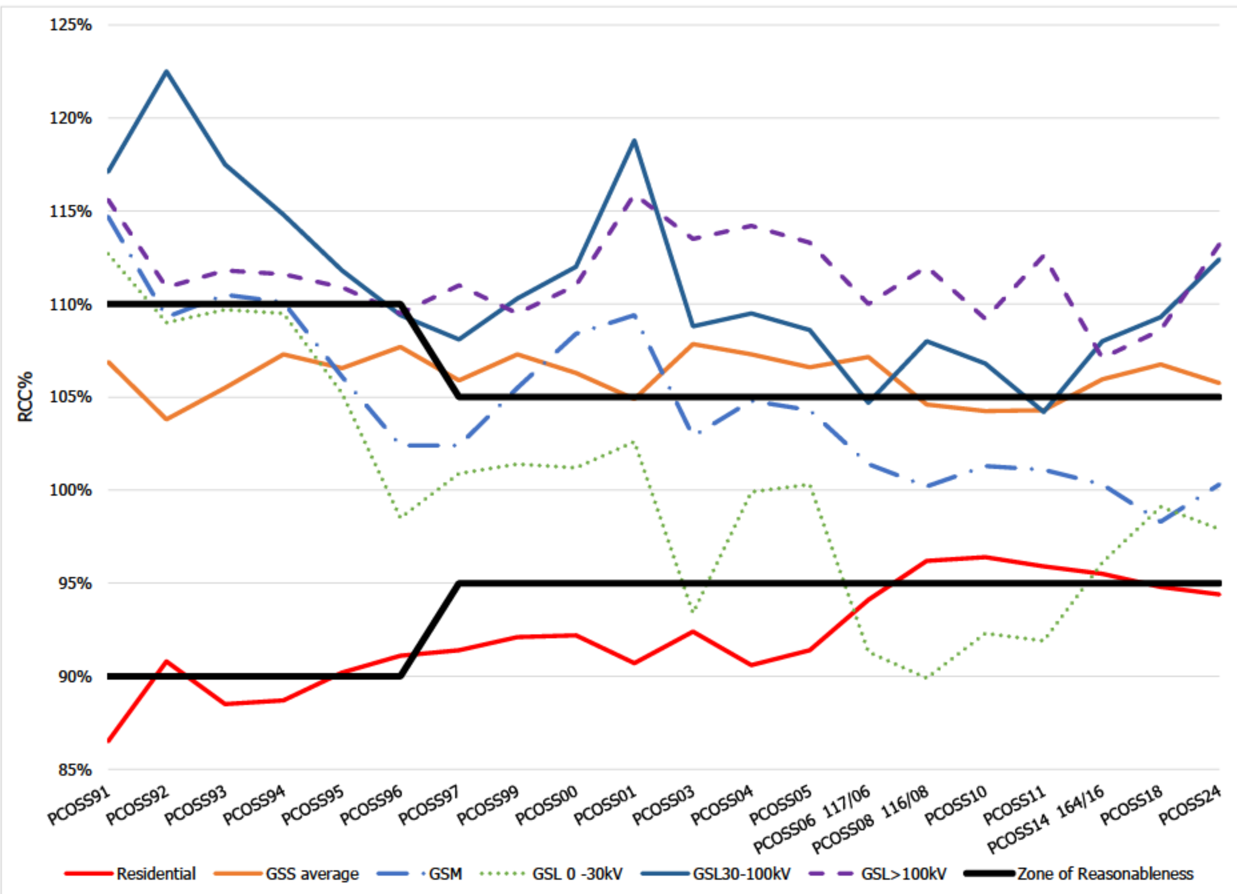

Figure 4-1 highlights that for many decades, Hydro's attempts to apply limited to no rebalancing to customer rates has resulted in some classes, notably the industrial classes (GSL 30-100 kV and GSL >100 kV) paying rates that are materially above measured costs, and other classes (notably residential) paying rates that are consistently below measured costs.

The basic premise for utility ratemaking is to recover rates that reflect costs – overall rates to reflect the costs of the utility, and between the classes, rates that reflect the costs to serve that class. Some jurisdictions, such as Newfoundland and Labrador Hydro, strictly target 100.00% for setting industrial rates, which can, at times, undermine other rate redesign objectives such as rate stability. Outside of such consideration, there is no reasonable basis to ignore a valid, regulatory-approved COS result in setting rates by class. Hydro's proposals in this GRA do not ignore COS, but are insufficiently distinguished to reflect the ZORs.

The Board has recognized this issue at multiple points in past proceedings, directing Hydro to attempt to move customer classes to within the ZOR. Typically, the Board has recognized the concept of a target timeframe, however as noted in the above figure these time frames have come and gone without notable progress on moving certain classes to within the ZOR. Most recently, in Order 59/18, the Board indicated[128]:

> For the 2018/19 Test Year rates, Manitoba Hydro is to assume a 10-year timeframe to move all classes within the zone of reasonableness, using the alternative methodology to calculate the Revenue to Cost Coverage ratios by treating export revenues as a reduction to allocated costs. This approach to the implementation of differentiated rates is consistent with the principle of gradualism and limits the revenue recovery responsibility of the other customer classes, while maintaining overall revenue neutrality.

This 10-year timeframe would require achievement of the ZOR by 2027/28.

An additional matter of importance to this issue is the new requirements under the *Manitoba Hydro Act* s.39.1(1), which it is understood will become in force for all periods starting April 1, 2025[129]. These provisions note[130]:

> 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 properly allocated to that class;

This section is not yet operative and no interpretations have been provided as to the meaning of the section with regard to rates being "based on" class costs. Analytically, this would appear to be consistent with the concept that rates should at minimum not exceed the ZOR boundaries. It appears clear that the history of rates for the industrial classes (GSL 30-100 kV and GSL >100 kV) as indicated in the above figure would not be consistent with section 39.1(1)(a).

Considering the above two conceptual time frames – the Board's target to achieve the ZOR by 2027/28, and the new Manitoba Hydro Act provisions which may require this achievement by

[128] Order 59/18 page 25-26.
[129] S.M. 2022, C.42, s.65.
[130] *Manitoba Hydro Act*, s.39.1(1).

2025/26, the current proposals are wholly insufficient for this purpose. The analysis for this conclusion is provided in Manitoba Hydro's response to IRs, as follows[131]:

Table 4-5: Rate Adjustments Needed to Achieve ZOR within 5 years and 10 years

	PCOSS24 RCC ratio	Current Rate Increase Proposal per year	Rate Adjustment needed to get to 95%-105% by 2027/28	*difference*	Rate Adjustment needed to get to 95%-105% by 2032/33	*difference*
Residential	94.4%	2.4%	2.4%	*0.0%*		
GS Small Non-Demand	109.7%	1.0%	1.1%	*(0.1%)*		
GS Small Demand	101.8%	2.1%	2.4%	*(0.3%)*		
GS Medium	100.3%	2.1%	2.4%	*(0.3%)*		
GS Large 0-30 kV	97.9%	2.1%	2.4%	*(0.3%)*		
GS Large 30-100 kV	112.4%	1.5%	0.6%	*0.9%*	1.3%	*0.2%*
GS Large 100+ kV	113.2%	1.5%	0.5%	*1.0%*	1.2%	*0.3%*
Area and Roadway Lighting	108.2%	1.0%	1.4%	*(0.4%)*		

As noted in the above table, Hydro's current rate proposals will largely achieve the ZOR within 5 years (2027/28) for all classes, with the exception of the industrial classes of GSL 30-100 kV and GSL >100 kV. Specifically, the GSS Non-Demand can be brought to within the ZOR with five years of 1.1% rate increases (based on the overall average increases being 2.0%), but Hydro has proposed 1.0%. Similarly, the Area and Roadway Lighting class can be brought down to the ZOR with 1.4% increases, while Hydro has proposed 1.0%. In both these cases, the PUB's 10-year target from Order 59/18 is projected to be achieved.

However, for the two largest industrial classes, the rate increases would need to be 0.5% and 0.6% respectively per year for five years, but Hydro has proposed 1.5% per year for each. The right-hand side of the table further notes that the current 1.5% proposal is even too high to achieve the ZOR by 2032/33, or more than fifteen years after the Board's direction in Order 59/18.

Clearly to achieve the ZOR by 2025/26 consistent with the new provisions of the *Manitoba Hydro Act* will take even further differentiated rate proposal than shown under the 2027/28 scenario. Also note that in all cases, the increases needed to the customers who would receive above average increases, in order to permit the industrial classes to get within the ZOR, remain well below the 3.6% per year increases that Hydro first proposed in the current application, so presumably remain well within the range of reasonable adjustments that can be imposed on customers.

It is also important to address clear misstatements by Hydro in respect of the rate proposal, as set out in Tab 8, as follows[132]:

> The General Service Large 750V-30 kV and >100 kV RCCs have trended above unity and towards the higher end of the ZOR in studies prepared since Order 164/16, however, given both classes had RCCs in the ZOR in PCOSS21, it is clear

[131] Data from Coalition/MH-I-143a-b.
[132] Manitoba Hydro Application, Tab 8, page 13.

> that PCOSS24 results are being driven by record levels of export revenue. Accordingly, Manitoba Hydro is proposing a smaller rate differential, relative to GSSND and A&RL, of 0.5% below the average increase be applied to these classes.

Since the preparation of Tab 8, Hydro has provided the results of PCOSS analysis for 2023/24 using a normalized water and export market regime consistent with the 2024/25 financial forecast. That analysis clarified that the impact of high water in PCOSS24 was not the reason for the high industrial class RCCs. Indeed, the RCCs for the two largest industrial classes (GSL 30-100 kV and GSL >100 kV) remain at 110.2% and 110.3% respectively under the normalized water scenario. Elimination of the 5+ percentage points over 5 years would still require a differentiation compared to the average 2% rate increase of over 1% (i.e., rate increases for industrials below 1%), far below the level proposed by Hydro in this proceeding.

Further, these revisions to RCCs are before the outstanding concerns regarding DSM functionalization to distribution and transmission, and wind classification to demand, each of which would yield a small increase to the RCCs of the industrial classes.

> **Recommendation 16: Differential rate increases should be implemented based on an amended PCOSS24 reflecting the Board's direction from this proceeding. Rate proposals should be based on achievement of the outer range of the ZOR by 2027/28, if not sooner.**

4.8 DESIGN OF GSL 30-100 KV AND GSL >100 KV RATES

The Application reflects a consistent picture of the future cost drivers on the Manitoba Hydro system – capacity will be a more significant factor in the future, and energy a less significant factor. This is true on three separate factors:

- **Need:** Resource requirements indicate capacity required by 2030/31 while energy is not required until 2033/34.
- **Availability:** The prime resource for supplying otherwise undefined future energy requirements is wind. This resource is readily available in the market, exhibits decreasing price profiles over time, and has few regulatory or technical constraints. Dispatchable natural gas is assumed as the proxy for new capacity resources, although this technology faces numerous potential regulatory hurdles due to emissions[133].
- **Market:** Hydro indicates a significant source of firm capacity in the form of diversity agreements with neighbouring US utilities are uncertain for future renewals. This removes a significant source of winter capacity[134]. At the same time, addition of the Manitoba-Minnesota Transmission Project has allowed Hydro to increase its planned reliance on energy imports to meet dependable supply conditions, which increases energy availability[135].

[133] Hydro Application Tab 5, including Section 5.9.
[134] A reduction of 600 MW, per Hydro Application, Tab 5, Figure 5.10.
[135] MIPUG/MH-II-14b.

Manitoba's domestic loads have also evolved to increase firm capacity requirements and decrease firm energy sales[136].

A further indication of the importance of this shift is illustrated by the System Supply Enhancements being considered for northern hydro generation, at Kettle and Long Spruce. These projects are being assessed for alternatives that would increase capacity output, while potentially sacrificing unit efficiency which can drive energy losses[137]. This approach is sound, as capacity becomes more important and valuable in relation to energy.

At the same time, Manitoba Hydro's pricing for capacity domestically has not achieved price signals consistent with even current embedded costs, as per the following examples:

- For industrial customers (e.g., GSL >100 kV) the current fully loaded cost of energy is 2.89 cents/kW.h while the cost for capacity is $9.20/kVA-month[138]. Existing rates for this customer class are 3.766 cents/kW.h for energy (30% above costs) and $7.36/kVA-month (20% below costs). Further, industrial demand charges are applied to usage at any time, whether on-peak or off-peak.
- For residential customers, there is no demand price signal. Unit costs for demand are unavailable[139], presumably due to an inability to estimate the theoretical billing units were demand charges to be applied. However, the costs of supplying residential demand is actually much larger than energy – at $544.5 million for demand versus only $242.2 million for energy[140]. Further, Hydro is still investigating whether to proceed with the necessary metering to improve price signals for residential customers[141].

Manitoba Hydro acknowledges this issue with price signals, albeit with limited urgency[142]:

> It is likely that over the next 20 years, Manitoba Hydro's existing simple tariff structure that does not consider when energy is either consumed or produced will need to incorporate more granular price signals.

A very limited move is proposed by Hydro to improve the price signals for demand for industrial customers. This comprises two components:

1) Improve peak/off-peak recognition: Hydro proposes to change the definition of demand in the industrial rate schedules to use only on-peak demand in the calculation of the demand portion of the bill starting in 2024/25. This is a small but important improvement in the price signal to these customers. Hydro proposes to implement this change on a revenue neutral basis[143] and to permit the off-peak demand to increase without adding to demand charges so long as it does not exceed the on-peak demand by 10%.

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[136] Hydro Application, Tab 5, Figure 5.19.
[137] MIPUG/MH-II-26d.
[138] Hydro Application, Appendix 8.1, PCOSS24, Table A2.
[139] Hydro Application, Appendix 8.1, PCOSS24, Table A2.
[140] Hydro Application, Appendix 8.1, PCOSS24, Table A2.
[141] MIPUG/MH-II-25a.
[142] PUB/MH-I-5a-c.
[143] Hydro Application, Tab 8, Page 32.

2) Hydro is proposing to implement the rate increase to industrial customers entirely as an adjustment to the demand portion of the rates, while keeping the energy portion unchanged. The demand portion of the industrial bills is much smaller than the energy portion. This means that the demand portion must increase multiples of the average increase imposed on the class (demand rates are proposed to increase 5.8% in order to achieve the average 1.5% increase in revenue for the GSL >100 kV class).[144]

In regard to the first matter noted above (changed billing demand definition), this is a positive and important improvement in the rate schedule, albeit a very modest price signal change. However, Hydro also indicates[145]:

> The change in billing demand definition will result in customers' billing demand being the same or less than under the current definition. An analysis of the hourly loads for customers served at voltages > 30 kV show that the proposed change in billing demand definition will reduce the demand billing determinant to approximately 99% of billing demand under the current definition. Manitoba Hydro is proposing a slight increase to the demand charge to ensure the full revenue requirement continues to be recovered and maintain revenue neutrality for the classes.

Given the existing and longstanding issues with over-recovery of costs from this class (see RCC discussion above), there would appear to be no need up adjust upward the demand charge in order to implement this change.

Further, the 10% off-peak cap above the on-peak load appears to be an unnecessary limitation on the ability of Hydro to benefit from industrial customers implementing beneficial load shifting. The likelihood is that most customers cannot practically implement large on-peak/off-peak swings given the limits on their contract demands, the size of their service connections, their need to produce a given amount of product to meet market needs, their existing contractual and workforce commitments, and the fact that a change would need to be implemented for an entire month in order to benefit from the swing (demand chares are based on the highest single relevant peaks in the month). For this reason, at the very same time that Hydro is making relatively small moves to improve price signals, it is simultaneously permitting only the smallest uptake notwithstanding the material potential system benefits from customer response.

In the event of some hypothetical abuse of the rate schedule by customers in future (if that were even possible) mitigation measures can be considered at that time. It is premature to pre-emptively impose higher costs as a penalty for customers who take up peak load shifting in a material way.

In regard to the second matter noted above – the application of the entire rate increase to the demand charge, this is a proposal that will improve price signals, but at the expense of adverse customer impacts in some cases. While it is in principle consistent with the cost profile of the

[144] From $7.36/kW-month to $7.79/kW-month in 2023/24, an increase of 5.8%. Per Tab 8, page 36.
[145] Hydro Application, Tab 8, Page 32.

system, acceptance by the PUB will need to also address customer impacts, which is beyond the scope of this submission.

> **Recommendation 17: The change to industrial rates to recognize on-peak demand rather than demand at any time is an improvement to the price signals and should be approved. There is no need to further adjust the demand charge for the approximately 1% in lost revenue when the industrial classes are already paying well above costs. Further, the 10% cap on off-peak usage is not justified at this time.**

APPENDIX A:
Resume

PATRICK BOWMAN

Principal Consultant
Bowman Economic Consulting Inc.

161 Rue Hebert
Winnipeg, Manitoba
R2H 0A5 CANADA

AREAS OF EXPERIENCE:

- Utility Regulation and Rates, including Depreciation
- Project Development and Planning
- Utility Resource Planning

EDUCATION:

- MNRM (Master of Natural Resources Management), University of Manitoba, 1998
- Bachelor of Arts (Human Development and Outdoor Education), Prescott College (Arizona), 1994

PROFESSIONAL EXPERIENCE:

Bowman Economic Consulting Inc., Winnipeg, Manitoba

2020 – current – Principal Consultant

Conduct consulting assignments as Principal Consultant of new economic consulting firm, focused on utility regulation.

Member, Society of Depreciation Professionals

InterGroup Consultants Ltd., Winnipeg, Manitoba
1998 – 2022 – Research Analyst/Consultant/Principal/Senior Associate

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in eight Canadian provinces and territories and international. Prepared evidence and expert testimony for regulatory hearings. Assisted in utility capital and operations planning to assess impact on rates and long-term rate stability.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

Government of Northwest Territories, Yellowknife, Northwest Territories
1996 – 1998 Land Use Policy Analyst

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	Northwest Territories Power Corporation (NTPC)	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000 - 2002	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001 - 2002	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002 - 2003	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony on all areas of Revenue Requirement, including Depreciation	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2006 - 2008	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008 - 2009	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation, Support to Legal Counsel	BCUC	BC Municipal Electrical Utilities	2009 - 2010	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009 - 2010	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010 - 2011	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
Newfoundland Hydro	Depreciation Methodology	Analysis, Support of Expert Witness, Advisor to Legal Counsel	NLPUB	Newfoundland Industrial Customers	2012	No
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2013	Yes
Manitoba Hydro	Needs For and Alternatives To Investigation	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analysis, Preparation of Intervenor Evidence & Expert Testimony on all areas of Revenue Reqt, COS and Rate Design, incl Depreciation	MPUB	MIPUG	2015	Yes

Patrick Bowman - Experience in Utility Regulatory Proceedings

Utility	Proceeding	Work Performed	Before	Client	Year	Oral Testimony
Newfoundland Hydro	Amended 2013 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	No - merged into 2015 General Rate Application
Newfoundland Hydro	2015 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2016 Cost of Service review	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2016	Yes
Chestermere Utilities Inc.	2017 Rate Increase Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2016	Presentation to Council
Newfoundland Hydro	2017 General Rate Application	Pre-Filed Testimony and Negotiated Settlement, including Depreciation	NLPUB	Newfoundland Industrial Customers	2017 - 2018	No - Negotiated Settlement
Altalink Management Limited	2017-18 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on Depreciation matters	Alberta Utilities Commission (AUC)	Alberta Utilities Consumer Advocate (UCA)	2016 - 2017	No - Negotiated Settlement
ATCO Pipelines	2017-18 General Rate Application	Analysis, Preparation of Intervenor Evidence on Depreciation matters	AUC	UCA	2016 - 2017	No - Written Process only
Manitoba Hydro	2017/18 and 2018/19 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2017 - 2018	Yes
ATCO Pipelines	2017-18 GRA Review and Vary	Analysis and Case Preparation for SCADA Depreciation	AUC	UCA	2017 - 2018	No
ATCO Pipelines	2019-20 General Rate Application	Analysis, Preparation of Intervenor Evidence including Depreciation	AUC	UCA	2018	No - Written Process only
Altalink Management Limited	2019-21 General Tariff Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process on depreciation matters, Preparation of Intervenor Evidence and Expert Testimony	AUC	UCA	2018	Yes
Newfoundland Hydro	Cost of Service Methodology	Analysis and Case Preparation	NLPUB	Newfoundland Industrial Customers	2018	No
ATCO Pipelines	Keephills Transmission Facilities Assessment	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2018 - 2019	No - Written Process only
Manitoba Hydro	2019/20 Electric Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2019	Yes
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2019 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2019	Presentation to Council
ATCO Electric Distribution	Distribution Depreciation	Analysis and Case Preparation	AUC	UCA	2019	No
AltaGas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
ATCO Gas	Distribution Depreciation	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2019	No - Written Process only
Nalcor Energy, Newfoundland and Labrador Hydro	Muskrat Falls Rate Mitigation Hearing	Analysis, Preparation of Intervenor Evidence and Expert Testimony. Included Depreciation Rate Mitigation Options	NLPUB	Newfoundland Industrial Customers	2019	Yes
Kinder Morgan Canada (Jet Fuel) Inc.	2019 Tariff Filing Application	Review pipeline tolling application on revenue requirement and depreciation, prepare interrogatories and draft issues for evidence	BCUC	Vancouver Airport Fuel Facilities Corporation (VAFFC)	2019 - 2021	No
BC Hydro	Fiscal 2020 to 2021 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence	BCUC	Association of Major Power Consumers of BC (AMPCBC)	2019-2020	Yes
FortisAlberta	Town of Fort Macleod RCN-D Valuation Application	Analysis, Preparation of Intervenor Evidence on Depreciation and Valuation matters	AUC	UCA	2019-2020	No - Written Process only
Manitoba Public Insurance	2021 General Rate Application	Review insurer evidence, draft IRs and prepare evidence on regulatory and rate setting principles	MPUB	Taxicab Coalition	2020	Yes
ATCO Gas	2020 Cost of Service and Phase II Application	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2020	No - Written Process only
Chestermere Water, Wastewater, Stormwater and Solid Waste Utility	2021 Rate Request	Analysis, Preparation of Rate Review	City of Chestermere City Council	City of Chestermere City Council	2020	Presentation to Council
ATCO Pipelines	Acquisition of Pioneer Pipeline	Review evidence, draft IRs. Evidence	AUC	UCA	2020	No - Written Process only
ATCO Electric Transmission	2020-2022 GTA Depreciation Expert	Analysis and support of intervenor evidence	AUC	UCA	2020-2021	No - Written Process only
Direct Energy Regulated Services (DERS)	2020-2022 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2021	No - Negotiated Settlement
AltaLink Management Ltd.	2022-23 General Tariff Application, and Review and Variance Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process, Preparation of Intervenor Evidence on Depreciation Matters.	AUC	UCA	2021-2022	No - Written Process only
Manitoba Hydro	2021 Interim Rate Application, Review and Variance Application	Analysis, Support of Intervenor position	MPUB	MIPUG	2021	No
NTPC	2022/23 General Rate Application, Interim Rate Application, and Taltson Hydro Major Project Permit Application	Analysis, support preparation of utility filing, responses to IRs on matters of revenue requirement, rate design and depreciation	NWT PUB	NTPC	2022	No
Nelson Hydro	Cost of Service and Rate Design Proceeding and 2022 Revenue Requirements proceeding	Support to Nelson Hydro on preparation of Cost of Service model and specified studies	BCUC	Nelson Hydro	2020-2022	No
Epcor Distribution and Transmission Inc (EDTI)	EDTI Phase II (Cost of Service and Rate Design) Distribution Tariff AUC proceeding 27018	Analysis, Preparation of Intervenor Evidence	AUC	UCA	2022	No - Written Process only
Newfoundland Hydro	Electrification, Conservation and Demand Management	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2021-2022	No - Written Process only
Centra Gas Manitoba	2021 Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence	MPUB	Industrial Gas Users of Manitoba (IGU)	2021-2022	No - Written Process only
BC Hydro	Fiscal 2022 to 2025 Revenue Requirements Application	Analysis, Preparation of Intervenor Evidence, primarily focused on depreciation	BCUC	AMPCBC	2022	Yes
DERS	2023 DRT and RRT Application	Analysis, Support of Consumer Advocate during Negotiated Settlement Process	AUC	UCA	2023	No - Negotiated Settlement and written process
EDTI	2023-2025 Transmission Facility Owner Revenue Requirement	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2023	No - Negotiated Settlement
ENMAX Power Corporation (EPC)	2023-2025 Transmission General Tariff Application	Analysis, Preparation of Intervenor Evidence on Depreciation	AUC	UCA	2024	No - Negotiated Settlement and written process
BC Hydro	2021 Intergrated Resource Plan	Analysis, Preparation of Intervenor Evidence	BCUC	AMPCBC	2023	Pending
Enbridge Gas Inc (EGI)	2024 Rebasing	Analysis, Preparation of Intervenor Evidence	Ontario Energy Board (OEB)	OEB Staff	2023	Pending

InterGroup
CONSULTANTS

300-259 Portage Avenue
Winnipeg, MB R3B 2A9
www.intergroup.ca